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BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
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COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY AND FOR RELATED APPROVALS, AUTHORIZATIONS AND WAIVERS.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1602 ET SEQ.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165

NOTICE OF FILING COMMONWEALTH'S POST-HEARING BRIEF

Commonwealth Energy Corporation ("Commonwealth"), through undersigned counsel, hereby provides notice of filing Commonwealth's Post-Hearing Brief.

Arizona Corporation Commission
DOCKETED
AUG 30 1999
DOCKETED BY

DATED this 30th day of August, 1999.

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Phoenix, Arizona 85007

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Docket No. RE-00000C-94-0165 Service List

By Venus Green

BEFORE THE ARIZONA CORPORATION COMMISSION

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JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY AND FOR RELATED APPROVALS, AUTHORIZATIONS AND WAIVERS.	DOCKET NO. E-01933A-98-0471
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IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165 **COMMONWEALTH'S POST-HEARING BRIEF**

TABLE OF CONTENTS

1. INTRODUCTION

Commonwealth Energy Corporation ("Commonwealth") desires to serve all electric customers in Arizona, including residential and small business consumers. Commonwealth was not asked to participate in this Proposed Settlement involving Tucson Electric Power Company ("TEP"). Commonwealth was not entitled to review the assumptions and numbers behind TEP's stranded cost methodology and negotiated number. Recognizing these constraints, Commonwealth summarizes its positions and offers its recommendations on this Proposed Settlement.

The Commission Staff, through its expert, says that in order to have competition in electric services, the following must occur:

- assurance that all potential suppliers have fair access to customers;
- assurance that all potential suppliers have fair access to wires;
- the ability to identify and address market power in generation;
- customers must have the opportunity to purchase electric services from a supplier of their choice;
- customers must be informed of what they pay the utility for each service, so they can compare different providers;
- subsidization of unregulated services by regulated services must be avoided, otherwise the utility will have an unfair advantage over competitive suppliers; and
- disputes over stranded cost must be resolved.[1]

Commonwealth concurs with these principles. However, Commonwealth does not believe TEP's Proposed Settlement meets these objectives. Moreover, Commonwealth proposes that, at a minimum, the Commission and its electric structure promote the following conditions:

- open access for all customers;
- rates for services required of the utility be based on the full embedded cost of those services purchased from the utility or an equivalent "shopping credit" if those services

[1] Direct Testimony of Lee Smith (July 28, 1999) at 1 & 2.

are purchased from others;

- any competitive transition charge ("CTC") be reflected as a fixed amount per kilowatt per hour ("kWh"); and
- true comparability for receiving unbundled services, either under Standard Offer or the Direct Access tariff, be reflected on each customer bill so as to send "pricing signals" to consumers.

II. TEP's PROPOSED SETTLEMENT AWARDS STRANDED COSTS AT THE EXPENSE OF NEAR TERM ELECTRIC COMPETITION

1. Residential and Small Business Customers Should Be Entitled to Full Open Access and the Opportunity for Savings as Are Available to Large Customers.

Fundamental inequities result from lack of equal access for all consumers. Fourteen large customers already have special contracts.[2] Other large users (1 Mw and above) are entitled to choose immediately and they have an additional 45 megawatts eligible for competitive service if this Proposed Settlement is approved.[3] Large customers have other options. They may self-generate or enter into special contracts again. Special contract customers pay a lower unbundled rate, and consequently, they pay less stranded costs.[4] Large customers create stranded costs if they close down or purchase from others. Residential and small customers, on the other hand, must rely either on the Standard Offer or the Direct Access rates that encourage competitors to enter the market. Residential and small business electric demand continues to grow. They do not create the risk of stranded costs – when one homeowner leaves, two more are building new houses. If small customers are allowed to enter the competitive generation market only after the CTC has expired, residential and small business customers are denied electric savings that presently is available to large customers, during that long transition period.

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[2] TEP Exhibit No. 7.

[3] Proposed Electric Competition Rules, R14-2-1604.A.1; Proposed Settlement, section 1.2.

[4] Transcript II at 347 (Higgins); *see also* Transcript II at 397-398 (Smith).

Under the Proposed Settlement, customers will receive a modest pre-existing rate reduction of 2 percent to "compensate" for the "alternative" to savings generated by competition. This rate decrease does not constitute consideration in this Proposed Settlement. Moreover, no study has been performed by the settling parties on the rate reduction or the potential additional savings to consumers which will result from competition.[5] No study has been conducted on whether the Proposed Settlement will result in at least a 5 percent overall savings on the small customer's overall bill so as to encourage customers to switch from TEP's Standard Offer.[6]

No study or evaluation has been preformed by the Residential Utility Consumer Officer ("RUCO") on this Proposed Settlement. Not one dollar was spent by RUCO to obtain an expert opinion on whether or not this Proposed Settlement is in the best interest of residential consumers.

TEP assures the Commission and the public that "the settlement establishes a sound market structure that is very necessary for competitive retail access to become a reality."[7] To assure that this objective is met, competitive benchmarks should be imposed. Residential and small business customers should be entitled to receive competitive generation service immediately when open access commences. Commonwealth urges that at least 18,750 residential customers must be receiving competitive generation services by January 1, 2000 and 30,000 residential customers by October 1, 2000. This condition would be consistent with the Proposed Electric Competition Rules (R14-2-1604.B). If these minimum requirements are not met, the Commission should revisit and rehear ways in which to stimulate competition under the Proposed Settlement.

2. TEP's Proposed Settlement Is Confusing to Competitors and Consumers, and Fraught With Potential Future Disputes.

Before an Electric Service Provider ("ESP") might offer generation services, these steps must

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[5] Commonwealth Exhibits Nos. 2 & 3 (RUCO has not performed any study); Commonwealth Exhibit No. 8 (TEP performed no study).

[6] Commonwealth Exhibit No. 13 (Request No. 5 (rr)); Transcript II at 395 (Lee Smith) (At least 10% savings was needed before customers switched in New Hampshire)..

[7] Transcript, I at 11 (lines 18-20) (Brad Carroll).

be taken by TEP: (a) the on-peak market generation credit ("MGC") must be calculated 45 days in advance of the next quarter for each month of the upcoming quarter, using the average of the last 3 business days of the highly volatile NYMEX index (different wholesale prices will be used for each month),[8] (b) the off-peak MGC will then be computed using the California Power Exchange ratios for off-peak and on-peak power uses during the month of the prior year for each customer or customer class, (c) the summer to winter ratio of kWh hour use for each customer must be determined in order to calculate the particular Adder for that customer,[9] (d) the Adder will be adjusted annually looking at 12 months of data for each customer,[10] and (e) TEP's must-run costs must be calculated with the fixed must-run costs billed directly to the customer and the variable must-run costs billed to the ESP's scheduling coordinator for that customer.[11] The MGC and Floating CTC will vary monthly for each customer.[12] Disputes might arise as to how this generation shopping credit is figured. Additional complexity is created by the "credit" for overcollection of stranded costs and how it might be reflected as savings to customers when ESPs attempt to market competitive generation. The administrative cost of implementing this inscrutable program is unknown, but will likely be substantial and further drive up TEP's distribution costs.[13] No known use of this complex method and formulas have occurred elsewhere.[14]

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[8] Direct Testimony of Lee Smith (July 28, 1999) at 6 & 8; Higgins Rebuttal Testimony at 5.

[9] TEP Exhibit No. 7.

[10] Transcript III at 524-525 (Erdwurm).

[11] Transcript III at 527 (Erdwurm).

[12] Proposed Settlement, section 2.1(c).

[13] Commonwealth Exhibit No. 10 (TEP's Response to Request No. 5(m)); Transcript I at 75 (Pignatelli - cost of implementing open access will be reviewed in 2004 for rate adjustment); Transcript III at .

[14] Commonwealth Exhibit No. 2 (RUCO's Response to Request No. 2.b); Commonwealth Exhibit No. 11 (TEP's Response to Request No. 5(x)); Transcript I at 124 (Higgins); Transcript II at 391(Smith).

"The whole process of a floating CTC violates the fundamental first rule of marketing, which is to provide the consumer with a clear price signal," was the testimony of Mr. Frederick Bloom of Commonwealth.[15] Mr. Bloom went on to explain:

> Any confusion will work to the advantage of the incumbent monopoly where customers, in fear of the unknown, will choose to stay put. And consequently, their entire process, in my opinion, is designed to make it confusing, confound the consumer, and to sway them through inaction to keep their monopoly position.
>
> The floating CTC will prevent continuity of an advertising and marketing campaign and a customer acquisition campaign. It will leave the consumers guessing about the future. No consumer wants to switch every couple of months, especially if wet ink signatures are required and what we call the proverbial jump through the hoops to figure out the savings you're going to get.
>
> * * *
>
> This process is like asking me to go to the grocery store to buy a tube of toothpaste that's based on some floating manufacturing cost of some plant in Illinois that's going to change from time to time. There's no clear price signal. The consumer cannot make an intelligent decision. When it comes to their energy bill, consumers are going to want to know that there's reliability, consistency. And if they have to reevaluate every couple of months, I doubt that professional energy analysts will be capable of doing this expeditiously, much less the average household or average consumer.[16]

Mr. Bloom testified that the Proposed Settlement will not result in competitive services for residential and small business consumers:

> This fixed CTC and floating CTC assumes that there's going to be customer loss. If this settlement is adopted, there's going to be very little customer loss because there's going to be very little competition because there is no room for profit for a new market entrant. You may have a few companies cherry pick the most desirable industrial loads, but there will not be competition in residential and small business marketplace, thereby eliminating the majority of the proposed stranded costs.[17]

Mr. Bloom later testified that the floating CTC "requires a recalculation on an ongoing basis of what the price is an ESP might charge a customer and what savings that might represent versus the

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[15] Transcript II at 288 (lines 15-17) (Bloom).

[16] Transcript II at 288 (line 24) - 289 (line 13) & 289 (line 17) - 290 (line 3) (Bloom); *see* Transcript II at 236 (Bloom).

[17] Transcript II at 292 (Bloom).

standard offer rate. It has to be recalculated on an ongoing basis, and that just drives up transaction costs and is going to be seen as a barrier to entry."[18]

UniSource recently sold its competitive affiliate, New Energy Ventures, now known as New Energy. Even though New Energy did not sell to residential customers, New Energy lost $20 million last year.[19] This illustrates the failed California approach in using the floating CTC to capture the differential between a structured wholesale market (similar to TEP's structured NYMEX wholesale price) and the true cost of the incumbent utility's generation cost. Commonwealth has been able to serve residential and business customers in California, because of the green power subsidy; without that program there would be no competition for those consumers.[20] If Arizona imports this California approach, Commonwealth believes it is doomed to the same failure in creating open access for all consumers, at least until the CTC is discontinued. Commonwealth's Attachment FB-S1 compares the Arizona and California approaches, and a copy thereof is attached to this brief.

3. TEP's Adder Does Not Cover "Retailing Costs" and the MGC and Adder Does Not Reflect TEP's Embedded Cost of Generation.

ESPs must be able to sell <u>retail</u> generation at a price greater than the generation wholesale index (MGC), plus the Adder, before earning a profit. ESPs must also beat TEP's Standard Offer, which is not possible because the MGC, Adder and other expenses are used to calculate the "residual" CTC which equals the Standard Offer rate. What is left over after paying all of TEP's expenses and CTC is the Adder. The net result is that all ESP retailing costs and potential profit must be found in the Adder.[21]

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[18] Transcript II at 332 (Bloom).

[19] Transcript II at 478-479 (Pignatelli).

[20] Transcript II at 316-317 (Bloom).

[21] "The ESP has the amount of the adder available from which to undersell the standard offer." "The ESP will have to cover its marketing costs from the Adder. AECC expects that these costs will vary across ESPs and over time. The Adder is a negotiated number and does not include a retail marketing calculation component as such." AECC Response to Commonwealth' Second Set of Data Request (July 29, 1999), Nos. 6 & 7 in Commonwealth Exhibit No. 1. Transcript I at 120 (Higgins).

The Adder proposed was negotiated.[22] In the opinion of Mr. Kevin Higgins, "the higher the adder is, the less stranded cost the utility recovers."[23] No study was performed on whether or not this Adder would result in a viable competitive option for consumers.[24] The modest Adder proposed by TEP only reflects the "shaping" of the 100% load factor wholesale index to expected retail actual use. The Proposed Settlement states "that the purpose of the Adder is to estimate the cost of supplying power to a specific customer or customer group and stratum relative to the value of the NYMEX future prices used in the calculation of the market price for a one hundred percent (100%) load factor."[25] The Adder does not begin to address all the retailing costs. Commonwealth urges that the Adder not be negotiated, rather that the MGC and Adder be reflective of TEP's full embedded cost of generation.

4. The Adder Should Be at Least 8.2 to 11.8 Mills for Small Customers and 6.4 to 8.5 Mills for Large Customers.

TEP is proposing only a load-shaping Adder ranging from 3.84 to 6.24 mills per kWh for small customers and 3.0 to 3.96 mills per kWh for large customers, as revised during the hearing.[26] For competition to occur, a retailing cost Adder of at least 8.2 to 11.8 mills for small customers, such as residential and general service customers, and 6.4 to 8.5 mills for large customers, is recommended by Dr. Richard Rosen.[27] Commonwealth urges that the Proposed Settlement be modified to include

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[22] Commonwealth Exhibit No. 1 (AECC - Response No. 1, July 29, 1999); Commonwealth Exhibit No. 2 (RUCO - Response No. 2.1 & 2.m on page 6); Transcript III at 545-546 (Erdwurm); Bentley Erdwurm Rejoinder.

[23] Transcript I at 125 (lines 6-8) (Higgins).

[24] Commonwealth Exhibit No. 11 (TEP Response).

[25] Proposed Settlement, section 2.1(e). Testimony of Mr. Pignatelli conflicts with the Proposed Settlement's language and TEP's discovery response: "The adder is a mix of many things that were developed under extensive discussion and negotiation, and it includes all avoided costs necessary to shape the Palo Verde NYMEX 100 percent load factor to the load factor of a specific group. And, in fact, it was increased to provide an unspecified amount to provide more incentive for competition." Transcript I, at 54 (lines 3-9) (Pignatelli).

[26] TEP Exhibit No. 7 ("Adder Associated with MGC - Rider No. 1 - Addendum Revised"); Transcript III at 507-508 (Higgins).

[27] Transcript I at 127 (Higgins); Transcript I at 170-171(Patterson).

the retailing cost Adder proposed by Dr. Rosen, on an interim basis.[28] Excepts of Dr. Rosen's January 1998 Testimony which was used in Commonwealth's data requests and during the hearing is attached as Commonwealth Post-Hearing Attachment A.[29]

Mr. Bloom testified that the costs of information technology, billing and collections, meter installation, advertising, customer acquisition costs and so forth in California serve as a proxy for that level of a new entrant's costs in Arizona.[30] Based upon those costs and the proposed Adder, he concluded there would be a negative margin for new entrants.[31]

Retailing costs include marketing, power procurement, load balancing, power scheduling, risk management, general and administrative, and other expenses. TEP, in contrast, collects these costs from all of its customers, including those that desire Direct Access service. Consequently, the load-shaping Adder does not reflect these retailing costs, and therefore it is anticompetitive because Direct Access customers are paying twice for those services.

Dr. Richard Rosen is the only witness who has studied the retailing costs of the Adder in promoting competition. Dr. Rosen addressed three separate issues: the unbundling of costs, the amount of the Adder, and the computation of expected stranded costs. In unbundling the costs, Dr. Rosen used the data filed by TEP with the Federal Energy Regulatory Commission ("FERC") in its Form 1. In addressing the Adder, Dr. Rosen studied ESPs' retailing costs incurred on top of buying wholesale power. These unbundling and Adder issues are separate from the stranded cost magnitude and methodology issues, as contested by the settling parties. No evidence, including any rebuttal

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[28] Transcript II at 284 (Bloom).

[29] Direct Testimony of Dr. Richard A. Rosen (Jan. 21, 1997 - sic 1998] in A.C.C. Docket No. U-0000-94-165 (submitted on behalf of RUCO), Cover Sheet, Table of Contents, pages 28-39, & Exhibit RAR-3.

[30] Transcript II at 316 (Bloom).

[31] Transcript II at 315 (Bloom).

testimony, refutes Dr. Rosen's testimony regarding the retailing cost Adder necessary for competition to occur.[32]

Without including the retailing cost Adder, ESP's may only compete if they purchase power significantly lower than the Palo Verde NYMEX price or make significant profits on value-added services, such as the selling of load controllers and other electric apparatus, according to TEP's Mr. Jim Pignatelli.[33] Neither option is feasible.

Generation suppliers cannot be expected to consistently purchase power below the NYMEX price for several reasons. First, the Palo Verde NYMEX is the "going" market price; that is why TEP claims it is using it as the wholesale index for its stranded cost calculation. Second, the competitor does not begin with an assured large customer base in which to purchase large volumes over a long term. Generation competitors will have to purchase on a short term basis subject to variances in the success of their marketing efforts, which is more reflective of the wholesale NYMEX index. Third, occasional purchases below the Palo Verde NYMEX price will obviously be offset by other purchases which will be above the Palo Verde NYMEX price. In other words, over a relatively moderate time period, the competitors average purchase price of wholesale power will likely mirror the Palo Verde NYMEX. Fourth, significant costs are incurred in operating a trading desk in which to purchase wholesale power, particularly when only a limited number of customers are free to purchase competitive generation. TEP's trading costs are included in its generation cost component which is paid for by all customers.[34] Fifth, all ESPs will have to purchase some must-run generation from TEP.[35] Thus, it is difficult to forecast the quantity of power that might be forward contracted because the delivery of must-run will not be known until shortly before the electricity will be used.

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[32] *See* RUCO Exhibit No. 2; TEP Notice of Filing Amended Settlement Agreement and Late Filed Exhibit (August 19, 1999)(TEP's cross-examination of Dr. Rosen on Feb. 17, 1998).

[33] Transcript I at 58 & 59 (Pignatelli).

[34] Transcript III at 484-487 (Pignatelli).

[35] Transcript II at 342-343 (Higgins).

Sixth and perhaps most important, generation owners in reality don't sell below the going wholesale price, as pointed out by Mr. Bloom. It would be "suicide for their job careers" if those generation traders reported to their boards that they were selling power at a discount below the going market price.[36]

Offering value added services cannot offset the retailing costs of selling the electric commodity. Commonwealth sells ancillary products that are energy efficiency devices along with the electric commodity. "However, 99 percent of those sales are to people who are existing customers who are taking [electric] commodity service from us," according to Mr. Bloom.[37] "So to contend that an energy service provider can come into the marketplace and lose money on its core product [electric sales] and make it up on an ancillary product simply shows the lack of experience of ever having had to do any marketing."[38] Customers switch to save on their total electric bill; not to purchase load controllers or other electric apparatus.

The Proposed Settlement allows for changes in the Adder as of January 1, 2005. However, this would be too late to correct the problem. Furthermore, the purpose of this 2005 adjustment is solely to address changes in load shapes of rate classes and changes in relative prices for on-peak and off-peak periods, not the adequacy of the Adder in stimulating a competitive generation market.[39]

Commonwealth recommends that the Adder (Rider No. 1 - Addendum) be increased by 5 mills per kWh for residential & general service customers and 3 mills per kWh for large general service, large light & power rate 14 and contract customers, pending the completion of TEP's cost of service study by June 30, 2000.

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[36] Transcript II at 337-338 (Bloom).

[37] Transcript II at 337 (lines 4-6) (Bloom).

[38] Transcript II at 337 (lines 10-14) (Bloom).

[39] Commonwealth Exhibit No. 11 (TEP's Response to Request No. 5(v)); Transcript III at 542-543 (Erdwurm).

5. Treatment of the Fixed CTC in the Proposed Settlement Conflicts with the Testimony.

AECC testified that the expiration of the Fixed CTC will not increase the Floating CTC.[40] However, the Floating CTC is defined in Section 2.1(c) of as the difference between the Standard Offer rate minus the Fixed CTC, MGC, Adder and all other TEP expenses. Commonwealth's Attachment FB-S1 further illustrates this point, which means TEP will be overcollecting stranded costs.

6. TEP's T&D Costs Have Increased and the Proposed Settlement Shifts TEP's Generation Costs to T&D.

TEP's distribution costs rose 18 percent since its last rate case, even with TEP's load growth of 15 percent over the past 5 years.[41] A comparison of the before and after cost components is instructive. Under TEP's present tariffs, the unbundled costs for generation and transmission and distribution ("T&D") are:

Cost Component	Percentage[42]
Generation	**67%**
Transmission and Distribution	33%

If this Proposed Settlement is approved, TEP's cost allocation will be as follows:

Cost Component	Percentage[43]
Generation	**36%**
Transmission and Distribution	52.5%
CTC	11.5%

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[40] Transcript I at 136 (Higgins), *see also* Transcript I at 181(Patterson).

[41] Transcript I at 21 (Ken Sundloff); Transcript I at 239 (Nichols); Transcript II at 299 (Bloom).

[42] Transcript I at 62 (Pignatelli).

[43] TEP Exhibit No. 9 (the residential bill of $94.44 reflects MGC + adder of $33.30 or 36%; Fixed CTC of $9.39 + Floating CTC of $1.42 or 11.5% of the bill, and the balance is 52.5%).

These figures reflect that cost shifting has occurred and unbundled services are not based on their full embedded costs.[44] "[I]t appears that lots of different expenses, for example, have been allocated to distribution," according to Mr. Robert Nichols of New West Energy.[45] Because of the constraint to unbundled rate levels, Staff's Ms. Lee Smith testified it "mean[s] that customers are paying more for other distribution services than the allocated costs. And probably this was accomplished through a shifting of administrative and general costs from one function to another."[46] Questions remain as to the proper allocation of TEP's costs between ACC (distribution) and FERC jurisdiction (transmission).[47] Furthermore, the lack of cost of service rates, the absence of annualized embedded cost generation credit, and the use of decremental metering and billing credits support the conclusion that no significant competition, at least for small customers, will likely occur until the CTC expires.

7. Five Years Is Too Long in Which to Review TEP's Cost of Service.

"The unbundled rates in the Settlement are a result of negotiations between the parties in which all parties compromised on a variety of issues," according to RUCO.[48] TEP's unbundled rates are not based upon an approved cost of service study.[49] Much debate has occurred on the reasonableness of these proposed rates.[50] Cost justification for TEP's services, and the allocation of those costs, uses the 1994 test year.[51] These costs may have changed because of depreciation,

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[44] Transcript II at 335 (Bloom).

[45] Transcript I at 201 (Nichols).

[46] Transcript II at 383 (lines 6-10) (Smith).

[47] Transcript I at 197 (Nichols).

[48] Commonwealth Exhibit No. 2 (RUCO Response to No. 2.o on page 6); Transcript I at 156 (Patterson).

[49] Transcript I at 105-106 & 139-140 (Higgins).

[50] Transcript I at 192 (Robert Nichols - New West Energy).

[51] Transcript I at 74 & 75 (Pignatelli); *see* Transcript I at 150-151 (Higgins); Transcript I at 237 (Nichols).

interest rates and customer growth.[52] Further review would be postponed for another five years, until 2004 with the new rates going into effect on January 1, 2005. The T&D rates affect the amount of the Floating CTC.[53] By that time, the Commission may not have jurisdiction over TEP's generation assets and it is unclear as to how the Commission could reallocate generation and T&D costs after generation assets are transferred. Moreover, the Commission may implicitly be affirming forever the cost allocation methodology of TEP by approving this Proposed Settlement. If substantial competition does not occur, approval of the Proposed Settlement would preclude the Commission from reevaluating TEP's cost of service, while the rest of the Nation moves forward with electric competition. Commonwealth urges that a current cost of service study be ordered and the hearing be completed no later than June 30, 2000 and thereafter the actual embedded costs be unbundled and allocated in accordance with the Proposed Electric Competition Rules.

8. Stranded Costs Should Be Determined Only After the Cost of Service Study With a Fixed CTC.

During the cost of service hearing, the Commission could publicly review the assumptions and projections used by TEP in computing its expected strandable costs. Pending that decision, the Commission could order the recovery of the 9.3 mill per kWh Fixed CTC as set forth in the Proposed Agreement. Following the cost of service and stranded cost proceeding, a Fixed CTC could be set at a level and duration, with possibly securitization, so as to allow for both the recovery of verified and fully mitigated stranded cost recovery <u>and</u> actual commencement of electric competition. The Fixed CTC could then be adjusted accordingly.

9. Dr. Rosen's January 1998 Stranded Cost Study Is the Only Study Admitted into Evidence in This Proceeding on TEP's Stranded Cost.

TEP's stranded cost figure was negotiated. No study other than Dr. Rosen's January 1998 work was relied upon. In response to Commonwealth's data request, RUCO said:

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[52] Transcript I at 151 (Higgins).

[53] Transcript I at 207 (Nichols).

> RUCO performed a study on TEP's stranded cost, which was included in the direct testimony of Dr. Richard Rosen dated January 21, 1998 in Arizona Corporation Commission Docket No. U-0000-94-165. . . RUCO has not performed or reviewed any other such studies.[54]

The stranded cost calculation methodology, assumptions and figures were not made public. However, it appears that TEP is using the Net Revenues Lost approach. Not all differences between expenditures and income are to be considered stranded costs, even though the Proposed Settlement reaches that result. By allowing TEP to recover all changes in revenues through the floating CTC, TEP will have no incentive to be efficient, lower its distribution costs, or mitigate its strandable costs. Although the settling parties have airbrushed Dr. Rosen's testimony on TEP's stranded cost, it is the only evidence in this proceeding on TEP's stranded cost.[55]

As we heard during the hearing, TEP will likely claim that it is "efficient" and ESPs are "inefficient" if they are unable to compete in TEP's service area, even though TEP brought us the Springerville Generating Station and the Adder proposal does not reflect TEP's embedded costs of generation.[56] Commonwealth and other parties should have the ability to review the projected market prices, projected loss of customers and other assumptions and data that were used in the negotiated stranded cost number used in setting the CTC and affects the ability to compete.

10. Standard Offer and Direct Access Billing Components for Services Purchased from TEP Should Be Comparable and Provide Price Signals to Consumers.

Until there is comparability between cost components in the Standard Offer and Direct Access tariffs, TEP will continue to maintain and expand its customer base. The actual transition to open retail access will become more difficult in the future as the disparity between these cost components increase.

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[54] Commonwealth Exhibit No. 2 (RUCO's Response to Data Request 2.a on page 5).

[55] Transcript II at 284 (Hearing Officer Rudibaugh).

[56] Transcript I at 52 (James Pignatelli). The Fixed CTC is in essence a Springerville charge. Of the $450 million Fixed CTC amount, all but approximately $60 million which is associated with Income Taxes Recoverable Through Future Rates is attributable to Springerville. New West Energy Exhibit No. 2.

With respect to metering and billing credits, Commonwealth concurs with the Staff's recommendation that they be based on the full unbundled embedded costs.[57] Commonwealth also concurs with TEP that the CTC, system benefit charge and generation shopping credit be illustrated on all customer bills for comparison.[58] Commonwealth further urges that the bill format reflect the comparative cost of services and shopping credits for transmission and distribution, generation, metering, meter reading, and billing & collection services.

11. Market Value Rather than the Net Revenue Approach Should Be Used in Transferring TEP's Generation Assets.

The divestiture of TEP's generation will determine its true strandable cost, which Dr. Rosen estimated having a 1998 present value of just $84.1 million -- substantially less than $676 million in the Proposed Settlement.[59] TEP intends to recover $250 million from the Fixed CTC, plus additional "above market"generation compensation from the Floating CTC.[60] The Commission could declare a failed auction if bids are inappropriate. TEP claims the time needed to transfer its generation assets to a TEP affiliate or by auction would be about the same.

TEP proposes using its stranded cost method used in this Proposed Settlement as the measure of the value of its generation assets, which is more like book value than market value.[61] Under the Proposed Settlement, above-market value will be recovered from TEP's customers and the "fair value" under General Accepted Accounting Principles ("GAAP") will be used to transfer those generation assets to TEP's affiliate.[62] This is not an arms length transaction value between buyers and sellers. As testified to by Mr. Bloom, an open auction is the only true method of determining TEP's

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[57] Direct Testimony of Lee Smith (July 28, 1999) at 7; Transcript II at 382-383 (Smith).

[58] Transcript III at 522 (Erdwurm).

[59] Transcript I at 168 (Patterson); Transcript II at 353 (Higgins).

[60] Transcript I at 196 (Nichols).

[61] Transcript I at 141-142 (Higgins); Transcript II at 432 (Smith).

[62] Transcript II at 433-434 (Smith).

potential strandable generation costs:

> Market numbers come from only one method, an open auction to the free market. Any other GAAP, measure or cost-based analysis is not a true measure of the market value. Market value, period, is what a willing buyer is willing to pay a willing seller.[63]

The "fair value" assumptions and figures for generation assets (and in computing the TEP's claim to stranded costs) have been declared confidential and proprietary by TEP.[64] TEP believes the GAAP FAS 121 fair value method will be greater than market value.[65] However, there is no evidence that will likely be the case. Commonwealth believes the assumptions and numbers must be publicly reviewed before the Commission and parties can actually determine if the "fair value" used by TEP represents the true market value of those generation assets. If the generation assets are not divested and sold at market value, Commonwealth urges that those assets be independently appraised (at the cost of TEP's generation affiliate) and any excess between the appraised value and the GAAP fair value be used to reduce TEP's stranded cost.

12. Uniform Transaction Affiliate Rules Should Be Adopted.

As Commonwealth has stated before, uniform transaction rules as were previously in the Electric Competition Rules will assure the public of consistent treatment for all participants. Therefore, Commonwealth urges the reinstatement of those affiliate transaction rules.

13. Transmission Access Through the AISA Will Not Likely Be Available Soon.

The Arizona Independent Scheduling Administrator ("AISA") is still working on protocols for open transmission and must-run service.[66] These protocols "are essential for the development of a competitive marketplace," according to AECC's Mr. Higgins.[67] The draft protocols must be

[63] Transcript II at 326 (lines 4-8) (Bloom).

[64] Transcript II at 436-437 (Smith).

[65] Transcript III at 466 & 491 (Pignatelli).

[66] *See* Commonwealth Exhibit No. 1 (Draft Protocols - Response to Request No. 2.a).

[67] Transcript II at 344 (lines 7-8) (Higgins).

approved by the AISA board and approved by FERC.[68] At certain times, ESPs must purchase must-run energy from TEP because of limited transmission availability to TEP's service area. The AISA proposes a framework in which TEP is urged to sell "must-offer" energy at regulated rates to ESPs, through their scheduling coordinator.[69] It is unclear how FERC will address these matters and it is uncertain as to how these additional must-run charges will affect competition.

III. SUMMARY AND CONCLUSION

Commonwealth is a strong advocate of electric competition and desires immediate open access which will allow competitors to compete. Commonwealth urges the Commission to avoid the mistakes of the California approach and employ the lessons of the Pennsylvania approach so that Arizona consumers will benefit from electric competition. Approval of this Proposed Settlement will delay choice, particularly for residential and small business customers, based upon the evidence. No study has been performed on this Proposed Settlement or its consequences.[70]

Commonwealth does not believe the Proposed Settlement presents a workable competitive paradigm. If this Proposed Settlement is not rejected, Commonwealth uges the following conditions be adopted:

1. "Competitive benchmarks" should be in place to assure that open retail access will actually occur, as suggested under Section 1 above.
2. Increase the Adder by 5 mills per kWh for small customers and 3 mills per kWh for large customers pending the completion of TEP's cost of service study, as recommended under Section 4.
3. During the interim, the Fixed CTC of 9.3 mills per kWh would be used until the completion of the cost of service study.

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[68] Transcript II at 365 (Higgins).

[69] *See* Commonwealth Exhibit No. 1 (Response No. 3 - July 29, 1999).

[70] None of the settling parties performed any study. Transcript I at 131 (Higgins).

4. A cost of service study verifying TEP's unbundled cost amounts and allocations be completed no later than June 30, 2000, with those costs used in unbundling TEP's Direct Access tariffs and in setting the generation, metering, metering and billing & collection shopping credits, as suggested under Section 6 above.

5. Verified stranded costs would be determined during the cost of service proceeding.

6. An independent appraisal of TEP's generation assets, paid for by TEP's generation affiliate, should be used to confirm the market value of those assets, and any excess between the appraised value and the GAAP fair value would be applied to TEP's Fixed CTC, as suggested under Section 11 above.

7. The final Fixed CTC would then be adjusted, based upon the final amount of the stranded cost and duration, so as to allow for robust competition to occur.

8. Uniform affiliate transaction rules as previously proposed in the Rules should be adopted in lieu of individual codes of conduct for each utility, as recommended under Section 12 above.

9. Oversight of the AISA and progress towards the RTO should be periodically reviewed by the Commission, as recommended under Section 13 above, and as also suggested by Staff.[71]

Commonwealth believes these changes to the Proposed Settlement will promote competition and savings for all Arizona consumers and provide TEP with the opportunity to recover its verified and legitimate stranded costs.

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[71] Direct Testimony of Lee Smith (July 28, 1999) at 3.

ATTACHMENT FB-S1

8/11/99

Generation Shopping Credit Comparison

TEP's MGC	CalPX	Commonwealth's Proposal
Palo Verde NYMEX + Adder for 100% wholesale load factor adjusted to retail class load profiles	Wholesale generation market	"Generation Shopping Credit" would equal the unbundled generation component (full embedded cost using annualized average for each direct access customer class)
CTC Fixed CTC[1] Floating CTC[2] (expands and contracts to reflect TEP's "imputed" generation cost differential from the Palo Verde NYMEX)	CTC	CTC - fixed for duration of recovery period
Margin is included in Adder, <u>without</u> retailing costs[3]	No margin and no significant competition is occurring in California	Margin is equal to difference in Customer's unbundled generation component and market price for generation.

c:\Commonwealth\Generation.tbl

[1] Average charge for customer class using TEP's average annual load factor (9.3 mills or 0.93 cents/kWh).

[2] This is the bundled Standard Offer rate <u>minus</u> the sum of MGC, Adder, Fixed CTC, and unbundled service charge for distribution, transmission, meter services, meter reading services, billing and collection, DSM, customer information and life-line discount system benefits charges, uncollectible accounts, ancillary services and fixed must-run generation. It runs through December 31, 2008 with possible adjustment after December 31, 2004.

[3] Retailing costs include marketing, advertising, procurement and scheduling, load forecasting, load balancing, financing costs, risk management, rate design, customer service and G&A costs.

COMMONWEALTH POST-HEARING ATTACHMENT A

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF	)	
COMPETITION IN THE	)	
PROVISION OF ELECTRIC	)	DOCKET NO. U-0000-94-165
SERVICES THROUGHOUT	)	
THE STATE OF ARIZONA	)	

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

Submitted on Behalf of
The Residential Utility Consumer Office

January 21, 1997 [sic 1998]

TABLE OF CONTENTS

LIST OF EXHIBITS

C. The Market Price of Retail Generation Services

Q. WOULD YOU BRIEFLY REVIEW THE CONCEPT OF "UNBUNDLING" AS IT RELATES TO THE CALCULATION OF STRANDED COSTS?

A. Again, unbundling refers to the process each utility must complete of dividing its current single or bundled rate into separate rates for customer services, transmission, distribution, and retail generation services. During this unbundling process, administrative and general costs (A&G) and various other common costs must be allocated fairly between these services. The resulting rates for transmission, distribution, and customer services would continue to be regulated by the ACC as monopoly services. However, the prices for retail generation services in Arizona will be competitive and set by the market beginning January 1, 1999. Thus, the difference between each utility's cost-based rate for retail generation services and the market price of retail generation is each utility's respective stranded cost for generation.

Q. WHAT TYPES OF COSTS WILL A COMPETITIVE SUPPLIER OF RETAIL GENERATION SERVICES LIKELY INCUR?

A. In addition to the cost of buying power at wholesale, the types of costs that a competitive supplier will incur to provide retail generation services fall into the following categories:

1. Generation-related customer services (e.g., billing, bill collection, responding to customer inquiries and complaints, arranging for new services or for switching services, etc.);

2. Ancillary services, such as load balancing and forecasting activities at the distribution circuit level needed to settle accounts with wholesale providers and to determine T&D charges and requirements, and risk management;

3. Marketing and advertising, including marketing incentives for new customers;

4. Generation-related administrative and general services, such as contracting for power, managing the aggregation company, providing office space to employees, etc.;

5. Profits and income taxes on profits; and

6. Other taxes.

Q. SHOULD EACH TYPE OF COST LISTED ABOVE BE INCLUDED IN THE MARKET PRICE FOR RETAIL GENERATION SERVICES USED TO COMPUTE STRANDED COSTS?

A. Yes, each type of cost listed above should be reflected in the estimated market price for retail generation services used to compute stranded costs. Each type of cost will be incurred by retail generation suppliers, regardless of whether they provide each and every service from in-house resources or whether they contract out certain services. Thus, projections of these retailing costs, which make up what I call the "retail margin," should be added to projections of competitive wholesale prices in order to derive a more accurate market price for retail generation services (an "RGS" market price) for computing stranded costs. Thus, it is the total market price for retail generation services as determined by alternative suppliers to the utilities that will determine the income that the existing utilities will be able to earn in the retail market.

Q. DID YOU EVALUATE THE LIKELY RETAIL MARGIN FOR APS, TEP AND SRP?

A. Yes, I did. The retail margin developed for each utility is a combination of A&G-related generation expenses developed in the unbundling process for each utility, and an estimate of the additional retail costs which would be incurred in order to sell generation services to customers within the State of Arizona.

Q. WHAT DID YOU ESTIMATE THE RETAIL MARGIN FOR APS, SRP, and TEP TO BE?

A. I estimated that a lower bound for the total retail margin would be about 0.77 cents per kWh in 1996 dollars. This is the sum of .50 cents per kWh for A&G related expenses, and a lower-bound estimate of additional retail services expenses of 0.27 cents per kWh. I have assumed that the retail margin would be the same for customers of all utilities within Arizona, since I have assumed the existence of a single state-wide retail market for generation.

Q. WHAT DOES THE CONCEPT OF RETAIL GENERATION SERVICES IMPLY FOR STRANDABLE COST CALCULATIONS?

A. The discussion above implies that the market price used to calculate costs that might become stranded due to retail competition must be the market price for retail generation services. Many parties have used wholesale market prices to calculate a utility's strandable costs, but by doing so, they have significantly over-estimated strandable costs.

In estimating ranges of the Affiliated Utilities' strandable costs, I have included the low retail adders appropriate for both small and large customers that I computed, and have weighted them across the 1996 sales of the small and large customer classes for the sum of APS' and TEP's retail sales in order to derive a low and a high value of the retail margin for the total load. Below, I will describe the full range of retailing costs that an efficient competitive supplier of retail generation services might incur in serving small and large customers. I will also provide estimates of the magnitude of each component of retail generation service cost. These estimates are summarized in Exhibit___(RAR-3), under the heading "Cost Components of a Retail Generation Services Adder."

Q. HAVE OTHER STATES ENDORSED THE CONCEPT OF MARKET PRICES OF RETAIL GENERATION SERVICES?

A. Yes, the New York State Public Service Commission, the New Hampshire Public Utilities Commission, and the Pennsylvania Public Utilities Commission have endorsed the concept of market prices of retail generation services for the purpose of establishing generation credits for pilot program participants.

In New York Case No. 96-E-0898, Rochester Gas and Electric identified thirteen "retailing functions" that would be the primary responsibility of the distribution company and fourteen retailing functions that would be the primary responsibility of the competitive supplier under retail competition. (See Exhibit___(RAR-11) for the list of retailing functions.) Furthermore, in New York Case No. 96-E-0948, the Commission established fixed adders to capture potential retailing generation costs and to encourage farms and food processors to participate in one of the state's retail pilot programs. The Commission set the retail adder at $4 per MWH for food processor participants (larger customers) and $10 per MWH for farm participants (smaller customers).[5]

In the New Hampshire pilot programs, the Public Utilities Commission approved a marketing cost credit of $3.70 per MWH for the state's 2-year pilot program for small customers. Finally, in Pennsylvania, the Commission concluded that for residential and commercial customers participating in the state's pilot programs, a retail generation credit of 3.0 cents per kWh should be adopted, along with a Customer Participation Credit ("CPC") of 13 percent of the difference between the current retail rate and the generation credit.[6]

Q. PLEASE BEGIN BY DISCUSSING EACH COST COMPONENT OF THE RETAIL MARGIN, IN PARTICULAR GENERATION-RELATED CUSTOMER SERVICE COSTS IN ORDER TO ILLUSTRATE HOW YOU DERIVED YOUR RESULTS IN EXHIBIT___(RAR-3).

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5 The difference is explained by the New York Public Service Commission as follows: Actual retail access experience may show that avoidable retail and other expenses are greater for smaller customers on a unit (per kWh) basis, and it also appears that more of a per unit (kWh) discount will be necessary to encourage the participation of such smaller customers in the programs." (Case 96-E-0948 - Order Establishing Retail Access Pilot Programs, page 7).

6 Docket Nos. P-00971168, P-00971169, P-00971170, P-00971171, P-00971172, P-00971173, P-00971175, and P-00971183. Motion of Chairman John M. Quain at 3 (August 21, 1997).

A. A key generation-related customer service cost is the cost of billing customers for retail generation services and collecting bill payments. Under retail generation services, there will also be customer calls to handle, including requests for information, requests for service, and complaints. Thus, generation-related customer service costs will at least include: 1) billing and collection service costs, and 2) costs to have customer service representatives available to answer telephone inquiries and requests from customers. Competitive alternative suppliers may do their own billing, they may pay the distribution company to do their billing for them, or they may pay a third party to do their billing. If they do their own billing, they will need to invest in computer systems to perform the task. If they pay the distribution company to do their billing, they should pay whatever the incremental cost is to the utility to perform this task. If they contract with a private billing company, they will pay according to their contract with that company.

Q. WHAT IS YOUR ESTIMATED RANGE FOR GENERATION-RELATED CUSTOMER SERVICE COSTS?

A. My estimates of generation-related customer service costs range from a low of \$1.00 per month per customer to a high of \$2.00 per month per customer, or about \$1.10 per MWH to \$2.20 per MWH, for small customers such as those served by APS and TEP, who together use an average of 917 kWh per month. My estimate of generation-related customer service costs is about \$0.50 per MWH for large customers in the low case and about \$1.00 per MWH in the high case.

My estimates are based, in part, on claims made by utilities in other states. As part of its pilot proposal, Pennsylvania Power & Light (PP&L) proposed a fee of $1.50 per bill for Billing and Collection Service, even though it claimed that its true cost would be $2.05.[7] Similarly, PECO Energy Company proposed a fee of $0.90 per bill.[8] It is important to note that so far, there is no evidence that the utilities' proposed fees reflect the true *incremental* costs that they would incur. Nonetheless, these proposed fees provide a conservative range of prices for *all* generation-related customer services, since my proposed ranges do not include any costs that a supplier would incur to install a billing and collection system or to answer customers' telephone inquiries and requests, outside of billing-related calls.

Q. PLEASE DISCUSS THE COSTS OF ANCILLARY GENERATION-RELATED SERVICES OTHER THAN THOSE THAT WILL BE PROVIDED UNDER TRANSMISSION TARIFFS REQUIRED BY FERC ORDER NO. 888.

A. There are likely to be additional generation-related ancillary services that were not identified in FERC Order No. 888. As I mentioned earlier, in New York Case No. 96-E-0898, Rochester Gas and Electric has identified twenty seven "retailing functions" that would be the responsibility of the distribution company and/or the competitive supplier. (Refer to Exhibit___(RAR-11) for the list of other potential ancillary services.) Of these twenty seven functions, ones such as "forecasting of customer energy requirements" and "scheduling of capacity and energy purchases

[7] Docket No. P-00971183, PP&L's Comments at 40 (May 22, 1997).

[8] Docket No. P-00971170, PECO's initial petition.

and delivery to the service area" could all be classified as additional generation-related ancillary services. These services will be either partially or fully the responsibility of alternative suppliers, depending on the responsibilities of the Independent System Operator (ISO).

Q. WHAT IS YOUR ESTIMATED RANGE FOR THE COSTS OF ANCILLARY SERVICES OTHER THAN THOSE THAT WILL BE PROVIDED UNDER TRANSMISSION TARIFFS REQUIRED BY FERC ORDER NO. 888?

A. In order to be conservative, my estimate of ancillary services other than those identified in FERC Order No. 888 ranges from $0 per MWH to $1.00 per MWH for both small and large customers under the low and high cases.

Q. PLEASE DISCUSS GENERATION-RELATED A&G COSTS.

A. All vertically-integrated utilities have incurred, and competitive alternative suppliers will continue to incur, generation-related A&G costs. These costs include those for corporate headquarters, salaries for top management, office supplies and services, administrative support, etc. Thus, when utilities properly unbundle their rates, they should allocate generation-related A&G to the generation component of rates. Furthermore, economic generation-related A&G should be moved to the utilities' own unregulated aggregation affiliates, if such affiliates are established as the sale of retail generation services become deregulated. This important aspect of unbundling has already been supported by some Pennsylvania utilities. For example, in the Code of Conduct proposed by

Pennsylvania Electric Company and Metropolitan Edison Company, the companies stated that "the LDC shall fairly allocate to its Affiliate costs for general administration or support services, ... so as not to give the LDC or its Affiliate an unfair advantage over competitors through an allocation of these costs."[9] This policy of fairly allocating generation-related A&G costs as the sales of retail generation services shift from the regulated utility to the unregulated subsidiary of the utility should be followed by all utilities, regardless of whether they only functionally unbundle, or whether they fully divest their generation function.

Q. WHAT IS YOUR ESTIMATE OF GENERATION-RELATED A&G COSTS FOR ALTERNATIVE SUPPLIERS?

A. My estimate of generation-related A&G costs is $5.00 per MWH for small and large customers in both low and high cases. This figure is based on APS' relatively low generation-related A&G costs, which I arrived at by allocating 71 percent of the utility's total A&G costs in 1996 to its generation function. The generation-related A&G value for SRP is almost identical. This figure is about 94 percent of my estimate of the 1994 national average generation-related A&G cost for investor-owned utilities (not corrected for inflation).[10] Therefore, I have made the assumption that efficient alternative suppliers could provide generation-related A&G at about the same cost as APS and SRP, since alternative suppliers will likely

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9 Companies' respective initial pilot proposal filings at 31.

10 The 1994 national average generation-related A&G component is approximately $5.30 per MWH and the national average bundled retail rate is $71.60 per MWH for investor-owned utilities.

try to keep their generation-related A&G costs to a minimum and APS and SRP appears to be fairly efficient as far as their generation-related A&G costs are concerned.

Q. PLEASE DISCUSS MARKETING AND ADVERTISING COSTS.

A. Competitive alternative suppliers will incur significant costs for marketing and advertising, which are costs that regulated vertically integrated utilities have not had to incur because their customers have been captive. (Sometimes the utilities have incurred these costs on a voluntary basis.) Alternative suppliers will have to incur large marketing costs initially to gain market share. They will have to make significant investments in marketing and advertising to foster good customer relations and to try to convince retail customers (especially smaller consumers) to switch from the existing service provider they know (and to which they may be loyal) to one they do not know.

Q. WHAT IS YOUR ESTIMATE OF MARKETING AND ADVERTISING COSTS?

A. My estimate of marketing and advertising costs ranges from a low of $1.00 per MWH to a high of $2.00 per MWH for small customers, and a low of $0.50 per MWH to a high of $1.00 per MWH for large customers. My estimated range derives, in part, from the New Hampshire pilot programs. There, the Public Utilities Commission approved a marketing cost credit of $3.70 per MWH for the state's 2-year pilot programs for small customers. The N.H. PUC arrived at this estimate by assuming that a competitive supplier participating in a 24 month pilot program would spend $44 on a customer who consumes an average of 500 kWh per month. Many alternative suppliers in the N.H. pilots offered to give each residential pilot participant approximately $25 as a "signing bonus" or roughly the equivalent in conservation measures and gifts. It is reasonable to assume that these suppliers will spend an additional $19 or more per customer over 2 years on other forms of marketing and advertising, such as telemarketing, multi-media advertising, and the like.

If suppliers in Arizona spend $44 in marketing and advertising over a 2-year period on small customers who consume an average of 917 kWh per month, then that it is equivalent to spending about $2.20 per MWH for small customers. Even if suppliers spend as little as $24 per customer on marketing and advertising, this is equivalent to spending about $1.10 per MWH on a customer who consumes 917 ,000 kWh per month for 24 months. I am assuming that the average customer may switch suppliers or need to be offered an incentive to stay with his/her existing supplier every 2 years or so. On a per MWH basis, marketers are likely to spend even less than this on large customers. This is why I chose the conservative range of $0.50 per MWH to $1.00 per MWH for large customers.

Q. ARE THERE ANY OTHER COST COMPONENTS THAT ALTERNATIVE SUPPLIERS WILL HAVE TO COLLECT FROM RETAIL RATEPAYERS IN THE LONG RUN?

A. Yes. If alternative suppliers want to stay in business during the mid- to long-term under retail competition, they will need to earn a profit margin on more than just their capital investment in generation, if they have any such investments. (Some alternative suppliers may purchase all their power from others.) Once they earn this profit margin, they will need to pay federal and state income taxes on it. Therefore, in the longer run, alternative suppliers will need to recover these types of costs through the prices they charge for retail generation services.

I have assumed a profit margin of 10 percent on the four above-mentioned components of the retail adder, and an income tax rate of 35 percent of the profit margin.

Q. PLEASE SUMMARIZE WHAT YOUR PROPOSED LOW AND HIGH RETAIL ADDERS ARE FOR SMALL AND LARGE CUSTOMERS.

A. Once the costs of the above components are added together, my proposed retail adder for small customers ranges from a low of $8.20 per MWH to a high of $11.80 per MWH. My proposed retail adder for large customers ranges from a low of $6.40 per MWH to a high of $8.50 per MWH. I then took a weighted average of the low and high estimates based the sum of APS' and TEP's 1996 retail sales by customer class that were cited in their 1996 FERC Form #1 data. Thus, my estimated retail adder, averaged across small and large customer classes, ranges from a low of 0.77 cents per kWh to a high of 1.1 cents per kWh. For my analysis of stranded costs I only utilized the low case value of 0.77 cents per kWh.

Cost Components of a Retail Generation Services Adder[1] (mills per kWh) Arizina Public Service Company (APS) & Tucson Electric Power Company (TEP)					
Sources	Cost Component	Small Customers[2]		Large Customers	
		- low case -	- high case -	- low case -	- high case -
1	Generation-related customer services	1.1	2.2	0.5	1.0
2	Other ancillary services not in current A&G	0.0	1.0	0.0	1.0
3	Generation-related A&G	5.0	5.0	5.0	5.0
4	Marketing and advertising	1.1	2.2	0.5	1.0
5	Subtotal	7.2	10.4	6.0	8.0
6	Profit	0.7	1.0	0.3	0.4
7	Income tax	0.3	0.4	0.1	0.1
8	Total	8.2	11.8	6.4	8.5

Weighted Average Retail Generation Services Adder Across Customer Classes APS & TEP– FERC Form 1 Data				
1996 Sales	Small Customers		Large Customers	
Residential Sales (MWH)		10,057,722		0
Commercial Sales (MWH)		9,540,588		0
Industrial Sales (MWH)		0		6,406,035
Total Sales to Ultimate Customers (MWH)		19,598,310		6,406,035
	- low case -	- high case -	- low case -	- high case -
Weighted Average Adder	7.7	11.0	7.7	11.0

Footnotes:

1 These retail adders are not intended to be estimates of appropriate "generation credits" for the purpose of stimulating competition in a pilot program.

2 Assumes a consumption of 917 kWh per month, average over APS and TEP small customers.

Sources

1 Billing and collection services, customer inquiries, etc.

2 Refer to Exhibit___(RAR-2) for a listing of these ancillary services.

3 APS: actual cost embedded in its average retail rate.

4 N.H. PUC set 3.7 mills per kWh in the N.H. pilots, based on expenditures of $44 per small customer (500 kWh per month) over two years.

5 Subtotal of lines 1-4

6 Profit = 10% of retail adder

7 Income tax = 35% of profit

8 Total of lines 5-7