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1200 West Washington
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Docket #: RE-00000C-94-0165

RE: Response to Staff's May 19, 1998 "Position Paper" on Retail Electric Competition Matters

Dear Ray:

Arizona Public Service Company ("APS" or "Company") hereby presents its initial comments on the May 19, 1998, Staff "Position Paper" on Retail Electric Competition. In order to meet Staff's deadline for responsive comments, these remarks will be necessarily brief. However, I trust they will convey our firm conviction that the Staff proposals are grossly deficient in many material respects, meet none of its stated objectives, are extraordinarily punitive to "Affected Utilities,"[1] and continue to lack the level of detail and specificity required to implement competition in the next seven months. APS has previously provided Staff a proposal for resolving many of the restructuring issues, and I have attached a copy to these comments. I ask you to give the Company's comments an objective reading and to continue to work together with interested stakeholders to produce meaningful reforms to the Commission's skeletal Competition Rules so that meaningful competition can, in fact, begin on January 1, 1999.

The Company's comments will be organized largely along the subject matter outline of the Staff's presentation. As you will see, many of the comments are more accurately

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[1] Staff's proposals do not indicate whether or not the Commission should attempt to impose (through intergovernmental agreement or otherwise) divestiture and the other requirements of the Staff "Position Paper" on public power entities in order to satisfy the "consistency" provisions of H.B. 2366 nor does it discuss public service corporations that are not "Affected Utilities" but which under H.B. 2366 must be open for competition by 1999.

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characterized as questions concerning the Staff proposals - questions that need answering prior to the Company's final evaluation of the merits, if any, of such proposals.

STRANDED COST

1. Staff's Divestiture "Option"

Staff claims "it is the policy of the Arizona Corporation Commission to encourage full divestiture of generation assets." In furtherance of this newly asserted "policy," Staff proposes to deny stranded cost recovery to any utility that chooses not to divest its generating assets and only limited stranded cost recovery to those who unsuccessfully try to divest.

Leaving aside the obvious issues of whether or not such divestiture is, indeed, "voluntary," as Staff claims, or whether the Commission has the power to order divestiture, directly or through coercion,[2] Staff's position is unsupported by any compelling rationale and is, indeed, counterproductive to the very goals of Staff to encourage fair competition. No state contemplating retail access has, by legislation or regulatory order, demanded the surrender of incumbent utility assets to foreign businesses as a precondition to stranded cost recovery.

Staff has never explained why divestiture is necessary, either as a measure of stranded cost valuation or to eliminate any perceived "market power" concerns in Arizona. To the contrary, Staff has consistently rejected divestiture as a preferred Commission policy. Staff rejected divestiture in the formulation of the original Competition Rules, and the Commission concurred. (*See* Decision No. 59943). During the various Working Group discussions held last year, Staff again rejected divestiture and issued a report identifying the many difficulties with such action. (*See* the September 30, 1997, Stranded Cost Working Group Report to the Arizona Corporation Commission in Docket No. U-0000-94-165). Even more recently, the Staff witness in the Stranded Cost Proceeding rejected the use of divestiture as a means of measuring stranded cost. In its reply brief filed less than 60 days ago, Staff was no more enthusiastic:

> The auction and divestiture methods may give rise to an arguably "truer" estimation of uneconomic costs, but only if a real market is

[2] In Decision No. 59943, the Commission recognized that "the Commission's regulatory authority to require divestiture of utility assets may be questioned and result in a protracted legal dispute" (page 63). APS demonstrated in its briefs in the Stranded Cost Proceeding that the Commission lacks the requisite authority to require divestiture. The Commission Staff has never provided any legal analysis supporting its authority to compel the sale or functional separation of utility assets.

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> established for the generation assets. And once done, divestiture is particularly difficult to undo. In addition, as we pointed out in our opening brief, the auction and divestiture methods only act to transfer uneconomic costs across categories, not as mitigation.

(Staff Reply Brief, page 4, March 23, 1998).

It is unclear why Staff has now suddenly and arbitrarily embarked down the path of dismantling Arizona's electric utilities. Certainly there has been no demonstration that any of the utilities exercise a degree of market power in the relevant generation market that would justify any consideration of the divestiture of some, much less all, generation assets. Nor has Staff ever offered support for the contention that divestiture will produce more meaningful estimates of stranded costs than that produced by other proposals or that it offers such an allegedly superior resolution of stranded cost concerns that outweigh the legal uncertainties and associated costs of and impediments to implementation that have been convincingly raised by other parties.

Divestiture is a completely inappropriate policy for other reasons, as well. First of all, it is hugely impractical. Given the contractual provisions governing the management and operation of many of the state's jointly owned power plants - provisions requiring rights of first refusal and extended notice periods prior to any attempted sale - divestiture would be time-consuming and perhaps impossible to conduct in an open market. In addition, under the most optimistic assumptions, the timing required to establish an auction procedure, receive competitive bids, and unwind the various financing, fuel, corporate restructuring and other related issues would extend well beyond the time frame contemplated in Staff's position, not to mention the significant expense associated with such activities. APS estimates that the cost to "untangle" existing arrangements sufficient to divest individual assets would be in the many tens of millions of dollars. As the Commission noted in Decision No. 59943:

> [T]he Commission's regulatory authority to require divestiture of utility assets may be questioned and result in a protracted legal dispute. Further, utilities, utility shareholders, and utility debt holders may strongly resist divestiture. Divestiture could be costly due to expensive debt re-financing. In addition, inefficiencies could result from the loss of traditional coordination of generation, transmission, and distribution services.

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> The restructuring policy proposed is preferred to [divestiture] because it: minimizes administrative complexity; . . . is relatively flexible so that policy could be adjusted mid-course; . . . minimizes utility organizational disruption; . . . and minimizes public confusion.

Id. at 63.

Of perhaps even greater significance is the fact that no nuclear facility has ever been successfully auctioned. As Staff well knows, there are substantial restrictions under the Atomic Energy Act and Nuclear Regulatory Commission Regulations on the transfer of the ownership of nuclear facilities that would significantly limit the field of potential bidders. More importantly, the transfer of APS' Palo Verde operating license (as opposed to a mere ownership interest) would be far more complex and would likely face insurmountable regulatory barriers under new NRC guidelines. To the best of APS' knowledge, the NRC has never approved the transfer of an operating license to an unaffiliated entity, much less the transfer of a non-operating agent's interest. If such a transfer were feasible, it would certainly have to be to an entity having actual experience in operating a nuclear power plant similar to Palo Verde. This would guarantee both an even smaller group of potential buyers and that operation of this country's largest nuclear power plant would be in the hands of some as of now unknown out-of-state corporation. Finally, by prohibiting Affected Utilities and their affiliates from bidding, the forced sale of such assets in a short time frame could easily lead to "fire sale" prices.

Even from the standpoint of developing a competitive market, divestiture makes no sense. Requiring all of Arizona's generating assets to be gobbled up by out-of-state owners could dramatically change the concentration of market power, could significantly increase reliability concerns, and would likely produce tax revenue shortfalls and other adverse economic consequences that Staff has yet to examine, much less even acknowledge. Moreover, the legitimate economies of scale and scope that Arizona utilities have created and that have enhanced consumer welfare will now be lost without any corresponding benefit to Arizona customers or the development of an efficient competitive market.

Interestingly enough, even for those utilities who are able to divest, stranded cost recovery would be far less than 100%. That fact is assured by the proposal that "Affected Utilities" absorb the stranded costs assigned to special contract customers (incidently, a proposal that is also inconsistent with the immediately preceding paragraph of Staff's "Position Paper") and the apparent forfeiture of the return on transition charges collected prior to divestiture. How

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much more less than 100% recovery would be received under Staff's divestiture "option" is highly dependent upon the answers to the following questions:

1) Will Affected Utilities be permitted a full return on the uncollected balance of stranded costs during the recovery period? If not, recovery will be far less than 100%.

2) What is the recovery period for stranded costs? The recovery period for stranded cost is not specifically described. Only a single reference is made. Does Staff intend to make the recovery period long enough to accommodate 100% stranded cost recovery <u>and</u> the suggested price reductions?

3) Will <u>all</u> costs incurred in divestiture be permitted full recovery? Costs directly attributable to the sale of the assets themselves, although considerable, will be dwarfed by the costs of renegotiating, refinancing, etc., the various agreements, financial and otherwise, that are necessary preconditions to any sale. For example, APS will need numerous approvals from creditors, vendors, preferred shareholders, non-ACC regulators and co-participants to accomplish the contemplated divestiture.[3] These approvals, even if obtainable, will cost considerable sums of money. In total, these transaction costs will be a significant fraction of total stranded costs.

4) What does Staff mean by the qualifier "unmitigated" stranded costs in the context of divestiture? Once generating assets are divested, there can be no mitigation. Thus, Staff's use of this term suggests future disallowances of already incurred stranded costs for as of yet unspecified reasons.

5) What happens if an "Affected Utility" can't divest by the end of 2000? Even if it started today and even if Palo Verde did not exist, divestiture could not be accomplished by APS within the time permitted. First it has to come up with a plan - no small task. Then the Commission must approve the plan after presumedly long and contentious hearings. Then APS must secure the various creditor, shareholder, vendor, lessor, co-participant and non-ACC governmental approvals. At the Four Corners and Navajo generation stations, the participants

[3] For example, APS may need participant approval of any change in its status as operating agent for Four Corners.

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have "rights of first refusal" that will certainly impact bidder interest and timing. Finally, APS must actually implement whatever divestiture plan is finally approved. This will certainly take much longer than the 19 months allowed even if the process started now.

6) The Staff proposal is silent on regulatory assets in the divestiture proposal. APS would like to believe that they would be fully recoverable, but the Staff proposal does not say as much. Moreover, even if Staff were to provide such explicit reassurance, would regulatory assets be truly "fully recoverable" or "fully recoverable" only in the same sense as Staff would have other stranded costs being "fully recoverable," i.e., far less than "fully recoverable".

7) Divestiture of units deemed to be "must run" without the proper reliability infrastructure in place will cross with the goal of providing reliability. Specific coordinated timing of divestiture of "must run" units and reliability oversight is a must.

8) What is the rationale for special contract customers not paying their share of stranded costs? This is clearly a special interest exclusion without foundation. In the stranded cost hearing, such exclusions were consistently rejected by most parties.

2. Staff's Non-Divestiture "Option"

The proposed non-divestiture option is neither "non-divestiture" or "optional" in any meaningful sense. "Affected Utilities" are, in fact, required to divest all their generation and other competitive assets into an affiliate. Such assets would be deemed to have been transferred for a "fair and reasonable" value without so much as a hint as to how such a "fair and reasonable" value is to be determined. Even assuming away that problem, what is to be done with any unrecovered balance? If recovery is to be denied, why?

Ironically, divestiture to a subsidiary or affiliate will raise most of the legal and creditor/shareholder/vendor/NRC, etc., issues (and require incurrence of most of the same costs) as would a divestiture to a third-party. Staff's attempt to impose these very considerable costs on shareholders is blatantly unfair. Staff certainly does not cite any authority for such an action nor did any party to the just recently concluded stranded cost proceeding make such a confiscatory recommendation.

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The inherently irrational nature of this "Hobson's Choice" created by these Staff "options" is perhaps best understood in the context of a partial divestiture - a situation that will likely apply to several "Affected Utilities." Staff's "Position Paper" clearly posits situations where the Commission would agree, if asked, that complete divestiture is neither practical nor in the public interest. Yet, if an "Affected Utility" nevertheless poured enough money and effort into the cause of making such an impractical and counterproductive divestiture come to pass, it would receive full stranded cost recovery, while the hypothetical utility that instead chose the practical and pro-public interest course of action is brutally punished.

The inclusion of this non-divestiture "option" is particularly significant in that it totally undermines any possible claim by the Commission that divestiture is being required under Staff's first "option" to address alleged market power concerns or that divestiture is believed a clearly superior method of asset valuation for stranded cost purposes. If either of these were true, and the Commission actually possessed the power to require divestiture, there would presumedly be no non-divestiture "option." Thus, the real purpose for granting "Affected Utilities" such an impractical and perhaps impossible "option" must be to create the appearance of allowing for stranded cost recovery in theory while totally denying such recovery in practice.

AFFILIATE RULES

APS has previously addressed the problems inherent in any precipitous effort to create a separate affiliate for generation.[4] Therefore, APS will discuss other problems created by this aspect of the Staff "Position Paper."

Staff would apparently require that APS' metering and billing functions be transferred into a separate affiliate. This is contrary to the position taken by Staff later in its "Position Paper." It is also contrary to H.B. 2663 and would threaten the "revenue neutral" tax aspects of that legislation. Even worse would be a requirement that the existing metering and billing infrastructure of APS be split in two, with "competitive" metering and billing going to an affiliate and "regulated" metering and billing remaining with the "Affected Utility." Such a hybrid would almost certainly guarantee higher costs for both the competitive and regulated entities, as well as their customers.

[4] APS would note that this "option" may have been more practical if: (1) stranded cost recovery (including all transaction costs incurred in restructuring) was permitted; and (2) "Affected Utilities" were allowed more time and discretion in accomplishing such a fundamental restructuring.

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The Staff's proposed prohibitions on cost sharing and joint use essentially deny to "Affected Utilities" the legitimate and procompetitive benefits of horizontal integration. Because these prohibitions would apparently not apply to competitors such as Enron and PG&E, both of which are affiliated with regulated electric utilities (let alone public power entities such as SRP), APS and other "Affected Utilities" would be placed at a severe competitive disadvantage. This harms more than just "Affected Utilities." With their natural and likely most formidable competitor (i.e., the incumbent electric company) out of the way or straddled with higher costs, new entrants will be able to command higher prices for electric generation and other competitive services than would otherwise be the case. Structuring competition for the convenience of the competitors rather than for the benefit of consumers and protecting inefficient producers by forcing up the costs of the incumbent is simply anti-consumer special interest regulation masquerading as competition. Lastly, without competitive affiliates to share its common costs, the regulated distribution entity will also have to charge higher rates than would otherwise have been necessary - creating a real "lose/lose" situation for consumers.

IMPLEMENTATION OF COMPETITION

1. <u>Timing and Customer Selection</u>

This implementation schedule directly conflicts with that mandated under H.B. 2663 and with the Commission's own proposed amendment to that legislation. Even without aggregation, customers 1MW or larger represent some 23% of the Company's 1995 peak load. Under Staff's proposal, we are talking about 40% of 1995 load with over 23,000 premises being "flash cut" to competition in 1999. Both numbers exceed the authorized limits under H.B. 236 and the existing Commission rules.

Aside from the issue of when it is practical to implement wide scale retail access, the Staff proposal regarding aggregation leaves unaddressed important "details". Does the 1 MW threshold refer to integrated peak demand, average demand or what? Can customers on different rate schedules be aggregated? Can customers of different classes be aggregated? Who is responsible for providing metering to the individual customers being so aggregated? In response, APS would make the following suggestions regarding aggregation:

1) Post-pone aggregation until 2001. Aggregation of loads >20kw increases eligible customer 10 fold, and would represent 55% of APS' sales. Infrastructure will not be in place to handle such a volume of customers by 1999, especially with the added complexity of aggregation.

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2) To provide proper allocation of competitive risk, a complete time differentiated energy accounting system must be in place, including system operation structure to allow aggregated scheduling. Adding large numbers of customers will significantly slow down access potential.

3) Each customer represents an entire group of transactions that are needed to effectuate customer choice. APS' analysis estimates that the current three transactions will increase to 27 per customer. This requires significant development of process systems. These systems will acknowledge competitive requests, assign an ESP, set the meter or assign load profiles, read the meter, interpret meter read data, integrate with load profile if necessary, integrate with power schedule, assign system energy imbalances, include third party billings (transmission, ancillary services, scheduling, etc.) and other items. (This list is provided to demonstrate the detail and is not meant to be exhaustive). Early in the transition period, a significant amount of manual processing will be needed.

4) The 1 MW requirement should refer to the aggregated group's minimum integrated demand since scheduling smaller amounts is difficult and inefficient;

5) Aggregations should only be permitted if all the aggregated end-users take distribution service from the same rate schedule. This not only reduces administrative problems but prevents customers from using competitive aggregation to merely arbitrage the pre-existing differences in rates as between the various Commission-approved rate schedules.

6) APS should provide metering to aggregated customers during the transition period. If competitive metering of the larger (1 MW and above) customers proves feasible, such aggregated metering could be made competitive after the year 2000.

With these clarifications, an aggregated retail access program could likely be implemented by 2001, which would allow residential customers to equally participate in the competitive market with small and medium commercial customers.

2. <u>Targeted Rate Reductions</u>

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Staff would mandate rate reductions for customers not granted access in 1999. This suggestion does not appear to have been supported by even the most rudimentary "back of the envelope" financial analysis of its impact on individual "Affected Utilities," nor does it appear to give any recognition to the over 8% in price reductions APS has requested since 1991. It should be obvious to even Staff that unless such "target" rate reductions are agreed to by the "Affected Utilities," they would be patently illegal absent a full blown rate case. *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 294 P.2d 378 (1956) - (rate reduction over utility's objection without full rate case finding that existing rates are unjust and unreasonable as measured solely by return on fair value rate base violates utility's constitutional rights). Adding some 12 general electric rate cases, including rate cases for APS, TEP and Citizens, to the Commission's already crushing work load for 1999 makes it impossible to prepare for competition in a timely fashion. Moreover, given Staff's obvious prejudgement that rates have to be reduced, legal appeals of any Commission attempt to truncate the normal rate review process to meet Staff's "targeted range" are both likely and yet another drain on everyone's limited resources.

3. Residential Phase-In

The objectives of the residential phase-in is unclear. If the purpose of the program is to be a pilot, why automatically increase the number every quarter without doing an analysis of the impact of the customers already participating? The proposal states that utilities must offer access on a first come, first served basis which means that the potential exists for APS to receive immediate inquiries from over 700,000 customers. Further, utilities would be required to establish tracking systems to monitor requests and then to reverify interest when the customer's number actually comes up. This proposal would only increase costs to the Affected Utilities and its customers. What is the purpose of submitting phase-in proposals when access is first come, first served?

METERING AND BILLING

1. Metering

As noted above, the statement by Staff that competitive metering could be provided "by the Affected Utility, the Electric Service Provider (ESP), or their agents" is totally inconsistent with the position taken by Staff in the "Affiliate Rules" section of its "Position Paper." Second, Staff is silent as to who is to provide metering to customers under 20 kw during the transition period and to Standard Offer ("S/O") customers both during and after the as of yet undefined

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"transition period." Third, Staff's position again conflicts with H.B. 2663 and will result in potential revenue losses to the state and to local governments.

APS would offer a solution that resolves some of the problems with Staff's proposal.

1) Metering would remain a regulated monopoly service provided by the distribution entity for customers under 1 MW until the year 2001 and thereafter for all customers under 20 kw unless the Commission makes a specific evidentiary finding that expanding competitive metering to all customers is in the public interest.

2) The distribution entity or the ESP could provide competitive metering services to eligible customers within the distribution entity's existing service territory.

3) APS could provide metering services outside its distribution service area only through an affiliated ESP.

A brief statement in the Staff "Position Paper" refers to load profiling. The statement is unclear in several aspects; (1) Is load profiling allowed for customers less than 20kw during the transition period? (2) What particular method of load profiling is suggested, static, dynamic or other?

Staff's additional proposal that metering data be required to be in electronic data interface (EDI) format is impractical because the act of metering might involve millions of separate transactions for which a separate charge would be incurred. Even if not financially prohibitive, Staff's proposal runs counter to its stated goal of "spurring technological innovation." EDI transmittal, if mandated, should be limited to billing rather than metering data.

2. <u>Billing</u>

Who provides billing services for residential customers before the year 2001? Who provides such services to S/O customers? Certainly not the "Affected Utility" - its billing apparatus and infrastructure has been shipped off to some unregulated affiliate. If the distribution entity is prohibited from billing for its services, who does it bill, and what happens when it isn't paid? Are ESP's required to provide billing services? If not, and the Affected Utility is prohibited from billing, how will bills be rendered? Does it make sense for the distribution entity to be in charge of connects and disconnects if it has no responsibility for

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metering (which is, after all, where all the connecting and disconnecting takes place)? If the customer has complete control over the release of billing data, what happens if the customer refuses to allow the ESP to provide such data to the distribution entity or vis a versa?

Aside from its obvious conflict with H.B. 2663, Staff's ill-conceived proposal raises more issues that it resolves, if it even resolves any. If the Commission is nevertheless enamored with the concept of competitive billing by ESPs, it should at least do so subject to the following conditions:

1) Any ESP wishing to do consolidated billing should be required to obtain a transaction privilege license from the Department of Revenue and from each local governmental subdivision in which it intends to provide such services and must agree to collect and remit all sales and use taxes to the appropriate governmental authority.

2) Any ESP wishing to provide consolidated billing should post a bond in favor of the distribution entity that is equal to at least one month's distribution charges.

3) The ESP must agree to pay all distribution charges regardless of whether or how much payment is received by the ESP from the end-using customer.

4) If the ESP fails to make full payment to the distribution entity, the ESP forfeits the right to provide consolidated billing, and thereafter APS may directly bill the ESP's customers for distribution services, including those left unpaid by the ESP.

5) APS would continue to provide billing and collection services on a regulated basis within its distribution service area to customers ineligible for retail access or taking S/O service and could provide such services on a competitive basis for those customers receiving competitive generation.

6) APS could provide competitive billing and collection services outside its distribution service area only through an ESP affiliate.

7) APS termination procedures would only apply in the following circumstances:

    a. failure to pay for distribution services;

    b. failure to pay for competitive services where:

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i. the contract between the ESP and the customer permits disconnection for non-payment; and,

ii. APS provides both metering and billing services for the ESP;

c. disconnection is required for health or safety reasons.

LOCAL DISTRIBUTION COMPANY SERVICES

1. Standard Offer (S/O)

To begin with, Staff's posited "safe haven" for S/O customers is totally illusory. Once an "Affected Utility's" generation assets have been divested, whether to a third party or to an affiliate, the distribution entity is merely another market player with S/O customers bearing all the market risks attendant thereto.

Second, APS does not understand the difference, if any, between Staff's proposed S/O and the concept of "provider of last resort." Since the costs of the former are borne by S/O customers while the costs of the latter are to be passed on to all customers, there must be some manner of subtle distinction between the two concepts that has somehow escaped the Company.

Third, neither of these Staff proposals is practical unless the Commission is prepared to allow for some purchased power adjuster mechanism. This would at least put the electric distribution provider in roughly the same position as gas distribution companies and existing electric distribution companies such as Citizens.

Aside from these conceptual issues, the mechanics of Staff's proposal creates several problems. These include administrative issues, problems of rate manipulation, and the very real potential for jurisdictional bypass by certain very large customers.

Allowing a customer to change from competitive to S/O service and back again at the end of each billing cycle ignores the fact that unless the request for such change comes before the end of the cycle, it will be impossible to effectuate it in time. In addition to the paperwork, there are deposit, metering and customer information issues that will have to be worked out among the switching the customer, the new or old ESP, and the distribution provider.

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Any customer either leaving or returning to S/O service should be required to leave or stay for a year before either returning or leaving again. Otherwise, certain customers will simply arbitrage the seasonal rate schedules of "Affected Utilities" such as APS (e.g., take S/O service during the summer and competitive service during the balance of the year) to the detriment of both the Company and other S/O customers.

2. System Benefits

If customers over 69kv are not required to use the distribution entity's metering, there is likely no jurisdictional basis for imposing a system benefits or, for that matter, a stranded cost charge. This is yet another flaw in Staff's proposal that works to the benefit of large customers and to the detriment of the "Affected Utility" and its smaller customers.

TRANSMISSION AND DISPATCH

The Commission lacks the authority to mandate or in any way regulate either an ISO or an ISA. The formation of these organizations and the matters which they will address once formed are clearly FERC issues, and APS must operate its transmission system or participate in any ISO/ISA solely in accordance with FERC criteria. Moreover, neither organization could operate efficiently without the participation of SRP and WAPA, both of which are unaffected by the Staff proposal. Even if the Commission had the authority to mandate these creation of these organizations, set the scope of their powers, and compel SRP/WAPA participation, certain of the specific proposals by Staff are unworkable. For example, no ISO has successfully resolved "seams" issues, and without any generation (remember, that was divested), the ISO can't determine pricing for ancillary services - it must take whatever the market commands for such services.

Staff would allow no prioritization of capacity by transmission and distribution owners in favor of those customers either denied competitive access or choosing S/O service. So much for their supposed "safe haven." Staff's proposal, which even FERC rejects, is nothing more than an attempt to sacrifice reliability for residential and small business customers and provide a special benefit to a few large users.

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Staff proposes Commission regulation of "must run" units. However, once divested the Commission loses all regulatory jurisdiction over such facilities.[5] The "Affected Utility" can attempt to preserve both the "must run" and "cost-based"aspects of these units through contract. but mere contractual remedies are an unproven safeguard of system reliability.

CONCLUSION

APS welcomes any opportunity to comment on Staff's "Position Paper", particularly since it represents a radical reversal of previous Staff positions on many subjects and previously undisclosed positions on others. However, the request that comments to these complex and substantive new proposals be submitted within three days of receipt, combined with the vague announcement that Staff will thereafter develop a final "position" and seek some manner of "Commissioner feedback" at an apparently already scheduled and publicly announced June 3, 1998 meeting raise serious due process questions regarding Staff's actions and concerns about the Commission's ultimate intent herein. These concerns are highlighted by the fact that Staff has apparently chosen to bypass (and/or circumvent) the traditional Commission hearing and rule-making procedures already in place with respect to the development of the Competition Rules in favor of some new process that insulates Staff from full public accountability for its numerous unsupported and often contradictory positions. Accordingly, APS urges Staff to clarify what specific steps it intends to take to promote its various "positions" and to reassure interested participants that all required due process procedures (including evidentiary hearings where appropriate) will be followed.

Sincerely,

Donald G. Robinson
Director, Pricing
Regulation and Planning

[5] An "Affected Utility" could, of course, petition the Commission to retain the "must run" units as being in the public interest. However, since this would result in less favorable treatment of stranded costs than if the units were divested, such a petition would be unlikely.

APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
Market structure	Only obliquely addressed in Rule 1605	Bilateral contracting is the appropriate market structure. Such structure is tied to an assurance of non-discriminatory access to transmission. To assure proper allocation of competitive transactions, there must also be a method for energy imbalance accounting, transmission congestion management and transmission interconnection security coordination. Spot markets have already formed without ACC intervention and need not be formally mandated. Orderly functioning of the bilateral market structure requires scheduling coordinators. Scheduling Coordinators are discussed in attachment "A."
Non-discriminatory transmission access for all competitors	Rules talk about it but do not address how or when it can come about.	The long term solution to assure a competitive generation market, is to have an independent organization perform three primary functions related to the interconnected transmission system: 1. Oversee the operation of interconnection transmission system and have the authority to order appropriate changes, 2. Assure independence of judgment regarding assignment of total transfer capability (TTC) and available transfer capability (ATC), and 3. Provide transmission use pricing such that prices are not layered on each other. The solution being addressed in Arizona, New Mexico, West Texas and Southern Nevada is the Desert Star independent system operator. The target is to file an agreement with the FERC by Dec. 31, 1998. To achieve customer choice in Arizona Jan. 1, 1999, an interim organization for Arizona is required. An independent system administrator (ISA) must be formed in Arizona to provide independent oversight of the transmission system use. The three major components of the ISA arrangement are scheduling coordinators, transmission providers and control area operators, and the administrator. The functions of the three components are shown in attachment "A". The governance of the ISA would be through a subset of the existing Southwest Regional Transmission Association board.
Costs associated with establishing ISAs	Not addressed	Costs should be recovered from customers using the transmission system through FERC-regulated prices.

APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
Priority to existing transmission capacity	Not addressed	Until all customers are being charged the market competitive price for generation service, the customers being charged for a cost based regulated generation price shall have priority of transmission capability usage.
"Must-run" generation	Not addressed	To assure delivery system reliability APS generation at West Phoenix, Ocotillo, Yuma and Douglas must operate at certain times to prevent system overload and customer outages. Shown in attachment "B" is the situation in the Phoenix metropolitan area where valley load exceeds the import capability of 6,200 MW and generation is needed to meet peak load (1,410 MW). Since there presently are not competitors to must run generation, such generation must remain regulated. The capital, fixed operation/maintenance and fuel cost will be collected from all transmission customers. Therefore, must-run units are not included in the stranded cost calculation or in distribution rates.
Revised Open Access Tariff ("OATT") to accommodate retail access	Not addressed	In order to accommodate retail direct access in a comparable and non-discriminatory manner, APS has identified a number of issues regarding the Company's Open Access Transmission Tariff ("OATT") that need to be addressed. <u>Customer Eligibility</u>- Because of certain operational criteria inherent in the OATT (e.g., pre-scheduling requirements, 1 MW minimum hourly schedules, etc.), rendering *services to the vast majority* of retail customers would not be practical under the existing OATT. Therefore, APS is proposing to revise the definition of eligible customer so that only Scheduling Coordinators can subscribe for retail access transmission service. <u>Metering/Billing Issues</u> – Transmission service and attendant ancillary services, requires customer load information on an hourly basis. Additionally, FERC's methodology calculates charges for transmission/ancillary services on a calendar month basis, whereas retail consumers are billed on a billing cycle basis. As a result, absent outfitting every retail customer with the required metering capability, a load profiling methodology will be developed in order to estimate the hourly loads of customers without the requisite metering. The Company is also in the process of developing the appropriate methodology for reconciling billing cycle information in order to bill Scheduling Coordinators for their aggregated retail loads on a calendar month basis. Lastly on this issue, the Company is developing extensive changes to billing protocols, in conjunction with IT personnel, so that these services can be billed accurately and in a timely manner. <u>Service Agreement Requirements</u> – APS'OATT requires transmission customers to

Issue	Current Rule Treatment	Proposal
		execute a service agreement that sets forth all the services being rendered, the rates for such services, and all of the customers points of receipt (Network Resources) and points of delivery (Network Loads). Because there will be constant changes in the customers that a specific Scheduling Coordinator aggregates and has responsibility for serving, APS is proposing criteria on when a retail customer can switch Scheduling Coordinators (not until the beginning of the billing cycle) and will request a change in its Network Resources or Network Loads. <u>Energy Imbalance Service</u> – The OATT provides for Energy Imbalance Service wherein a transmission customer who over or under schedules their hourly third-party power may be subject to disincentive charges if the hourly over/under scheduled power exceeded a certain threshold band (within which no penalties are assessed). Because of the way FERC requires transmission providers, such as APS, to calculate losses, the potential exists for APS to incur significant costs. FERC requires the use of an average system loss factor; however, actual losses vary in any given hour. The difference between average loss factor and actual system losses is primarily a loss calculation error which results in unaccounted for energy. Because actual losses will significantly exceed the average loss factor during high load and summer months, significant amount of unaccounted for energy could result. APS is proposing to FERC a method to identify the amount of unaccounted for energy on an hourly basis, and a methodology for allocating the unaccounted for energy to each Scheduling Coordinator as well as APS itself. <u>ACC Concurrence</u> – The modifications to the OATT must be approved by FERC. FERC has allowed a number of utilities to implement revisions to their OATTs in order to accommodate retail access programs. FERC expects the state-regulating agency to participate in such filings and support the requested revisions. Therefore, APS will work with the ACC to gain its support for the requested OATT revisions.
Energy imbalance calculation		Actual loads will be based on metered and load profited loads, adjusted for unaccounted energy [unaccounted energy is a result of energy diversion, loss calculation errors and automatic generation control moving generation units to provide system regulation]. Unaccounted energy will be provided on hourly loads and changed pursuant to APS' OATT. An example calculation is shown in attachment "D."
Procedure for granting CC&N's for competition services	See A.A.C. R14-2-701, et. seq.	Hearing should be required and affected Utilities have the right to participate in CC&N hearings for applications made to provide service in the utility service territory.

APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
Phase-in period for customer	Jan. 1, 1999 – 20% 1995 retail peak load – 50% 3MW + above – 15% residential Jan. 1, 2001 – 50% 1995 retail peak load – 50% 3MW + above – 30% residential Jan. 1, 2003 – 100% access	The appropriate phase-in would be 20% of 1995 load as of Jan. 1, 1999 and all customers on Jan. 1, 2001.
Customer selection	Not determined	Competition should be available to all classes customers with the following eligibility on Jan. 1, 1999. All customer premises will be sent a card that they should return if they want to be eligible for direct access. The cards will be segregated by the sizes shown below and then a random selection will occur up to the percentages of numbers shown below. The selected premises will be eligible for direct access. These are the only premises which will be able to choose direct access until Jan. 1, 2001. 2 MW + premise – 100% of customers Large 300kW – 1999kW – 5% of customers Medium 30kW – 299kW – 5% of customers Small 5kW – 29kW – 5% of customers Residential – 20,000 An Affected Utility has made 20% of its 1995 system retail peak demand available for competitive generation supply in 1999 if such supply has been offered to customers constituting 20% of the Affected Utilities 1995 system retail peak demand whether or not such offer is accepted. If a utility believes that it would be impractical or impossible to include this number of residential customers, the utility may elect to implement a 1,000 residential customer pilot and provide the remaining residential customers a ____% rate decrease in lieu of competition.
Rate reduction mechanism	Not addressed	A performance-based mechanism should be developed which provides an opportunity for rate reductions and an incentive to increase efficiency. It should consider the costs incurred by the companies and the prices paid by customers.

APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
Buy-throughs	Affected Utilities can engage in Buy-throughs with customers	Buy-throughs are not necessary for those customers who are eligible for direct access. They can make purchases directly from other suppliers. Customers not eligible for direct access cannot do buy-throughs.
Load profiling	Not addressed	For customers that are 20kW or smaller at each premise, load profiling will be allowed. Initially static load profiling based on historic data will be used where profiles will be determined for customer segments and used to determine hourly energy consumption from energy suppliers. Within 18 months additional meters will be added that will provide dynamic load profiles such that actual delivery conditions are captured for a segment. The load profiles will be applied to customers in a particular segment to determine hourly energy consumption. Data from the load profiling analysis will be used by scheduling agents, energy service suppliers, and control area operators to determine correct aggregated schedules, correct billing and energy imbalance accounting. An example of load profiling is shown in attachment "C". The example is for a customer that consumes 100kws in a 24-hour period. By using the load ratio each hour (Y-axis), the kW demand consumption is determined for each hour. This information is used for the purposes mentioned above.
Charge for interval meters	Not addressed	The customer will be assessed a meter charge for interval meters.
Metering and meter reading	Designated a competitive service	Metering and meter reading should remain an exclusive regulated distribution function.
Standard offer rates	Exist until the ACC determines competition is substantially implemented	Standard offer rates are available only during the transition period while stranded costs are being recovered, which is through 2006.
Provider of last resort after the transition period	Not addressed	The distribution company will provide service through a Buy through process for those customers who do not want to buy from a competitive supplier.
Recovery of uncollectable costs for "provider of last resort" service	Not addressed	Uncollectable costs will be recovered through distribution tariffs.
Ability to return to the standard offer rates	Current service establishment policies	Customers will be able to return to a standard offer rate pursuant to the required service

APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
once customer has chosen competitive service		establishment policies, but then must remain on it for a minimum of one year to prevent manipulation of seasonal rates.
Stranded cost recovery	Recovery mechanism specifically addressed	Stranded costs should be recovered through a non-bypassable charge paid by all customers.
Costs associated with sales of generation assets	Not addressed	All costs incurred during the sale of generation assets should be included in the stranded costs to be recovered.
Costs incurred in establishing required competitive affiliates and to transfer corresponding assets to the affiliates	Not addressed	All costs incurred for establishing required competitive affiliates and transferring assets to same should be included in the stranded costs to be recovered.
System benefits charges	Not specified Company may file for changes.	Currently the appropriate levels of system benefit charges for APS are. Nuclear decommissioning — $12.2 million Nuclear fuel disposal — $6.0 million DSM — $ 3.0 million Renewables — $ 3.5 million Low income, weatherzation, bill assistance And energy education — $0.5 million Low income rate discounts — $3.7 million $28.9 million The Company would file for changes as needed. These changes would be implemented through the use of a system benefits adjustment clause and not through a general rate case.
E-3 and E-4 low income rate discounts eligibility	Not addressed	Available to customers who remain on standard offer and qualify.
Low income discounts available to direct access customers	Not addressed	A low-income discount for the regulated portion of their bill should be developed.
Consumer protections must be in place	Written authorization of customer required and provision for ESP to pay cost	1. ESP must receive written authorization from the customer to switch him and must maintain it on file.

Issue	Current Rule Treatment	Proposal
	associated with slamming	2. ESP must send a written notification to the customer that he is being switched to another provider and notice of the effective date. 3. If a consumer is switched (or slammed) to a different ("new supplier") without such written authorization, the new supplier shall cause service by the previous supplier to be resumed and the new supplier shall bear all costs associated with switching the customer back to the previous supplier. 4. ESP are required to notify the ACC of all slamming violations on a quarterly basis. The ACC can access fines or penalties for violations and can suspend or revoke the supplier's CC&N for excessive violations. 5. Customer can not be disconnected or have his service terminated by an ESP for non-payment of a bill unless agreement between ESP and customer permits.
Access to customer information	Not addressed	Distribution companies would only release customer information to Energy Service Providers (ESPs) and vice versa after receiving the customers consent. The information that will be released is, consumption, history, payment history and credit profile. The only exception to requiring customer consent is that the former ESP is required to provide the new ESP the customer's 13-month consumption history upon the customer's authorization to switch. ESPs and LDCs should be able to charge administrative fees for such information.
Billing and collection	Defined as a competitive	LDCs will always provide billing and collection services for their customers. ESPs have the right to bill for their services, either directly or through a third party, or they can choose to have the LDC provide these services pursuant to contract. ESPs are responsible for their own collection activities.
Changing energy suppliers	Not addressed	A customer can change energy suppliers once a month although there will be an administrative charge imposed with each switch. An additional charge will be imposed if the change is not coincident with the meter read. Customer must contact new ESP to switch ESPs not LDC. The ESP will submit request for customer change to LDC.
Process for an ESP to request a customer change	Not addressed	A uniform document, Direct Access Service Request (DASR) must be developed for bi-directional communications. An ESP must electronically communicate the information on this document to the LDC. The LDC must approve the DASR. The LDC has the right to deny the request if information is (1) false, incomplete or inaccurate (2) ESP in not an authorized ESP and/or has not executed a LDC – ESP Service agreement (3) more than one DASR has

Issue	Current Rule Treatment	Proposal
		been received for the same account within a billing month (only the first is processed) (4) Customer does not qualify for direct access. If the DASR is approved by the LDC, the ESP initiating the DASR must notify the old ESP and provide written notification to the customer that the switch is approved and the effective date of the switch.
Connect / disconnect of customers	Not addressed	The LDC will be the only party able to connect or disconnect a customer , and can only disconnect under following circumstances: 1. health and safety 2. failure to pay LDC bill or LDC portion of aggregated bill 3. customer has agreed in writing that service can be disconnected if don't pay ESP bill 4. Customer theft
Partial payment or non-payment of an aggregated bill	Not addressed	This issue will be negotiated between the LDC providing the billing service and those providing energy service.
Credit worthiness, late payment and deposit requirements	Not addressed	The ACC will continue to approve the distribution company credit policies, however, each ESP will be free to establish their own policies.
Multiple Suppliers	Not addressed	Premises may not split load among electric service option or providers.
Billing Data to be Retained	Not addressed	Data used in determining the bills should be stored for a minimum for three (3) years. Thirteen (13) months of on-line billing data will be maintained in the agreed upon standard format. These requirements are in addition to any federal statute or local requirements. This applies to both the LDC and ESP when two bills are issued.
ESP Disclosure of it's generation mix	Not addressed	The ESP should provide its generation mix at the customer's request.
ESP customer complaints resolution	Subject to existing ACC Procedure	The Commission should require that the ESPs demonstrate a complaint resolution procedure or they are subject to existing ACC procedure.
Minimum information required on ESP bills to residential customers	Subject to existing ACC Rule	♦ Customers name and address ♦ Date and meter reading at the start of the billing period or number of days in the

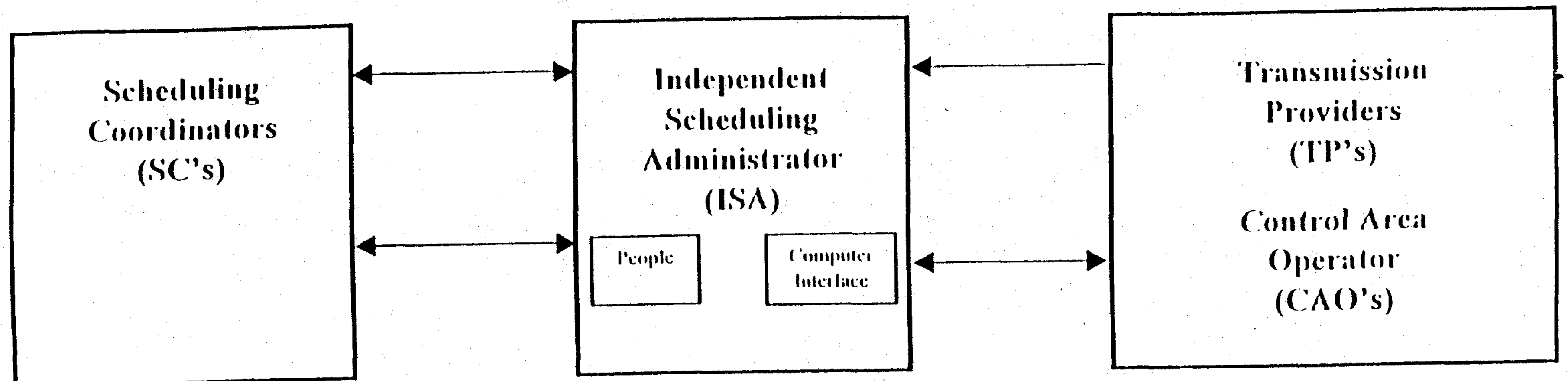
APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
		billing period ♦ Date and meter reading at the end of the billing period ♦ Billed usage and demand ♦ LDC, billing agent and ACC telephone numbers ♦ Service account number ♦ Amount due and due date ♦ Past due amount ♦ Applicable taxes
Customer Education -- ACC	Not addressed	Customer education materials developed, determined or required by the ACC should be paid for by the ACC.
Customer Education -- Companies	Not addressed	Customer education developed by individual companies should be paid for by the companies and not recovered through regulated rates.
Changes to electric line extension policies	Not addressed	Economic evaluations should continue to be used. However only the distribution revenues and costs should be included in the analysis.
Requirement for competitive ESPs to seek ACC approval for selling, leasing or mortgaging property	Not addressed	Such entities should be exempted from A.R.S. §40-285
Requirement for competitive ESPs to seek ACC approval before borrowing money or issuing stock	Not addressed	Such entities should be exempted from A.R.S. §40-301, *et seq.*
Requirement for ACC approval of ESP rates for competitive services and having those rates be matters of public record	- Requires approval - Silent on procedure - Purport to make confidential (conflicts with statute)	Competitive rates should be exempted from the requirements of A.R.S. §§40-248, 40-250, 40-251, 40-365 , 40-367 and corresponding provisions of competition Rules amended.
Non-discrimination criteria for competitive rates	Not addressed	Competitive markets make distinctions between customers that might be regarded as discriminatory if done by a monopolist. Competitively determined rates should enjoy at

APS Proposal for Restructuring Issues

Issue	Current Rule Treatment	Proposal
		least the presumption that they are non-discriminatory. Thus, an amendment to A.R.S. §§40-334 and 40-374 is necessary.
Transmission Planning	Not addressed	Planning should be conducted jointly between the individual transmission owning entities and the ISA/ISO in coordination with SWARTA and the WSCC. Any entity willing to fund transmission expansion should be permitted to do so and to obtain transmission capacity rights.
Integrated Planning Rules	Not addressed	In the new competitive environment, Integrated Planning Rules serve no useful purpose and they should be replaced.
ACC regulation of ESP accounting practices	Not addressed	Such entities should be exempted from A.R.S. §§221, 40-222 and from ACC regulations enacted thereunder.
ACC determination of the adequacy of a competitive service	Not addressed	The market should decide, and thus such entities should be exempted from A.R.S. §§40-321 and 40-322.
ACC ability to order one competitive ESP to share facilities with another competitive ESP	Not addressed	Such entities should be exempted from A.R.S. §§40-331 and 40-332.
Constitutional Amendment	Not addressed	A constitutional amendment should be passed to remove unnecessary regulation of competitive services and suppliers while still retaining authority to enforce consumer protection measures.
Unbundled Rates	See A.R.C. R-14-2-16	Unbundled rates should not create prices increase, cause price distortions, be anti-competitive or have one single CTC.

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 transmission 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	1. Process, review SC's schedules, submit existing contract schedules to ISA, submit generation participants schedules to ISA 2. Posts ancillary services to ISA's OASIS 3. Processes additional schedules from transmission reservation updates 4. Participates in activities for checkout/settlement process for previous day 5. Publish next day operating plan to ISA
Current Day	1. Additional schedules submitted to ISA & CAO with tags 2. Responds to contingencies and curtailments as directed by control areas (7 X 24 operations)	1. Receives and posts curtailment information 2. Provides appeals process for transmission use denials and curtailment orders	1. Manage real-time operations and specify curtailment and contingency actions 2. Processes additional schedules from transmission reservation updates

FIGURE III-A

Valley Transmission Import Capability

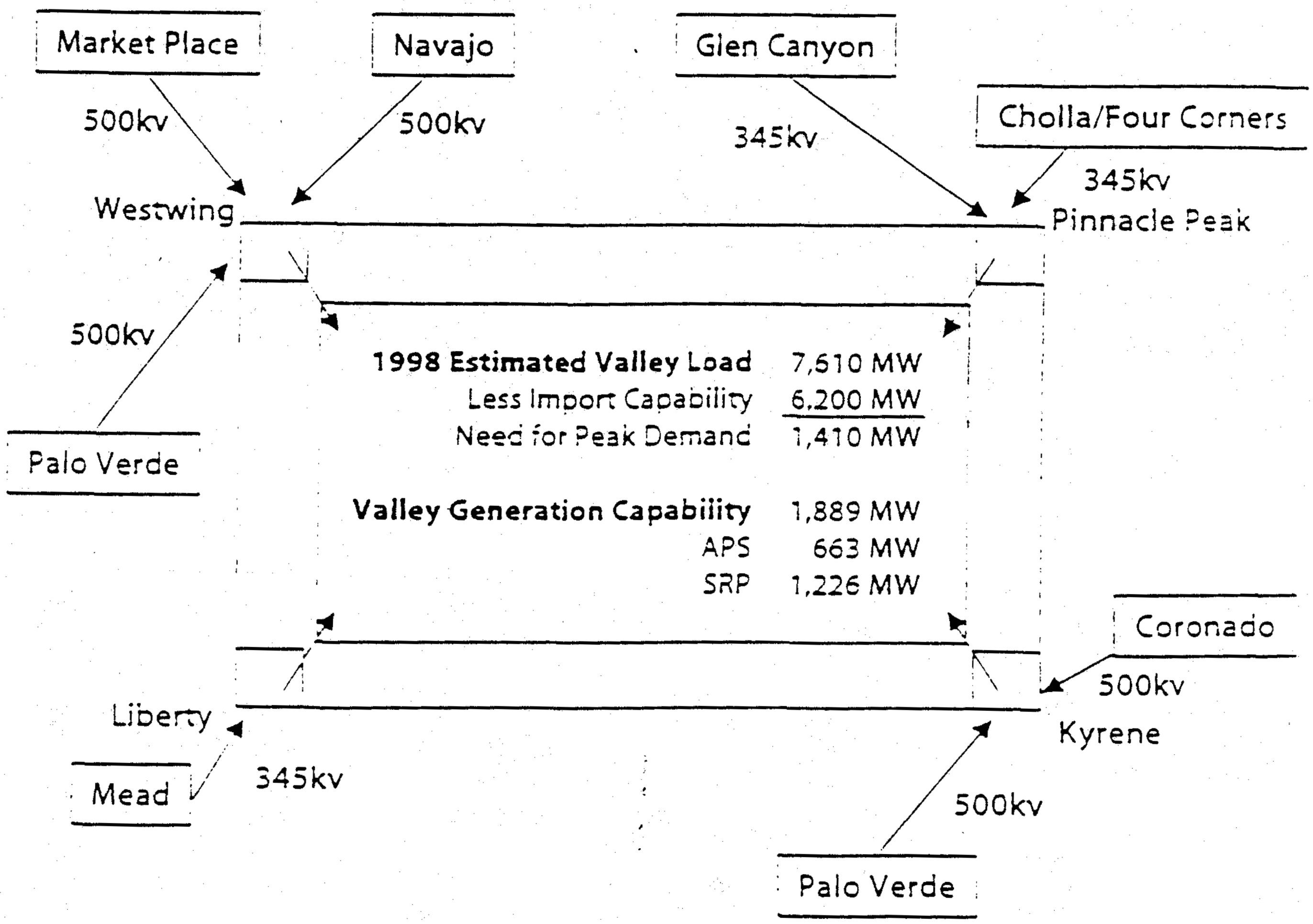
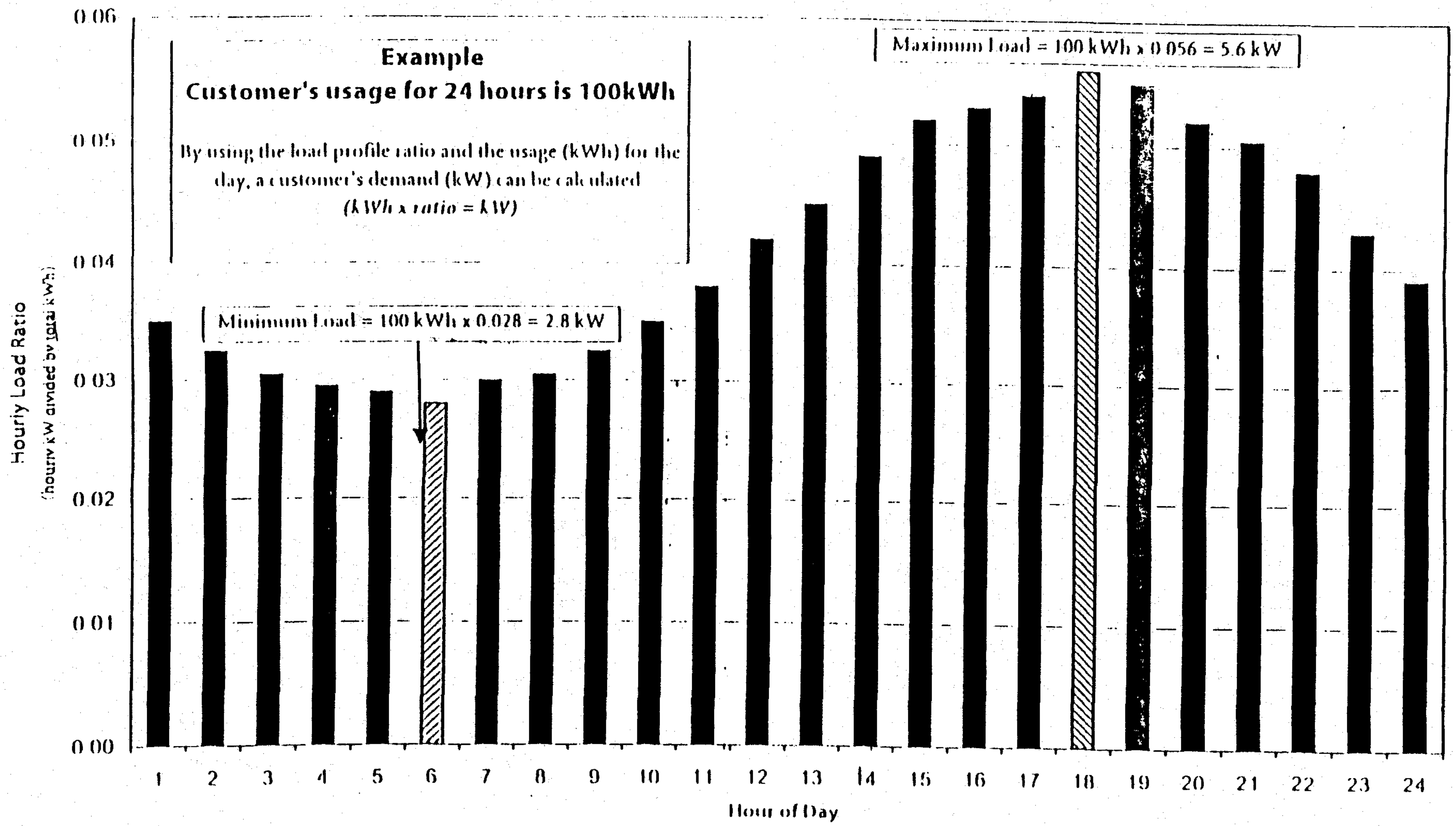


FIGURE - II-C

Customer Load Profiling



ATTACHMENT D

ENERGY IMBALANCE CALCULATION EXAMPLE FOR A GIVEN HOUR

Scheduling Coordinator A	-Schedule 190 MW; metered load is 200 MW*
Scheduling Coordination B	-Schedules 330 MW; metered load is 300 MW*
APS	-Schedules 2,550 MW; metered & profiled loads are 2500 MW*
Total	-Scheduled 3,070 MW; metered/profiled 3,000 MW*

Actual Control Area Load During the Hour = 3,150 MW

Unaccounted for Energy = 3,150-3,000* = 150 MW

Proration Methodology:

Scheduling Coordinator A allocation factor = 200 MW / 3,000 MW = 0.0667

Scheduling Coordinator A allocated unaccounted for energy = 0.0667 x 150 = 10 MW

Scheduling Coordinator B allocation factor = 300 MW / 3,000 MW = 0.10

Scheduling Coordinator B allocated unaccounted for energy = 0.10 x 150 = 15 MW

APS' allocation factor = 2,5000 MW / 3,000 MW = 0.833

APS' allocated unaccounted for energy = 0.833 x 150 = 125 MW

	Schedule	Actual Load	Unadjusted Imbalance	Allocation of Unaccounted Energy	Adjusted Imbalance
Scheduling Coordinator A	190	200	(10)	(10)	(20)
Scheduling Coordinator B	330	300	30	(15)	15
APS	2,550	2,550	50	(125)	(75)
Total	3,070	3,000	70	(150)	(80)

Scheduling Coordinator A underscheduled by 20 MW:

1.5% of 190 MW is 3 MW, which will be paid back within the next 30 days.
17 MW will be billed at the higher of 100 mills/KWh or 100% of system.

Scheduling Coordinator B overscheduled by 15 MW:

1.5% of 330 MW, which will be paid back within the next 30 days.
Scheduling Coordinator B will receive a payment of 90% APS' decremental cost for 10.0 megawatts.

APS underscheduled by 75 MW:

1.5% of of 2,550 is 38 MW, APS' Merchant Group will imput back to the system within 30 days.
37 MW will be billed to APS' Merchant Group at the higher of 100 Mills/kWh or 100% of system incremental cost.