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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-01933A-98-0471

Arizona Corporation Commission
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COMMENTS / DISAGREEMENTS
OF PG&E ENERGY SERVICES
September 21, 1998

BACKGROUND

Commission Decision No. 60977 ordered that "all other parties shall file any comments/disagreements and requests for hearing" within 30 days of each Affected Utility's filing of its implementation plan.

PG&E Energy Services herein submits its comments / disagreements on Tucson Electric Power Company's plan for stranded cost recovery filed on August 21, 1998. We do not request a hearing, but if one is required, we desire to participate.

SUMMARY OF COMMENTS

PG&E Energy Services ("Energy Services") praises Tucson Electric Power ("TEP") for submitting a stranded cost recovery plan that is thorough, detailed and generally consistent with the Commission's recently adopted divestiture policy. As a result, we believe TEP deserves an opportunity to recover 100% of its legitimate, verifiable and non-mitigatable stranded costs so long as it continues to cooperate and successfully implement a Commission approved generation divestiture program. It is our hope that TEP will view our comments as supportive of a genuine opportunity for them to recover legitimate stranded costs.

TEP's plan, however, is deficient in **three** significant aspects.

First, it attempts to solve more of its problems than just stranded costs. For example, it is apparent that TEP would like get out from under its onerous lease obligations on Springerville 1 (and common plant) and Irvington 4. However, it makes no sense to trigger well over $600 million in stipulated lease losses (and add them to recoverable stranded costs) simply to accomplish divestiture of these units. We request that the Commission evaluate all reasonable alternatives to divestiture that accomplish the objectives of the Commission's divestiture policy without triggering lease losses. This could include evaluating whether TEP could sell the output of leased units on a long-term basis to an entity that, in turn, sells the output to its customers without violating lease terms. As a last option, TEP should retain these leased units (representing 28% of their total owned and leased generation assets) and recover leased units' stranded costs under a separate mechanism if that is the only way to avoid triggering lease loss payments.

Second, the plan is a traditional "split the baby" regulatory proposal which now requires significant Commission modification to reasonably limit TEP's opportunity for recovery to 100%. For example, TEP's interim CTC request seeks way too much recovery. The interim CTC should be a valid forecast of the actual CTC in place once divestiture is completed. The actual CTC will credit TEP's generation asset sales proceeds and, therefore, any interim CTC must contain a forecast of such proceeds. Energy Services has prepared such a forecast using the comparable sales data on other plants divested in the United States provided by TEP in their filing (Schedule 3, Table 1). We forecast a gross sales price of $1.26 billion in 1998 dollars. This compares with $1.28 billion in net book and net lease value for TEP displayed in TEP's Schedule 5 at 12-31-97. We note that TEP has claimed additional stranded costs in other categories as well. Energy Services requests that the Commission accept or improve upon our forecast, possibly through an immediate independent analysis that produces an appraisal of TEP's generation plants and further analyzes comparable sales data. Energy Services presents its sales proceed forecast and methodology in Attachment A herein. Attachment A assumes that Springerville 1 and Irvington 4 can somehow sold at market without triggering lease losses. However, footnote 3 provides a forecast on the alternative assumption of TEP retaining these units. Hence, the difference between these two forecasts is an implicit forecast of the sales proceeds and stranded costs of the leased units.

The Commission should reject TEP's proposed **form** (i.e., net lost revenues) of interim CTC. As proposed, it will completely stifle competition. Moreover, their proposal would create a perverse incentive for TEP to delay or defeat their divestiture program because the interim CTC would be more favorable than the eventual actual CTC. They would have an incentive to keep the more favorable interim CTC in place as long as possible. The Commission must avoid this situation and provide incentives for TEP to advance its divestiture program quickly, yet simultaneously providing them the opportunity of 100% recovery to which they are entitled, but no more.

Third, there must be a reasonableness ceiling established on the amount TEP can securitize. TEP's proposal is open-ended with attendant risks for customers.

In summary, if TEP's plan is approved as proposed, it will be impossible for any new entrant to offer savings next year to any retail customer located in Tucson on the electricity services they currently receive from TEP. In fact, we are quite sure the opposite would occur - switching would produce a higher electric bill.

We recommend the following **solution** and provide more detail on our solution in the next section:

First, every reasonable option should be explored to avoid triggering stipulated lease loss payments. As a last resort, TEP should retain leased assets. In this event, stranded cost recovery and performance mechanisms should be placed on leased units to provide TEP recovery and encourage mitigation on those units. Such recovery should not depend on these units remaining operational.

Second, a forecast of the sales proceeds on the generation assets to be sold should be prepared and subtracted from an estimate of TEP's strandable costs. The net balance should form the basis for an interim CTC that remains in place until divestiture can be completed and an actual CTC can be established.

DETAILED COMMENTS

1. **TEP's plan attempts to solve more of its problems than just stranded costs:**

   The Commission should seriously consider whether it is in the public interest for TEP to divest leased assets as part of a stranded cost program. According to TEP's Schedule 5, leased assets – net book are $651 million, yet the stipulated loss is presently $1.2 billion. We cannot support creating this much additional cost simply to accomplish divestiture of these leased units. Other alternatives need to be explored that achieve the Commission's divestiture objectives (e.g., market power) without creating lease losses. As a last option, TEP would retain Springerville 1, Irvington 4 and possibly Springerville 2. The latter possibility, arises from leases on common plant assignable to Springerville 2. We would support divestiture of Springerville 2 if the associated lease payments on that unit's share of common plant could be somehow assured with no lease loss payments. Perhaps, the new owner could be contractually obligated to pay TEP these costs or the Commission could grant explicit recovery of these costs to TEP in regulated rates.

2. **The plan is a traditional "split the baby" regulatory proposal which now requires significant Commission modification to limit the opportunity for recovery to 100%.**

   a) The Commission needs a valid forecast of generation sales proceeds in order to establish an interim CTC. The interim CTC should be trued up for differences between forecast and actual generation sales proceeds. Attachment A herein provides Energy Services' forecast of $1.26 billion in generation sales proceeds. In this calculation, we segment comparable sales into coal plants and gas / oil plants because TEP has a greater percentage of its assets in coal resources than has been divested to-date in the U.S. Footnote 3 presents this calculation as if TEP retained leased units.

b) The embedded cost generation portion of each rate schedule presented in Exhibit C must be updated and reduced. For example, that Schedule indicates a General Service embedded cost of 7.94 cents per kilowatt hour. This is very hard to fathom in light of the net book values presented in Schedule 5 and values for other utilities in Arizona and elsewhere. The Commission must obtain an updated cost of service study and project even further unit cost reductions to form the basis of an interim CTC. Energy Services suggests that the Commission use the historical trend to project future cost reductions unless TEP can clearly demonstrate a reason to the contrary.

c) TEP hasn't demonstrated whether or how it will cease measuring stranded costs on December 1996 as required by Commission Decision No. 60977.

d) TEP should lower its allowed return on equity on stranded assets from its proposed 10.5 % to, say, 90% of the embedded debt cost as a result of **reduced risk** from Commission assurance of recovery. TEP's stated debt cost is 6.1% and, thus, the equity return on stranded cost could be as low as 5.5%.

e) TEP has not proposed removing any costs for sales, marketing or corporate services from unbundled regulated rates available to direct access customers. These costs are not appropriate for inclusion in regulated rates nor are they stranded costs. These are avoidable costs. However, TEP's interim CTC method would recover these costs in regulated rates from customers that switch. These are costs that any ESP has and there is no reason for switching customers to pay for them twice. If TEP wants to include these costs in its standard offer tariff, that is fine with us, but they do not belong in unbundled direct access tariffs. Likewise, TEP has apparently not included any other factors which mitigate costs.

f) The 50% shareholder premium approved in Decision No. 60977 must apply on a net basis after all divestiture costs (including lease losses, if any) are paid and not on an individual plant basis as TEP proposes. We believe that is the intent of the Commission in Order No. 60977.

g) We think it is highly unlikely a TEP auction will "fail." We agree with TEP that they need assurance, however, for this very unlikely event. We would continue to support TEP's opportunity for 100% recovery, but likewise continue to reject the use of net lost revenue mechanisms because they provide more than 100% recovery unless they apply for only brief periods of time.

3) There must be a reasonableness ceiling placed on the amount TEP can securitize.

TEP must propose a reasonable maximum amount for securitized costs from the outset. TEP must accept some risk in this regard. We are not fully convinced securitization is needed if leased assets are not sold.

We ask the Commission to take a detailed look at non-standard practices proposed by TEP such as service fees for securitized bonds, overcollateralization, and bond issuance by a TEP subsidiary. We appreciate TEP's apparent effort to reduce alleged tax consequences of divestiture, but we are concerned as these features were not present in the California securitization program.

TEP total company (information only):

1) TEP generation net book value:	\$631 million (Schedule 5)
2) TEP's leased asset – net book:	\$651 million (")
3) TEP's total owned and leased MW:	1,895 MW (page 6)
4) Cost of TEP per kilowatt ((1+2)/3)	\$677 per kilowatt

A **forecast** of TEP's gross proceeds from auction based on United States' divestiture experience to date is:

5) TEP's **coal** net book value:	\$571 million
6) TEP's **coal** leased asset – net book:	\$651 million
7) TEP's **coal** owned and leased MW:	1,462 MW (includes Irvington 4)
8) Cost of TEP **coal** per kilowatt ((5+6)/7)	**\$836** per kilowatt
9) US Auctions of **coal** to date:	**\$820** per kilowatt (\$ 2.92 billion divided by 3,560 MW – Source: TEP Schedule 3 Table 1)
10) Difference coal: TEP versus US	\$16 per kilowatt
11) Estimate of TEP's stranded **coal** costs:	**\$23.4** million stranded costs (\$16 multiplied by 1,462 MW)
12) TEP's **gas/oil** net book value:	\$26 million
13) TEP's **gas/oil** leases	\$ 0
14) TEP's **gas/oil** MW	387 MW
15) Cost per kilowatt ((12+13)/14)	\$67 per kilowatt
16) US Auctions of **gas/oil** to date:	\$156 per kilowatt
17) Difference gas/oil: TEP versus US	\$(89) per kilowatt
18) Estimate of TEP's stranded gas/oil	**\$(34.4)** million stranded benefit
19) Estimate of TEP's total stranded costs	**\$(11.0)** million stranded benefit
20) Forecast of TEP's sales proceeds	**\$1.26 billion (1,462 Mw * \$820,000 per MW plus 387 mw * \$156,000 per MW)**

Note:

1) This work sheet does not include strandable costs, if any, beyond lines 1) and 2) above in the calculations displayed on lines 11), 18) and 19) above. Please note that

$34 million in intangible and unallocated plant in line 1) was not included because it was unclear how to allocate it between coal and gas/oil.

2) Lines 7) and 14) do not sum to 1,895 Mw because Irvington 4 has been classified as coal. This unit can run on either coal or gas.
3) If TEP's leased assets (Springerville 1 and Irvington 4) are removed from the calculation on line 8, then TEP's coal cost falls to $542 per kilowatt ($527 million divided by 972 MW). Total coal and gas / oil sales proceeds fall to $858 million (line 20) representing a total stranded benefit of $(304.4) million for the non-leased assets (line 19).

Respectfully Submitted, September 21, 1998.

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Distribution list for parties that intervened in the Stranded Cost hearing in which Decision No. 60977 was issued.