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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816 **NOTICE OF FILING OF SURREBUTTAL TESTIMONY, ATTACHMENTS, AND SUMMARY OF KEVIN C. HIGGINS ON BEHALF OF PHELPS DODGE MINING COMPANY AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

Phelps Dodge Mining Company and Arizonans for Electric Choice and Competition, through undersigned counsel, hereby provide notice of filing the Surrebuttal Testimony, Attachments, and Summary of their witness, Kevin C. Higgins, in the above

Arizona Corporation Commission
DOCKETED
SEP 27 2006

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captioned docket.

RESPECTFULLY SUBMITTED this 27th day of September 2006.

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	**Docket No. E-01345A-05-0816**

Summary of the

Surrebuttal Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

September 27, 2006

SUMMARY

SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

In my surrebuttal testimony I offer the following conclusions and recommendations:

(1) Witness Stephen J. Baron for The Kroger Co. ("Kroger") is correct in asserting that APS over-allocated transmission costs to General Service customers, because the Company unreasonably allocated transmission costs based on energy. In response to Mr. Baron's point, I have revised the cost-of-service, rate spread, and transmission rate design results presented in my direct testimony to more appropriately reflect the allocation of transmission costs on a 4-CP basis.

(2) I recommend against adoption of the Peak and Average production cost allocation method proposed by Staff, and support the continued application of the 4-CP approach proposed by APS. However, if the Commission orders that an energy-weighted method be used to allocate fixed production costs, then I recommend that the Average and Excess Demand method be used instead of the Peak and Average approach, because the former avoids the analytical shortcomings of the latter.

(3) With respect to General Service rate design:

(a) I continue to urge rejection of APS's proposed weighting of demand-related charges and energy charges, which is strongly biased to the disadvantage of higher-load-factor customers;

(b) I support adoption of Mr. Baron's proposal for Rate E-32 in which the "first 100 kW" and "all additional kW" of delivery charge would receive the same percentage increase; and

(c) I support adoption of the proposal by Federal Executive Agencies ("FEA") witness Dennis W. Goins to increase the Rate E-34 voltage discounts to more fully reflect cost-of-service differences between primary and secondary service.

(4) I support adoption of the proportionate increase in the Environmental Portfolio Surcharge rates and caps recommended by Staff witness Barbara Keene.

(5) After review of APS's rebuttal testimony, I continue to support the adjustments to revenue requirements offered in my direct testimony.

1 (6) Staff's proposal for a prospective PSA Adjustor creates some serious
2 concerns, and I recommend that the Commission be very cautious in considering
3 Staff's proposed change to the PSA mechanism.
4 1839228.1/23040.041

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	)	**Docket No. E-01345A-05-0816**

Surrebuttal Testimony of Kevin C. Higgins

on behalf of

Phelps Dodge Mining Company and

Arizonans for Electric Choice and Competition

September 27, 2006

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ATTACHMENTS

KCH-1SR.....Derivation of Transmission Charges for Major Rate Schedules

KCH-2SR..... APS COS Results Adjusted for Hourly Energy and 4-CP Transmission

KCH-3SR.....AECC Recommended Rate Spread

KCH-4SR.....COS Results Using Average and Excess Demand Method

REVISED ATTACHMENTS

KCH-5, page 2 (Revised).....Summary of Energy Cost Multipliers

KCH-7 (Revised).....Derivation of Transmission Demand Charges

1 SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

2

3 I. <u>Introduction</u>

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

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

6 84111.

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

8 A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies

9 is a private consulting firm specializing in economic and policy analysis

10 applicable to energy production, transportation, and consumption.

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

12 A. My testimony is being sponsored by Phelps Dodge Mining Company

13 ("Phelps Dodge") and Arizonans for Electric Choice and Competition ("AECC").

14 AECC is a business coalition that advocates on behalf of retail electric customers

15 in Arizona.

16 **Q. Are you the same Kevin C. Higgins who submitted direct testimony on behalf**

17 **of Phelps Dodge and AECC with respect to Revenue Requirements and Cost-**

18 **of-Service / Rate Spread / Rate Design?**

19 A. Yes, I am.

20 **Q. What is the purpose of your surrebuttal testimony?**

21 A. My surrebuttal testimony responds to issues raised by parties in direct

22 testimony filed on September 1, 2006 addressing non-revenue-requirements

23 issues, and to issues raised in APS's rebuttal testimony filed on September 15,

2006. With respect to the later, I do not respond here to each instance in which APS has disagreed with my direct testimony, in order to avoid restating my direct testimony. Consequently, absence of a surrebuttal response here should not be taken as acceptance of the Company's rebuttal argument; to the contrary, it should be taken as an indication that I continue to adhere to the positions expressed in my direct testimony.

In addition, I present corrections to three numbers that appear in attachments filed with my direct testimony. These corrections do not affect the conclusions or recommendations in my direct testimony.

Q. What conclusions and recommendations do you offer as part of your surrebuttal testimony?

A. I offer the following conclusions and recommendations:

(1) Witness Stephen J. Baron for The Kroger Co. ("Kroger") is correct in asserting that APS over-allocated transmission costs to General Service customers, because the Company unreasonably allocated transmission costs based on energy. In response to Mr. Baron's point, I have revised the cost-of-service, rate spread, and transmission rate design results presented in my direct testimony to more appropriately reflect the allocation of transmission costs on a 4-CP basis.

(2) I recommend against adoption of the Peak and Average production cost allocation method proposed by Staff, and support the continued application of the 4-CP approach proposed by APS. However, if the Commission orders that an energy-weighted method be used to allocate fixed production costs, then I recommend that the Average and Excess Demand method be used instead of the Peak and Average approach, because the former avoids the analytical shortcomings of the latter.

(3) With respect to General Service rate design:

(a) I continue to urge rejection of APS's proposed weighting of demand-related charges and energy charges, which is strongly biased to the disadvantage of higher-load-factor customers;

(b) I support adoption of Mr. Baron's proposal for Rate E-32 in which the "first 100 kW" and "all additional kW" of delivery charge would receive the same percentage increase; and

(c) I support adoption of the proposal by Federal Executive Agencies ("FEA") witness Dennis W. Goins to increase the Rate E-34 voltage discounts to more fully reflect cost-of-service differences between primary and secondary service.

(4) I support adoption of the proportionate increase in the Environmental Portfolio Surcharge rates and caps recommended by Staff witness Barbara Keene.

(5) After review of APS's rebuttal testimony, I continue to support the adjustments to revenue requirements offered in my direct testimony.

(6) Staff's proposal for a prospective PSA Adjustor creates some serious concerns, and I recommend that the Commission be very cautious in considering Staff's proposed change to the PSA mechanism.

II. <u>Transmission Cost Allocation and Rate Design</u>

Q. In his direct testimony, Kroger witness Stephen J. Baron testifies that APS over-allocated transmission costs to General Service customers. What is your assessment of Mr. Baron's statement?

A. Mr. Baron is correct. Although APS had described its transmission allocation as being based on a 4-CP method, upon closer inspection of the allocation formulas, it is clear that the Company actually allocated transmission costs to customer classes based on energy. In my opinion, this approach is not reasonable. Transmission costs are largely, if not entirely, demand-related, and thus, are more properly allocated on a demand basis. Consequently, APS's transmission costs are not properly allocated to the customer classes.

In my direct testimony, I recommended that for most customers with demand meters (e.g., Rates E-32 [> 20 kW], E-34, E-35), the transmission

revenue requirement should be recovered exclusively through a demand charge instead of an energy charge. Also, as part of my direct testimony, I calculated demand charges for Rates E-32, E-34 , and E-35 based on APS's allocation of transmission costs, which I presented in Attachment KCH-7.[1] However, because, as Mr. Baron points out, APS over-allocated transmission costs to General Service customers, it is necessary for me to revise the calculations in Attachment KCH-7 to correct for this problem. This revision is presented in Attachment KCH-1SR.

For the same reason, it is also necessary for me to revise the cost-of-service and rate spread results presented in my direct testimony to reflect the allocation of transmission costs on a 4-CP basis. These cost-of-service and rate spread revisions are presented in Attachments KCH-2SR and KCH-3SR, respectively, and are summarized in Tables KCH-1SR and KCH-2SR, below. For ease of exposition, the tables below include a side-by-side comparison of the cost-of-service results and rate spread recommendations from my direct testimony, which reflects APS's allocation of transmission costs on an energy basis.

[1] I note that the kW-billing determinant for E-32 in Attachment KCH-7 contains a transcription error. This also causes an error in the E-32 kW charge in that attachment. These corrections are addressed at the end of this surrebuttal testimony.

Table KCH-1SR

AECC Cost-of-Service Results
Transmission Allocated on an Energy Basis vs 4-CP Basis

Class	Rate Change Based on AECC COS [2] Transmission allocated using Energy	Rate Change Based on AECC COS [3] Transmission allocated using 4-CP
Residential	28.74%	29.23%
General Service	13.19%	12.80%
E-32	12.14%	12.11%
E-34	21.60%	19.98%
E-35	18.72%	15.11%
Water Pumping	(2.82)%	(6.94)%
Street Lighting	35.16%	31.17%
Dusk-to-Dawn	14.53%	12.60%
Total	21.14%	21.14%

[2] Source: AECC Attachment KCH-5.
[3] Source: AECC Attachment KCH-2SR.

Table KCH-2SR

AECC Recommended Rate Spread
Transmission Allocated on an Energy Basis vs 4-CP Basis
Calculated at APS's Requested Revenue Requirement

Class	AECC Proposed Rate Change[4] Transmission allocated using Energy	AECC Proposed Rate Change [5] Transmission allocated using 4-CP
Residential	24.94%	25.18%
General Service	17.34%	17.13%
E-32	16.97%	17.13%
E-34	21.60%	19.98%
E-35	18.72%	15.11%
Water Pumping	2.01%	0.00%[6]
Street Lighting	24.94%	25.18%
Dusk-to-Dawn	19.36%	17.62%
Total	21.14%	21.14%

As can be seen in the preceding tables, properly allocating transmission costs on a 4-CP basis results in a small increase in cost responsibility for Residential customers,[7] and a more substantial relative decrease in cost responsibility for Rates E-34, E-35, as well as those customer classes that primarily use the system during off-peak periods.

III. Production Cost-of-Service Methodology

Q. What method has Staff recommended for production cost-of-service?

[4] Source: AECC Attachment KCH-6.
[5] Source: AECC Attachment KCH-3SR.
[6] I have added a constraint to my rate spread proposal that precludes providing a rate decrease to any customer class in this proceeding. Thus, Water Pumping would receive a 0% rate change, instead of a rate reduction.
[7] The Residential Transmission Charge would increase from 4.76 mills/kWh to 5.07 mills/kWh, but the net increase to Residential would be half that amount due to rate spread mitigation.

A. As described in the direct testimony of Staff witness Michael L. Brosch, Staff is recommending adoption of the "Peak and Average" methodology to allocate fixed production cost to customer classes.

Q. What is the "Peak and Average" method?

A. The Peak and Average method is classified in the NARUC Cost Allocation Manual as a "Judgmental Energy Weighting" approach. According to this method, fixed production cost is allocated based on a combination of each class's share of coincident peak demand, as well as each class's share of energy usage. In applying this method, class energy consumption is typically expressed as "average demand," which gives rise to the term "Peak and Average." (Average demand is simply annual energy divided by the number of hours in the year.)

Q. How does the Peak and Average method differ from the approach used by APS?

A. APS uses the Four Coincident Peak ("4-CP") method to allocate fixed production cost. According to this method, fixed production costs are allocated on the basis of each class's share of coincident peak demand during the four greatest peak-demand months, which in the case of APS are June through September. In contrast, the Peak and Average method combines a CP allocation with an energy (or "average demand") allocation. In the specific case of Staff's proposal, fixed production costs are allocated using a combination of 4-CP and average demand.

Q. What rationale is offered by Mr. Brosch in proposing this method?

A. Although Mr. Brosch states that the 4-CP allocations performed by APS were generally reasonable and are comparable to the allocation methodologies

1 previously employed in APS general rate case proceedings, he goes on to state
2 that Staff believes the Company's cost-of-service study should utilize an energy-
3 weighted allocation approach in order to reflect the use of production facilities
4 throughout the year. The Peak and Average study prepared by Mr. Brosch is
5 Staff's attempt to incorporate an energy-weighting into the allocation of fixed
6 production costs.

7 **Q. In your direct testimony, do you address APS's use of the 4-CP method?**

8 A. Yes, given APS's load characteristics, I support APS's use of the 4-CP
9 method for allocating fixed production costs.

10 **Q. Do the witnesses sponsored by other intervening parties address APS's use of**
11 **the 4-CP method?**

12 A. Yes. Both Mr. Baron for Kroger and Dr. Goins for the FEA testified in
13 support of the 4-CP method.

14 **Q. Do you agree with Staff's proposal to use a Peak and Average approach**
15 **instead of the 4-CP method?**

16 A. No, I do not. The average peak demand during APS's four summer peak
17 months is over 50 percent higher than the average peak demand in the remaining
18 eight months, and the new capacity being added to APS's system is driven by
19 APS's growing summer demands. The Peak and Average method attempts to shift
20 cost responsibility for these capacity requirements by allocating fixed production
21 costs on an energy basis, placing more of the cost burden on higher-load factor
22 customers who use energy at a relatively constant level throughout the year, rather

than those classes whose summer usage is driving the Company's need for production capacity.

Moreover, if the intention of Staff is to allocate a portion of fixed production costs on an energy basis, then there are approaches that are conceptually superior to the Peak and Average method.

Q. Please elaborate on this latter point.

A. The Peak and Average method is conceptually flawed in that average demand is already included in peak demand and is thus counted twice in the allocation of costs. This double-counting contributes to the bias against higher-load-factor customers inherent in this method.

In contrast, an analytically-superior methodology that incorporates an energy weighting in the allocation of fixed production costs is the "Average and Excess Demand" method. This method is described at length in the NARUC Cost Allocation Manual and is used by both Salt River Project and Public Service Company of Colorado. The "Average and Excess Demand" method avoids double-counting by allocating costs based on a combination of average demand and the *excess* of class non-coincident peak over average demand. This method meets Staff's stated objectives of using an energy weighting and allocates a share of fixed production costs to the classes using the system solely during off-peak periods.

Q. Have you prepared a cost-of-service analysis using the Average and Excess Demand approach?

A. Yes, I have. The results are presented in Attachment KCH-4SR. These results also include the hourly allocation of fuel and purchased power costs described in my direct testimony and the allocation of transmission costs on a 4-CP basis as described above.

Q. Are you recommending the use of the Average and Excess Demand method in lieu of the 4-CP method for allocating fixed production costs?

A. No, I am not. However, if the Commission orders that an energy-weighted method be used to allocate fixed production costs, then I recommend that the Average and Excess Demand method be used instead of the Peak and Average approach.

Q. If an energy-weighted approach is adopted by the Commission for the allocation of fixed production costs, should the Commission also adopt the recommendation in your direct testimony to allocate fuel and purchased power costs using hourly cost information?

A. Yes, absolutely. The reasons presented in my direct testimony for using an hourly allocation of fuel and purchased power costs remain just as compelling if an energy-weighted approach to fixed-production costs is adopted by the Commission.

IV. General Service Rate Design

Q. Do you have any comments on the testimony addressing General Service rate design that was filed by other parties?

A. Yes. In our respective direct testimonies, both Mr. Baron and I pointed out that APS's proposed rate design would negatively impact high-load-factor customers. This negative impact would result from APS's proposal to levy a much greater proportion of its requested generation rate increase on the energy charge relative to the demand-related charges. For example, APS proposes that the generation demand charge for Rate E-34 be increased 11 percent and that the generation energy charge be increased by 53 percent. The negative impact of the Company's proposed design on higher-load-factor customers is evident in APS's Schedule H-4, excerpts of which are reproduced in Table KCH-3SR, below.

Table KCH-3SR

Impact of APS Proposed Rate Design on General Service Customers Differentiated by Load Factor

Rate	Customer Size	Load Factor	APS Proposed Rate Change
E-32	200 kW	15%	15.1% (W) 18.0% (S)
E-32	200 kW	45%	20.0% (W) 24.1% (S)
E-32	200 kW	75%	24.1% (W) 28.6% (S)
E-34	5000 kW	20%	17.6%
E-34	5000 kW	40%	22.7%
E-34	5000 kW	75%	27.8%
E-35	5000 kW	20%	21.1%
E-35	5000 kW	40%	24.1%
E-35	5000 kW	75%	27.3%

Table KCH-3SR shows that APS's proposed rate design would raise rates for higher load-factor customers by as much as 10 percentage points higher than lower-load-factor customers of the same size. The proposal I advanced, as well as the ones advanced by Mr. Baron, would remedy this bias. Mr. Baron's

recommendation is limited to Rate E-32. My recommendation is applicable to the generation rate for Rates E-32, E-34, and E-35. The thrust of our recommendations is similar: remove the bias against high-load-factor customers in APS's proposal because such a bias is not supported by the Company's own cost-of-service analysis.

In the Company's rebuttal testimony, the rate design proposals made by Mr. Baron and myself are characterized as being adverse to low-load-factor customers. A better characterization of our proposals is that they would *neutralize* the negative impact on higher-load-factor customers in the Company's proposal. Equally weighting demand and energy rate components, as I am recommending, is clearly neutral with respect to load factor.

Q. On page 17 of her direct testimony, Staff witness Erinn Andreasen recommends that the demand rates for Rate E-32 not be increased significantly beyond the levels proposed by APS in this proceeding. Do you wish to respond?

A. Yes. Subject to one exception and two qualifications, I do not object to Ms. Andreasen's recommendation. The exception is that the transmission charge for all demand-billed general service customers (except partial requirements) should be converted from an energy charge to a demand charge, as discussed in my direct testimony. Because of the need to correctly design the transmission charge, the limitation on the Rate E-32 demand charge proposed by Staff should not apply to the transmission portion of the rate.

Q. Please address the qualifications that accompany your support for Staff's recommendations for the design of Rate E-32.

A. The first qualification regarding my support for Staff's recommendation pertains to the design of the delivery charge. As Mr. Baron correctly notes, the Rate E-32 Delivery Charge increase proposed by APS for the first 100 kW of demand is, inexplicably, lower than the proposed increase for all additional kW. Mr. Baron proposes that the "first 100 kW" and "all additional kW" receive the same percentage increase. I support this modification. Mr. Baron's proposal does not change the total demand charge to Rate E-32 – it just spreads the demand charge increase on a more even and equitable basis. Presumably this adjustment would not violate Staff's recommendation.

The second qualification pertains to my recommendation to increase, on an equal-percentage-basis, the first energy block and the energy tailblock in the Rate E-32 generation rate. My proposal affects the demand-related charges in the first energy block (i.e., the portion of the first energy block intended to recover demand-related costs), but does not impact the Rate E-32 demand charge itself. To the extent that Staff's recommendation is directed to the Rate E-32 demand charge, my proposal with respect to Rate E-32 generation rates is consistent with Staff's recommendation.

Q. Do you have any other observations with respect to General Service rate design issues?

A. Yes. On pages 16 through 17 of his direct testimony, FEA witness Dennis W. Goins addresses the fact that APS's proposed voltage discounts for Rate E-34

is not fully reflective of costs. Dr. Goins recommends that the Rate E-34 voltage discounts should be increased to more fully reflect cost-of-service differences between primary and secondary service. I concur with Dr. Goins' assessment and support his recommendation.

Q. Have you reviewed the rate design testimony of DEAA witness William J. Murphy?

A. Yes, I have.

Q. Do you have any response to Mr. Murphy's testimony?

A. Yes. Mr. Murphy's testimony is directed primarily to Rate 32-R, which is applicable to Partial Requirements service, i.e., customers with on-site generation. I do not disagree with designing rates for partial requirements service in a manner that takes into account the special characteristics of partial requirements customers. In fact, I have proposed an exception for partial requirements service in my recommended transmission charge design. To the extent that Mr. Murphy's rate design objectives are limited to partial requirements rate schedules I do not offer any objections to them. However, I would strongly object if Mr. Murphy's rate design preferences were applied to Rate 32, which is applicable to the large majority of General Service customers. Shifting cost responsibility from the demand-related charges to the energy charges for Rate E-32 customers would result in an increased subsidy from higher-load-factor customers to lower-load-factor customers. Such an increased subsidy would be inequitable and unreasonable.

V. Environmental Portfolio Surcharge ("EPS")

Q. Have you reviewed the proposal by Staff witness Barbara Keene to increase the EPS adjustor rate and caps to allow for more funding of the EPS Credit Purchase Program?

A. Yes, I have. Staff is recommending that the EPS surcharge rate and caps be increased proportionately to fund the additional $4.25 million EPS revenue requirement approved for APS in Decision No. 68668.

Q. What is your assessment of Staff's recommendation?

A. Staff's recommendation for a proportional increase in the surcharge rates and caps is consistent with the terms of the settlement agreement approved in Decision No. 67744 and I support its adoption.

VI. Fuel Expense

Q. In his rebuttal testimony, APS witness Peter Ewen objects to your recommendation to reduce APS's fuel expense by $67 million. Do you wish to respond?

A. Yes. In the Company's rebuttal testimony filed in the Interim proceeding, APS acknowledged that fuel and purchased power costs had declined by about one-third relative to the November 30, 2005 forward prices that are the basis for the fuel expense used by APS in its direct case in this general rate proceeding. In his rebuttal testimony filed in the Interim docket on March 13, 2006, Company witness Peter Ewen stated that the Company's fuel-related expense in the general rate case filing would decline by $67 million if February 28, 2006 prices held. In

my direct testimony in this proceeding, I testified that as these prices have generally held during the subsequent months (citing prices as of June 30, 2006) the $67 million reduction in fuel expense should be adopted.

In his rebuttal testimony in this proceeding, Mr. Ewen has reversed his stated expectation that a $67 million fuel expense reduction would be forthcoming based on February 28 prices, and instead is recommending a $32 million *increase* in fuel expense relative to the Company's initial filing. Mr. Ewen objects to my recommendation to adopt the $67 million reduction indicated in the Interim proceeding, asserting that the price of natural gas had risen by more than $1.00 by July 31, 2006 relative to the mid-year forward price on June 30, 2006, cited in my testimony. He takes the position that fuel expense should be based on more recent forward prices.

In that regard, I note that the most recent forward prices – those available on September 25, 2006 – indicate that forward gas prices have, in fact, *fallen* significantly relative to the June 30, 2006 prices cited in my testimony. This information is presented in Table KCH-4SR, below.

Table KCH-4R
12-Month Forward Price of Natural Gas
S/MMBtu

Date	Term	NYMEX	San Juan	Permian Basin
11-30-05	Jan 06 - Dec 06	$11.066	$9.522	$9.787
2-28-06	Apr 06 - Mar 07	$ 8.312	$6.538	$6.943
6-30-06	Aug 06 - Jul 07	$ 8.451	$6.967	$7.285
9-25-06	Oct 06 - Sep 08	$ 6.958	$5.928	$6.156

On September 25, the twelve-month forward price for Permian Basin gas stood at $6.156/mmbtu, 11 percent lower than the twelve-month forward price on February 28, and 37 percent lower than the price on November 30, 2005. Comparable reductions have occurred with respect to San Juan gas prices. Yet APS is attempting to increase the fuel expense relative to its November 30, 2005 calculation.

As the most recent fuel prices are significantly below the February 28 levels that formed the basis for APS's prior indications that fuel expense would be reduced from its initial filing, and consequently, are even further below the November 30, 2005 levels upon which APS based its initial fuel expense projections, I see no reason to change my recommendation to reduce APS's fuel expense by $67 million.

VII. PWEC-Related Costs

Q. In her rebuttal testimony, APS witness Laura Rockenberger reduces PWEC-related expense by $5.1 million, but objects to your recommendation to reduce A&G expenses associated with PWEC units by $11.7 million, which is

to the level of A&G expense indicated in the prior rate case. Do you wish to respond?

A. Yes. I continue to recommend that for the purpose of this proceeding, the A&G and O&M expense allowed for the PWEC units should be based on the levels represented to the parties to the 2004 Settlement Agreement and the Commission when the benefits of including the PWEC units in rate base was being advanced by APS. This adjustment is not "arbitrary", as Ms. Rockenberger states. To the contrary, it is sound policy and follow-through to insist that the benefits to customers not be eroded in this proceeding by escalating the allowed A&G and O&M costs above the levels depicted by APS when APS was persuading the parties and the Commission that the PWEC units should be included in rate base.

As I indicated in my direct testimony, maintaining consistency between the PWEC costs depicted in the prior proceeding and those allowed in this proceeding does not mean that PWEC-related costs should be permanently capped at these levels. This rate proceeding is following relatively close in time to the decision that allowed the PWEC units into rate base. It is reasonable, at this time, to limit the O&M and A&G expense for these units at the amounts indicated by APS in the prior rate proceeding.

1 **VIII. <u>Prospective PSA Adjustor</u>**

2 **Q. Have you reviewed the proposal for a prospective PSA Adjustor**
3 **recommended by Staff witness John Antonuk on pages 33 through 42 of his**
4 **direct testimony?**

5 A. Yes, I have.

6 **Q. What is your assessment of that proposal?**

7 A. The specifics of the proposal are not entirely clear to me. However, on
8 pages 8 through 9 of his rebuttal testimony, APS witness Donald G. Robinson has
9 attempted to elaborate on how Staff's proposal would work. Based on my review
10 of Mr. Antonuk's testimony and Mr. Robinson's discussion of it, I have two
11 serious concerns with the proposal and recommend that the Commission proceed
12 cautiously with respect to it.

13 **Q. Please describe your concerns with the Prospective PSA Adjustor proposal.**

14 A. First, I agree with Mr. Robinson's statement that Staff's proposal is a
15 dramatic change to the current form of the PSA Adjustor.[8] As the current PSA
16 was negotiated as a package, and was intended to be in place for at least five
17 years, I have serious concerns with making changes to the design of the
18 mechanism before the five-year implementation period has run its course.

19 My second concern is that changing the mechanism from a retrospective
20 calculation to a prospective calculation appears to require a "doubling up" of the
21 adjustor in the coming year. That is, customers would be asked to pay both the
22 original adjustor and the prospective adjustor simultaneously, as described on

[8] Rebuttal testimony of Donald G. Robinson, p. 3, lines 3-4.

page 9 of Mr. Robinson's rebuttal testimony (see items 2 and 3 in Mr. Robinson's testimony). The rate impact on customers resulting from this overlapping payment should be considered before action is taken on this proposal.

Corrections

Q. Please describe the corrections to exhibits to your direct testimony.

A. It is necessary for me to correct three numbers that appeared in exhibits in my direct testimony. These corrections do not affect the conclusions or recommendations in my direct testimony.

The first corrections are in Attachment KCH-7. Due to a transcription error, I entered an incorrect billing determinant for Rate E-32 billing demand of 24,696,457 kW. The correct billing demand is 25,196,428 kW. This, in turn, impacted the calculation of the Proposed Transmission Charge for Rate E-32 in that attachment. Instead of $1.826 per kW-month, the correct charge should have read $1.790 per kW-month. I note, however, that in this surrebuttal testimony I have re-calculated the appropriate transmission charge for Rate E-32 using a 4-CP cost allocation for transmission service. Consequently, I view the proposed transmission charges in Attachment KCH-7 to be superseded by the proposed charges in Attachment KCH-1SR. Nevertheless, I wish to make these corrections to Attachment KCH-7 to ensure an accurate record. The corrected attachment is designated as Attachment KCH-7 (Revised).

The other correction applies to Attachment KCH-5, page 2. Due to a formula error that double-counted the megawatts-hours for Rate E-32 in the

summary, the ACC Total Energy Use at the Meter is incorrectly shown as 36,923,342 MWH. The correct amount is 26,148,942 MWH. This value was presented for summary purposes only, and consequently, did not affect any of the calculations in my attachments or workpapers. The corrected page is designated as Attachment KCH-5, page 2 (Revised).

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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Derivation of Transmission Charges for Major Rate Schedules
Based on 4-CP Allocation of APS Trasmission Costs

Residential	kWh Units	Transmission Revenue Requirement	Proposed Transmission Charge
Total	12,362,652,000	$62,703,331	$0.00507

E-32 General Service	Demand Units (Over 20 kW)[1]	Transmission Revenues (Over 20 kW)[2]	Proposed Transmission Charge
Total	25,196,428	$39,586,312	$1.571

E-34	Demand Units[1]	Transmission Revenues[2]	Proposed Transmission Charge
	2,327,022	$4,055,471	$1.743

E-35	Demand Units[1]	Transmission Revenues[2]	Proposed Transmission Charge
	2,310,533	$3,698,384	$1.601

1. Source: DJR_WP9
2. Source: Attachment KCH - 2 SR, pp. 2-3, Lines 32 & 43

APS's Cost of Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs and Allocation of Transmission Expenses Using APS's 4-CP Demand Allocator

Revenue Increase Required to Move each Customer Class to Cost of Service using AECC's Proposed Cost of Service Study Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Required Revenue Increase	Req'd Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$1,408,005,912	$318,454,882	29.23%
2	General Service								
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$3,643,363	$56,663	1.58%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$963,215,325	$104,042,736	12.11%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$80,047,975	$13,328,694	19.98%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$77,885,179	$10,223,942	15.11%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$1,124,791,842	$127,652,035	12.80%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	$19,416,207	($1,447,894)	-6.94%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$17,503,500	$4,159,235	31.17%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$7,232,097	$809,401	12.60%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$2,576,949,559	$449,627,660	21.14%

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs and 4-CP
for Transmission Expenses
for the 12 Months ending Sep. 30, 2005
($)

	1	2	3	4	5	6	7	8	9	10	11
Line No.	Description	Allocation Factor	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
	SUMMARY OF RESULTS										
16	TOTAL RATE BASE		$5,327,833,192	$4,466,696,504	$861,136,688	$2,489,739,663	$148,234,534	$795,627,566	$79,691,088	$1,227,004,375	$239,182,100
17											
18	DEVELOPMENT OF RETURN										
19	Revenues from Rates		$2,103,857,729	$2,066,144,726	$37,713,003	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
20	Proforma to Revenues from Rates		$60,953,295	$61,177,173	($223,878)	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341
21	Other Electric Revenues		$1,344,909,372	$1,313,268,573	$31,640,799	$624,903,158	$40,280,141	$189,690,778	$23,754,957	$301,576,795	$69,600,487
22	TOTAL OPERATING REVENUES		$3,509,720,396	$3,440,590,472	$69,129,924	$1,714,454,188	$108,392,813	$562,129,152	$59,186,157	$812,376,977	$172,369,089
23	Revenue Increase Required to Achieve Equalized ROR		$449,627,660	$449,627,660	$0	$318,454,882	$18,559,116	$78,492,739	$11,439,813	$173,670,901	$36,292,314
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$3,959,348,056	$3,890,218,132	$69,129,924	$2,032,909,070	$126,951,929	$640,621,891	$70,625,970	$986,047,878	$208,661,403
25	Percent Increase		20.77%	21.14%	0.00%	29.23%	27.25%	21.08%	32.29%	34.00%	35.31%
24											
25	OPERATING EXPENSES										
26											
27	O&M Energy Related										
28	Energy Production	Energy1	$74,369,000	$73,170,843	$1,198,157	$34,692,327	$2,239,528	$10,508,029	$1,325,029	$16,737,158	$3,882,582
29	Energy Production - Related Fuel (M&T)	Energy2	$842,735,000	$829,157,722	$13,577,278	$393,126,677	$25,377,890	$119,074,939	$15,014,971	$189,662,215	$43,996,662
30	Energy Production - Related Fuel	Energy100	$885,397,911	$871,149,260	$14,248,651	$426,382,540	$27,140,225	$128,542,154	$16,160,595	$207,200,327	$47,339,237
31	Total Energy Related		$1,802,501,911	$1,773,477,826	$29,024,085	$854,201,543	$54,757,643	$258,125,123	$32,500,595	$413,599,700	$95,218,481
32	OATT Transmission Expense	4-CP Trans.	$0	$117,547,846	($117,547,846)	$61,040,586	$3,503,525	$18,288,673	$2,080,159	$30,710,312	$6,457,917
33	Other O&M Enon-Energy Expenses		$443,510,786	$411,439,063	$32,071,723	$246,087,716	$16,086,269	$85,510,463	$7,662,534	$115,255,312	$21,573,138
34	Total O&M Non-Energy Related		$443,510,786	$528,986,909	($85,476,123)	$307,128,302	$19,589,794	$103,799,136	$9,742,693	$145,965,624	$28,031,055
35	Operation & Maintenance		$2,246,012,697	$2,302,464,735	($56,452,038)	$1,161,329,845	$74,347,438	$361,924,259	$42,243,288	$559,565,324	$123,249,536
36	Administrative & General		$141,768,184	$132,687,129	$9,081,055	$81,444,413	$5,435,590	$28,926,720	$2,483,640	$37,721,841	$6,876,622
37	Depreciation & Amortization Expense		$321,526,002	$285,758,992	$35,767,010	$159,732,184	$9,911,645	$51,449,950	$5,249,433	$77,904,622	$15,216,534
38	Amortization on Gain		($6,613,637)	($6,528,054)	($85,583)	($3,299,367)	($196,177)	($991,655)	($116,349)	($1,640,307)	($354,879)
39	Regulatory Assets		($2,203,511)	($2,203,511)	$0	($1,144,246)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$61,052,503	$60,070,266	$982,237	$29,401,291	$1,871,459	$8,863,649	$1,114,357	$14,287,539	$3,264,286
41	Pro-Forma Energy Related - ACC	Energy100'	$269,376,144	$269,376,144	$0	$131,845,700	$8,392,281	$39,747,712	$4,997,168	$64,070,335	$14,638,205
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$18,114,000	$18,114,000	$0	$9,044,540	($677,719)	$3,428,524	($350,866)	$5,867,427	$777,174
43	Pro-Forma OATT Transmission Expense	4-CP Trans.	$3,202,002	$3,202,002	$0	$1,662,745	$95,436	$498,183	$56,664	$836,549	$175,914
44	Other Pro-Forma Expenses		$152,816,718	$145,032,119	$7,784,599	$79,062,774	$4,806,393	$25,528,196	$2,577,998	$38,313,459	$7,836,728
45	Pro-Forma Non-Energy Related		$485,465,130	$477,680,531	$7,784,599	$80,725,519	$4,901,829	$26,026,379	$2,634,662	$39,150,008	$8,012,642
46	Proforma Adjustments		$504,561,367	$495,794,531	$8,766,836	$251,017,050	$14,487,850	$78,066,264	$8,395,320	$123,375,308	$26,692,307
47	Taxes Other than Income		$139,970,769	$116,332,656	$23,638,113	$65,666,582	$4,071,767	$21,173,025	$2,145,953	$32,090,164	$6,185,673
48	Income Tax		$185,532,148	$175,969,050	$9,563,098	$100,808,337	$6,018,617	$30,957,874	$3,306,647	$50,489,128	$10,036,071
49	TOTAL OPERATING EXPENSES		$3,530,554,019	$3,500,275,528	$30,278,491	$1,815,554,798	$114,011,054	$571,163,604	$63,668,938	$878,930,396	$187,780,805
50											
51	OPERATING INCOME		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597
52											
53	RETURN		$428,794,038	$389,942,605	$38,851,433	$217,354,273	$12,940,875	$69,458,287	$6,957,032	$107,117,482	$20,880,597
54											
55	RATE OF RETURN (EQUALIZED)		8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
56											
57	INDEX RATE OF RETURN		1.00	1.08	0.56	1.08	1.08	1.08	1.08	1.08	1.08
58											
59	ACC JURISDICTION INDEX RATE OF RETURN			1.00		1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
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($)

	1	2	12	13		14	15	16	17	18
Line No.	Description	Allocation Factor	Total General Service	E-20 Church Rate	E-30, E-32 Total	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)
	SUMMARY OF RESULTS									
16	TOTAL RATE BASE		$1,876,563,794	$7,360,472	$1,664,603,376	$378,234,736	$469,359,372	$410,940,132	$228,078,549	$177,990,587
17										
18	DEVELOPMENT OF RETURN									
19	Revenues from Rates		$967,398,538	$3,344,799	$830,331,951	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699
20	Proforma to Revenues from Rates		$29,741,269	$241,901	$28,840,638	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448
21	Other Electric Revenues		$662,981,780	$1,836,772	$535,912,322	$67,075,107	$127,027,116	$155,000,606	$107,242,574	$79,566,919
22	TOTAL OPERATING REVENUES		$1,660,121,587	$5,423,472	$1,395,084,911	$218,411,696	$349,027,815	$398,492,063	$254,419,271	$174,734,066
23	Revenue Increase Required to Achieve Equalized ROR		$127,652,035	$56,663	$104,042,736	$34,524,136	$29,657,534	$12,604,856	$4,598,998	$22,657,212
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$1,787,773,622	$5,480,135	$1,499,127,647	$252,935,832	$378,685,349	$411,096,919	$259,018,269	$197,391,278
25	Percent Increase		12.80%	1.58%	12.11%	22.81%	13.36%	5.18%	3.12%	23.81%
24										
25	OPERATING EXPENSES									
26										
27	O&M Energy Related									
28	Energy Production	Energy1	$37,182,385	$101,497	$29,995,769	$3,687,388	$7,082,367	$8,703,502	$6,038,893	$4,483,619
29	Energy Production - Related Fuel (M&T)	Energy2	$421,343,530	$1,150,143	$339,906,198	$41,784,757	$80,256,003	$98,626,385	$68,431,554	$50,807,500
30	Energy Production - Related Fuel	Energy100	$430,410,906	$1,256,908	$349,267,098	$43,043,545	$82,787,067	$101,682,496	$70,057,238	$51,696,753
31	Total Energy Related		$888,936,821	$2,508,548	$719,169,065	$88,515,690	$170,125,436	$209,012,382	$144,527,685	$106,987,872
32	OATT Transmission Expense	4-CP Trans.	$55,972,307	$127,881	$48,296,185	$9,759,609	$13,213,344	$12,483,728	$6,900,440	$5,939,065
33	Other O&M Enon-Energy Expenses		$157,203,584	$480,779	$138,332,015	$34,011,718	$37,863,262	$33,259,267	$18,402,164	$14,795,604
34	Total O&M Non-Energy Related		$213,175,891	$608,660	$186,628,200	$43,771,326	$51,076,606	$45,742,995	$25,302,604	$20,734,669
35	Operation & Maintenance		$1,102,112,712	$3,117,207	$905,797,266	$132,287,016	$221,202,042	$254,755,377	$169,830,288	$127,722,542
36	Administrative & General		$48,487,581	$168,558	$42,560,789	$10,453,288	$11,676,787	$10,128,362	$5,827,742	$4,474,610
37	Depreciation & Amortization Expense		$119,779,815	$441,855	$105,486,858	$23,085,668	$29,369,824	$26,524,854	$15,018,891	$11,487,621
38	Amortization on Gain		($3,172,586)	($7,702)	($2,680,293)	($476,581)	($702,487)	($718,845)	($430,995)	($351,385)
39	Regulatory Assets		($1,049,237)	($2,397)	($905,344)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$29,679,067	$86,670	$24,083,780	$2,968,076	$5,708,598	$7,011,536	$4,830,810	$3,564,760
41	Pro-Forma Energy Related - ACC	Energy100'	$133,091,349	$388,660	$108,000,119	$13,309,894	$25,599,357	$31,442,188	$21,663,048	$15,985,633
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$9,157,238	$56,452	$9,679,725	$2,669,378	$500,908	$6,436,947	$40,808	$31,684
43	Pro-Forma OATT Transmission Expense	4-CP Trans.	$1,524,685	$3,483	$1,315,588	$265,852	$359,931	$340,057	$187,968	$161,780
44	Other Pro-Forma Expenses		$65,130,863	$144,621	$55,549,088	$11,359,243	$14,791,230	$14,211,306	$8,199,897	$6,987,412
45	Pro-Forma Non-Energy Related		$66,655,548	$148,104	$56,864,676	$11,625,095	$15,151,161	$14,551,363	$8,387,865	$7,149,192
46	Proforma Adjustments		$238,583,202	$679,887	$198,628,300	$30,572,442	$46,960,024	$59,442,034	$34,922,532	$26,731,268
47	Taxes Other than Income		$47,839,519	$190,638	$42,553,612	$9,622,639	$12,021,204	$10,585,525	$5,888,989	$4,435,255
48	Income Tax		$71,368,597	$249,519	$62,366,584	$14,554,417	$17,430,575	$14,738,555	$8,178,917	$7,464,121
49	TOTAL OPERATING EXPENSES		$1,623,949,603	$4,837,566	$1,353,807,772	$219,915,939	$337,710,276	$375,221,846	$239,107,012	$181,852,700
50										
51	OPERATING INCOME		$163,824,019	$642,569	$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578
52										
53	RETURN		$163,824,019	$642,569	$145,319,875	$33,019,892	$40,975,073	$35,875,074	$19,911,257	$15,538,578
54										
55	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
56										
57	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
58										
59	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs and 4-CP
for Transmission Expenses
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	19 E-34	20 E-35	21 E-38, 221 Water Pumping	22 Street Lighting	23 Dusk to Dawn
	SUMMARY OF RESULTS						
16	TOTAL RATE BASE		$115,618,777	$88,981,169	$25,474,477	$51,298,120	$23,620,450
17							
18	DEVELOPMENT OF RETURN						
19	Revenues from Rates		$66,695,622	$67,026,166	$20,966,540	$12,913,053	$6,136,856
20	Proforma to Revenues from Rates		$23,659	$635,071	($102,439)	$431,212	$285,840
21	Other Electric Revenues		$57,813,897	$67,418,789	$15,739,104	$8,074,267	$1,570,264
22	TOTAL OPERATING REVENUES		$124,533,178	$135,080,026	$36,603,205	$21,418,532	$7,992,960
23	Revenue Increase Required to Achieve Equalized ROR		$13,328,694	$10,223,942	($1,447,893.6)	$4,159,235	$809,401
24	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$137,861,872	$145,303,968	$35,155,311	$25,577,767	$8,802,361
25	Percent Increase		19.98%	15.11%	-6.94%	31.17%	12.60%
24							
25	OPERATING EXPENSES						
26							
27	O&M Energy Related						
28	Energy Production	Energy1	$3,261,592	$3,823,527	$891,253	$327,752	$77,127
29	Energy Production - Related Fuel (M&T)	Energy2	$36,959,723	$43,327,466	$10,099,502	$3,714,023	$873,989
30	Energy Production - Related Fuel	Energy100	$37,374,165	$42,512,734	$10,358,616	$3,230,153	$767,046
31	Total Energy Related		$77,595,480	$89,663,727	$21,349,371	$7,271,928	$1,718,163
32	*OATT Transmission Expense*	4-CP Trans.	$3,947,929	$3,600,312	$534,953	$0	$0
33	Other O&M Enon-Energy Expenses		$9,842,957	$8,547,834	$2,203,432	$4,683,266	$1,261,065
34	Total O&M Non-Energy Related		$13,790,886	$12,148,146	$2,738,385	$4,683,266	$1,261,065
35	Operation & Maintenance		$91,386,366	$101,811,873	$24,087,756	$11,955,194	$2,979,228
36	Administrative & General		$3,006,658	$2,751,576	$880,883	$1,303,165	$571,087
37	Depreciation & Amortization Expense		$7,583,550	$6,267,552	$1,842,301	$3,034,821	$1,369,871
38	Amortization on Gain		($241,284)	($243,307)	($45,007)	($8,981)	($2,113)
39	Regulatory Assets		($74,006)	($67,490)	($10,028)	$0	$0
40	Pro-Forma Energy Related - Jurisdictional	Energy100'	$2,577,143	$2,931,474	$714,280	$222,736	$52,892
41	Pro-Forma Energy Related - ACC	Energy100'	$11,556,812	$13,145,757	$3,203,084	$998,825	$237,186
42	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	($578,939)	$0	($125,097)	$37,319	$0
43	Pro-Forma OATT Transmission Expense	4-CP Trans.	$107,542	$98,072	$14,572	$0	$0
44	*Other Pro-Forma Expenses*		$4,740,120	$4,697,034	$789,312	$43,984	$5,186
45	Pro-Forma Non-Energy Related		$4,847,662	$4,795,106	$803,884	$43,984	$5,186
46	Proforma Adjustments		$18,402,678	$20,872,337	$4,596,151	$1,302,864	$295,263
47	Taxes Other than Income		$2,889,635	$2,205,634	$739,434	$1,432,424	$654,697
48	Income Tax		$4,814,757	$3,937,736	$839,900	$2,079,954	$872,263
49	TOTAL OPERATING EXPENSES		$127,768,353	$137,535,911	$32,931,390	$21,099,441	$6,740,296
50							
51	OPERATING INCOME		$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
52							
53	RETURN		$10,093,519	$7,768,056	$2,223,922	$4,478,326	$2,062,065
54							
55	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%
56							
57	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08
58							
59	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00

AECC Proposed Rate Spread at APS Requested Revenue Increase

AECC Proposed Revenue Increase for each Customer Class based on AECC's Proposed Cost of Service Study Reflecting Hourly Fuel and Purchased Power Costs and Allocation of Transmission Expenses Using APS's 4-CP Demand Allocator

E-32, Water Pumping & Dusk to Dawn Adder Above Cost (if Change > 0%) = 5.018%

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Req'd Percent Change	AECC Proposed Revenue Increase w/o EIC	AECC Percent Change
1	Residential	$1,089,551,030	$2,489,739,663	$217,354,273	8.73%	1.00	$318,454,882	29.23%	$274,370,401	25.18%
2	General Service									
3	E-20	$3,586,700	$7,360,472	$642,569	8.73%	1.00	$56,663	1.58%	$56,663	1.58%
4	E-32	$859,172,589	$1,664,603,376	$145,319,875	8.73%	1.00	$104,042,736	12.11%	$147,155,919	17.13%
5	E-34	$66,719,281	$115,618,777	$10,093,519	8.73%	1.00	$13,328,694	19.98%	$13,328,694	19.98%
6	E35	$67,661,237	$88,981,169	$7,768,056	8.73%	1.00	$10,223,942	15.11%	$10,223,942	15.11%
7	General Service Total	$997,139,807	$1,876,563,794	$163,824,019	8.73%	1.00	$127,652,035	12.80%	$170,765,219	17.13%
8	Water Pumping (E-38, E-221)	$20,864,101	$25,474,477	$2,223,922	8.73%	1.00	($1,447,894)	-6.94%	$0	0.00%
9	Street Lighting	$13,344,265	$51,298,120	$4,478,326	8.73%	1.00	$4,159,235	31.17%	$3,360,349	25.18%
10	Dusk to Dawn	$6,422,696	$23,620,450	$2,062,065	8.73%	1.00	$809,401	12.60%	$1,131,692	17.62%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$449,627,660	21.14%	$449,627,660	21.14%

APS's Cost of Service Results Adjusted to Reflect Hourly Fuel and Purchased Power Costs, Allocation of Transmission Expenses Using APS's 4-CP Demand Allocator and Use of Average and Excess Demand Allocator

Revenue Increase Required to Move each Customer Class to Cost of Service using AECC's Proposed Cost of Service Study Results

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Rate Class	Current Retail Revenues	Rate Base	Return Req'd Return @ Equal ROR	Equalized Rate of Return	Equalized Relative Rate of Return	Required Revenue Increase w/o EIC	Required Revenue Increase	Req'd Percent Change
1	Residential	$1,089,551,030	$2,580,945,496	$225,316,542	8.73%	1.00	$1,443,666,166	$354,115,136	32.50%
2	General Service								
3	E-20	$3,586,700	$10,488,903	$915,681	8.73%	1.00	$4,866,297	$1,279,597	35.68%
4	E-32	$859,172,589	$1,540,595,739	$134,494,008	8.73%	1.00	$914,733,051	$55,560,462	6.47%
5	E-34	$66,719,281	$109,636,156	$9,571,236	8.73%	1.00	$77,708,554	$10,989,273	16.47%
6	E35	$67,661,237	$89,723,138	$7,832,830	8.73%	1.00	$78,174,574	$10,513,337	15.54%
7	General Service Total	$997,139,807	$1,750,443,936	$152,813,756	8.73%	1.00	$1,075,482,476	$78,342,669	7.86%
8	Water Pumping (E-38, E-221)	$20,864,101	$46,494,343	$4,058,956	8.73%	1.00	$27,633,087	$6,768,986	32.44%
9	Street Lighting	$13,344,265	$62,924,087	$5,493,273	8.73%	1.00	$22,048,805	$8,704,540	65.23%
10	Dusk to Dawn	$6,422,696	$25,888,643	$2,260,078	8.73%	1.00	$8,119,024	$1,696,328	26.41%
11	ACC Total	$2,127,321,899	$4,466,696,504	$389,942,605	8.73%	1.00	$2,576,949,558	$449,627,659	21.14%

Development of Average and Excess Demand Factor

A&E Factor = Avg Demand Component + Excess Demand Component

Where: Avg Demand Component = Class Avg. Demand + Jurisdictional Peak Demand
Excess Demand Component = (((Class NCP - Class Avg Demand) + (Juris. NCP Total - Juris. Avg Demand)) x (Juris. Peak Demand - Juris. Avg Demand)) + Juris. Peak Demand

			Source
Jurisdictional Maximum (Peak) Demand @ Generation- (MW):	6,245	=j	= JP
Sum of Individual Class Maximum Demand @ Gneration (MW):	7,203	=k	= Σ Ln 1 for each class
Total Energy @ Generation (MWh):	27,881,695	=l	Source: APS Data Response to AECC 3.1
Ln 6 [Total] = Jurisdiction Peak Demand [6245 MW] - Jurisdictional Average Demand [3183 MW]:	3,062	=m	= JP - Ln 4 [Total]

		Residential						
Ln #	Description	E-10	E-12	EC-1	ET-1	ECT-1R	Residential Total	Source
1	*Annual NCP* Peak Demand@ Generator (MW)	238	1,254	153	2,060	428	4,129	APS Data Response to AECC 3.1
2	Annual Energy @ Input (MWh)	852,812	4,001,457	504,571	6,373,509	1,478,487	13,210,836	APS Data Response to AECC 3.1
3	Calculated Annual Load Factor (%)	40.88%	36.42%	37.61%	35.31%	39.41%	36.53%	= Ln 2 ÷ (Ln 1 x 8760)
4	Average Demand (MW)	97	457	58	728	169	1,508	= Ln 2 ÷ 8760
5	Individual Excess Demand (MW)	141	797	96	1,333	259	2,621	= Ln 1 - Ln 4
6	Allocated Jurisdictional Excess Demand (MW)	107	607	73	1,015	198	1,996	= Ln 6 (Total) x (Ln 5 ÷ Ln 5(Total))
7	Average and Alloc. Juris. Excess Demand (MW)	205	1,064	130	1,743	366	3,504	= Ln 4 + Ln 6
8	Avg Demand Factor Component	1.56%	7.31%	0.92%	11.65%	2.70%	24.15%	= Ln 4 ÷ ln 7 [Total]
9	Excess Demand Factor Component	1.72%	9.73%	1.17%	16.25%	3.16%	31.96%	= ((Ln 5 + Ln 5 [Total]) x (Ln 6 [Total]) ÷ Ln 5 [Total]
10	Avg & Excess Demand Factor	3.28%	17.04%	2.09%	27.91%	5.87%	56.11%	= Ln 8 + Ln 9

		General Service									
Ln #	Description	Church Rate E-20	0 - 20 kW E-21, E-23, E-30 E-32 & E-32 TOU	21 - 100 kW E-22, E-32 & E-32 TOU	101-400 kW E-32 & E-32 TOU	401-999 kW E-24, E-32 & E-32 TOU	1000 + kW E-32 & E-32 TOU	E-32 Total	E-34	E-35	Source
1	*Annual NCP* Peak Demand@ Generator (MW)	19	354	589	718	502	324	2,467	208	202	APS Data Response to AECC 3.1
2	Annual Energy @ Input (MWh)	38,650	1,404,282	2,696,965	3,314,293	2,310,169	1,714,920	11,440,629	1,242,014	1,455,999	APS Data Response to AECC 3.1
3	Calculated Annual Load Factor (%)	22.64%	45.26%	52.26%	52.72%	52.55%	60.47%	52.93%	68.11%	82.30%	= Ln 2 ÷ (Ln 1 x 8760)
4	Average Demand (MW)	4	160	308	378	264	196	1,306	142	166	= Ln 2 ÷ 8760
5	Individual Excess Demand (MW)	15	194	281	339	238	128	1,161	66	36	= Ln 1 - Ln 4
6	Allocated Jurisdictional Excess Demand (MW)	11	148	214	258	181	97	885	51	27	= Ln 6 (Total) x (Ln 5 ÷ Ln 5(Total))
7	Average and Alloc. Juris. Excess Demand (MW)	16	308	522	637	445	293	2,191	192	193	= Ln 4 + Ln 6
8	Avg Demand Factor Component	0.07%	2.57%	4.93%	6.06%	4.22%	3.13%	20.91%	2.27%	2.66%	= Ln 4 ÷ ln 7 [Total]
9	Excess Demand Factor Component	0.18%	2.36%	3.43%	4.14%	2.90%	1.56%	14.16%	0.81%	0.44%	= ((Ln 5 + Ln 5 [Total]) x (Ln 6 [Total]) ÷ Ln 5 [Total]
10	Avg & Excess Demand Factor	0.25%	4.93%	8.36%	10.20%	7.13%	4.70%	35.08%	3.08%	3.10%	= Ln 8 + Ln 9

Ln #	Description	Water Pumping E-38/E-221	Streetlights	Dusk to Dawn	ACC Total		Source
1	*Annual NCP* Peak Demand@ Generator (MW)	105	40	8	7,203	=k	APS Data Response to AECC 3.1
2	Annual Energy @ Input (MWh)	339,389	124,808	29,370	27,881,695	=l	APS Data Response to AECC 3.1
3	Calculated Annual Load Factor (%)	36.74%	35.67%	44.04%	44.19%		= Ln 2 ÷ (Ln 1 x 8760)
4	Average Demand (MW)	39	14	3	3,183		= Ln 2 ÷ 8760
5	Individual Excess Demand (MW)	67	26	4	4,020		= Ln 1 - Ln 4
6	Allocated Jurisdictional Excess Demand (MW)	51	20	3	3,062	=m	= Ln 6 (Total) x (Ln 5 ÷ Ln 5(Total))
7	Average and Alloc. Juris. Excess Demand (MW)	90	34	7	6,245	=j	= Ln 4 + Ln 6
8	Avg Demand Factor Component	0.62%	0.23%	0.05%	50.97%		= Ln 4 ÷ ln 7 [Total]
9	Excess Demand Factor Component	0.81%	0.31%	0.05%	49.03%		= ((Ln 5 + Ln 5 [Total]) x (Ln 6 [Total]) ÷ Ln 5 [Total]
10	Avg & Excess Demand Factor	1.43%	0.54%	0.11%	100.00%		= Ln 8 + Ln 9

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs, 4-CP for Transmission
Expenses and Avg and Excess Demand Allocator
for the 12 Months ending Sep. 30, 2005
($)

	1	2	3	4	5	6	7	8	9	10	11
Line No.	Description	Allocation Factor	Electric Total	ACC Jurisdiction	All Other	Total Residential	E-10 Residential	E-12 Residential	EC-1 Residential	ET-1 Residential	ECT-1 Residential
	SUMMARY OF RESULTS										
16	Rate Base - Production Demand Related Related		$2,172,189,724	$2,147,019,278	$25,170,446	$1,206,116,221	$70,335,410	$365,864,854	$44,818,693	$599,129,401	$125,967,864
17	Rate Base - Non-Production Demand Related		$3,155,643,468	$2,319,677,226	$835,966,242	$1,374,829,274	$84,242,416	$461,583,726	$41,696,842	$666,078,469	$121,227,821
18	TOTAL RATE BASE		$5,327,833,192	$4,466,696,504	$861,136,688	$2,580,945,496	$154,577,826	$827,448,580	$86,515,535	$1,265,207,870	$247,195,685
19											
20	DEVELOPMENT OF RETURN										
21	Revenues from Rates		$2,103,857,729	$2,066,144,726	$37,713,003	$1,058,729,739	$70,337,587	$360,585,198	$36,686,029	$490,471,664	$100,649,261
22	Proforma to Revenues from Rates		$60,953,295	$61,177,173	($223,878)	$30,821,291	($2,224,915)	$11,853,176	($1,254,829)	$20,328,518	$2,119,341
23	Other Electric Rev. - DEMPROD1 Related	Dem-A&E	$4,714,348	$4,659,999	$54,349	$2,617,816	$152,660	$794,092	$97,277	$1,300,381	$273,407
24	Other Electric Rev. - Non-DEMPROD1 Demand		$1,340,195,024	$1,308,608,574	$31,586,450	$622,483,300	$40,141,249	$188,965,752	$23,672,492	$300,359,333	$69,344,473
25	Other Electric Revenues		$1,344,909,372	$1,313,268,573	$31,640,799	$625,101,116	$40,293,909	$189,759,844	$23,769,769	$301,659,714	$69,617,880
26	TOTAL OPERATING REVENUES		$3,509,720,396	$3,440,590,472	$69,129,924	$1,714,652,146	$108,406,581	$562,198,218	$59,200,969	$812,459,896	$172,386,482
27	Revenue Increase Required to Achieve Equalized ROR		$449,627,659	$449,627,659	$0	$354,115,136	$21,039,581	$90,936,624	$14,107,604	$188,606,658	$39,424,669
28	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$3,959,348,055	$3,890,218,131	$69,129,924	$2,068,767,282	$129,446,162	$653,134,842	$73,308,573	$1,001,066,554	$211,811,151
29	Percent Increase		20.77%	21.14%	0.00%	32.50%	30.89%	24.42%	39.82%	36.92%	38.36%
30											
31	OPERATING EXPENSES										
32											
33	O&M Energy Related										
34	Energy Production	Energy1	$74,369,000	$73,170,843	$1,198,157	$34,692,327	$2,239,528	$10,508,029	$1,325,029	$16,737,158	$3,882,582
35	Energy Production - Related Fuel (M&T)	Energy2	$842,735,000	$829,157,722	$13,577,278	$393,126,677	$25,377,890	$119,074,939	$15,014,971	$189,662,215	$43,996,662
36	Energy Production - Related Fuel	Energy100	$885,397,911	$871,149,260	$14,248,651	$426,382,540	$27,140,225	$128,542,154	$16,160,595	$207,200,327	$47,339,237
37	Total O&M Energy Related		$1,802,501,911	$1,773,477,826	$29,024,085	$854,201,543	$54,757,643	$258,125,123	$32,500,595	$413,599,700	$95,218,481
38	OATT Transmission Expense	4-CP Trans.	$0	$117,547,846	($117,547,846)	$61,040,586	$3,503,525	$18,288,673	$2,080,159	$30,710,312	$6,457,917
39	O&M - DEMPROD1 Related	Dem-A&E	$238,634,716	$235,883,642	$2,751,074	$132,510,728	$7,727,445	$40,195,975	$4,924,034	$65,823,734	$13,839,540
40	Other O&M		$204,876,070	$175,555,421	$29,320,649	$123,597,376	$9,055,735	$48,810,523	$3,488,272	$53,628,830	$8,614,016
41	Total O&M Non-Energy Related		$443,510,786	$528,986,909	($85,476,123)	$317,148,689	$20,286,704	$107,295,172	$10,492,465	$150,162,875	$28,911,473
42	Operation & Maintenance		$2,246,012,697	$2,302,464,735	($56,452,038)	$1,171,350,232	$75,044,348	$365,420,295	$42,993,060	$563,762,576	$124,129,954
43	A&G - DEMPROD1 Related	Dem-A&E	$47,709,445	$47,159,432	$550,013	$26,492,429	$1,544,922	$8,036,248	$984,446	$13,159,920	$2,766,893
44	A&G - Non-DEMPROD1 Demand		$94,058,739	$85,527,697	$8,531,042	$56,955,327	$4,029,999	$21,589,423	$1,649,094	$25,401,063	$4,285,748
45	Administrative & General		$141,768,184	$132,687,129	$9,081,055	$83,447,756	$5,574,921	$29,625,671	$2,633,539	$38,560,984	$7,052,641
46	Depr. & Amort. - DEMPROD1 Related	Dem-A&E	$131,357,492	$129,843,152	$1,514,340	$72,941,092	$4,253,605	$22,126,045	$2,710,456	$36,232,953	$7,618,033
47	Depr. & Amort. - Non-DEMPROD1 Demand		$190,168,510	$155,915,840	$34,252,670	$92,306,856	$6,041,657	$31,248,313	$2,951,693	$43,982,063	$8,083,130
48	Depreciation & Amortization Expense		$321,526,002	$285,758,992	$35,767,010	$165,247,949	$10,295,262	$53,374,358	$5,662,148	$80,215,017	$15,701,164
49	*Amort. of Gain - DEMPROD1 Related*	*Dem-A&E*	($4,575,723)	($4,522,972)	($52,751)	($2,540,839)	($148,171)	($770,741)	($94,416)	($1,262,143)	($265,368)
50	Amort. of Gain - Non-DEMPROD1 Demand		($2,037,914)	($2,005,082)	($32,832)	($950,665)	($61,369)	($287,949)	($36,309)	($458,644)	($106,393)
51	Amortization on Gain		($6,613,637)	($6,528,054)	($85,583)	($3,491,504)	($209,540)	($1,058,690)	($130,726)	($1,720,788)	($371,761)
52	*Regulatory Assets*		($2,203,511)	($2,203,511)	$0	($1,144,246)	($65,676)	($342,833)	($38,994)	($575,685)	($121,058)
53	Pro-Forma Energy Related - Jurisdictional	Energy100'	$61,052,503	$60,070,266	$982,237	$29,401,291	$1,871,459	$8,863,649	$1,114,357	$14,287,539	$3,264,286
54	Pro-Forma Energy Related - ACC	Energy100'	$269,376,144	$269,376,144	$0	$131,845,700	$8,392,281	$39,747,712	$4,997,168	$64,070,335	$14,638,205
55	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$18,114,000	$18,114,000	$0	$9,044,540	($677,719)	$3,428,524	($350,866)	$5,867,427	$777,174
56	Pro-Forma OATT Transmission Expense	4-CP Trans.	$3,202,002	$3,202,002	$0	$1,662,745	$95,436	$498,183	$56,664	$836,549	$175,914
57	Pro-Forma - DEMPROD1 Related	Dem-A&E	$116,501,191	$115,144,635	$1,356,556	$64,684,008	$3,772,088	$19,621,331	$2,403,626	$32,131,307	$6,755,656
58	Other Pro-Forma Expenses		$36,315,529	$29,887,486	$6,428,043	$19,277,356	$1,375,322	$7,618,243	$540,430	$8,232,734	$1,510,627
59	Total Pro-Forma Non-Energy Related		$485,465,132	$477,680,533	$7,784,599	$85,624,109	$5,242,846	$27,737,757	$3,000,720	$41,200,590	$8,442,197
60	Proforma Adjustments		$504,561,369	$495,794,533	$8,766,836	$255,915,640	$14,828,867	$79,777,642	$8,761,378	$125,425,891	$27,121,862
61	Taxes Other than Income - DEMPROD1 Related	Dem-A&E	$50,248,418	$49,669,135	$579,283	$27,902,288	$1,627,139	$8,463,916	$1,036,835	$13,860,257	$2,914,140
62	Taxes Other than Income - Non-DEMPROD1 Demand		$89,722,351	$66,663,521	$23,058,830	$39,874,250	$2,591,374	$13,445,256	$1,266,994	$19,113,706	$3,456,919
63	Taxes Other than Income		$139,970,769	$116,332,656	$23,638,113	$67,776,537	$4,218,513	$21,909,172	$2,303,830	$32,973,963	$6,371,059
64	Income Tax		$185,532,145	$175,969,046	$9,563,098	$104,348,376	$6,264,823	$32,192,966	$3,571,530	$51,971,949	$10,347,108
65	TOTAL OPERATING EXPENSES		$3,530,554,018	$3,500,275,526	$30,278,491	$1,843,450,740	$115,951,518	$580,898,581	$65,755,767	$890,613,907	$190,230,968
66											
67	OPERATING INCOME		$428,794,038	$389,942,605	$38,851,433	$225,316,542	$13,494,644	$72,236,261	$7,552,806	$110,452,647	$21,580,183
68											
69	RETURN		$428,794,038	$389,942,605	$38,851,433	$225,316,542	$13,494,644	$72,236,261	$7,552,806	$110,452,647	$21,580,183
70											
71	RATE OF RETURN (EQUALIZED)		8.05%	8.73%	4.51%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
72											
73	INDEX RATE OF RETURN		1.00	1.08	0.56	1.08	1.08	1.08	1.08	1.08	1.08
74											
75	ACC JURISDICTION INDEX RATE OF RETURN			1.00		1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs, 4-CP for Transmission
Expenses and Avg and Excess Demand Allocator
for the 12 Months ending Sep. 30, 2005
($)

	1	2	12	13		14	15	16	17	18
Line No.	Description	Allocation Factor	Total General Service	E-20 Church Rate	E-30, E-32 Total	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401 - 999 kW)	E-32 (1,000 + kW)
	SUMMARY OF RESULTS									
16	Rate Base - Production Demand Related Related		$896,218,080	$5,464,184	$758,125,412	$105,885,022	$179,496,608	$218,919,573	$153,012,872	$100,811,337
17	Rate Base - Non-Production Demand Related		$854,225,856	$5,024,719	$782,470,326	$199,974,829	$228,016,761	$182,924,012	$102,041,558	$69,513,166
18	TOTAL RATE BASE		$1,750,443,936	$10,488,903	$1,540,595,739	$305,859,852	$407,513,370	$401,843,584	$255,054,430	$170,324,503
19										
20	DEVELOPMENT OF RETURN									
21	Revenues from Rates		$967,398,538	$3,344,799	$830,331,951	$142,275,889	$218,138,380	$229,640,445	$146,123,538	$94,153,699
22	Proforma to Revenues from Rates		$29,741,269	$241,901	$28,840,638	$9,060,700	$3,862,319	$13,851,012	$1,053,159	$1,013,448
23	Other Electric Rev. - DEMPROD1 Related	Dem-A&E	$1,945,197	$11,860	$1,645,474	$229,818	$389,589	$475,154	$332,107	$218,806
24	Other Electric Rev. - Non-DEMPROD1 Demand		$660,762,846	$1,831,702	$533,997,696	$66,688,203	$126,503,294	$154,505,708	$106,969,017	$79,331,474
25	Other Electric Revenues		$662,708,043	$1,843,562	$535,643,170	$66,918,021	$126,892,882	$154,980,862	$107,301,124	$79,550,280
26	TOTAL OPERATING REVENUES		$1,659,847,850	$5,430,262	$1,394,815,759	$218,254,610	$348,893,581	$398,472,319	$254,477,821	$174,717,427
27	Revenue Increase Required to Achieve Equalized ROR		$78,342,669	$1,279,597	$55,560,462	$6,231,970	$5,479,599	$9,046,662	$15,142,943	$19,659,288
28	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$1,738,190,519	$6,709,859	$1,450,376,221	$224,486,580	$354,373,180	$407,518,982	$269,620,764	$194,376,715
29	Percent Increase		7.86%	35.68%	6.47%	4.12%	2.47%	3.72%	10.29%	20.66%
30										
31	OPERATING EXPENSES									
32										
33	O&M Energy Related									
34	Energy Production	Energy1	$37,182,385	$101,497	$29,995,769	$3,687,388	$7,082,367	$8,703,502	$6,038,893	$4,483,619
35	Energy Production - Related Fuel (M&T)	Energy2	$421,343,530	$1,150,143	$339,906,198	$41,784,757	$80,256,003	$98,626,385	$68,431,554	$50,807,500
36	Energy Production - Related Fuel	Energy100	$430,410,906	$1,256,908	$349,267,098	$43,043,545	$82,787,067	$101,682,496	$70,057,238	$51,696,753
37	Total O&M Energy Related		$888,936,821	$2,508,548	$719,169,065	$88,515,690	$170,125,436	$209,012,382	$144,527,685	$106,987,872
38	OATT Transmission Expense	4-CP Trans.	$55,972,307	$127,881	$48,296,185	$9,759,609	$13,213,344	$12,483,728	$6,900,440	$5,939,065
39	O&M - DEMPROD1 Related	Dem-A&E	$98,463,571	$600,326	$83,291,932	$11,633,126	$19,720,509	$24,051,738	$16,810,857	$11,075,702
40	Other O&M		$44,883,775	$224,160	$41,415,905	$14,427,079	$11,348,002	$8,208,131	$4,555,030	$2,877,663
41	Total O&M Non-Energy Related		$199,319,653	$952,367	$173,004,022	$35,819,814	$44,281,855	$44,743,597	$28,266,326	$19,892,430
42	Operation & Maintenance		$1,088,256,473	$3,460,915	$892,173,087	$124,335,503	$214,407,292	$253,755,979	$172,794,011	$126,880,302
43	A&G - DEMPROD1 Related	Dem-A&E	$19,685,494	$120,021	$16,652,279	$2,325,772	$3,942,656	$4,808,584	$3,360,939	$2,214,328
44	A&G - Non-DEMPROD1 Demand		$26,031,855	$117,253	$23,184,673	$6,537,796	$6,375,679	$5,119,972	$3,059,330	$2,091,896
45	Administrative & General		$45,717,349	$237,274	$39,836,952	$8,863,568	$10,318,335	$9,928,556	$6,420,269	$4,306,224
46	Depr. & Amort. - DEMPROD1 Related	Dem-A&E	$54,199,690	$330,452	$45,848,397	$6,403,503	$10,855,238	$13,239,381	$9,253,607	$6,096,667
47	Depr. & Amort. - Non-DEMPROD1 Demand		$57,952,899	$300,598	$52,138,974	$12,305,221	$14,774,387	$12,735,350	$7,396,677	$4,927,340
48	Depreciation & Amortization Expense		$112,152,590	$631,050	$97,987,371	$18,708,724	$25,629,625	$25,974,731	$16,650,285	$11,024,007
49	Amort. of Gain - DEMPROD1 Related	Dem-A&E	($1,887,999)	($11,511)	($1,597,089)	($223,060)	($378,133)	($461,182)	($322,341)	($212,372)
50	Amort. of Gain - Non-DEMPROD1 Demand		($1,018,900)	($2,781)	($821,966)	($101,054)	($194,068)	($238,500)	($165,482)	($122,863)
51	Amortization on Gain		($2,906,898)	($14,292)	($2,419,055)	($324,114)	($572,200)	($699,682)	($487,823)	($335,235)
52	Regulatory Assets		($1,049,237)	($2,397)	($905,344)	($182,950)	($247,693)	($234,016)	($129,353)	($111,332)
53	Pro-Forma Energy Related - Jurisdictional	Energy100'	$29,679,067	$86,670	$24,083,780	$2,968,076	$5,708,598	$7,011,536	$4,830,810	$3,564,760
54	Pro-Forma Energy Related - ACC	Energy100'	$133,091,349	$388,660	$108,000,119	$13,309,894	$25,599,357	$31,442,188	$21,663,048	$15,985,633
55	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	$9,157,238	$56,452	$9,679,725	$2,669,378	$500,908	$6,436,947	$40,808	$31,684
56	Pro-Forma OATT Transmission Expense	4-CP Trans.	$1,524,685	$3,483	$1,315,588	$265,852	$359,931	$340,057	$187,968	$161,780
57	Pro-Forma - DEMPROD1 Related	Dem-A&E	$48,064,172	$293,044	$40,658,263	$5,678,613	$9,626,402	$11,740,656	$8,206,080	$5,406,512
58	Other Pro-Forma Expenses		$10,294,702	$19,362	$8,233,523	$1,798,875	$1,846,150	$1,980,516	$1,439,408	$1,168,574
59	Total Pro-Forma Non-Energy Related		$59,883,559	$315,890	$50,207,373	$7,743,340	$11,832,484	$14,061,228	$9,833,456	$6,736,866
60	Proforma Adjustments		$231,811,213	$847,672	$191,970,998	$26,690,688	$43,641,347	$58,951,899	$36,368,122	$26,318,942
61	Taxes Other than Income - DEMPROD1 Related	Dem-A&E	$20,733,105	$126,408	$17,538,470	$2,449,544	$4,152,474	$5,064,484	$3,539,799	$2,332,169
62	Taxes Other than Income - Non-DEMPROD1 Demand		$24,188,757	$136,603	$22,146,350	$5,498,775	$6,437,985	$5,310,601	$2,973,250	$1,925,739
63	Taxes Other than Income		$44,921,863	$263,011	$39,684,820	$7,948,319	$10,590,459	$10,375,086	$6,513,049	$4,257,908
64	Income Tax		$66,473,411	$370,945	$57,553,383	$11,745,277	$15,030,099	$14,385,484	$9,225,952	$7,166,571
65	TOTAL OPERATING EXPENSES		$1,585,376,764	$5,794,178	$1,315,882,213	$197,785,015	$318,797,263	$372,438,037	$247,354,512	$179,507,386
66										
67	OPERATING INCOME		$152,813,756	$915,681	$134,494,008	$26,701,565	$35,575,917	$35,080,945	$22,266,252	$14,869,329
68										
69	RETURN		$152,813,756	$915,681	$134,494,008	$26,701,565	$35,575,917	$35,080,945	$22,266,252	$14,869,329
70										
71	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
72										
73	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
74										
75	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

AECC's Adjusted Cost of Service Study Using Energy Scalars
for Fuel and Purchased Power Costs, 4-CP for Transmission
Expenses and Avg and Excess Demand Allocator
for the 12 Months ending Sep. 30, 2005
($)

Line No.	1 Description	2 Allocation Factor	19 E-34	20 E-35	21 E-38, 221 Water Pumping	22 Street Lighting	23 Dusk to Dawn
	SUMMARY OF RESULTS						
16	Rate Base - Production Demand Related Related		$66,126,575	$66,501,909	$30,790,817	$11,625,967	$2,268,193
17	Rate Base - Non-Production Demand Related		$43,509,581	$23,221,229	$15,703,526	$51,298,120	$23,620,450
18	TOTAL RATE BASE		$109,636,156	$89,723,138	$46,494,343	$62,924,087	$25,888,643
19							
20	DEVELOPMENT OF RETURN						
21	Revenues from Rates		$66,695,622	$67,026,166	$20,966,540	$12,913,053	$6,136,856
22	Proforma to Revenues from Rates		$23,659	$635,071	($102,439)	$431,212	$285,840
23	Other Electric Rev. - DEMPROD1 Related	Dem-A&E	$143,524	$144,339	$66,830	$25,234	$4,923
24	Other Electric Rev. - Non-DEMPROD1 Demand		$57,657,388	$67,276,060	$15,717,897	$8,074,267	$1,570,264
25	Other Electric Revenues		$57,800,912	$67,420,399	$15,784,727	$8,099,501	$1,575,187
26	TOTAL OPERATING REVENUES		$124,520,193	$135,081,636	$36,648,828	$21,443,766	$7,997,883
27	Revenue Increase Required to Achieve Equalized ROR		$10,989,273	$10,513,337	$6,768,986.5	$8,704,540	$1,696,328
28	TOTAL OPERATING REVENUES WITH REVENUE INCREASE		$135,509,466	$145,594,973	$43,417,814	$30,148,306	$9,694,211
29	Percent Increase		16.47%	15.54%	32.44%	65.23%	26.41%
30							
31	*OPERATING EXPENSES*						
32							
33	O&M Energy Related						
34	Energy Production	Energy1	$3,261,592	$3,823,527	$891,253	$327,752	$77,127
35	Energy Production - Related Fuel (M&T)	Energy2	$36,959,723	$43,327,466	$10,099,502	$3,714,023	$873,989
36	Energy Production - Related Fuel	Energy100	$37,374,165	$42,512,734	$10,358,616	$3,230,153	$767,046
37	Total O&M Energy Related		$77,595,480	$89,663,727	$21,349,371	$7,271,928	$1,718,163
38	OATT Transmission Expense	4-CP Trans.	$3,947,929	$3,600,312	$534,953	$0	$0
39	O&M - DEMPROD1 Related	Dem-A&E	$7,265,038	$7,306,275	$3,382,853	$1,277,294	$249,196
40	Other O&M		$1,920,634	$1,323,076	$1,129,940	$4,683,266	$1,261,065
41	Total O&M Non-Energy Related		$13,133,602	$12,229,663	$5,047,746	$5,960,560	$1,510,261
42	Operation & Maintenance		$90,729,081	$101,893,390	$26,397,117	$13,232,488	$3,228,424
43	A&G - DEMPROD1 Related	Dem-A&E	$1,452,475	$1,460,719	$676,323	$255,365	$49,821
44	A&G - Non-DEMPROD1 Demand		$1,422,774	$1,307,154	$666,263	$1,303,165	$571,087
45	Administrative & General		$2,875,249	$2,767,873	$1,342,586	$1,558,530	$620,908
46	Depr. & Amort. - DEMPROD1 Related	Dem-A&E	$3,999,071	$4,021,770	$1,862,106	$703,092	$137,171
47	Depr. & Amort. - Non-DEMPROD1 Demand		$3,222,674	$2,290,653	$1,251,393	$3,034,821	$1,369,871
48	Depreciation & Amortization Expense		$7,221,745	$6,312,423	$3,113,499	$3,737,913	$1,507,042
49	Amort. of Gain - DEMPROD1 Related	Dem-A&E	($139,304)	($140,095)	($64,865)	($24,492)	($4,778)
50	Amort. of Gain - Non-DEMPROD1 Demand		($89,377)	($104,775)	($24,423)	($8,981)	($2,113)
51	Amortization on Gain		($228,681)	($244,870)	($89,288)	($33,473)	($6,891)
52	Regulatory Assets		($74,006)	($67,490)	($10,028)	$0	$0
53	Pro-Forma Energy Related - Jurisdictional	Energy100'	$2,577,143	$2,931,474	$714,280	$222,736	$52,892
54	Pro-Forma Energy Related - ACC	Energy100'	$11,556,812	$13,145,757	$3,203,084	$998,825	$237,186
55	Pro-Forma Energy Related - ACC(Weather & Cust)	Assigned	($578,939)	$0	($125,097)	$37,319	$0
56	Pro-Forma OATT Transmission Expense	4-CP Trans.	$107,542	$98,072	$14,572	$0	$0
57	Pro-Forma - DEMPROD1 Related	Dem-A&E	$3,546,368	$3,566,497	$1,651,311	$623,501	$121,643
58	Other Pro-Forma Expenses		$872,134	$1,169,683	$265,356	$44,613	$5,459
59	Total Pro-Forma Non-Energy Related		$4,526,043	$4,834,253	$1,931,240	$668,114	$127,102
60	Proforma Adjustments		$18,081,060	$20,911,483	$5,723,507	$1,926,994	$417,180
61	Taxes Other than Income - DEMPROD1 Related	Dem-A&E	$1,529,772	$1,538,455	$712,315	$268,955	$52,472
62	Taxes Other than Income - Non-DEMPROD1 Demand		$1,221,461	$684,344	$513,393	$1,432,424	$654,697
63	Taxes Other than Income		$2,751,233	$2,222,799	$1,225,707	$1,701,379	$707,169
64	Income Tax		$4,582,549	$3,966,534	$1,655,759	$2,531,201	$960,300
65	TOTAL OPERATING EXPENSES		$125,938,230	$137,762,143	$39,358,858	$24,655,033	$7,434,132
66							
67	OPERATING INCOME		$9,571,236	$7,832,830	$4,058,956	$5,493,273	$2,260,078
68							
69	RETURN		$9,571,236	$7,832,830	$4,058,956	$5,493,273	$2,260,078
70							
71	RATE OF RETURN (EQUALIZED)		8.73%	8.73%	8.73%	8.73%	8.73%
72							
73	INDEX RATE OF RETURN		1.08	1.08	1.08	1.08	1.08
74							
75	ACC JURISDICTION INDEX RATE OF RETURN		1.00	1.00	1.00	1.00	1.00

Summary of Energy Cost Multipliers (Relecting Hourly Energy Cost Differences)

	Residential					
	E-10	E-12	EC-1	ET-1	ECT-1R	Residential Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0179	1.0275	1.0244	1.0398	1.0241	1.0323
Class Energy Rate (¢/kWh)	3.2475	3.2781	3.2684	3.3175	3.2674	3.2936
Energy Use @ Generation (MWh)	852,812	4,001,457	504,571	6,373,509	1,478,487	13,210,836
Energy Use @ Meter (MWh)	793,929	3,725,172	469,732	5,933,443	1,376,403	12,298,679
Energy Revenue ($)	$25,783,227	$122,115,055	$15,352,556	$196,840,323	$44,972,271	$405,063,432

	General Service								
	Church Rate E-20	0 - 20 kW E-21, E-23, E-30 E-32 & E-32 TOU	21 - 100 kW E-22, E-32 & E-32 TOU	101-400 kW E-32 & E-32 TOU	401-999 kW E-24, E-32 & E-32 TOU	1000 + kW E-32 & E-32 TOU	E-32 Total	E-34	E-35
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	1.0402	0.9805	0.9818	0.9813	0.9744	0.9685	0.9780	0.9625	0.9339
Class Energy Rate (¢/kWh)	3.3186	3.1282	3.1324	3.1308	3.1088	3.0898	3.1203	3.0707	2.9796
Energy Use @ Generation (MWh)	38,650	1,404,282	2,696,965	3,314,293	2,310,169	1,714,920	11,440,629	1,242,014	1,455,999
Energy Use @ Meter (MWh)	36,618	1,307,541	2,511,175	3,140,255	2,188,928	1,626,501	10,774,400	1,178,438	1,397,289
Energy Revenue ($)	$1,215,190	$40,901,867	$78,661,029	$98,314,070	$68,049,629	$50,255,946	$336,190,235	$36,186,552	$41,633,187

	Water Pumping E-38/E-221	Streetlights	Dusk to Dawn	ACC Total
Overall Retail Energy Cost (¢/kWh)	3.1904	3.1904	3.1904	3.1904
Class Cost Ratio (Step 3)	0.9762	0.8278	0.8353	1.0000
Class Energy Rate (¢/kWh)	3.1146	2.6410	2.6651	3.1904
Energy Use @ Generation (MWh)	339,389	124,808	29,370	27,881,695
Energy Use @ Meter (MWh)	321,550	114,924	27,044	26,148,942
Energy Revenue ($)	$10,014,931	$3,035,197	$720,749	$834,255,846

(Note: Hourly load data based on 12 months ending Sept. 30, 2005)
(Note: Overall energy cost of 3.1904 ¢/kWh based on 12 months ending Dec. 31, 2006)

Derivation of Transmission Demand Charges

E-32 General Service	Demand Units (Over 20 kW) [1]	Transmission Revenues (Over 20 kW)[1]	Proposed Transmission Charge
Total	25,196,428	$45,092,740	$1.790

E-34	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,327,022	$5,757,046	$2.474

E-35	Demand Units[1]	Transmission Revenues[1]	Proposed Transmission Charge
Total	2,310,533	$6,592,489	$2.853

1. Source DJR_WP9