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Tucson Electric Power Company

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Mail Stop DB203
220 West Sixth Street
P.O. Box 711
Tucson, Arizona 85702

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Bradley S. Carroll
Counsel
Regulatory Affairs

(520) 884-3945
Fax: (520) 770-2000

May 22, 1998

Arizona Corporation Commission
DOCKETED

MAY 26 1998

DOCKETED BY

Via Facsimile and U.S. Mail
Ray Williamson, Acting Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Re: Tucson Electric Power Company's Comments on Staff's May 19, 1998 Statement of Position on Retail Electric Competition

Dear Mr. Williamson:

Tucson Electric Power Company ("TEP" or "Company") is in receipt of the May 19, 1998 Statement of Position on Retail Electric Competition ("Position") and appreciates the opportunity to provide comments in respect thereof. Given the time constraints, these comments do not represent an exhaustive analysis of the Position, but a general overview of what the Company considers the most critical issues. We reserve the right to further analyze the issues and respond more fully when such analysis is completed.

General Comments

TEP commends Staff for taking the initiative to redefine the principals governing the introduction of retail electric competition in Arizona in light of the various knowledge and experience that has been garnered since the adoption of the Electric Competition Rules ("Rules") on December 26, 1996. Much has happened including, but not limited to, the various workshops that have taken place, the generic stranded cost hearings held this past February, the proposed legislation in Arizona and the experiences of other jurisdictions such as California which have gone down this path. It is clear that the Position put forth by Staff is designed to enable the Commission and the various stakeholders to move more rapidly with respect to some of the crucial issues that must be resolved in order to make retail electric competition a reality in Arizona. However, given the proposed timetables, options and requirements set forth in the Position, modifications are necessary and a greater degree of specificity must be provided with respect to financial and operational considerations. Moreover, to the extent that it may not be possible to provide specificity with respect to some issues in a short timeframe, there at least must be a recognition of such issues and a timetable for the resolution thereof.

A. Stranded Cost

General

TEP believes that all Affected Utilities must have a reasonable opportunity to recover 100 percent of their unmitigated stranded costs regardless of the method selected. However, despite the assertion on page one of the Position that "Affected Utilities are not required to divest generation assets," unless Affected Utilities elect divestiture, they do not have an opportunity to recover all of their stranded costs. This constructively constitutes a forced divestiture despite the semantical assertion. In effect, the Position puts the Commission in the shoes of management by forcing this decision. No other state has adopted legislation or rules that conditioned full stranded cost recovery on divestiture of generation assets. It is management's prerogative, and, indeed, its responsibility to shareholders, to decide this issue.

Divestiture Option

TEP supports a divestiture option for Affected Utilities. The Position proposes "unmitigated stranded costs shall include reasonable costs associated with sale of generation assets." TEP supports this proposal in concept. Given the unique financial and ownership structure of the Company's generating assets, however, the proposal must provide greater specificity regarding the type of costs that will be recoverable. For example, the Company may not be able to divest its leasehold interest in its leveraged leases without incurring premiums, penalties or other payments to the Lessors and Debt Participants. Any such payments should be included as elements of stranded costs. In addition, a significant portion of the Company's generating assets is financed with tax-exempt two-county debt, which may have to be redeemed upon transfer of the assets. The Company should be able to recover the higher average interest cost if low cost debt must be redeemed. Similarly, costs associated with the transfer of the Company's fuel and transportation contracts and interests in jointly-owned generating facilities must be accounted for in determining the costs associated with divestiture. Furthermore, all tax ramifications of a divestiture should be recoverable by the Affected Utility. Finally, the definition should reference "book value" as opposed to just "value."

Staff's Position would prohibit any Affected Utility from purchasing generation assets of another Affected Utility. TEP believes in the absence of a clear demonstration of the potential of market dominance by the acquirer, the prohibition needlessly limits the market for such assets and may limit the value received, thereby increasing stranded cost. The prohibition may also violate the interstate commerce clause of the U.S. Constitution. Affected Utilities have unique knowledge of the value inherent in generation assets within the region, and the assets have potentially more value to Affected Utilities due to system and regulatory considerations. Limiting the potential buyers is contrary to the concept of a competitive market, and provides a competitive advantage to out of state interests who are pushing for divestiture. Because the Commission must approve any sale of the assets, it will be in a position to determine the existence or potential of market dominance as part of the proceeding.

The Position does not address the possibility that no acceptable bids will be received for the generating assets, or that the Commission does not approve a submitted divestiture plan. Under such circumstances, the Company should be provided with another option that provides a reasonable opportunity for recovery of 100 percent of unmitigated stranded costs.

In its current form, the Position may negatively impact the financial viability of TEP during and after the divestiture process. The Company's ability to maintain adequate cash flows is imperative. Customers will begin to leave the Company's system on January 1, 1999. Transition charges associated with such losses will be estimated and held in trust until divestiture of the generating assets is completed. Yet, until the divestiture of its generating assets is completed, the Company will continue to have payment obligations associated with the assets (including fuel, lease payments, interest and O&M expense). The establishment of the trust essentially withholds revenues that are necessary to meet those payment obligations. In addition, TEP's Credit Agreement with its bank lenders contains covenants relating to interest coverage and financial leverage, both of which are measured based on cash flows available to the Company. The loss of revenue associated with the establishment of a competitive transition charge ("CTC") trust would impair the Company's ability to meet the financial covenants, and could result in a default under the Credit Agreement. That result would obviously have a negative impact on the ability of the Company to conduct its business and to participate in the divestiture process.

In order to complete the divestiture of its generating assets, the Company may be required to (1) redeem debt obligations associated with the assets, (2) compensate substitute lessees for assuming the Company's obligations under its leveraged leases, and/or (3) pay premiums or penalties to Lessors, Debt Participants, fuel and transportation providers or participants in jointly-owned facilities, all as discussed previously. The cash required to make such payments may exceed the proceeds received by the Company from the divestiture of the assets. Consequently, funding would be required to finance the potential cash requirement.

The additional funds could be obtained by the local distribution company (*i.e.*, TEP, following divestiture) through one or more financings. The financing would be dependent on the CTC the Company receives for its stranded costs. Lenders would look to the CTC cash payments as a source for the payment of interest and principal on the new loan(s). The loan terms (including the amount, interest rate, and maturity) would be determined by the size and term of the CTC and, of key importance, assurance that the CTC is an irrevocable obligation, subject to change only for true-up. One means of obtaining such assurance is through an irrevocable order of the Commission. Additional assurance and enhanced financing ability would result if an approved Commission order created a property right in the transition property for the benefit of a special purpose entity. Bonds secured with such property rights could probably be issued by the special purpose entity on more favorable terms than the LDC would receive, thereby reducing costs to customers.

TEP believes that the January 1, 2000 date for competition of divestiture is unreasonable. Under optimal circumstances, the average time for divestiture, including all FERC and other approvals, has been 18 months to two years. TEP has in place very complex contractual and other financial structures which could take at least two years to address in the event TEP chooses to divest its generation assets. These structures include sale and leaseback transactions, coal sales agreements, coal transportation contracts, remote coal plant joint operating agreements, tax exempt local furnishing bonds, pollution control revenue bonds and wholesale power and transmission agreements. TEP is also a participant in joint projects that currently require three-years notice of divestiture. Additionally, as the Affected Utility will be required to provide regulated generation services to most of its existing customer base until January 1, 2001, the Affected Utility should have a reliable source of generation until that time. To require divestiture prior to that will force the Affected Utility to procure the generation in the market which could be more costly and raise rates. Therefore, TEP suggests that the latest date for divestiture should be January 1, 2001 unless otherwise approved by the Commission.

TEP also supports a requirement that existing employees continue to operate any divested plants for two years after plant sales take place in order to maintain operating continuity.

Finally, the Position must state that the recovery period for the CTC must be sufficient to allow for the opportunity for 100 percent recovery and to support any securitization and that regulatory assets are recoverable as part of the CTC or distribution charge, as appropriate.

Special Contracts

Special contracts were approved by the Commission to retain load for the benefit of all customers of the Affected Utility and are included in customer class cost allocations. The concept of retaining load and providing some fixed margin has benefited all customers and been supported by the Commission. TEP's shareholders should not be responsible for stranded cost associated with these contracts, especially to the extent there could be no allocation of such costs pursuant to class cost allocations. Under the Position, special contract customers would not be required to pay their share of stranded costs while other customers will pay their full share. Unless modified, Staff's Position may result in a write-off for TEP and not provide TEP the opportunity for 100 percent stranded cost recovery. Further, it will be unlikely to negotiate a contract extension that contains a stranded cost assessment. This will result in large customers escaping their obligation to pay their fair share of stranded costs while captive customers such as residential consumers will be forced to pay. Additionally, there are write-off implications that are more fully discussed below.

Non-Divestiture Option

It appears that with the exception of regulatory assets, this option does not provide for any stranded cost recovery. TEP believes that this provision is not a viable option for those Affected Utilities whose management determines that it is not in their best interest to divest <u>and</u>

would constitute a taking without due process or just compensation. Such a position is unprecedented in the electric deregulation initiatives proposed at the federal and state levels. TEP believes that it would be more appropriate for the Commission to allow an opportunity for full stranded cost recovery under this option through a net lost revenues or similar approach during a defined recovery period.

It is also unclear from the Position whether the Commission has the authority to require the transfer of generation assets to an unregulated affiliate. From TEP's perspective, this is of particular concern to those assets under lease where the lessors hold the consent rights to transfer.

Financial Viability Option

The Commission has a legal obligation to prescribe just and reasonable rates and allow for a reasonable return on the fair value of a utility's property. This is not discretionary. This option could be interpreted to mean that the Commission will provide sufficient revenues to provide one dollar over bankruptcy or sufficient revenues to meet financial obligations but no return to shareholders. The option is also vague and needs considerably more specificity. TEP would support this option if it provided for sufficient revenues for an Affected Utility to reach and maintain an investment grade credit rating and not require any FAS 71 write-offs.

Accounting and FAS 71 Considerations

While the Position states that it has the objective of providing an opportunity for 100 percent recovery of stranded cost, it is unclear from the Position whether Staff is proposing a plan that will actually provide this opportunity, or whether the Position will be structured so that it can be recognized by utilities following the accounting guidelines of FAS 71 and related accounting literature that applies to rate regulated enterprises. Failure to meet the FAS 71 criteria in any material way would result in significant write-offs that would financially cripple the Company and cause defaults under various credit agreements.

For recovery of costs to be recognized in the Affected Utilities' financial statements, the recovery must have the following characteristics:

- Cash flows must come from regulated revenues, rather than competitive revenues, even if it is probable that such competitive revenues will be earned by the entity. The cash flows can come from rates charged directly as a tariffed rate, or as a competitive transition charge, or through proceeds from securitized bonds which will be paid off through regulated revenues. In addition, the cash flows must be certain enough to warrant reliance upon them as a recovery mechanism. This certainty level should be interpreted as 80 percent (or better) probability of occurrence. Note that this does not constitute a guarantee of recovery.

- Recovery periods of five years or less appear to provide sufficient timely recovery to provide reasonable certainty that the utility will receive its costs. If the plan provides for recovery over a five-to-ten year period, the plan *may* be considered adequately timely, but recovery over a period in excess of ten years may not be sufficiently timely. The longer the recovery period, the greater the need for a true-up mechanism to allow the utility's cost recovery to be re-evaluated and modified. In the alternative, a greater amount of "head room" within the rate or increased evidence that the costs will be recovered by the end of the stated recovery period would be needed to avoid recognizing a write-off.

- A direct correlation between the costs incurred and the revenues being provided must exist. Setting rates, for example, based on a financial viability measure as proposed earlier by Staff in this Docket would be an approach to ratemaking based on factors other than cost of service. This would not fulfill the requirements of FAS 71 and may require write-offs, depending upon how it is implemented.

It is unclear from the Position what the length of the recovery period would be, whether the recovery plan uses only regulated revenues as a recovery mechanism and whether the determinations of amounts recoverable are directly related to costs incurred. These points are especially unclear for the option to transfer generation assets to an unregulated affiliate. There is no guidance in the "non-divestiture" option as to whether any stranded cost recovery is contemplated, nor as to how the Commission would determine a value to ascribe to assets so transferred. It would be extremely difficult, if not impossible, for a utility to make an informed judgment as to the appropriate path to take, without further clarification of these issues. If the "non-divestiture" option is intended to preclude stranded cost recovery, all stranded costs would be written off immediately.

In addition, there are two issues which present potential write-offs for the Affected Utilities. First, under the divestiture option, the Staff proposes to put funds in a trust until generation assets have been divested. The interest earned on the funds are used to reduce stranded cost. While there is little detail to this plan, it appears possible that this plan could be construed as an indirect disallowance, which would require the utilities to write-off the amounts of the stranded cost at least equal to the anticipated return on the funds. The trust arrangement appears to represent a penalty provision to the divesting utilities. Under other circumstances, the utilities would collect the rates directly from customers and keep any earnings thereon. This disallowance would be avoided with the omission of the proposed trust arrangement.

The special contract provision would likely cause write-offs. The Position states that customers under special contract will be exempt from the CTC and that the amounts are not collectible from other customers. Since the amounts would therefore be collectible from no one, those amounts would likely have to be written off immediately.

In addition to the trust fund related FAS 71 concerns noted above, there are trust fund administrative concerns as well. This trust fund appears to be more administratively costly than the benefit it provides. The following issues must be addressed before such a plan could be implemented:

- How would the transition charge be collected?
- Does the collection method change after divestiture of generation assets has occurred and is there a trust account maintained thereafter?
- What happens to uncollectable amounts while such amounts are due to the trust account?
- Who administers the trust account?
- If this charge is on the same bill as all other customer charges, would the funds would come first to the utility or the ESP? Separate arrangements would have to be made to forward the funds to a Commission-controlled trust account.

To summarize, the Position would avoid causing write-offs under FAS 71 if the Position provided an "opportunity" (of 80 percent probability or higher) for recovery of 100 percent of stranded cost over ten years or less, and was based solely on regulatory cash flows. In addition, the trust arrangement should be omitted from the plan and the CTC should be made recoverable from all parties, including those under special contracts. Further, the recovery plan must be designed based on the specific costs of the entity, rather than some other method, such as the maintenance of financial viability.

B. Affiliate Rules

In November 1997, the Commission approved cost allocation procedures for shared resources, such as payroll system, accounting department personnel, etc., between TEP and its commonly-controlled affiliates, as a part of the approval of the formation of TEP's holding company. An absolute prohibition of shared services and savings may not be in the public interest if it increases the costs of regulated activities. Would these requirements now set aside those procedures and force UniSource Energy/TEP to provide separate accounting and other operating departments, separate information systems (payroll, general ledger, accounts payable, etc.) for TEP versus unregulated affiliates? This is a large and unnecessary cost to incur. Competitive companies, including likely new entrants to this market, share administrative costs between business units as a common practice, without hindering competition. The Staff should reconsider this proposal and, at a minimum, grandfather cost allocation arrangements which have been previously approved by the Commission. Alternatively, the Commission should allow the routine use of cost allocation procedures, provided that such procedures are not established to benefit one commonly-controlled entity over another.

The Position further states, "costs associated with restructuring the Affected Utilities into separate corporate affiliates shall be borne by the shareholders." TEP believes that any costs mandated by the Commission associated with implementing competition should be borne by customers since they are the ones receiving the benefits of competition. These costs would include, but not be limited to, those related to installing new computer systems, capital expenditures to assure reliability, capital expenditures to implement any pilot program, system control room expenses, metering and customer information systems.

Other issues include:

- Do the new market entrants have to comply with these provisions? If not, it provides them with a competitive advantage.

- If the Commission establishes a value of the competitive assets below the book value of the assets, would that be included as a stranded cost?

- The provision for offering the same terms and conditions to competitors should apply only to the Affected Utility's distribution service territory. Otherwise, new entrants receive a competitive advantage.

C. Implementation of Competition

Timing and Customer Selection

There needs to be a clear definition of what 1 MW means. TEP believes the Position should clearly state that a minimum net hourly load of 1 MW is required.

TEP does not support load profiling. There are many reasons load profiling is not a solution to open access including economic efficiency, system reliability, proper allocation of costs to customers and proper allocation of costs to third-party suppliers. These issues are explained in detail in the Commission report submitted by the Unbundled Services and Standard Offer Working Group November 3, 1997. The Company believes that all customers that want to access the competitive market must have a real time meter. This position is feasible given that the majority of customers will not have competitive access until the year 2001.

TEP also does not support the option to aggregate customers with > 20 kW loads or the residential pilot program as there are many unresolved technical issues in order to aggregate customers > 20 kW. These issues were described in TEP's filing "Second Set of Comments on Proposed Rule Regarding Retail Electric Competition," dated December 4, 1996. The basic premise is that it is far more difficult technically to serve individual residential customers than it is to serve several large customers. In its report TEP states:

> "Energy management systems, communication systems, billing systems and general system operations will need to undergo significant changes and improvements before the number of independent system transactions dramatically increase. A full choice competitive environment will result in local area control rooms that facilitate transactions between specific suppliers and specific customers and require that the local area control room be able to follow specific customer loads and their respective suppliers moment to moment. If a customer's supplier does not deliver power, then that specific customer will be required to cut its load or purchase alternative supplies. This change from managing a handful of suppliers for one customer (total retail load) to a brokering role between many separate customers and suppliers will require significant changes to existing energy management systems as well as more phone lines and people to facilitate customer transactions."

Considering the time frame of the phase-in and the additional requirements to include residential customers in their own phase-in program on a quarterly basis, the technical issues become even more crucial to resolve before direct access implementation. TEP believes that it could implement the requirements for customers over 1 MW. However, TEP strongly objects to the aggregation of customers 20 kW and above. The Position negates any attempt to phase-in competition in an orderly manner in order to accomplish meter installation, development of billing systems and other operational protocols.

The addition of 20 kW customers will dramatically increase the number of customers having choice. The number is not ever clearly known to TEP because our system has few demand meters for the small customers; however, the 20 kW requirement could potentially allow large homeowners to qualify, bringing the number into the tens of thousands. Additionally, one half of one percent of our residential customers is just under 1500 customers. These customers would require a new computer system to accurately track loads. Without such a system, which has yet to be designed, system reliability could be affected. Moreover, due to the lack of demand meters, load profiling would be very difficult to implement. Therefore, TEP believes that before any load profiling is utilized, that demand meters be installed on a statistically valid sample of customers and 24 months of data be obtained. For these reasons the residential pilot program could not be implemented by 7/1/99.

Targeted Rate Decrease

The level of any required rate decrease should be determined based on a balance of the recovery of 100 percent of stranded costs, term limits on any such recovery and rate cap requirements. Although TEP recognizes the need to share significant operational savings with customers as evidenced by its pending shared savings proposal, any mandated decrease beyond this is requiring shareholders to fund a decrease for customers. For TEP, a three-to-five percent rate decrease could be as much as $30 million of revenues or up to $18 million after tax. This represents more than half of TEP's earnings today and is not acceptable to TEP.

D. Metering and Billing

Metering

The Position states, "Competitive metering shall be offered to customers having access to competitive electric power services as of 1/1/99. These services can be provided by the Affected Utility, the ESP or their Agents." Yet it also states in the Affiliate Rules, " ...Affected Utilities create separate corporate affiliates for competitive activities and monopoly activities. The Affected Utilities will transfer competitive assets to a separate affiliate at a value determined by the Commission to be fair and reasonable." It is unclear if metering must be moved to an affiliate or if it should remain with the LDC. This issue is also linked to the Standard Offer requirements. Does the LDC have standard offer metering obligations even if metering is determined to be competitive? Must the LDC purchase metering services as well as generation services?

There needs to be a clear definition of what "competitive metering" is. The Subcommittee working on metering is still working out the details concerning competitive versus regulated services. There is still an issue concerning current transformers and potential transformers as far as who should own this equipment and who should have access. Because of these issues, TEP believes that metering should remain with the LDC during the transition period.

Billing

Since there will be a need to implement a new billing system in order to accommodate direct access, the customers should be responsible for the cost of any upgrades or a new system. Customer information should be closely monitored and only companies to which the customer gives access should receive any customer information.

The Position provides for the Affected Utility to determine the appropriate termination procedure. A significant number of joint use issues exist prior to termination of service delivery that must be resolved before joint billing can be instituted:

- Who determines credit policy (how much deposit or alternative credit support is required)?
- If a customer makes a partial payment, which party gets paid?
- Who bears the cost and responsibility of collections?
- How are the costs of providing the billing service allocated back to the other party (such as the LDC bills for the ESP)?

- Who determines that the various parties (LDC or ESP) have the billing system capability to ensure that the appropriate amounts are billed to customers, collected, credited to and remitted to the appropriate ESP or other provider? Are there minimum standards which must be met?
- Shouldn't all competitive CC&N's be contingent upon an "interconnection" agreement with the LDC?

Again, as with metering, billing should remain with the LDC during the transition in order to resolve these very significant issues.

E. Local Distribution Company Services

Standard Offer

The Position states, "There shall be no additional constraints for a consumer switching to or from Standard Offer Service." TEP believes that there should be some limit as to how many times a customer may switch from standard offer service per year. There should be some limit as to how many ESPs the customer switches to or from. It would be unreasonably difficult to perform system planning and to purchase power if the customer base is switching back and forth from Standard Offer Services to market without limitation as to frequency of such changes. This would encourage customers to "game" the system depending on market prices, seasonal rates and the purchased power pass through to customers. It will create a constant need to amend standard offer tariffs in response to market gaming. Further, as there are administrative costs associated with a customer switching, a nominal charge to cover the cost should be permitted.

The Standard Offer Section of the proposal states that a customer may change service provider at the end of a billing cycle. We suggest that this be changed to every third billing cycle. The experience in California has shown that it takes 60 days just to perform the process.

The utility should be allowed to arrange standard offer purchases through a subsidiary, subject to Commission approval, in order to minimize the cost of power acquisition. Further, it should be explicit that the costs of purchasing energy competitively to supply the standard offer is fully recoverable under an energy adjustment clause. The LDC should not be at risk for those costs due to rate caps or rate reductions. Staff should be aware that purchasing power under variable contracts with "ratchet-down" provisions tends to be expensive.

The Position is silent concerning rate design issues. There needs to be some guidelines for companies who sell generation. Allocation procedures that were used in the past will have to be refined given the changes in the corporate structure. A Company that divests generation should be given an opportunity to file a rate structure that reflects the new corporate and market structure and new business and financial risks.

Thus, the Commission must recognize that procuring energy for standard offer customers raises additional issues. The Commission could set standard offer service as a direct pass through in which case the LDC takes no risk. Alternatively, the LDC could accept a certain level of risk if it was permitted to share in any profits associated with the procurement of power as measured by relevant benchmarks.

F. Transmission and Dispatch

The Electric System Reliability and Safety Work Group has been discussing infrastructure issues relative to direct access for well over a year. As a part of these discussions a document laying out the functions of Scheduling Coordinators, Transmission Providers/Control Area Operators and an entity called the Independent Scheduling Administrator ("ISA") has been drafted. This document is supported by the stakeholders taking part in the discussions as a roadmap for implementing direct access in Arizona. As such, this document should be included in the Position to formally adopt the ISA model for Arizona direct access purposes. Enclosed is a copy of the ISA model.

Coincident with the start of direct access on 1/1/99, scheduling coordinators ("SC") shall provide for any aggregation of customers' schedules prior to submission to the respective Control Area Operator and the ISA. These schedules must have a minimum net hourly load of 1 MW. The SC must receive certification from the ISA prior to operating in Arizona.

The list of potential functions for an Independent System Operator ("ISO") in the Position should be modified as follows:

1. Administration of grid-wide tariff that eliminates pancaked rates;

2. Managing congestion and establishing congestion pricing;

3. Coordinate the planning and transmission expansion with existing regional planning (RTG) and operating groups;

4. Security Coordinator;

5. Provision and pricing of ancillary services;

6. Provide for Alternative Dispute Resolution (ADR) process;

7. Operate the Open Access Same-time Information System (OASIS);

8. Resolve "seams" issues; and

9. Follow WSCC/NERC (NAERO) standards.

The Commission should require the ISA to be operational prior to implementation of Direct Access on 1/1/99. Furthermore, the Commission should require formation of an ISO by 1/1/01. For both the ISA and the ISO, timetables should be established by the Commission to accomplish this.

In regards to the treatment of must run units, the Affected Utilities, with approval by the ISA, should determine which generation units are must run for distribution reliability in order to mitigate market power. The price of power from such units should be determined by the appropriate Commission.

Finally, the Commission should support the Affected Utilities with respect to modifications needed to their FERC tariffs.

Other Considerations

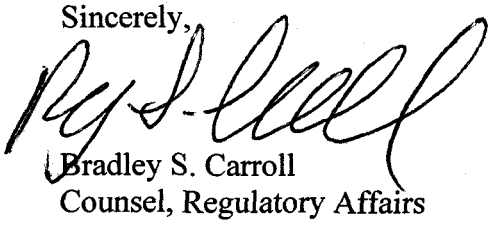
The Position is silent with respect to any intergovernmental agreement ("IGA") between the Commission and SRP. TEP has been consistent in its position since 1996 that SRP should implement competition consistent with the Commission's plan. TEP reiterates this position again.

Conclusion

Through these comments, the Company has attempted to provide all stakeholders Staff with constructive recommendations based upon its financial circumstances and its operational experience. The submission of this Position by Staff at this time is indicative of Staff and the Commission's goal to bring retail electric competition to Arizona as quickly as possible. In order to meet that goal, it is crucial that the Position that Staff will ask the Commission to consider and ultimately adopt must provide a greater degree of specificity with respect to crucial operational and financial concerns of the Affected Utilities. It also must not advantage some stakeholders at the expense of other stakeholders based upon arbitrary or political considerations. This means making some tough choices now because they cannot be put off until later. As all parties are very serious about meeting this goal in a timely manner, this Position may represent the last opportunity to do so. If principles of equity and fairness are ignored, protracted litigation may result. Such litigation could potentially set back the introduction of competition in this State indefinitely. The Company urges Staff to consider what the Company has recommended and incorporate such recommendations into the final Position and to answer questions posed by the Company through a cooperative resolution of the issues raised. Only after such a full and complete response to our concerns will TEP support the adoption of the Position.

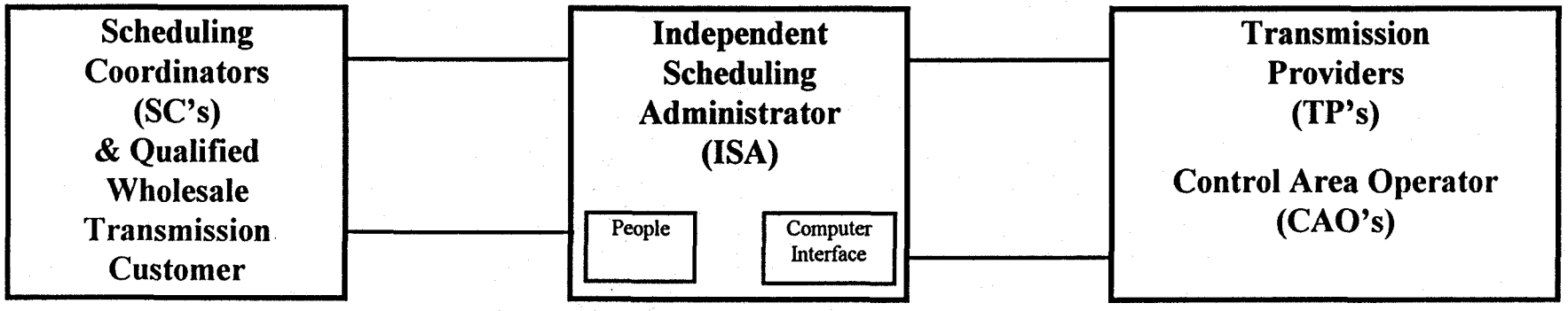
Thank you again for the opportunity to provide these comments. Representatives of the Company would be happy to meet with you or provide additional information prior to the submission of the final Position on May 29. If you have any questions, please do not hesitate to contact me.

Sincerely,



Bradley S. Carroll
Counsel, Regulatory Affairs

SC/ISA/TP/CAO FUNCTIONS
For 1/1/99 Implementation



	SC's	ISA	TP's & CAO's
Future		1. Participate in the processes of: ▪ Operating Studies used to determine TTC ▪ Maintenance schedules of Transmission [1] ▪ Control Area Operator TTC determination 2. Define, review and oversight of committed use. (Implementation of Western Interconnection ATC document)	1. Production of: ▪ Operating studies for TTC determined ▪ Determine TTC and allocate to path owners ▪ Publish Transmission maintenance schedules[1]
Day Ahead	1. Forecast load requirements for day-ahead 2. Acquires necessary transmission and distribution 3. Arranges for appropriate ancillary services 4. Submits balanced schedules (load + loss = gen) to ISA & CAO simultaneously and provides necessary NERC/WSCC tags	1. Responsible for calculation of ATC (Implementation of Western Interconnection ATC document) 2. Operate over arching state-wide OASIS ▪ All ATC posted here ▪ All loads scheduled here ▪ All Xmiss reservations requests made here [1] ▪ Ancillary Services posted here ▪ Secondary transmission posted here 3. Receives copy of transmission schedule and update ATC after receipt of confirmed schedule 4. Receives additional requests for transmission and update ATC 5. Monitor release of ATC	2. Process, review SC's schedules, submit existing contract schedules to ISA, submit generation participants schedules to ISA 3. Posts ancillary services to ISA's OASIS 4. Processes additional schedules from transmission reservation updates 5. Participates in activities for checkout/settlement process for previous day 6. Publish next day operating plan to ISA
Current Day	5. Additional schedules submitted to ISA & CAO with tags 6. Responds to contingencies and curtailments as directed by control areas (7 X 24 ops)	6. Receives and posts curtailment information 7. Provides appeals process for transmission use denials and curtailment orders	7. Manage Real-time operations and specify curtailment and contingency actions 8. Processes additional schedules from transmission reservation updates
After the Fact	7. Required to participate in checkout/settlement process and provide metering information 8. Provides meter data	8. Facilitate ADR process 9. Participates in checkout/settlement process, as needed	9. Responsible for the checkout/settlement process

[1] Presumption: Once a Scheduling Coordinator receives transmission access, distribution access will not be a problem. However, if there is distribution congestion, there may be a role for the ISA in overseeing distribution congestion management and distribution access.