0000112815

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED
AZ CORP COMMISSION
SEP 21 3 56 PM '98
DOCUMENT CONTROL

JIM IRVIN
COMMISSIONER-CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY AND FOR RELATED APPROVALS, AUTHORIZATIONS AND WAIVERS.

Docket No. E-10933A-98-0471

COMMENTS OF THE RESIDENTIAL UTILITY CONSUMER OFFICE

AND REQUEST FOR HEARING

The Residential Utility Consumer Office ("RUCO") hereby files the attached comments on Tucson Electric Power Company's ("TEP") stranded cost filing. RUCO requests that the Commission hold a hearing on TEP's interim competition transition charge. In addition, RUCO reserves the right to request an additional hearing on the amount of the final competition transition charge.

RESPECTFULLY SUBMITTED this 21st day of September, 1998

Scott S. Wakefield
Chief Counsel

Arizona Corporation Commission
DOCKETED
SEP 21 1998
DOCKETED BY

Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing

Docket No. E-01933A-98-0471

Introduction

The Residential Utility Consumer Office (RUCO) is responding to the Tucson Electric Power Company's (TEP's) stranded cost "Application" of August 21, 1998. In this Application, TEP describes a possible process for auctioning its generating assets, although the Company proposes to "retain the ability to amend the auction procedures or protocols or suspend or terminate the auction" (p. 19). For those generating assets not sold, the Company requests that it nonetheless "be authorized to recover 100 percent of the Final Stranded Cost Amount associated with such asset(s)" (Exhibit A, p. 12, lines 2-3). TEP estimates that its stranded costs after the sale of its generating assets, in 2001, will be between $600 million and $1.1 billion (p. 20), "based on numerous assumptions" which are unspecified. Presumably, then, the Company's methodology would estimate even higher strandable costs beginning in 1999.

Until the divestiture process, successful or not, is complete, TEP proposes an interim competition transition charge (ICTC) to be paid by all customers. This charge would equal the difference between "the generation portion of each rate schedule" and the wholesale price of electricity at California's Palo Verde switchyard (Exhibit C).

After the divestiture process, the Company's stranded costs would be calculated again. For any generating assets sold, the stranded cost would equal the difference between net book value and sale price, plus the transportation costs associated with selling the assets. For any assets TEP decided not to sell, the strandable cost would be estimated using a "Net Lost Revenues approach" (p. 23). After divestiture, the ICTC would be replaced by a permanent competition transition surcharge (CTC) designed to recover the newly calculated strandable cost amount within ten years.

RUCO generally approves of the idea of divesting TEP's assets but finds many aspects of the Application and plan unacceptable. At present, the Application asks for approval of TEP's stranded cost recovery methodologies without fully revealing those methodologies. The methodology for calculating the ICTC is revealed, but the use of a wholesale, rather than a retail, market generation price to compute stranded costs on an interim basis, would leave no opportunity for alternative generation suppliers to offer power at lower prices than the standard offer. It would also lead to a significant over-estimation of stranded costs.

Also, TEP's divestiture plan would not require TEP to actually sell any units, but would nonetheless guarantee 100% recovery of estimated stranded costs. Furthermore, the plan seems to give the Company unrestricted power to manipulate the auction process and to eliminate or select bidders entirely at its own discretion. This could allow TEP to sell units to affiliates at bargain prices. In conjunction with TEP's distortion of the Commission's generous offer to let Affected Utilities keep 50% percent of negative stranded costs, this unrestricted power would also enable the Company to severely overcollect such a 50% reward at the expense of ratepayers, if stranded costs for some generating units were negative.

Finally, the Application would allow TEP to collect stranded costs on a fixed fee (per customer) basis, which would clearly be unfair to Arizonans who use little electricity. This approach would greatly increase their average electricity rates, and is, therefore, contrary to the Emergency Rules. Some of the Company's cash requirements would be financed through securitization, which in itself may be sensible. However, securitization should not be allowed for the stranded costs of any plants not divested, because securitization restricts the flexibility of the true-up process. Furthermore, the particulars of TEP's securitization plan, as written, may create opportunities for unregulated profit-skimming by TEP and its affiliates.

TEP's Stranded Cost Estimate

TEP's Application reports stranded costs of between $600 million and $1.1 billion, "based on numerous assumptions" (p. 20) which are neither explained nor revealed. In confidential Schedule 3 of the Company's Application, a table presents the estimates' basic components. A second table displays the assumed "value," per kilowatt, of each TEP generating plant. Just two sentences describe how the numbers in the tables were developed. After the second table, the following sentence appears: "This Application seeks approval for the proposed methodology of determining stranded costs, including the components set forth in the foregoing table."

Clearly, two tables and two sentences are not an adequate basis on which to judge the validity of a methodology for calculating stranded costs. RUCO recommends that no final methodology for calculating recoverable stranded costs on an interim basis or a final basis be approved unless it is thoroughly revealed and examined first in hearings. The ACC's Stranded Cost Working Group found in its September 30, 1997 report that "for purposes of the required stranded cost filings to be made by the Affected Utilities, they should bear a strong burden of proof as to the reasonableness of whatever estimation method they may incorporate into their respective filings" (p. 33). Thus, RUCO may supplement its comments later once the details of the proposed methodology become known through the discovery process, and can be analyzed.

In contrast to the mysterious methodology proffered by TEP, RUCO witness Dr. Richard Rosen's stranded cost methodology was explained at length in Dr. Rosen's January, 1998 testimony in ACC Docket No. RE-00000C-94-0165. Dr. Rosen estimated that the TEP's strandable generation costs at that time were $513.4 million dollars over the time period 1998-2020. However, beginning in 1998 they decline rapidly as TEP ratepayers continue to pay above-market generation rates as they have in the past. TEP's estimate is for the time beginning when the plants change hands, presumably at the beginning of 2001, through the life of the assets. Therefore, to make Dr. Rosen's estimate comparable to the TEP estimate, the over-market payments for the years 1998, 1999, and 2000 must be removed from Dr. Rosen's estimate. This is shown on page one of Attachment RUCO-1. The result is estimated positive stranded costs with a 1998 present value of just $84.1 million dollars.

Interim Competition Transition Charge

TEP describes its proposed Interim Competition Transition Charge (ICTC) on pages 21-22 of its Application:

> The ICTC will be in effect until such time as the CTC is implemented and will be charged to competitive customers and to Standard Offer customers as a component of the Standard Offer Rate. The ICTC will be the difference between the Standard Offer embedded cost of generation under traditional ratemaking and a market price for power. The market price of power will be based on the Dow Jones Palo Verde Index,...a measure of actual spot market prices....at Palo Verde Switchyard.

Theoretically, the ICTC would simply continue to collect the above-market values of generation assets at the same rate at which they would be collected under continued traditional ratemaking. However, a proper ICTC that is consistent with this objective must be calculated using retail generation prices rather than wholesale prices such as those at Palo Verde. The competition which TEP will face as a result of the Commission's competition rules is for retail generation sales within its own service area, not for spot market sales at the Palo Verde switchyard. Thus, the appropriate "market price for power" for computing stranded costs is the local retail market price, which will vary from class to class. This local retail market price for each class is also the appropriate standard offer generation rate for that class.

All ESPs offering retail generation service in TEP's service district will incur significant costs in addition to the wholesale cost of generation. In earlier testimony in Docket No. RE-00000C-94-0165, Dr. Richard Rosen estimated that these additional costs would range from 0.82 to 1.18 cents per kWh for service to small customers and from 0.54 to 0.85 cents per kWh for service to large customers. The largest component of these "retail adders" is the administrative and general costs of providing retail service. The remainder consists of associated customer services, marketing and advertising, ancillary services (not including those mentioned in FERC Order 888), profit, and taxes (Exhibit RAR-3). Dr. Rosen used an average retail adder of 0.77 cents per kWh in computing stranded costs, and in computing the price of Standard Offer Service.

If the standard offer generation rate is too low to allow alternative ESPs to cover the wholesale cost of generation plus their retailing expenses, then "full generation competition as soon as possible," one of the Commission's stated objectives in addressing the stranded cost issue (Decision 60977, p. 8), will not be accomplished. In fact, there will probably not be any retail competition, as is generally the case in California, Massachusetts and Rhode Island, which made this same mistake in using a wholesale price of generation to set the standard offer service price.

Thus, to encourage a competitive generation market, the standard offer generation rate for each class should be set at least as high as the expected retail market cost of generation service for that class. There are two reasons to set these rates towards the higher end of a reasonable retail market price range for each customer class, at least initially, as Pennsylvania has done. One is to overcome the inertia and suspicions of customers who have been accustomed to buying their electricity from the same provider. The second is that it will not be possible to predict the retail market prices with certainty.

Neither the underlying wholesale price of power nor the retailing costs are precisely known in advance. If the standard offer generation is somewhat higher than the competitive retail price of power, more customers will switch. At the beginning of retail competition, this is better than having few customers switch, which would be the consequence of a standard offer generation rate lower than the competitive retail price of power. Periodically, perhaps each year, the Commission can adjust the standard offer generation rate for each rate class so that it stays in reasonable relationship to the spread of retail prices in the market.

If the ICTC is the difference between the company's generation cost of service and the standard offer generation rate, then a higher generation rate would result in a lower ICTC. The consequence would be lower TEP revenues from direct access customers. This would not be a problem, as any stranded cost amount not collected through the ICTC would be collected through the CTC, duly adjusted for the Company's cost of capital. Thus, the actual level of the ICTC must be set in litigated hearings in a manner consistent with the way that the standard offer generation rate is set, so rates do not increase. However the ICTC is set, the total present value of stranded costs charged to ratepayers over the 10-year recovery period should not exceed the sum of the present values of the ICTC collected and the permanent CTC. Note also that according to Dr. Rosen's calculations, if an ICTC is set the way the Company proposes, there may be little in the way of stranded costs to collect later.

Auction

There are several problems with TEP's proposal for an auction of its generating assets. First, as the Application is written, the Company is not obligated to auction anything. "The Company will retain the ability to…suspend or terminate the auction, should it be in the best interest of the Company and its stakeholders" (p. 19).

Yet, for any generating assets it chooses not to sell, the Company states that it "must have a definitive alternative mechanism that provides full recovery of Stranded Costs" (p. 4). This mechanism would consist of estimating the stranded costs on the unsold units and adding that estimate to a "Stranded Cost Recovery Asset" to be recovered in its entirety through regulated cash flows (pp. 23-24). Such a sequence of events would not adhere to the Commission's statement that "the opportunity for full stranded cost recovery should be available only to those Affected Utilities that choose to divest" (Decision 60977, p. 10). However, if any portion of the strandable cost amount to be recovered from ratepayers is based on an administrative rather than a market determination, that portion should be trued up over time as actual market price information becomes available in place of the projections used in the first administrative strandable cost determination. A true-up is needed to protect ratepayers from overpaying stranded costs when an administrative determination of stranded costs is relied on.

The Application, in addition to giving the Company the ability to terminate the auction, would also grant the Company arbitrary power to select the winning bidders without regard to the merits of their bids, if the Company so choses. On page 4 of the Application's Exhibit B, "TEP reserves the right to at any time, in its sole discretion, to [sic] select which bidders to invite to Phase III, Phase IV or the bidder(s) with which to execute Documents, terminate discussions with any or all bidders, amend or otherwise change the protocols…." This provision, and others like it in the Application, might give TEP the opportunity to sell generating assets to an affiliate for a price lower than that which some competing bidder would make. This might contradict item R14-2-1617(A)(7)(b) of the Affiliate Transactions rules. That item states, "Goods and services…developed for sale on the open market by the Affected Utility or Utility Distribution Company will be provided to its affiliates and unaffiliated companies on a nondiscriminatory basis, except as otherwise permitted by these rules or applicable law."

The previous decisions of the Commission may make it more difficult for TEP to favor its affiliates, but they may not prevent it altogether. Page 12 of Decision No. 60977 stipulates that "no entity or its affiliate(s) may purchase generation assets at any divestiture auction unless it is the highest bidder…." However, if TEP eliminated some or all of the other bidders early in the auction process, then a TEP affiliate could end up offering the winning bid even if other capable parties had been prepared to offer more. If all other bidders were eliminated, then any bid would suffice, and the auction would be a sham.

R14-2-1617(A)(7)(a) is an important provision for preventing items from being sold by utilities to their affiliates at below-market prices. It states that in such a sale, "the transfer price will be the higher of fully allocated cost or the market price." This may prevent TEP from selling a plant to an affiliate for less than the fully allocated cost, but an appropriate "market price" might never be established if TEP eliminated other bidders at early stages or otherwise manipulated the auction process. As a result, TEP might be able to sell one or more generating units to one or more affiliates for bargain prices.

Incidentally, R14-2-1617(A)(7)(a) could also effectively prevent utility affiliates from bidding on any generating units whose fully allocated costs are higher than their market prices. The Commission should, perhaps, clarify the applicability of this provision to sales of generation assets, if it has not done so already.

In its Application the Company reserves for itself not only the rights to eliminate and select bidders at its sole discretion and to cancel the auction, but also "the ability to amend the auction procedures and protocols without ACC approval." This unfettered freedom to manipulate the auction process potentially enhances the Company's power to profit from divestiture at the expense of ratepayers, in ways not explicitly approved by the Commission.

Aside from the need to prevent abuses such as the ones described above, an additional reason for the Commission to retain supervisory control over TEP's auction process is that the process should be conducted in a manner that prevents undue market power from resulting. The issue of how to structure an auction in a way to mitigate the likelihood of undue market power requires considerable study, and TEP has not proposed a method for dealing with it. An auction process that takes no account of market power could result in market power that would significantly increase costs for Arizonans. The Commission must require TEP to devise an auction plan that explicitly minimizes market power by the purchasers of the plants. Part of doing this requires an analysis of whether Tucson is a load pocket, and, therefore, whether special market power mitigation provisions like price caps are required in the auction.

Incentive for Divestiture in Case of Negative Stranded Costs

Decision No. 60977 gives the utilities a considerable incentive to sell their power plants to non-affiliated entities for the highest possible prices: "An Affected Utility that divests all its generation costs to non-affiliated entities, that results in negative stranded costs (not including regulatory assets) as defined by the Commission's Retail Electric Competition Rules and this Order, shall be entitled to keep 50 percent of the negative stranded costs" (p. 12, lines 7-9).

The 50 percent reward concept is addressed in TEP's plan as well, but is significantly distorted. If the reward were calculated as TEP proposes, the Company could receive a substantial reward for *negative* stranded costs even if its net stranded cost amount were a considerable *positive* sum, as both the Company and Dr. Rosen estimate.

The Company seeks the following reward provision: "...to the extent that the final sale price of *any* [emphasis added] Asset exceeds the Company's net book value for such Asset, 50 percent of the gain on such Asset will be applied to reduce the Company's Stranded Costs" (Application, p. 22).

TEP's plan proposes, then, that the Company potentially receive the reward on <u>each individual unit</u> to be sold which has negative stranded costs, rather than on the <u>net</u> amount of stranded costs for all units together. This proposal would give the Company no incentive to maximize the sale prices of generating units that truly have market values lower than their net book values (i.e. units that truly have positive stranded costs), because the prices of those units would have no effect on the amount of the reward the Company would receive.

Worse, calculating an award on the basis of each individual unit's stranded costs would create a perverse incentive to prefer bids which offer a minimal price on one unit (or group of units) in exchange for a higher price on another unit (or group of units) in order to increase the negative stranded costs on those units which would be subject to the reward. These sorts of bids would maximize TEP's rewards even if they reduced the aggregate sale prices. Since TEP's plan also would grant the Company unchecked power to manipulate the auction process however it chose, the Company would have many tools for encouraging reward-maximizing bids. The bidders could easily figure out that if they paired a high bid on one power plant with a minimal bid on a another plant, they could gain TEP's favor while possibly saving themselves money. To the extent that the Company chose to sell its assets, the reward structure it proposes would tend to turn its power plant auction into a "buy one, get one free" sale. Therefore, TEP's plant-by-plant reward proposal must be totally rejected by the Commission. All components of stranded costs should be netted out against each other before any incentives are given.

Furthermore, TEP's plan would expand the rewards by excluding enormous positive stranded costs from the amounts on which the rewards would be based. This violates the Commission's instructions that any reward is to be based on "stranded costs" (implying total stranded costs), not on a narrow subset of these costs. As the first table in Schedule 3 shows, TEP's proposed methodology holds large and diverse stranded costs separate from this calculation. Aside from leading to much larger TEP rewards at the expense of ratepayers, this feature of TEP's plan would also remove any incentive for the Company to minimize these other stranded costs.

Moreover, by excluding many categories of stranded costs from the reward basis, TEP would give itself a perverse incentive to incur new costs that would not be included in the reward basis, but would increase the sale price of a generation asset. The Company could spend $500 million dollars in certain types of new stranded costs to increase the sale prices of the generation units by just $50 million, but still benefit because the higher sale prices would increase the reward while the stranded costs would be fully recovered and yet would not reduce the reward. In particular, RUCO is concerned that TEP may choose to pay high penalties for terminating leases on its generation assets (Application, p. 11) in order to increase their value at auction even if directly reassigning the leases to purchasers of the plants would be more cost-effective. The increased sale prices would add to TEP's reward, but the termination payments would not reduce the reward because they are a category of stranded cost not included in TEP's proposed basis for calculating the reward. Indeed, the Application indicates that "The Company's preferred alternative for disposition of its leasehold assets is to negotiate a termination of the leases" prior to the auction (p. 17) because "terminating the leases will result in a more streamlined auction and increase the number of potential purchasers" (p. 18).

Aside from lease termination payments, there may be other types of unjustified new stranded costs the Company would choose to incur under its perverse incentive scheme in order to increase the sale price of its generating assets. The stakes are extremely high, since "the total of the [payments required to complete the divestiture of TEP's assets] are likely to exceed the sale proceeds received for the Assets" (Application, p. 15).

Guaranteed 100% stranded cost recovery is generous. A 50% reward for net negative stranded costs is even more generous, all the more so when the "negative stranded cost" amount used for calculating the reward does not include regulatory assets, which are positive stranded costs. TEP appears to have taken this ACC incentive structure, to be funded by ratepayers, and distorted it into something that could cost the ratepayers even more, first by increasing the rewards to the company, then by potentially promoting wasteful decisions that add to overall positive stranded costs. To avoid these problems, any reward for TEP, or any other company, should be based on stranded costs in the aggregate, on a net basis.

For logical consistency, the purpose of calculating only reward, one of the items that must be included in the net, aggregate stranded cost amount is the present value of all ICTC payments received by TEP. They are part of the Company's stranded costs as of the advent of retail competition. If they are not included in the calculation, then stranded costs will be grossly underestimated, and an unjustified reward could result. The ICTC will rapidly reduce the lifetime strandable cost amount associated with TEP's generation assets, turning it negative in just a few years. Again, according to Dr. Rosen's estimates, the remaining stranded costs will already have approached zero as of January 1, 2001, TEP's scheduled date for transferring auctioned assets to new owners. If this projection understates the rate of decline of the lifetime stranded cost amount, or if there is any delay in the divestiture process, then the lifetime stranded cost amount on TEP's generation assets at that time could be negative. It would very rapidly become more negative with time. If the ICTC payments were not added back into the stranded cost calculation for the purpose of calculating the reward, then TEP would also have an incentive to try to delay the divestiture process. The later the transfer of assets, the larger the reward. This would result in a completely unjustified reward, potentially a large sum, that would come out of the pockets of ratepayers.

Finally, in TEP's adaptation of the reward concept, there is no mention of the Commission's conditions for reward eligibility: 1) the Affected Utility must "divest *all* [emphasis added] its generation costs," and 2) the purchasers must all be non-affiliated utilities (Decision 60977, p. 12).

Determination of Stranded Cost Amount to be Recovered from Ratepayers

If the Commission passes the order which TEP asks it to pass (Exhibit A of the Application), then "The Company's Final Stranded Cost Amount to be recovered shall be determined by the Company" (p. 6, lines 5-6). This is clearly unacceptable to RUCO. Furthermore, the "Charges shall be filed with the Commission and will be effective on filing" (p. 12, lines 26-27). RUCO is concerned that if TEP is given the unmitigated power to determine how much money it will collect from ratepayers, the Company may abuse the power. This approach must be rejected and any interim or final determination of stranded costs, whether through auction or through administrative calculation, must be reached in a litigated hearing.

Even requiring TEP to adhere to the stranded cost calculation methodologies it used to derive the estimates and examples in its Application would not be sufficient to prevent overcollection from ratepayers, in RUCO's opinion. These methodologies are not revealed in sufficient detail for their adequacy to be judged. The most important methodology is the one used to derive the estimates of TEP's overall stranded costs on page 20, and in Schedule 3. Yet, very little of this methodology is revealed in the Application, as noted in the summary above and the "TEP's Stranded Cost Estimate" section of this analysis. The ICTC calculation methodology described in Exhibit C of TEP's application is simple, but the "generation portion of each rate schedule" is presented without any indication of how each was derived, or what data it is based on. The methodology for estimating the strandable costs of any generating assets TEP chooses not to sell is not illustrated at all. It is merely described in general terms. The longest description is a few vague sentences on pages 23-24.

All of TEP's calculations of its stranded costs would seemingly depend on the Company's unbundling methodology for generation costs, which is most appropriately addressed in the ACC's unbundling proceedings. Thus, RUCO believes that the final stranded cost determination for TEP must await the ACC's final order on TEP's unbundling, and that this unbundling should include the development of the approved generation components of rates.

Method of Recovering Final Stranded Cost Amount

TEP's generation assets, with their corresponding negative or positive overall stranded cost, were built to meet the energy and capacity demands of ratepayers. Thus, any responsibility for paying stranded costs attributed to those ratepayers should be in proportion to their use of electricity. As such, any recovery of net positive stranded costs should be on a per-kWh basis, and possibly on a per-kW basis if appropriate, according to actual usage. Of course, per-kW recovery should apply only to customers whose peak demand is metered. Positive stranded costs should definitely not be recovered on a per-customer, one-fee-fits-all basis. Therefore, TEP's proposal that the CTC be recovered "on a per-kWh, a kW and/or a fixed fee basis" (Exhibit A, p. 6, line 30) should not be accepted. To accept TEP's approach would be completely inconsistent with the ACC's Emergency Rules whereby stranded costs must be recovered in a manner consistent with the way in which they are currently being charged in rates. TEP's fixed fee option must be excluded. It would clearly impact the lowest usage customers the hardest.

Requests for Waivers

RUCO opposes the granting of several of the waivers which TEP has requested. Specifically, RUCO objects to the waiver of condition numbers 19, 20, 21 and 28 in Decision No. 60480.

Conditions 19, 20 and 21 restrict TEP's actions in certain ways, for the purpose of improving TEP's debt-heavy capital structure. TEP requests a waiver of these conditions, claiming that its capital structure will be dramatically redefined after divestiture. While divestiture would likely improve TEP's capital structure, it is premature to waive these conditions at this time. After any Commission-authorized divestiture is completed, waiver of these conditions may be appropriate. However, it is premature to grant these waivers at this time.

Condition 28 prevents TEP's parent company and sister companies from investing amounts greater than $60 million in any single investment without Commission approval. This condition was also designed to protect TEP's customers from further deterioration of TEP's capital structure. The Commission may approve any such investment, but it is inappropriate to waive the condition in its entirety.

Conclusion

RUCO believes that the divestiture of generation assets by TEP could help promote a competitive market for retail generation services. However, there are many serious problems with the Company's proposed divestiture plan, as described above. These would give the Company unjustifiable opportunities for profiting at the expense of ratepayers, and these problems must be corrected before the relevant elements of TEP's Application are approved by the Commission.

Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.10	3.10	6,986	216.4
1998	2.65	2.65	7,122	188.5
1999	2.13	2.13	7,261	154.4
2000	1.53	1.53	7,403	113.3
2001	1.39	1.39	7,548	105.1
2002	1.25	1.25	7,695	96.4
2003	1.11	1.11	7,846	86.9
2004	0.96	0.96	7,999	76.6
2005	0.80	0.80	8,155	65.6
2006	0.65	0.65	8,315	53.7
2007	0.48	0.48	8,477	40.9
2008	0.31	0.31	8,643	27.2
2009	0.14	0.14	8,812	12.5
2010	(0.04)	(0.04)	8,984	(3.3)
2011	(0.22)	(0.22)	9,159	(20.2)
2012	(0.41)	(0.41)	9,338	(38.2)
2013	(0.60)	(0.60)	9,521	(57.5)
2014	(0.80)	(0.80)	9,707	(78.1)
2015	(1.01)	(1.01)	9,897	(100.0)
2016	(1.22)	(1.22)	10,090	(123.4)
2017	(1.44)	(1.44)	10,287	(148.3)
2018	(1.67)	(1.67)	10,488	(174.9)
2019	(1.90)	(1.90)	10,693	(203.1)
2020	(2.14)	(2.14)	10,902	(233.1)

Net Present Value of Stranded Costs (1998-2020) (1998$):	**$513.4**
Net Present Value of Stranded Costs (2001-2020) (1998$):	**$84.1**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (2001-2020) (1998$)	**$84.1**

Assumed utility nominal discount rate **7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on: User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates: See Table 4: Scenario Assumptions

Year when excess capacity ends: 2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.02	6.12	0.00
1998	3.47	6.12	0.00
1999	3.99	6.12	0.00
2000	4.59	6.12	0.00
2001	4.73	6.12	0.00
2002	4.87	6.12	0.00
2003	5.01	6.12	0.00
2004	5.16	6.12	0.00
2005	5.32	6.12	0.00
2006	5.48	6.12	0.00
2007	5.64	6.12	0.00
2008	5.81	6.12	0.00
2009	5.98	6.12	0.00
2010	6.16	6.12	0.00
2011	6.34	6.12	0.00
2012	6.53	6.12	0.00
2013	6.72	6.12	0.00
2014	6.93	6.12	0.00
2015	7.13	6.12	0.00
2016	7.34	6.12	0.00
2017	7.56	6.12	0.00
2018	7.79	6.12	0.00
2019	8.02	6.12	0.00
2020	8.26	6.12	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Tucson Electric Power Company
(thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$339,092	$339,092			
O&M Minus Fuel	$135,991	$135,991			
Fuel	$203,102	$203,102			
Transmission	$6,894		$6,894		
Distribution	$12,284			$12,284	
Customer/Sales	$14,501				$14,501
Subtotal	$372,771	$339,092	$6,894	$12,284	$14,501
A&G[1]	$59,943	$48,044	$2,436	$4,340	$5,123
Total	$432,714	$387,136	$9,330	$16,624	$19,624
Plant Related Costs:					
Depreciation and Amort.	$76,229	$38,188	$17,533	$20,508	$0
Net Interest	$103,096	$49,431	$23,867	$29,799	$0
Net Income	$11,982	$5,745	$2,774	$3,463	$0
Income Taxes[2]	$9,892	$4,743	$2,290	$2,859	$0
Other Taxes[3]	$37,604	$18,030	$8,705	$10,869	$0
Residual[4]	$21,514	$10,315	$4,980	$6,218	$0
Total	$260,317	$126,452	$60,149	$73,716	$0
Total Operating Revenues[5]	$693,031	$513,588	$69,479	$90,341	$19,624
less Wholesale Revenues	($106,945)	($94,201)	($12,744)	$0	$0
Total Retail Revenues	$586,087	$419,387	$56,735	$90,341	$19,624
Total Retail Sales (MWH)	6,851,706				
Average Retail Rate (cents/kWh)	**8.55**	**6.12**	**0.83**	**1.32**	**0.29**

Footnotes:

[1] A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 80.2%, 4.1%, 7.2%, and 8.5%.

[2] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

[3] Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

[4] Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

[5] Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

Combined Cycle:	Total Costs:	1996 Real Levelized Costs
Capital Costs	383.0 \$/kW	0.79 ¢/kWh
Fixed O&M	11.7 \$/kW-yr	0.22 ¢/kWh
Variable O&M	0.20 mills/kWh	0.02 ¢/kWh
Fuel	1.97 ¢/kWh	1.71 ¢/kWh
	Sum of Levelized Costs:	*2.74 ¢/kWh*
	Levelized Capacity Costs:	*53.4 \$/kW-yr*

Combustion Turbine:	Total Costs:	1996 Real Levelized Costs
Capital Costs	275.0 \$/kW	29.47 ¢/kWh
Fixed O&M	9.4 \$/kW-yr	9.26 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.13 ¢/kWh
	Sum of Levelized Costs:	*41.86 ¢/kWh*
	Levelized Capacity Costs:	*39.3 \$/kW-yr*

Capacity Factor Crossover for CC/CT		11%
Percent of CC energy in Market Price		99.6%
Percent of CT energy in Market Price		0.4%
Average Price of CC/CT mix		**2.91 ¢/kWh**
T&D Line Loss Adjustment	10%	0.30 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
Adjusted Retail Market Price based on CC/CT mix		**4.08 ¢/kWh**
Year Excess Capacity Ends		**2000**

(2) Using Capacity Charge and Energy Charge:

Capacity Charge (\$/kW-yr):	**NA**	
Energy Charge (¢/kWh):	**NA**	
Average Market Price for Electricity:		**none ¢/kWh**

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		**1.59 ¢/kWh**
T&D Line Loss Adjustment	10%	**0.17 ¢/kWh**
Order 888 Ancillary Services		**0.10 ¢/kWh**
Retailing A&G Adjustment		**0.50 ¢/kWh**
Other Retailing Costs Adjustment		**0.27 ¢/kWh**
User-Input Retail Market Price for Electricity		**2.63 ¢/kWh**

Table 4
Assumptions Used in Estimating Stranded Costs for Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):	*User-Input*				
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Source: Rosen testimony in ACC Docket No. U-0000-94-165, Exhibit_(RAR-6)

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6,500	Btu/kWh

Schnitzer, in Docket #16705, Direct Testimony on behalf of Texas OPUC, and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11,900	Btu/kWh

Tellus Institute, Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	57%
Max. Annual Load (MW)	1619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1862
Cut-off point:	11.0%
Load at above Cut-off (MW)	1527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
Percentage of Energy Supplied by CTs	0.4%
Percentage of Energy Supplied by CCs	99.6%

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	855,793	261,591	594,202	1,062
Feb	763,804	224,230	539,574	1,043
Mar	806,714	236,376	570,338	961
Apr	836,467	249,242	587,225	1,255
May	920,007	212,419	707,588	1,410
Jun	992,763	213,336	779,427	1,519
Jul	1,144,033	262,289	881,744	1,619
Aug	1,131,929	276,469	855,460	1,608
Sep	1,012,034	307,068	704,966	1,369
Oct	1,032,968	378,436	654,532	1,355
Nov	942,033	383,554	558,479	987
Dec	994,999	373,905	621,094	1,102
TOTAL	11,433,544	3,378,915	8,054,629	1,619

Utility FERC Form 1 Data

Average Wholesale Market Price	
of Electricity Based	29.09 $/MWh
on CC/CT Method	2.91 c/kWh
T&D Line Loss Adjustment	0.30 c/kWh
Order 888 Ancillary Services	0.10 c/kWh
Retailing A&G Adjustment	0.50 c/kWh
Other Retailing Costs Adjstmt	0.27 c/kWh

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	2.63	c/kWh

CC-CT Market Price Worksheet for: Tucson Electric Power Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user.

Month	Total Monthly Energy (MWh) USER-INPUT	Monthly Non-Requirements Sales for Resale & Associated Losses (MWh) USER-INPUT	Net Energy (MWh)	Monthly Peak (MW) USER-INPUT	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
Jan	855,793	261,591	594,202	1,062			
Feb	763,804	224,230	539,574	1,043			
Mar	806,714	236,376	570,338	961	961	81%	781
Apr	836,467	249,242	587,225	1,255			
May	920,007	212,419	707,588	1,410			
Jun	992,763	213,336	779,427	1,519			
Jul	1,144,033	262,289	881,744	1,619			
Aug	1,131,929	276,469	855,460	1,608			
Sep	1,012,034	307,068	704,966	1,369			
Oct	1,032,968	378,436	654,532	1,355			
Nov	942,033	383,554	558,479	987			
Dec	994,999	373,905	621,094	1,102			
TOTAL	**11,433,544**	**3,378,915**	**8,054,629**	**1,619**	**961**	**0.81**	**781**

LOAD FACTOR	**57%**		
Max. Annual Load (MW)	1,619		
Min. Monthly Peak (MW)	961	ratio between total energy under load curve and total monthly energy	**0.92**
Load Factor for Min. Monthly Load	0.81		
Effective Min. Annual Load	781		
Max. Load + Reserve Margin (MW)	1,862		
Cut-off point:	11%		
Load at above Cut-off (MW)	1,527		
Total Energy under Load Curve (MWh)	10,513,248		
Energy Supplied by CTs (MWh)	44,397	**Ratio of energy supplied by CTs**	0.4%
Energy Supplied by CCs (MWh)	10,468,851	**Ratio of energy supplied by CCs**	99.6%
check	0		

CC

Capital Cost	41.67	$/kW times	1,527	MW	equals	**63,624,506**	dollars	$	**27.43** MWh
Fixed O&M	11.70	$/kW times	1,527	MW	equals	**17,864,161**	dollars		
Var O&M	0.20	mills/kWh times	8,020,614	MWh	equals	**1,604,123**	dollars		
Fuel	1.71	cents/kWh times	8,020,614	MWh	equals	**136,950,332**	dollars		

CT

Capital Cost	29.92	$/kW times	335	MW	equals	**10,023,160**	dollars	$	**418.61** MWh
Fixed O&M	9.40	$/kW times	335	MW	equals	**3,148,987**	dollars		
Var O&M	0.10	mills/kWh times	34,015	MWh	equals	**3,401**	dollars		
Fuel	3.13	cents/kWh times	34,015	MWh	equals	**1,063,294**	dollars		
					TOTAL	**234,281,965**	dollars		
					Tot Energy in real LDC	**8,054,629**	MWh		

OUTPUT

Average Market Price of Electricity - 1996

29.09	**$/MWh**
2.91	**c/kWh**

AN ORIGINAL AND TEN COPIES
of the foregoing filed this 21st day
of September, 1998 with:

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

COPIES of the foregoing
mailed/hand delivered this 21st day
of September, 1998 to the
following:

Jerry Rudibaugh, Chief Hearing Officer
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Ray Williamson, Acting Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Paul Bullis, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Bradley Carroll, Attorney
Legal Department
Tucson Electric Power Company
P.O. Box 711
Tucson, Arizona 85702

Craig Marks
Citizens Utilities Company
2901 North Central Avenue, Suite 1660
Phoenix, Arizona 85012

Barbara Klemstine
Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona 85072-3999

Steven Wheeler
Thomas Mumaw
Snell & Wilmer
400 East Van Buren
Phoenix, Arizona 85004-0001

C. Webb Crockett
Fennemore Craig
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913

Michael Curtis
Martinez & Curtis
2712 North Seventh Street
Phoenix, Arizona 85006

Rick Gilliam
Land and Water Fund of the Rockies
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Norman J. Furuta
Department of the Navy
900 Commodore Drive, Building 107
San Bruno, California 94066-5006

Terry Ross, Vice President
Center for Energy and Economic Development
7853 East Arapahoe Court, Suite 2600
Englewood, Colorado 80112

Christopher Hitchcock
Hitchcock, Hicks & Conlogue
P.O. Box 87
Bisbee, Arizona 85603-0087

Albert Sterman, Vice President
Arizona Consumer Council
2849 East 8th Street
Tucson, Arizona 85716

K. R. Saline
K. R. Saline & Associates
160 North Pasadena, Suite 101
Mesa, Arizona 85201-6764

Robert S. Lynch
340 East Palm Lane, Suite 140
Phoenix, Arizona 85004-4529

Dan Neidllinger
Neidlinger & Associates, Ltd.
3020 North 17th Drive
Phoenix, Arizona 85015

Russell E. Jones
O'Connor Cavanagh Molloy Jones
P.O. Box 2268
Tucson, Arizona 85702

Debra S. Jacobson, Manager
Southwest Gas Corporation
P.O. Box 98510
Las Vegas, Nevada 89193-8510

Douglas C. Nelson, P.C.
7000 North 16th Street #102-307
Phoenix, Arizona 85020

Jessica Youle
Salt River Project
P.O. Box 52025, PAB 300
Phoenix, Arizona 85072-2025

Betty Pruitt
Arizona Community Action Association
2627 North Third Street, Suite 2
Phoenix, Arizona 85004

Michael Grant
Gallagher & Kennedy
2600 North Central Avenue
Phoenix, Arizona 85004-3020

Timothy Hogan
Arizona Center for Law in the Public Interest
202 East McDowell, Suite 153
Phoenix, Arizona 85004

Andrew Bettwy
Southwest Gas Corporation
P.O. Box 98510
Las Vegas, Nevada 89193-8510

Bill Meek
Arizona Utility Investors Association
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004

Jesse Sears, Assistant Chief Attorney
Phoenix, City Attorney's Office
200 West Washington, Suite 1300
Phoenix, Arizona 85003-1611

Suzanne M. Dallimore
Attorney General's office
1275 West Washington
Phoenix, Arizona 85007

Michael Block
Goldwater Institute
201 North Central Avenue
Phoenix, Arizona 85004

Lawrence V. Robertson, Jr.
Munger Chadwick, P.L.C.
333 North Wilmot, Suite 300
Tucson, Arizona 85711-2634

Tom Broderick
PG&E Energy Services
6900 East Camelback Road, Suite 800
Scottsdale, Arizona 85251

Lex Smith
Brown & Bain, P.C.
P.O. Box 400
Phoenix, Arizona 85001-0400

Vinnie Hunt
City of Tucson Department of Operations
4004 South Park Avenue, Building #2
Tucson, Arizona 85714

Phyllis Rowe
Arizona Consumers Council
6841 North 15th Place
Phoenix, Arizona 85014

Elizabeth S. Firkins
International Brotherhood of Electrical Workers
750 South Tucson Boulevard
Tucson, Arizona 85716-5698

Choi Lee
Phelps Dodge Corporation
2600 North Central Avenue
Phoenix, Arizona 85004-3014

Myron L. Scott
1628 East Southern Avenue, No. 9-328
Tempe, Arizona 85282-2179

Barbara R. Goldberg
Scottsdale City Attorney's Office
3939 Civic Center Boulevard
Scottsdale, Arizona 85251

Thomas W. Pickrell, Esq.
Arizona School Board Association
2100 North Central Avenue
Phoenix, Arizona 85004

Patricia Cooper
Arizona Electric Power Cooperative
P.O. Box 670
Benson, Arizona 85602

By Cheryl Fraulob
Cheryl Fraulob
Legal Secretary II

09/17/98 7:57 AM