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EXIHIBITS

PART 1

BAR COD
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AES 1-2
AECC 1-3
STAFF 1-17
APS 1-8
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EXHIBIT
S-1
admitted

BEFORE THE ARIZONA CORPORATION COMMISSI

WILLIAM A. MUNDELL
Chairman

JIM IRVIN
Commissioner

MARC SPITZER
Commissioner

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OCT 18 2001
LEGAL DIV.
ARIZ. CORPORATION COMMISSION

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606

DOCKET NO. E-01345A-01-0822

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REQUEST OF ARIZONA PUBLIC SERVICE COMPANY FOR A PARTIAL VARIANCE TO A.A.C. R14-2-1606(B) AND FOR APPROVAL OF A PURCHASE POWER AGREEMENT

[An examination of the current and likely future state of the volatile wholesale power market has led Arizona Public Service Company ("APS" or "Company") to the inescapable conclusion that adherence to the competitive bidding requirements of the Electric Competition Rules will not produce the intended result of reliable retail electric service for Standard Offer customers at reasonable rates.] Moreover, it would not constitute a prudent power acquisition strategy under such circumstances. Accordingly, APS hereby requests that the Arizona Corporation Commission ("Commission") grant the Company a partial variance to A.A.C. R14-2-1606(B) ("Rule 1606")[1], which Rule would otherwise obligate APS to acquire all of its customers' Standard Offer generation requirements from the competitive market (with at least 50% of that coming through an untested and unspecified "competitive bidding" process) beginning in 2003.

[1] A.A.C. R14-2-1816(C) specifically allows the Commission to grant "variances or exemptions" to the Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*).

In conjunction with the requested partial variance, APS further asks the Commission to approve as just and reasonable the attached long-term purchase power agreement ("PPA") between the Company and Pinnacle West Capital Corporation ("PWCC"). The PPA represents a firm contract backed by the physical assets of a diverse portfolio of Arizona-based generation supplies dedicated to APS Standard Offer customers.

For the reasons set forth below, APS believes this partial variance and the PPA are in the public interest and represent the sort of prudent power acquisition strategy that is at the heart of Rule 1606. The Company therefore requests that the Commission act on these matters by year's end.

I.
INTRODUCTION

APS has never construed the Commission's Electric Competition Rules as abrogating the Company's responsibility to provide reliable and reasonably-priced service to its customers. To that end, APS (through its electric generation affiliate) has invested more than a billion dollars since 1999 to reliably meet the needs of APS consumers. Indeed, the genesis of this partial variance request is the Company's deep concern over the need for continued reliable service to APS Standard Offer customers in an increasingly competitive yet unstable wholesale generation market. That instability is evidenced by the almost 54,000% swing in wholesale energy prices over the past eighteen months. Such wild price variability is indisputable evidence of the illiquid nature of the competitive markets in the West – a factor clearly not contemplated when Rule 1606 was first drafted – and the over-reliance by many western energy suppliers on volatile natural gas supplies.

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Perhaps more important than the price risk inherent in relying totally on the competitive wholesale power market is the reliability risk. None of the merchant plant owners upon whom APS customers would be dependent under Rule 1606 has any responsibility for APS system reliability.

Because APS does assume that responsibility, it has continued to task its affiliates [Pinnacle West Energy Corporation ("PWEC") and PWCC] with the job of building and otherwise acquiring the generating resources demanded by its Arizona customers. Granting the requested variance will benefit APS Standard Offer customers by providing them with continued access to a highly reliable and fuel-diverse source of electric power through the end of 2015. [This will enable APS customers to avoid the severe electric price spikes and capacity shortages that have plagued other western states in the last few years.]

Aside from considerations of electric supply reliability and electric price stability, there is the very real issue of Rule 1606's impracticality. Under Rule 1606, APS would have to bid out over 3000 MW (including reserves) of system load. [APS believes there are few if any non-affiliated generators that will be able to provide such a large block of power in 2003 or for several years after that.] The thinner the supply market, the higher the anticipated cost to APS consumers from competitive bidding. [If the market is so thin that it cannot supply at any price the full 3000 plus MW, APS would be able neither to comply with Rule 1606 nor meet the expected demands of Arizona consumers.]

Faced with a Rule that either could not be complied with or complied with only at the expense of its customers, and mindful of PWEC's significant and tangible

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financial commitment to APS reliability, the Company believed a long-term supply agreement with its power marketing and trading affiliate, PWCC – an agreement that combines long-term stability with market opportunities – would be a more prudent course of action. The result of these discussions was a PPA between PWCC and APS that would address all the additional Standard Offer capacity, energy, and reserve requirements of the Company through the year 2015. In addition to providing a reasonably-priced, diverse and reliable source of power through at least 2015, the PPA will obligate PWCC to be the wholesale "provider of last resort" to APS. As "provider of last resort," PWCC will step in to supply Standard Offer generation to APS under any foreseeable eventuality. This assures reliability of generation service to APS even during unstable market conditions or in the event of unplanned losses of generating units in Arizona. [APS is firmly convinced that absent this PPA, the Company's acquisition costs of Standard Offer power would be higher and more volatile and the reliability of that supply degraded.]

Finally, APS wishes to make it clear to the Commission from the outset that it seeks absolutely no change in the current ability of APS customers to choose competitive retail suppliers of Commission-designated "Competitive Electric Services," including electric generation. This right of choice is recognized by both the Commission's Electric Competition Rules and the 1999 APS Settlement Agreement. The Company supports customer choice and believes the continued availability from APS of reliable and reasonably-priced Standard Offer service is an important component of that customer choice, especially for residential and small commercial consumers.

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In addition to its continued support for direct retail competition by independent power producers, APS has required that the PPA allow an opportunity for participation by these non-affiliated power providers in supplying APS Standard Offer generation needs. Under terms of the PPA, PWCC must obtain an increasing amount of the Company's Standard Offer requirements, up to 1670 MWs (or 23% of APS peak load) by 2008, through competitive bidding.

II.
THE REQUESTED VARIANCE IS IN THE PUBLIC INTEREST

In relevant part, Rule 1606 states:

> After January 1, 2001, power purchased by an investor owned Utility Distribution Company [e.g., APS] for Standard Offer Service shall be acquired from the competitive market through prudent arm's length transactions, and with at least 50% through a competitive bid process.

This provision was modified in Decision No. 61973 (October 6, 1999), which Decision adopted, with certain modifications not relevant to this request, the APS Settlement Agreement of May 14, 1999. Decision No. 61973 provided: "[A] similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B)." *Id.* at 9. This "similar" extension corresponded to the two-year extension granted by Decision No. 61973 for APS compliance with A.A.C. R14-2-1615 ("Rule 1615").

APS has viewed with concern the Western power market for the past year and a half. Spot prices for energy have been both extremely volatile and often extremely high, even during periods of relatively moderate demand. As the State of California has learned, long-term electric market prices, although much less than the spot market, were still above the levels of generation costs then reflected in retail electric rates. The results have been skyrocketing customer bills in both California and neighboring states

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such as Nevada, Oregon and Washington, as well as actual supply shortages in California itself. Much of this situation was due to unprecedented natural gas prices in the West (natural gas is the exclusive fuel source for many generators), and to the poorly designed market and utility rate structure in California. However, it is also safe to say that the competitive wholesale market in California and other Western states has yet to fully mature into the academic's model of a transparently-priced market with no exercises of market power and with perfect knowledge on the part of all consumers.

In recent months, wholesale power costs have softened and some have even talked about a future "glut" of power. APS is mindful that this recent downturn in prices was no more foreseen by these "experts" than was the explosion in prices a year earlier. Wishful thinking does not take the place of prudent planning, and even the recent unexpected drop in wholesale power and natural gas prices is proof that electric markets continue to be very volatile and susceptible to wild and irrational price swings.

APS, of course, has done more than passively "view" the wholesale market with concern. It has proactively engaged in precisely the sort of prudent planning alluded to above. More than 200 MW of new generation has been added to the APS system since 1999 (not including almost another 200 MW of temporary generation capacity procured by PWEC for APS during 2001), and another 1500 MW will be added by 2003. This represents well over $1 billion of "steel and concrete" invested to preserve APS system reliability.

In contrast, the open market carries with it significant reliability risk. On the transmission side, APS has joined with other transmission-owning entities in forming WestConnect in an effort to better address reliability concerns based on transmission

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availability and adequacy. However, on the supply side, merchant plant owners would not want to assume responsibility for APS system reliability. If their plants fail to operate (either due to mechanical failure or gas supply problems), or transmission paths from their plants to the APS system become constrained, APS will be on its own in the scramble to obtain replacement resources. Even if the merchant plant owner is willing to accept some financial responsibility for its reliability shortcomings, this does nothing to keep the lights on for hundreds of thousands of APS Standard Offer customers.

For these reasons, the PPA is a full-requirements contract. PWCC assumes full contractual responsibility for reliability. Moreover, PWCC will even provide APS a "safety net" to assure the reliable supply of power from those non-affiliated providers called for under the PPA. PWCC is further committed to using its power marketing skills to supplement any potential shortfall even after full utilization of PWEC's dedicated generating resources.

The PPA will provide APS with its retail electric generation needs at a cost that is reasonable in relation to the high level of reliability provided and the length of that reliability commitment under the PPA. Because it will be essentially a full-requirements agreement rather than unit-contingent, and uses a diverse portfolio of fuel sources, it will also provide more reliability and flexibility than is typically available in the wholesale market, especially for purchases of this size and this duration. Indeed, APS believes it would be imprudent to turn down the type of firm commitment represented by the PPA. However, the PPA will not be in conformance with the requirements of Rule 1606 precisely because it was not obtained through competitive bidding – hence the need for the instant request for a variance to Rule 1606 in favor of entering into the PPA.

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III.
THE PPA IS A PRUDENT AND REASONABLE ALTERNATIVE TO RULE 1606(B)

APS will soon have to complete its planning for the acquisition of resources to serve its Standard Offer customers in 2003. If, as Rule 1606 requires, some 50% of these resources must be competitively bid, with the remainder also obtained through "arms-length" [competitive] bilateral negotiation, the process of properly developing a request for proposals ("RFP"), soliciting and evaluating bids, identifying potential parties for negotiations, engaging in and concluding such negotiations, etc., will take the better part of a year. APS did not and does not believe this long drawn-out process is practical or can result in anything other than reduced reliability and very significantly more volatile and potentially much higher costs to serve its Standard Offer customers. It also fails to acknowledge PWEC's ongoing investment in APS reliability. Thus, the Company initiated discussions with its electric power marketing affiliate, PWCC, to secure a long-term agreement for 100% firm electric supplies at stable rates.[2] In turn, PWCC has negotiated with PWEC for a long-term commitment of PWEC resources, present and (in some instances) future, to the ongoing needs of APS Standard Offer customers.

APS and PWCC have negotiated a long-term full-requirements PPA. The contract, which would run through at least 2015 with several renewal options, provides for all of the Company's presently anticipated Standard Offer generation needs, excepting only the following:

[2] PWCC has assumed from APS the competitive business of bulk power marketing and trading in order to satisfy the requirements of Rule 1615 and Decision No. 61973. PWCC is responsible for marketing all of the generation output of PWEC, its wholly-owned subsidiary. It is to PWEC that APS will transfer the bulk of its generation assets, as also called for in Decision No. 61973 and Rule 1615.

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1) those provided by APS itself through renewable resources required by the Commission;[3]

2) amounts that APS is obligated by law to purchase from "Qualified Facilities" ("QFs") and other forms of distributed generation; [4]and,

3) any purchased power agreements that cannot be transferred to PWCC at the present time.[5]

The term of the PPA includes three optional five-year renewal terms, which renewals would occur automatically unless notice is given by either APS or PWCC. If all three of these options were to be exercised by the parties, these renewals would extend the PPA term out to the end of the estimated depreciable life of longest-lived of the Dedicated Units (2030).

PWCC would directly supply APS Standard Offer requirements through a combination of: (1) generation transferred to PWEC from APS pursuant to Commission Decision No. 61973 and Rule 1615; (2) the over $1 billion in new Arizona generation constructed or to be constructed during the 2001-2004 period by PWEC to reliably service APS load; (3) power procured by PWCC from "Dedicated [Purchase Power] Contracts"; and (4) power procured on the open market.[6] Beginning in 2003, PWCC will acquire 270 MW of APS Standard Offer requirements through a

[3] Pursuant to Decision No. 63354 (February 8, 2001), APS was permitted to retain its existing renewable generating resources and to acquire new ones despite the provisions of Rule 1615.

[4] APS presently has obligations to buy QF power under PURPA, and certain of the federal energy legislation under consideration in Washington would require similar purchases from specified forms of distributed generation.

[5] At present, these would include the Pacificorp and SRP purchase power agreements ("Dedicated Contracts").

[6] The generation assets to be acquired from APS (pursuant to Decision No. 61973 and Rule 1615) and those built or under construction by PWEC solely for APS's benefits (West Phoenix CC-4 and CC-5, Redhawk-1 and Redhawk-2, and Saguaro SC-3) are collectively referred to in the PPA as the "Dedicated Units". "Dedicated Units" together with the "Dedicated Contracts" comprise the "Dedicated Assets" from which APS receives "Dedicated Units" and "Dedicated Contracts" Energy Products.

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competitive bidding process. This will permit non-affiliated electric suppliers an opportunity to participate in the APS market. That opportunity would, of course, be in addition to any Direct Access customers these same suppliers serve, directly or indirectly, as Electric Service Providers. This competitive bid obligation will be increased by another 270 MW each year through the balance of 2008. The steady and assured expansion of market-based supplies from non-affiliated generators to 1620 MW (23% of estimated 2008 peak load) is consistent with the anticipated addition of uncommitted non-affiliated generation supplies in the Arizona wholesale market.

The combination of long-term Dedicated Assets and Competitively-Bid Energy Products represents a prudent power acquisition plan, especially for risk-adverse Standard Offer customers. This is especially true when the Dedicated Assets themselves reflect a diverse portfolio of technologies and fuels. Balancing long-term resources with the opportunity to increasingly access competitive wholesale markets will better serve the goals of Rule 1606 than an arbitrary and inflexible 50% bidding mandate.

As the Company's "provider of last resort, PWCC will stand ready to step in if PWCC receives insufficient bids to provide all of the non-affiliated portion of APS' Standard Offer requirements under the PPA. As in the case of a default by one of the non-affiliated providers, PWCC will secure any shortfall at then prevailing market rates and pass it along to APS at cost.

PWCC plans to meet APS Standard Offer demand using the PWEC Dedicated Assets it has under contract plus the amounts obtained through mandatory competitive bidding. However, APS will eventually need PWCC to acquire additional resources.

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The same would be true should a presently available Dedicated Asset be removed from service or otherwise become unavailable.[7] These additional resources will supply APS what the PPA terms as either "Supplemental Energy Products" or "Replacement Energy Products."

Upon completion of the generating plant transfer to PWEC in 2002, PWCC will charge APS facilities (fixed) and per/MWH (variable) prices of $63,600,000/mo. and $17.40/MWH for all Dedicated Units Energy Products. Dedicated Units Energy Products are those derived by PWCC from PWEC's Dedicated Units. The variable price component is set to recover fuel costs in accordance with a baseline forecast of such costs, but is subject to an annual surcharge adjustment for actual and forecast variations (from the projected baseline or "base" energy price) in the cost of fuel used to provide or procure the Dedicated Units Energy Products.

The facilities and base energy prices are set forth explicitly in the Service Schedule to the PPA through 2004, but the base energy price will remain constant from 2003 through the remaining term of the PPA. Moreover, the monthly facilities charge will be calculated using the same formula throughout the entire original term of the PPA. At APS' present system load factor for Standard Offer customers, these two price components would be approximately equivalent to a total per MWH price of $48.00 in 2004. This figure reflects the increases in facilities charges for 2003 and 2004 (when additional PWEC generating facilities are added to the portfolio of Dedicated Units) and assumes no material deviation during the years 2002-2004 from the base projection of fuel costs for the Dedicated Units Energy Products.

[7] Some of the "Dedicated Assets" may be retired prior to the end of the PPA. Others, such as the SRP Agreement, can be terminated by the other party to the agreement. Yet others may undergo prolonged forced outages that would serve to reduce the available Dedicated Unit Energy Products to PWCC and APS.

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The 2004 facilities charge will be recalculated in 2005 using the formula set forth in the PPA to reflect the then three-year projection of fixed costs (depreciation, property taxes, return, etc.) for the portfolio of PWEC's Dedicated Units available to PWCC for APS demand. After any 2005 adjustment, the facilities charge would be set for another three years, although as in prior years, net fuel cost increases/decreases incurred directly by PWCC for Dedicated Units or passed through to PWCC by PWEC for Dedicated Units Energy Products would be passed through to APS annually.

In addition to the Dedicated Units Energy Products, APS Standard Offer requirements will also include Dedicated Contracts Energy Products and the portion of generation acquired by PWCC under the mandatory competitive bidding provisions of the PPA ("Competitively Bid Energy Products"), described above, plus any shortfall between such requirements and the sum of these three (the previously identified Supplemental Energy Products). Supplemental Energy Products will be billed monthly to APS as a direct pass-through.

Under the PPA, PWCC will also provide any necessary reserves using the criterion of "good utility practice." This is consistent with its "provider of last resort" responsibilities to APS under the PPA and is an important reliability feature of the PPA to the Company and its Standard Offer customers.

If any of the suppliers, affiliated or non-affiliated, default on an agreement with PWCC to provide APS with Standard Offer power, PWCC will, on the Company's behalf and at the Company's cost, pursue whatever contractual and regulatory remedies are available and feasible, whether they be at FERC, through contract arbitration, or through the courts. As the "provider of last resort" to APS, PWCC will also obtain, at

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its full cost, any power that is necessary to replace the defaulted-upon obligations of such non-affiliated suppliers. Like Competitively Bid Energy Products, Supplemental Energy Products, and Dedicated Contracts Energy Products, any such Replacement Energy Products will be a monthly pass-through to APS.

The PPA offers APS a flexible package of term, price, price stability, fuel diversity, performance incentives, and reliability features that are simply unobtainable from today's wholesale market. The Company's proposed power acquisition plan will also allow an opportunity for a gradual phase-in of competitively-acquired generation resources from non-affiliated suppliers, but only as such resources are needed and consistent with the increasing availability of such resources in Arizona from such non-affiliated parties and the corresponding development in this state of a fully competitive wholesale power market.

The PPA takes effect on the latest of following three events:

1) transfer of non-nuclear generating assets from APS to PWEC, which is presently planned to take place by year's end;[8]

2) Commission approval as just and reasonable of the requested partial variance and of the PPA; and,

3) FERC acceptance of the PPA and the companion agreement between PWCC and PWEC .

However, as a practical matter, at least the partial variance and Commission-approval phases of the above sequence of events must take place by year's end if the Company is to properly conclude preparations for its 2003 Standard Offer power requirements. Otherwise, there is the real likelihood that APS will waste resources preparing to meet a 50% competitive bidding requirement under Rule 1606 that is thereafter waived by the Commission to one extent or another. Finally, APS has secured various tax rulings in conjunction with the anticipated transfer of non-nuclear generation assets. These

[8] Palo Verde would thereafter be transferred in the fall of 2002.

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rulings from the Internal Revenue Service ("IRS", by their own terms, will expire at the end of 2001.

IV.
CONCLUSION

Going 100% to the open market for Standard Offer power supplies beginning in 2003 is a gamble APS is unwilling to take on behalf of its Standard Offer customers. Compliance with Rule 1606, even with the two-year delay authorized by Decision No. 61973, is likely impossible and at the very least could jeopardize for years to come the price stability APS Standard Offer customers have come to expect over the past decade. More importantly, it would also leave no party responsible for reliable supplies of electric generation to APS Standard Offer customers and leave APS Standard Offer customers over-exposed to volatile gas prices. The PPA negotiated with PWCC offers a flexible, practical and economic alternative – providing both price stability and complete reliability, while at the same time allowing for a gradual phasing in of competitive market supplies when needed. Commission approval of the PPA provides a clear confirmation of PWCC's ultimate responsibility to APS for assuring reliable electric supplies for many years to come and recognizes the huge investment already committed by PWEC to fulfilling the needs of the Company's nearly 1 million customers.

As noted above, APS will very soon need to know whether it can proceed with the PPA or if it needs to prepare for full compliance with Rule 1606. PWCC needs to know if its existing and future commitment of resources from PWEC to APS will be called upon under the provisions of the PPA. PWEC must receive APS's non-nuclear generating assets while certain favorable IRS rulings are still in effect. APS asks the Commission to act by year's end on its request for a variance to Rule 1606 as described

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herein and for Commission approval as just and reasonable of the Company's decision to enter into the attached PPA with PWCC.

RESPECTFULLY SUBMITTED this 18th day of October, 2001.

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OCTOBER 18, 2001

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LEGAL DIV.
ARIZ. CORPORATION COMMISSION

Purchase Power Agreement Between Pinnacle West Capital Corporation and Arizona Public Service Company

Contract No. _____

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PURCHASE POWER AGREEMENT
BETWEEN
PINNACLE WEST CAPITAL CORPORATION AND
ARIZONA PUBLIC SERVICE COMPANY

Introduction

A. **Parties.** The Parties to this Agreement are Pinnacle West Capital Corporation ("PWCC") and Arizona Public Service Company ("APS").

B. **Agreement.** This Agreement is made under PWCC's Tariff and includes all attached exhibits and schedules, all of which are incorporated by reference. Defined terms used in this Agreement are set forth in Exhibit A.

C. **Purpose.** The Parties intend to enter into a purchase and sale agreement of Energy Products so that APS can adequately, economically, and reliably serve its retail customers under a pricing mechanism that combines general rate stability, long-term access to dedicated generation assets, recovery of the costs of those dedicated assets, and market-based opportunities for competitive wholesale providers.

Article 1
Services Provided

1.1 Purchase and Sale of Power.

(A) PWCC shall supply to APS, on a firm basis, APS' Full Load Requirements. PWCC shall be the exclusive provider of APS' Full Load Requirements during the term of this Agreement, except as otherwise provided in this Agreement.

(B) APS shall pay PWCC for the sales in Section 1.1(A) as provided in the attached Service Schedule and in accordance with PWCC's Tariff.

1.2 Firm Deliveries.

(A) PWCC shall provide Dedicated Energy Products on a firm basis, and shall include adequate reserves to satisfy Good Utility Practice.

(B) Subject to Section 2.1 of this Agreement and Section 3.2 of the Service Schedule, PWCC has the sole discretion to select or acquire the resources, including the determination of the adequacy of reserves, to provide Energy Products. Such discretion includes the right of PWCC, under economic dispatch and subject to the fuel and purchase power adjustment in Section 3.2 of the Service Schedule, to purchase power rather than schedule the Dedicated Units.

(C) PWCC shall also procure purchased power as necessary to satisfy the requirements of Section 1.1, as provided in the attached Service Schedule.

1.3 Relationship to Tariff.

(A) If the Agreement is or becomes inconsistent with PWCC's Tariff, the Tariff shall control with respect to such inconsistency.

(B) The Tariff and this Agreement together form a single agreement. The Parties would not have entered into this Agreement without such a relationship.

(C) This Agreement does not amend the Tariff.

1.4 Transfer of Title and Risk of Loss.

(A) As between the Parties, and except as expressly limited in the attached Service Schedule or Exhibit A, or unless the Parties have agreed in writing otherwise:

(1) Before Energy Products subject to this Agreement are delivered to APS, PWCC will be deemed to have exclusive control and possession of the Energy Products and will be responsible for all damages, injuries, and other losses occurring before such delivery.

(2) After Energy Products subject to this Agreement are delivered to APS, APS will be deemed to have exclusive control and possession of the Energy Products and APS will be responsible for all damages, injuries, and other losses occurring after such delivery.

(3) Ownership of the Energy Products and risk of loss shall pass from PWCC to APS at the Delivery Points.

(B) Except as provided in Section 1.4(C), the Parties each assume full responsibility for and shall indemnify and hold harmless the other Party for, from and against all liability, costs and expenses, including but not limited to those relating to the injury or death of persons, arising or caused after title to the Energy Product has passed to the indemnifying Party. Expenses include but are not limited to court costs, reasonable attorneys' fees, and litigation expenses.

(C) The indemnifying Party shall not be liable to the indemnified Party to the extent the liability, costs or expenses resulted from gross negligence or

willful misconduct of the indemnified Party or from the indemnified Party's breach of this Agreement.

1.5 **Transmission and Ancillary Services Arrangements.** Except as expressly limited in the attached Service Schedule or Exhibit A, or unless the Parties have agreed otherwise in writing:

(A) PWCC shall make all arrangements necessary for transmission of the Dedicated Energy Products to the Delivery Points.

(B) PWCC is responsible for all costs, including but not limited to losses and Ancillary Services, associated with the transmission of the Dedicated Units Energy Products to the Delivery Points. Transmission and Ancillary Services costs associated with the Dedicated Contracts Energy Products, Competitively-Bid Energy Products, Supplemental Energy Products, and Replacement Energy Products shall be charged as provided in the Service Schedule.

(C) APS shall make all arrangements necessary for transmission of Energy Products from the Delivery Points.

(D) APS is responsible for all costs, including but not limited to losses and Ancillary Services, associated with the transmission of the Energy Products from the Delivery Points.

Article 2
Reliability Guidelines

2.1 **Reliability Guidelines.**

(A) Each Party shall adhere to:

(1) Good Utility Practice;

(2) all applicable operating policies, criteria, and guidelines of the NERC, the WSCC, the control area operator, and their respective successors; and

(3) all applicable regional and national reliability requirements;

(4) all applicable requirements of an RTO, to the extent not inconsistent with this Agreement.

(B) PWCC shall secure sufficient generating capacity to fulfill its Dedicated Units Energy Products obligations under this Agreement.

(C) As part of the obligation in Section 2.1(B) and concurrently with this Agreement, PWCC shall enter into an agreement with Pinnacle West Energy Corporation for rights to generating capacity to ensure the reliable delivery of APS' Full Load Requirements.

Article 3
Metering

3.1 Metering Procedures.

(A) Inspection and Testing.

(1) As long as APS is the control area operator, it shall conduct or provide for periodic inspection and testing of meters used to perform this Agreement. Inspection and testing shall be at APS' own expense and shall conform to APS' generator interconnection agreements and APS' transmission interconnection agreements.

(2) Inspection and testing under Section 3.1(A) shall be conducted as necessary to maintain a commercial standard of accuracy for the meters. APS shall repair or replace meters not meeting such standard.

(3) Upon request to APS, PWCC shall be provided the results of meter tests, be given notice of meter tests and inspections, and be given the opportunity to attend meter tests and inspections, to the extent allowed under APS' generator interconnection agreements and APS' transmission interconnection agreements.

(4) APS shall conduct or provide for additional meter testing at PWCC's request and in the presence of PWCC's representatives to the extent allowed under APS' generator interconnection agreements and APS' transmission interconnection agreements.

(B) Corrections for Inaccurate Meters. If testing or inspection in Section 3.1(A) shows that a meter is inaccurate by more than the amount specified in APS' generator interconnection agreements and APS' transmission interconnection agreements, then:

(1) PWCC shall correct the billings from the date the error can be definitely identified, or for the previous six billing months or from the date of the last test, whichever is most recent; and

(2) APS and PWCC shall correct the meter records for the elapsed period of the month in which the test was conducted.

(C) **Costs for Additional Testing.** The cost of inspection and testing requested by PWCC shall be borne by PWCC if the test does not require a correction under Section 3.1(B). Otherwise, APS shall bear the cost of inspection and testing.

(D) **Estimated Meter Data.** If at any time a meter fails to register or its registration is too erratic to be meaningful, then:

(1) the registration for billing purposes shall be based on the records of check meters, if available;

(2) the Parties shall mutually agree on the best available data to estimate the registration if check meters are not available; and

(3) APS shall in good faith remedy the meter inaccuracy using commercially reasonable means and in a reasonable period of time.

3.2 Availability of Meter Data.

(A) APS shall provide meter data or estimates to PWCC no later than three Business Days following the last day of each calendar month.

(B) APS may aggregate data when necessary to comply with confidentiality obligations.

Article 4
Billing, Payment and Netting

4.1 Invoices.

(A) PWCC shall endeavor to provide APS with a written invoice showing the Purchase Price and all other charges due by the 20th calendar day of the month following such delivery of Energy Products.

(B) Invoices issued pursuant to Section 4.1(A) shall contain sufficient detail for APS to confirm all calculations on the invoice.

(C) APS shall promptly provide to PWCC all information reasonably needed by PWCC to calculate the invoice.

(D) If data needed to calculate an invoice is unavailable, PWCC shall estimate the necessary data. PWCC shall revise such estimates when the necessary

data becomes available and include a true-up adjustment in the next invoice, but all revisions must be made within 12 months of the estimated invoice.

(E) Invoices may be provided to APS by facsimile or another method agreed upon by the Parties.

4.2 Payment.

(A) **Payment Due Dates.** Invoices shall be paid no later than 10 calendar days after receipt of the invoice.

(B) **Next Business Day.** If the payment date specified in Section 4.2(A) is not a Business Day, the payment shall be due no later than the next Business Day.

(C) **Method of Payment.** APS shall pay by electronic funds transfer or another method that results in the payment being available for the account of PWCC on or before the payment date specified in Section 4.2(A) or Section 4.2(B).

(D) **Late Payments.** If either Party fails to remit an amount payable when due, Interest shall accrue on the net unpaid amount.

(E) **Netting of Payments.** If both Parties owe amounts accruing under this Agreement, such amounts shall be netted with the Party owing the greater amount paying the other Party the difference in the amounts owed.

4.3 Disputed Invoices or Payments.

(A) If either Party disputes an invoice, it shall nonetheless pay the full amount due on or before the due date and submit a written statement detailing the dispute to the other Party.

(B) Within 15 calendar days after receipt of the written statement described in Section 4.3(A), a written response shall be submitted to the Party disputing the invoice.

(C) In order to facilitate the negotiations provided in Section 4.3 (D), the statement and response described in Section 4.3(A) and Section 4.3(B) shall each include a statement of the Party's position, a summary of the arguments supporting that position, the name and title of the person who will represent that Party, and any other person who may accompany the Party's representative .

(D) The Parties shall attempt in good faith to resolve the dispute promptly through negotiation as follows:

(1) Within 30 calendar days after delivery of the statement described in Section 4.3(A), the Parties shall meet at a mutually agreed upon place and time.

(2) The Parties shall continue to meet as often as necessary to attempt to resolve the dispute in good faith.

(3) All negotiations pursuant to this Section 4.3 shall be confidential and subject to Rule 408 of state and federal rules of evidence.

(4) Each Party is responsible for its own costs, fees and expenses incurred in the negotiations.

(E) If the dispute has not been resolved within 60 calendar days after delivery of the statement described in Section 4.3(A), or if the Parties fail to meet in accordance with Section 4.3(D), then either Party may initiate the alternative dispute resolution provisions in Article 12.

4.4 **Refunds.** If either Party is owed a refund or additional payment, such refund or additional payment shall include Interest, unless otherwise directed by FERC.

Article 5
Representations and Warranties

5.1 **Mutual Representations and Warranties.** Each Party represents and warrants to the other Party that, as of the date it signs this Agreement and as of the date of each delivery of Energy Products to or from the Delivery Points, as applicable, that:

(A) It is duly organized, validly existing, and in good standing, under the laws of the jurisdiction of its organization or incorporation.

(B) It has the corporate, governmental and legal capacity, authority and power to execute, deliver, and perform this Agreement.

(C) The execution, delivery, and performance of this Agreement does not violate or conflict with any:

(1) laws or regulations applicable to the Party;

(2) organizational or corporate documents applicable to the Party;

(3) orders or judgments of any court or regulatory body applicable to the Party or its assets; or

(4) contractual restrictions applicable to the Party or its assets.

(D) No Event of Default under Article 7, including an event which with notice or lapse of time would constitute an Event of Default:

(1) has occurred and is continuing for the Party; or

(2) would occur as a result of the execution, delivery, or performance of this Agreement for the Party.

(E) It has executed this Agreement in connection with the conduct of its business and it has the ability to make or take delivery of Energy Products as provided in this Agreement.

(F) It is not relying on any representation of the other Party except for those expressly set forth in this Agreement, or on any Credit Support of the obligations of the other Party.

(G) It has executed this Agreement with a full understanding of the material terms and risks and is capable of assuming those risks.

(H) It has made its trading and investment decisions, including the suitability of such decisions, based solely on its own judgment and advice from its advisors, and not in reliance on information or opinion from the other Party or the other Party's advisors.

(I) It has not received from the other Party any assurances or promises regarding financial results or benefits from this Agreement.

5.2 **Representations and Warranties of PWCC.** Unless otherwise agreed upon and as expressly limited in the attached Service Schedule, PWCC further represents and warrants, as of the date of delivery of Energy Products as provided in this Agreement, that:

(A) PWCC is the owner of and has good title to the Energy Products;

(B) the Energy Products are transferred to APS free and clear of all liens, taxes, claims, security interests and other encumbrances; and

(C) the Energy Products are transferred to APS free of any right or interest in or to the Energy Products by any other person or entity.

5.3 LIMITATION OF WARRANTIES. ALL OTHER WARRANTIES, WHETHER WRITTEN OR ORAL, EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ANY WARRANTY OF MERCHANTABILITY OR WARRANTY OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

5.4 **Survival.** This Article 5 survives the termination of this Agreement.

Article 6
Assurances

6.1 **Adequate Assurances.** If a material change occurs such that a Party can reasonably call the continued performance of this Agreement by the Affected Party into question, then:

(A) A Party may request in writing that the Affected Party provide Credit Support, in a commercially reasonable amount and in a form acceptable to the requesting Party.

(B) Upon receipt of the request described in Section 6.1(A), the Affected Party shall provide Credit Support within five Business Days.

(C) If the Affected Party fails to comply with Section 6.1(B), then an Event of Default shall occur.

(D) If the Affected Party complies with Section 6.1(B), then no Event of Default shall have occurred as a result of the Affected Party incurring a material change.

Article 7
Default and Remedies

7.1 **Default.**

(A) **Events of Default.** Events of Default are as follows:

(1) **Failure to Deliver or Receive Energy Products.** A Party defaults if it fails to deliver or receive all or a substantial portion of the required Energy Product for a period of 5 calendar days or more after receiving written notice of the failure from the other Party.

(2) **Failure to Pay.** A Party defaults if it or its Credit Support Provider fails within 5 Business Days after receiving written notice from the other Party to make any payment when due, whether under this Agreement or under the Credit Support.

(3) **Failure to Deliver Assurances.** A Party defaults if it or its Credit Support Provider fails, within 5 Business Days after receiving written notice from the other Party, to provide adequate assurances pursuant to Section 6.1.

(4) **Failure to Perform Agreement.** A Party defaults if it fails, within 5 Business Days after receiving written notice from the other Party, to comply with or perform any material term of this Agreement.

(5) **Failure to Maintain Credit Support.** A Party defaults if:

(a) it fails to maintain Credit Support in full force and effect pursuant to the terms of and during the duration specified in this Agreement, unless the other Party agrees to the failure in writing or unless the Credit Support terminates according to its terms; or

(b) the Credit Support Provider disaffirms, repudiates, rejects, or challenges the validity of the Credit Support, whether in whole or in part.

(6) **Failure to Remain Solvent.** A Party defaults if it or its Credit Support Provider:

(a) is dissolved other than pursuant to a merger;

(b) becomes insolvent, or is unable to pay its debts, or fails or admits in writing its inability generally to pay its debts as they become due;

(c) makes a general assignment, arrangement or composition with or for the benefit of its creditors;

(d) institutes or has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditors' rights;

(e) has a resolution passed for its winding-up, official management or liquidation, other than pursuant to a merger;

(f) seeks or becomes subject to the appointment of an administrator, provisional liquidation, conservator, receiver, trustee, custodian or other similar official for all or substantially all of its assets;

(g) has a secured party take possession of all or substantially all of its assets;

(h) has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on against all or substantially all its assets and within 30 calendar days from the initiation of such process:

(i) the secured party maintains possession of the assets; or

(ii) the legal process is not dismissed, discharged, or stayed;

(i) causes or is subject to any event with respect to it which has an analogous effect to any of the events listed in Section 7.1(A)(6)(a) – (h); or

(j) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the events listed in Section 7.1(A)(6)(a) - (i).

(7) **Failure Following Merger or Transfer.** A Party defaults if it or its Credit Support Provider:

(a) merges with or into, or transfers all or substantially all its assets to, another entity and at that time:

(i) the resulting, surviving, or transferee entity fails to assume all the obligations of the Party or Credit Support Provider under this Agreement or any required Credit Support; or

(ii) the benefits of any Credit Support fail to extend, without consent of the other Party, to the performance of the resulting, surviving or transferee entity; or

(b) merges with or into, or transfers all or substantially all its assets to, another entity, and:

(i) the merger or transfer is not itself an Event of Default;

(ii) the creditworthiness of the successor is materially weaker than the creditworthiness of the assignor before the merger or transfer, taking into account Credit Support; and

(iii) the transferee fails to make collateral arrangements with and provide collateral to the other Party or provide adequate assurances pursuant to Section 6.1.

(B) **Notices of Default.** Each Party shall notify the other Party promptly of any event that, with the giving of notice or the passage of time or both, would constitute an Event of Default with respect to the other Party.

(C) **Remedies Upon Event of Default.** If an Event of Default is continuing and not cured for a period of 3 Business Days after the Defaulting Party receives written notice of the Event of Default, the Performing Party may, at its sole option, do one or more of the following:

(1) Withhold or suspend all or part of the payments to the Defaulting Party required under this Agreement until the default is cured.

(2) Withhold or suspend all or part of the deliveries of Energy Products to the Defaulting Party required under this Agreement until the default is cured.

(3) Designate an Early Termination Date by providing written notice to the Defaulting Party. The Early Termination Date shall be no earlier than 2 Business Days following the date written notice is received by the Defaulting Party.

(D) **Liquidation on Early Termination.**

(1) On the Early Termination Date, the Parties shall liquidate all transactions, including any portion of transactions not yet fully delivered, that are then outstanding.

(2) Liquidation shall occur by canceling each transaction being liquidated and calculating a Net Settlement Amount pursuant to Section 7.1(E).

(3) To the extent that, in the reasonable opinion of the Performing Party, a transaction is commercially or legally impracticable to terminate and liquidate on the Early Termination Date, then that transaction shall be terminated and liquidated as soon thereafter as is reasonably practicable, but the determination of the liquidated amount for that transaction shall not delay the payment or calculation of the Net Settlement Amount.

(4) Except for the payment of the Net Settlement Amount, no further planned payments or deliveries under this Agreement shall be required after the Early Termination Date.

(5) The Performing Party shall notify the Defaulting Party in writing of the amount and basis for calculation of the Net Settlement Amount.

(6) The Net Settlement Amount shall be paid as follows:

(a) If the Net Settlement Amount is a positive number, the Defaulting Party shall, within 5 Business Days of receipt of such notice, pay to the Performing Party an amount equal to the Net Settlement Amount plus Interest.

(b) If the Net Settlement Amount is a negative number, the Performing Party shall pay to the Defaulting Party an amount equal to the Net Settlement Amount within 5 Business Days of determining the Net Settlement Amount.

(E) Calculation of Net Settlement Amount.

(1) Net Settlement Amount. The Net Settlement Amount is calculated for each transaction as follows:

(a) If a Market Quotation can be determined:

(i) the Market Quotation, determined in accordance with Section 7.1(E)(2), for the transactions, whether positive or negative; plus

(ii) Unpaid Amounts, determined in accordance with Section 7.1(E)(3), owed by the Defaulting Party to the Performing Party; less

(iii) Unpaid Amounts, determined in accordance with Section 7.1(E)(3), owed by the Performing Party to the Defaulting Party.

(b) If a Market Quotation cannot be determined, or in the reasonable belief of the Performing Party would not produce a commercially reasonable result:

(i) the amount the Performing Party reasonably and in good faith determines to be its aggregate losses and costs (net of gains) associated with this Agreement, including but not limited to brokerage fees and commissions, loss of bargain damages, and cost of funds; or

(ii) at the election of the Performing Party, all losses and costs (net of gains) incurred to terminate, liquidate, obtain, or reestablish hedges and related trading positions.

(2) **Market Quotation.** The Market Quotation is an amount that would be paid by Reference Market Makers to enter into a transaction that would preserve for the Performing Party the economic benefits of this Agreement after the Early Termination Date. The Market Quotation shall be determined as follows:

(a) The Performing Party shall request quotations from at least 3 Reference Market Makers on a date and time selected in good faith by the Performing Party.

(b) The quotations from Reference Market Makers shall consider existing Credit Support and would be subject to such documentation to which the Performing Party and Reference Market Maker agree in good faith.

(c) The quotations from Reference Market Makers shall exclude Unpaid Amounts, but shall include any payment or delivery that would have been required after the Early Termination Date assuming the satisfaction of all conditions precedent.

(d) A quotation to be paid by the Performing Party shall be expressed as a positive number and a quotation to be paid to the Performing Party shall be expressed as a negative number.

(e) Each Reference Market Maker shall provide its quotation as of the same date and local time as the Early Termination Date to the extent reasonably practicable, or otherwise as soon as practicable after the Early Termination Date.

(f) The Market Quotation shall be the arithmetic mean of all quotations after disregarding the highest and lowest quotation. If more than one quotation has the same highest or lowest value, then only one such quotation shall be disregarded.

(g) If less than 3 quotations are provided by Reference Market Makers, then the Market Quotation cannot be determined and the Net Settlement Amount shall be determined under Section 7.1(E)(1)(b).

(3) **Unpaid Amounts.** Unpaid Amounts are determined as follows:

(a) The amount for all terminated transactions that became or would have become payable on or prior to the Early Termination Date and which remain unpaid as of the Early Termination Date; plus

(b) The fair market value, as reasonably determined by the Performing Party as of the delivery date, of Energy Products that were required to be delivered on or prior to the Early Termination Date and which have not been settled as of the Early Termination Date; plus

(c) All non-duplicative Direct Actual Damages incurred prior to the Early Termination Date; plus

(d) Interest on all such amounts to the extent permitted by law.

(4) **Disputes Regarding Net Settlement Amount.** If the Defaulting Party disputes the calculation of the Net Settlement Amount by the Performing Party, then:

(a) the dispute shall be resolved as provided in Article 12;

(b) pending resolution of the dispute, the Defaulting Party shall pay the full amount of the Net Settlement Amount as provided in Section 7.1(D)(6); and

(c) if the dispute results in a refund of any portion of the Net Settlement Amount, the Performing Party shall make the refund within 3 Business Days of such determination plus Interest.

7.2 Remedies Upon Breach of Agreement.

(A) If there is no express remedy or measure of damages for breach of the Agreement, then the breaching Party shall be liable for Direct Actual Damages for any breach of this Agreement determined as follows:

(1) If APS is the breaching Party and the amount of Energy Products it received is less than the amount provided for in this Agreement, then the damages APS will owe to PWCC are:

(a) the Contract Price minus the Sales Price, multiplied by the amount of Energy Products due under the Agreement minus the actual amount received by APS;[1] plus

(b) transmission charges for firm transmission service upstream of the Delivery Point incurred to achieve the Sales Price, less the reduction in transmission charges achieved as a result of the reduction in APS' receipt of Energy Products based on PWCC's reasonable efforts to achieve the reduction; unless

(c) the total amount calculated is negative, in which case there are no Direct Actual Damages.

(2) If PWCC is the breaching Party and the amount of Energy Products it delivered is less than the amount provided for in this Agreement, then the damages PWCC will owe to APS are:

(a) the Substitute Price minus the Contract Price, multiplied by the amount of Energy Products due under the Agreement minus the actual amount delivered to APS;[2] plus

(b) transmission charges for firm transmission service upstream of the Delivery Point that APS incurred to achieve the Substitute Price, less the reduction in transmission charges achieved as a result of the reduction in PWCC's delivery of Energy Products based on APS' reasonable efforts to achieve the reduction; unless

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1 [Contract Price – Sales Price] × [quantity due – quantity received]

2 [Substitute Price – Contract Price] × [quantity due – quantity received]

(c) the total amount calculated using the foregoing formula is negative, in which case there are no Direct Actual Damages.

7.3 **Forward Contracts.** The Parties agree that transactions for the forward sale and purchase of Energy Products entered into under this Agreement are "forward contracts" and the Parties are "forward contract merchants" within the meaning of the United States Bankruptcy Code.

7.4 **Enforcement of Remedies.**

(A) Except as otherwise provided in this Agreement, the rights, powers, remedies and privileges provided in this Agreement are cumulative and not exclusive of any rights, powers, remedies and privileges provided by law.

(B) A single or partial exercise of any right, power or privilege will not be presumed to preclude any subsequent or further exercise of that right, power or privilege or the exercise of any other right, power or privilege.

7.5 **Duty to Mitigate.**

(A) Except as provided in Section 7.5(B), each Party has a duty to mitigate damages in good faith and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of an Event of Default.

(B) Neither Party is required to utilize or change the utilization of its owned or controlled assets, including contractual assets, or its market positions, or to curtail load, to minimize the other Party's liability for damages.

7.6 **Set-Off.**

(A) At the option of the Performing Party and without prior notice to the Defaulting Party or breaching Party, any amounts payable to one Party by the other Party may be set-off against any amounts payable, whether at that time or in the future or upon the occurrence of a contingency and irrespective of the currency, place of payment or booking office of the obligation, under any other agreements or obligations between the Parties.

(B) If the Performing Party exercises a set-off under Section 7.6(A), it shall give notice to the Defaulting Party or breaching Party of the set-off.

(C) If an obligation used for a set-off under Section 7.6(A) is unascertained, the Performing Party may in good faith estimate that obligation and set-off in respect of that estimate, but the Performing Party shall account to the Defaulting Party or breaching Party when the obligation is ascertained.

7.7 **LIMITATIONS OF LIABILITY.**

(A) THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES OF THIS AGREEMENT.

(B) FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES IS THE SOLE AND EXCLUSIVE REMEDY FOR SUCH BREACH.

(C) IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED FOR, LIABILITY IS LIMITED TO DIRECT ACTUAL DAMAGES AND SUCH DIRECT ACTUAL DAMAGES IS THE SOLE AND EXCLUSIVE REMEDY.

(D) EXCEPT WHERE SPECIFICALLY SET FORTH IN THIS AGREEMENT, NEITHER PARTY SHALL BE REQUIRED TO PAY OR BE LIABLE FOR SPECIAL, CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, INCLUDING BUT NOT LIMITED TO LOST PROFITS OR BUSINESS INTERRUPTION DAMAGES AND WHETHER BY STATUTE, IN TORT, IN CONTRACT, OR OTHERWISE.

(E) THE PARTIES INTEND THAT THE LIMITATIONS OF LIABILITY IMPOSED IN THIS AGREEMENT ARE WITHOUT REGARD TO THE CAUSE OR CAUSES, INCLUDING BUT NOT LIMITED TO THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE IS SOLE, JOINT, CONCURRENT, ACTIVE OR PASSIVE, OR OTHERWISE.

(F) IF ANY DAMAGES UNDER THIS AGREEMENT ARE DEEMED LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT SUCH DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

7.8 **Survival.** This Article 7 survives the termination of this Agreement.

Article 8
Force Majeure

8.1 Suspension of Obligations.

(A) Except with regard to any obligation to pay money under the Agreement, if either Party cannot, in whole or in part, carry out its obligations under this Agreement as a result of Force Majeure, then

(1) The Party claiming Force Majeure shall give the other Party written notice and full particulars of the Force Majeure as soon as reasonably possible after the occurrence of the cause relied upon.

(2) Only to the extent affected by the Force Majeure, the obligations of the affected Party are suspended.

(3) During the pendency of the Force Majeure, the affected Party is not liable to the other Party for:

(a) any claims relating directly or indirectly to the failure of the affected Party to perform under this Agreement as a result of the Force Majeure; and

(b) any loss, damage, injury or expense resulting from, or arising out of, the Force Majeure.

(B) If an event of Force Majeure excuses PWCC from delivering any of the Energy Products, PWCC shall make best efforts to secure on APS' behalf Replacement Energy Products for the Energy Products that PWCC is excused from delivering if:

(1) APS requests such efforts; and

(2) APS assumes responsibility for all resulting costs.

(C) PWCC shall use reasonable efforts to minimize the costs to APS of Replacement Energy Products obtained under Section 8.1(B).

8.2 Due Diligence.

(A) A Party claiming Force Majeure shall use due diligence to fulfill its obligations under this Agreement and to remove any disability caused by such event at the earliest practicable time.

(B) Nothing in this Article 8 shall require a Party to settle any strike or labor dispute.

(C) A Party claiming Force Majeure shall continue to perform immediately after the Force Majeure has been removed.

Article 9
Taxes and Other Charges

9.1 Responsibility for Taxes and Other Charges.

(A) Except as otherwise provided in this Section 9.1, PWCC is responsible for all Taxes on or with respect to the Energy Products incurred prior to delivery to APS up to and at the Delivery Points.

(B) APS is responsible for all Taxes on or with respect to the Energy Products incurred from the Delivery Points except for ad valorem or income taxes, which relate to the wholesale of the Energy Products and which are the responsibility of PWCC.

(C) If during the term of this Agreement, any material increased costs are associated with the Dedicated Units as a result of any Governmental Authority or any judicial order, APS shall be responsible for all such increased costs through an annualized charge.

(D) If PWCC is required by law or regulation to remit or pay Taxes that are APS' responsibility under Section 9.1(B), APS shall promptly reimburse PWCC for such Taxes.

(E) If APS is required by law or regulation to remit or pay Taxes that are PWCC's responsibility under Section 9.1(A), APS may deduct the amount of any such Taxes from the sums due to PWCC under this Agreement.

(F) Nothing in this Agreement obligates a Party to be responsible for any taxes for which it is exempt by law.

(G) Each Party shall indemnify, defend and hold the other Party harmless for, from and against all liability for Taxes for which the indemnifying Party is responsible.

Article 10
Notices and Other Communications

10.1 Methods of Providing Notice. All invoices, payments, statements, notices, and communications made under this Agreement shall be in writing as follows:

(A) By registered or certified or express mail, with a return receipt requested, postage prepaid, or by comparable delivery service, or by hand with a receipt, or by facsimile with the original sent by first class mail, to the individuals listed on Exhibit B.

(B) Either Party may modify any information specified in Exhibit B by giving written notice to the other Party.

10.2 **Receipt of Notice.** All written communications made as provided in Section 10.1 are deemed given upon receipt by the addressee. In the case of facsimiles, receipt occurs on the date that the facsimile is received by the addressee in legible form.

Article 11
Effective Date and Term

11.1 **Effective Date.** This Agreement shall become effective upon the completion of all the following:

(A) The grant of a variance to APS of Arizona Administrative Code Rule R14-2-1606(B) by the Arizona Corporation Commission consistent with Section 3.1 of the attached Service Schedule.

(B) The transfer of the non-nuclear generation assets to Pinnacle West Energy Corporation.

(C) The acceptance of both this Agreement and the Pinnacle West Energy Contract by FERC without modification or condition, except that if FERC or any court imposes any condition, limitation, or qualification, then:

(1) each Party shall determine whether the condition, limitation or qualification individually, or in the aggregate, has a material adverse effect on the Party with respect to this Agreement;

(2) a Party determining an adverse effect under Section 11.1(C)(1) shall as soon as practicable, but in no case after more than 30 calendar days of the FERC or court action, notify the other Party;

(3) after notification, the Parties shall cooperate on a commercially reasonable basis to renegotiate the terms of this Agreement to preserve the original economic relationship of the Parties with respect to this Agreement; and

(4) if the parties fail to renegotiate the terms of this Agreement, the Agreement is null and void and have no further force and effect.

(D) Approval of this Agreement by the Arizona Corporation Commission.

11.2 Termination Date.

(A) Unless earlier terminated pursuant to the terms of this Agreement or extended pursuant to Section 11.2(B), this Agreement shall terminate at midnight on December 31, 2015.

(B) This Agreement shall automatically be renewed for up to three additional 5-year terms unless either Party provides to the other Party a notice of termination at least 12 months prior to the scheduled termination of this Agreement.

11.3 Partial Termination.

(A) The obligations of the Parties with respect to the Dedicated Units Energy Products shall terminate upon the termination or material change of the Pinnacle West Energy Contract, if the termination or material change of the Pinnacle West Energy Contract is outside of the control of PWCC and Pinnacle West Energy Corporation and regardless of whether such termination or material change occurs during a renewal period pursuant to Section 11.2(B).

(B) If this Agreement is partially terminated under Section 11.3(A), the Parties shall engage in good faith negotiations for a subsequent agreement regarding the provision of Energy Products in lieu of the Dedicated Units Energy Products.

11.4 Regulatory Approvals. Each Party shall use commercially reasonable efforts to obtain the necessary regulatory approvals so that this Agreement shall become effective on the earliest practicable date.

Article 12
Dispute Resolution

12.1 Alternative Dispute Resolution. Except as provided in Section 12.4, all claims or disputes, whether sounding in tort or contract or otherwise, between the Parties, including their agents and representatives, arising under or relating to this Agreement are subject to alternative dispute resolution as provided in this Article 12.

12.2 Mediation. Any dispute between the Parties shall first be submitted to non-binding mediation using the following procedures:

(A) A Party shall provide a written request for mediation to the other Party.

(B) The mediation shall commence within 60 calendar days from receipt of the request in Section 12.2(A).

(C) A mediator shall be chosen by mutual agreement of the Parties within 15 calendar days of receipt of the request in Section 12.2(A).

(D) All discussions or materials presented during or for purposes of the mediation shall be considered Confidential Information and subject to Rule 408 of the federal and state rules of evidence and any similar regulatory rules.

12.3 **Arbitration.** If a dispute cannot be resolved after mediation under Section 12.2 and except as provided in Section 12.4, the dispute shall be submitted to binding arbitration as follows:

(A) The arbitration shall be conducted in Phoenix, Arizona in accordance with the Federal Arbitration Act and by the then-prevailing Commercial Arbitration Rules of the American Arbitration Association. The arbitration proceedings, decision and award under this Section 12.3 shall be governed by the Federal Arbitration Act.

(B) The validity, construction, and interpretation of this Article 12 and all procedural aspects of the arbitration shall be governed by the Federal Arbitration Act and shall be decided by the arbitrators.

(C) Submission to arbitration shall be made upon the request of either Party.

(D) There shall be 3 arbitrators. Each Party shall appoint a single arbitrator within 20 calendar days after service of the notice of arbitration. The 2 arbitrators so appointed shall select the third arbitrator, who shall be the chairperson of the tribunal, within 20 calendar days after the both arbitrators are appointed. The chairperson shall have over 8 years of experience in energy-related transactions.

(E) None of the arbitrators shall be employees or former employees of either Party or have any direct interest in either Party or the subject matter of the arbitration, unless the conflict is expressly acknowledged and waived in writing by both Parties.

(F) The chairperson shall schedule and hear the dispute within 6 months after appointment and shall render the panel's decision within 30 calendar days after the hearing concludes.

(G) The arbitrators shall have no authority to award consequential, treble, exemplary, or punitive damages of any type or kind regardless of whether such damages may be available under any law or right. The Parties waive their rights, if any, to recover or claim such damages.

(H) All discussions or materials presented during or for purposes of the arbitration shall be considered Confidential Information.

(I) All costs and expenses of the arbitrators shall be borne equally by the Parties. The arbitration shall take place in Phoenix, Arizona.

(J) The arbitration award shall be final and binding on the Parties and may be entered in any court of competent jurisdiction. If required by applicable law, the arbitration award shall be filed with FERC and subject to FERC approval.

12.4 Equitable Relief. Either Party may petition a court of appropriate and proper jurisdiction, as described in Section 13.6, for non-monetary relief relating to any claim of breach of this Agreement to prevent undue hardship relating to the claimed breach pending the completion of mediation or arbitration under Sections 12.2 and 12.3.

Article 13
General Provisions

13.1 Entire Agreement; Amendments and Counterparts.

(A) Except as provided in Section 1.3, the terms of this Agreement constitute the entire agreement between the Parties with respect to its subject matter.

(B) The terms of this Agreement may be changed only by mutual written agreement executed by both Parties after the date of this Agreement.

(C) This Agreement may be executed in counterparts.

13.2 No Waiver.

(A) No waiver of a default constitutes a waiver of any other default or defaults whether of a like kind or different nature.

(B) Any delay in asserting or enforcing any right under this Agreement does not waive such right, unless barred by an applicable statute of limitation.

13.3 Headings. Headings and titles are for convenience only and do not affect the meaning or interpretation of any provision of this Agreement.

13.4 Confidentiality.

(A) Each Party and their agents shall maintain all Confidential Information in confidence and shall use such information solely in connection with this Agreement.

(B) Neither Party may disclose Confidential Information to third parties without the prior written consent of the other Party, except to the extent necessary to effectuate the transfer of Energy Products after providing the other Party with prompt written notice of the intent to disclose to the third party.

(C) This Section 13.4 shall survive the termination of this Agreement for a period of one year.

13.5 Governing Law.

(A) This Agreement shall be governed by, construed and enforced in accordance with the laws of Arizona, without regard to principles of conflict of laws.

(B) The Parties agree that for purposes of this Agreement the products sold herein are not "goods" within the meaning of any Uniform Commercial Code.

13.6 Jurisdiction and Costs.

(A) Subject to Article 12 and Section 13.6(B), any judicial action relating in any way to this Agreement shall be brought only in a state or federal court located in Phoenix, Arizona.

(B) An action to enforce an arbitration award may be brought in any jurisdiction.

(C) The Parties waive any right to trial by jury in an action relating to this Agreement.

(D) The prevailing Party in any judicial action is entitled to recover its costs, litigation and other expenses, and reasonable attorneys' fees incurred in connection with such proceedings.

13.7 No Third-Party Beneficiaries.

(A) There are no third-party beneficiaries to this Agreement.

(B) This Agreement does not create, nor shall it be construed to create, any standard of care, duty or liability to any third party.

13.8 Binding Effect. This Agreement is binding on and inures to the benefit of the Parties and their respective successors and permitted assigns.

13.9 Recording.

(A) Either Party may record telephone conversations and other discussions regarding matters arising under this Agreement.

(B) Each Party agrees to obtain the consent of its employees and agents to such recording to the extent required by applicable law.

(C) All recordings of telephone conversations and other discussions are deemed Confidential Information.

13.10 Regulatory Jurisdiction. This Agreement and any actions under this Agreement shall be subject to applicable regulatory jurisdiction and approvals, but this Agreement shall not be construed as subjecting either Party to the jurisdiction of any regulatory agency that would not otherwise have jurisdiction over such Party.

13.11 Assignment.

(A) Neither Party may transfer or assign any of its rights, title, interests or obligations in or under this Agreement, including assignments of the Dedicated Contracts from PWCC, without the prior written consent of the other Party, except for:

(1) an assignment, including but not limited to a transfer or pledge, made as security for any financing if:

(a) the assigning Party provides prompt notice to the other Party of the assignment, including the effective date; and

(b) the assignment does not release the assigning Party from any obligations or liabilities under this Agreement prior to the effective date of the assignment; or

(2) an assignment, including but not limited to a transfer or delegation, to an Affiliate if:

(a) the assigning Party provides prompt notice to the other Party of the assignment, including the effective date;

(b) the assignee Affiliate agrees to be fully bound by the Agreement;

(c) the assignee Affiliate meets the Credit Support requirements of the non-assigning Party; and

(d) the assignment does not release the assigning Party from any obligations or liabilities under this Agreement prior to the effective date of the assignment.

(B) Any transfer that does not comply with Section 3.11(A) is null and void.

13.12 Records.

(A) Each Party shall maintain records of all transactions under this Agreement for a minimum of 3 years from the billing date of the transaction.

(B) Each Party may require the other Party to produce the other Party's records to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement.

(C) If the records produced under Section 13.12(B) reveal any inaccuracy in any invoice or similar statement, a refund shall issue to the Party owed money plus Interest, except that if the invoice or statement resulting in the refund is over 12 months old, no refund shall issue.

13.13 Negotiated Agreement. The Parties agree that they have had meaningful discussions and negotiations over the provisions of this Agreement and therefore no provision is to be construed against the Party who drafted and prepared this Agreement.

13.14 Severability. If any provision of this Agreement is determined to be unenforceable, illegal or otherwise invalid, then that provision shall be severed and the remainder of the Agreement shall remain in full force and effect if:

(A) the Parties can legally, practically, and commercially continue without the severed provision; and

(B) the severance does not defeat the purpose or relative economic position of either or both Parties in entering into this Agreement.

13.15 Time of the Essence. Time is of the essence of this Agreement.

Signed:

PINNACLE WEST CAPITAL CORPORATION	ARIZONA PUBLIC SERVICE COMPANY
By:_____	By:_____
Name:_____	Name:_____
Title:_____	Title:_____
Date:_____	Date:_____

EXHIBIT A

Definitions

When initially capitalized, the following terms used in the Agreement, including the Service Schedule and exhibits, have the meanings set forth below:

"Affected Party" means a Party affected by a material change under Section 6.1.

"Affiliate" means: (a) an entity directly or indirectly controlling the other entity; (b) an entity directly or indirectly controlled by the other entity; or (c) an entity commonly controlled directly or indirectly with the other entity.

"Ancillary Services" means the services specified in Schedules 1 through 6 of APS' Open Access Transmission Tariff.

"APS" means Arizona Public Service Company.

"APS' Full Load Requirements" means APS' full Energy Product requirements needed to serve APS' present and future Standard Offer retail customers. APS' Full Load Requirements excludes the amount of APS' retail load served by the following resources: (1) the SRP Power Coordination Agreement of September 15, 1955 and Territorial Agreement of August 31, 1955 to the extent such agreement is not a Dedicated Contract; (2) deliveries of capacity and energy under the September 21, 1990 Asset Purchase and Power Exchange Agreement, Sections 3 and 4, between APS and PacificCorp to the extent such agreement is not a Dedicated Contract; (3) the Arizona Corporation Commission's environmental portfolio standard in effect on the date of this Agreement; (4) APS' purchase power contracts with Qualifying Facilities and customer-owned generation in effect on the date of this Agreement or as subsequently authorized by law; (5) the output of APS' Palo Verde Nuclear Generation Station assets until they are transferred to Pinnacle West Energy Corporation; and (6) other generating assets retained by APS pursuant to an order of the Arizona Corporation Commission.

"Base Rate" means the lesser of (a) the annual interest rate published as the "Prime Rate" in the *Wall Street Journal*'s "Money Rates" section, unless the *Wall Street Journal* no longer publishes the "Prime Rate," in which case a comparable rate agreed to by the Parties, plus 2 percent; or (b) the maximum interest rate allowed by law.

"Business Day" means a weekday during which United States banks are open for general commercial business and ending at 5:00 p.m. Phoenix time.

"Capacity" means electric generating capability, expressed in kilowatts (kW) or megawatts (MW).

"Competitive Bidding Process" means the bidding process through which PWCC or its assignee or agent shall contract for the portion of the Energy Products described in the Service Schedule as Competitively-Bid Energy Products.

"Competitively-Bid Energy Products" means Energy Products obtained through the Competitive Bidding Process described in Section 3.1 of the Service Schedule.

"Confidential Information" means any information relating to or provided under this Agreement that is designated by a Party as confidential, except (a) information in a Party's possession prior to its receipt from the other Party; (b) information obtained from a third person who, as far as the obtaining Party is aware, was not prohibited by a contractual, legal or fiduciary obligation from transmitting the information; (c) information that has become publicly available through no fault of the obtaining Party; and (d) information that a Party is required by law, regulation, or administrative or judicial order to disclose, including information related to satisfying regulatory requirements, if the Party disclosing such information has provided prompt notice of the requirement and allowed a reasonable period of time for the other Party to seek to restrain such disclosure.

"Contract Price" means the price specified in the attached Service Schedule for each Contract Year including adjustments.

"Contract Term" or **"Term"** means the period beginning on the Effective Date and ending on the termination date specified in Section 11.2.

"Contract Year" means (a) for the initial contract year, 12:01 A.M. on the date delivery of Energy Products commences pursuant to Section 1 of the attached Service Schedule, and ending 12:00 Midnight, December 31 of the same calendar year; and (b) for each subsequent calendar year, the period of time between 12:01 A.M., January 1 and ending 12:00 Midnight, December 31.

"Credit Support" means: (a) a Letter of Credit, (b) a Guaranty, or (c) such other form of commercially-reasonable security acceptable to the secured Party.

"Credit Support Provider" means: (a) a Guarantor, (b) an Issuer, or (c) a provider of another form of Credit Support who is acceptable to the secured Party.

"Dedicated Contracts Energy Products" means Energy and Capacity sold to APS from the Dedicated Contracts.

"Dedicated Contracts" means energy and capacity procured pursuant to the: (a) SRP Power Coordination Agreement and Territorial Agreement, and (b) Sections 3 and 4 of the Asset Purchase and Power Exchange Agreement between APS and Pacificorp dated September 21, 1990; but (c) only to the extent that such contracts are transferred to or assumed by Pinnacle West Capital Corporation.

"Dedicated Energy Products" means Energy and Capacity sold to APS from the Dedicated Units and Dedicated Contracts.

"Dedicated Units" means Palo Verde Units 1-3, West Phoenix Units 1-5 and CT1-2, Saguaro Steam Units 1&2 and CTs 1-3, Navajo Units 1-3, Four Corners Units 1-5, Yucca Unit 1 and CTs 1-4, Douglas CT, Cholla Units 1-3, Ocotillo Units 1-2 and CT1-2 and Redhawk Units 1-2, from commissioning until such units are retired, as applicable.

"Dedicated Units Billing Energy" means the quantity of Energy billed to APS by PWCC each calendar month under Section 3.2 of the Service Schedule. Unless revised as a result of an applicable RTO requirement, Dedicated Units Billing Energy shall equal: (a) the sum of net tie metering for all interconnections between APS' control area and other control areas as measured through telemetered data and adjusted for end-of-month system revenue metering as agreed between the Parties, plus (b) all net metered generation interconnected with APS' control area as measured through telemetered data and adjusted for end-of-month system revenue metering as agreed between the Parties, plus (c) losses on third parties' transmission systems associated with transmission used by APS to serve APS' Full Load Requirements, less (d) retail and wholesale loads served by other providers or supplied by PWCC to APS under separate contract within APS' control area, less (e) Supplemental Energy Products, less (f) Replacement Energy Products, less (g) Competitively-Bid Energy Products, less (h) Dedicated Contracts Energy Products, less (i) those resources specifically excluded in the definition of APS' Full Load Requirements.

"Dedicated Units Energy Products" means Energy and Capacity sold the APS from the Dedicated Units.

"Defaulting Party" means a Party who itself or through its Credit Support Provider is subject to an Event of Default.

"Delivery Point" means a location or locations, as agreed-upon from time to time, at which PWCC's resources used to provide Energy Products to APS interconnect with: (a) APS' transmission or distribution system; (b) the system of a future RTO in which APS' retail load is located; or (c) points of interconnection between such systems and adjoining systems.

"Demand" means the rate at which Energy is delivered.

"Direct Actual Damages" means the damages calculated under Section 7.2.

"Early Termination Date" means a date on which the Agreement is terminated that is earlier than the date specified in Section 11.2 of the Agreement.

"Energy" means three-phase, sixty-hertz electric energy delivered at the nominal voltage of the Delivery Point expressed in megawatt hours (MWh) or kilowatt hours (kWh).

"Energy Products" means Energy and Capacity.

"Event of Default" means an event of default described in Section 7.1.

"FERC" means the Federal Energy Regulatory Commission or its successor.

"Force Majeure" means an event that: (a) is not anticipated on the date the Agreement is signed; (b) is not within the reasonable control of the Party claiming Force Majeure; (c) could not, in the exercise of reasonable diligence and Good Utility Practice by the Party claiming Force Majeure, have been prevented or avoided; and (d) renders the Party claiming Force Majeure unable to carry out, wholly or in part, its obligations under this Agreement. Subject to the foregoing, Force Majeure includes, but is not limited to, the following events: (1) act of God; (2) act of public enemy, war, terrorism, blockade, insurrection, civil disturbance, disobedience or riot; (3) strike, lockout, material shortage or other industrial disturbance; (4) epidemic, landslide, earthquake, fire, storm, lightning, flood or other natural catastrophe; (5) failure of the transmission or distribution grid, including third parties' transmission facilities, to transmit or distribute Energy; (6) reductions or interruptions in services which may be required by the control area operator or regional transmission organization; (7) material failure of performance by any PWCC supplier, including failures as a result of Force Majeure, which results in a shutdown or material reduction of any of the generation capacity or output owned or controlled by PWCC or a PWCC Affiliate; (8) shutdown or reduction by the Nuclear Regulatory Commission of a material portion of the generation capacity or output which is owned or controlled by PWCC or a PWCC Affiliate; (9) act, omission, failure to act, or order of a civil, judicial, regulatory or government authority, if the Party claiming Force Majeure has acted to the fullest extent reasonable to prevent or correct the act, omission, failure to act or order; and (10) any other act or omission similar to the foregoing examples which by the exercise of a Party's reasonable diligence cannot be overcome. Force Majeure specifically excludes PWCC's ability to sell Dedicated Energy Products at a more advantageous price.

"Good Utility Practice" means (a) any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period; and (b) any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not necessarily require the optimum practice, method, or act to the exclusion of all others but does include a requirement that PWCC provide installed or purchased generating reserves reasonably needed to supply firm Dedicated Energy Products to APS as required under this Agreement.

"Governmental Authority" means (a) a city, municipality, county, state or other governmental board or authority; (b) a regulatory or public power board or authority; (c) a public utility or public power district; (d) a joint action agency; (e) a federally recognized tribal board, authority or agency; or (e) other similar political subdivisions or public entities of the United States, or any state or a territory, acting individually or in combination.

"Guarantor" means an entity or entities executing a Guaranty of the obligation of one Party to the other Party. A Guarantor must be reasonably acceptable to the Party receiving the Guaranty.

"Guaranty" means a guaranty, hypothecation agreement, security agreement, or any other document containing an obligation of a Guarantor in favor of, and supporting obligations of, one Party to the other Party. The Guaranty must be in a form and substance reasonably acceptable to the Party receiving the Guaranty.

"Interest" means interest accruing at the Base Rate, compounded daily based on a 360-day year, from and including the due date to and including the payment date or, if applicable, interest as ordered by FERC.

"Issuer" means a person executing and delivering to a Party a Letter of Credit or another form of Credit Support document that is not a Guaranty. An Issuer must be reasonably acceptable to the receiving Party.

"Letter of Credit" means an instrument or agreement, revocable or irrevocable, entered into by a bank or other financial institution providing that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the credit.

"Market Quotation" means a quotation determined under Section 7.1(E)(2).

"NERC" means the North American Electric Reliability Council and any successor.

"Net Settlement Amount" means the amount calculated under Section 7.1(E)(1).

"Off-Systems Sales Margin" means the revenue received from energy sales to anyone other than APS from the Dedicated Units less: (a) the costs of associated fuel, transmission and Ancillary Services if applicable, and (b) any other out-of-pocket costs associated with the sale.

"Parties" means both APS and PWCC.

"Party" means either APS or PWCC.

"Performing Party" means the non-defaulting Party upon an Event of Default or the non-breaching Party in the case of a breach.

"Pinnacle West Energy Contract" means the contract between PWCC and Pinnacle West Energy Corporation referred to in Section 2.1(C) of the Agreement.

"Purchase Price" means the price in United States dollars, unless otherwise agreed, to be paid by APS to PWCC in exchange for the Energy Products. The Purchase Price may be stated in a per unit price for a specific Energy Product or Products or as a total price for all Energy Products.

EXHIBIT B

Notification and Points of Contact

For PWCC:

Contract Administration to:

PINNACLE WEST CAPITAL CORPORATION
400 N. 5th Street, Station 9842
Phoenix, AZ 85004
ATTN: Dennis Beals

PHONE: (602) 250-3101
FAX: (602) 250-3719

Payments to:

PINNACLE WEST CAPITAL CORPORATION
Bank Name: Bank One of Arizona
Acct No.: 2270-3938
ABA No.: 122100024

For APS:

ARIZONA PUBLIC SERVICE COMPANY
400 N. 5th Street, Station 8632
Phoenix, AZ 85004
ATTN: Keith Van Ausdal

PHONE: (602) 250-2951
FAX: (602) 250-213

SERVICE SCHEDULE

This Service Schedule further defines the obligations of the Parties with respect to the Agreement.

1. **Effective Date.**

   1.1 This Service Schedule is for the sale and purchase of APS' Full Load Requirements, beginning on the Effective Date of the Agreement and continuing through December 31, 2015, unless otherwise terminated or extended pursuant to this Agreement.

2. **Forecast.**

   2.1 APS shall provide a five-year forecast of the APS' Full Load Requirements on an hourly basis 60 days prior to each calendar year. The first five-year forecast shall be provided within 30 days of the execution of this Agreement. APS shall also update the forecast during each calendar year for known or anticipated changes in load.

   2.2 Scheduling/Forecast. APS shall use its best efforts to submit accurate and timely forecasts and to facilitate PWCC's submittal of an accurate schedule for receipt of APS' Full Load Requirements. PWCC may schedule the delivery of Energy Products to APS in any combination of MW amounts and at any combination of Delivery Points as necessary to satisfy the total Energy Products supply requirements.

3. **Providing APS' Full Load Requirements.** PWCC shall provide APS' Full Load Requirements and APS shall pay all costs associated with such service as follows:

   3.1 Competitively-Bid Energy Products.

      3.1.1 Commencing on January 1, 2003, PWCC shall secure and provide Energy Products to APS through a competitive bidding process in the initial amount of 270 MWs at an overall 51% load factor. Energy Products acquired through a competitive bidding process shall include transmission to the Delivery Points. PWCC may charge APS for Ancillary Services or other delivery costs if not included in the Competitively-Bid Energy Products.

      3.1.2 Energy Products acquired through a competitive bidding process shall be increased by an additional 270 MWs at an overall 51% load factor each Contract Year thereafter through 2008 so that by the end of 2008, 1620

MW will be supplied—an amount which APS estimates to be approximately 23% of 2008 peak load.

3.1.3 PWCC shall, directly or through an assignee or agent, conduct the Competitive Bidding Process for the benefit of APS. The specific details of the Competitive Bidding Process shall be determined by PWCC in consultation with APS, provided that the selection of the winning bidders, as well as contract provisions, specifications and creditworthiness shall be expressly approved by APS.

3.1.4 APS shall be responsible for any and all costs and expenses incurred in the acquisition of any Energy Products supplied through the Competitive Bidding Process, including PWCC's administrative expenses associated with bid development and evaluation, and procurement. In the event of non-performance by parties that are under contractual commitments as a result of the Competitive Bidding Process, PWCC will use commercially reasonable efforts to obtain Replacement Energy Products for the benefit of APS. APS shall be responsible for all costs incurred for the Replacement Energy Products. In consultation with APS, PWCC shall pursue all commercially legal remedies for defaults under contracts entered into as a result of the Competitive Bidding Process. APS shall be responsible for all costs and fees associated with the pursuit of such remedies, and APS shall receive all monies awarded as a remedy.

3.1.5 Should PWCC wish to participate in the Competitive Bidding Process as a seller, PWCC shall engage an independent third party to perform the necessary functions of the Competitive Bidding Process on behalf of PWCC. APS shall approve such independent third party. If PWCC is selected in the Competitive Bidding Process, then a separate agreement between APS and PWCC will be executed for such Competitively Bid Energy Products.

3.2 Dedicated Energy Products. Subject to the Agreement and this Service Schedule, PWCC shall provide Dedicated Energy Products from the Dedicated Units and the Dedicated Contracts to serve APS' Full Load Requirements.

3.2.1 Dedicated Units Energy Products. Dedicated Units Energy Products shall be priced at the actual prices charged to PWCC in the Pinnacle West Energy Contract. The Parties recognize that the prices in the Pinnacle West Energy Contract include:

- a Facilities Charge that includes a return of and on the fixed capital assets of the Dedicated Units and their associated operation and maintenance costs excluding fuel, as set forth in Attachment 1 to this Service Schedule;

- a Base Fuel Charge ("BFC") for fuel and related costs associated with the Dedicated Units Energy Products, as set forth in Attachment 2 to this Service Schedule;

- a Fuel and Purchased Power Adjustment ("FPPA") for variable costs, as set forth in Attachment 2 to this Service Schedule; and

- transmission, losses, and Ancillary Services costs to the Delivery Points as a pass-through charge to APS.

The Fuel and Purchased Power Adjustment can be positive or negative.

3.2.2 Pricing of Dedicated Units Energy Products.

3.2.2.1 Based on Section 3.2.1 above and Attachment 1 to this Service Schedule, the initial Facilities Charges for Dedicated Units Energy Products in the Pinnacle West Energy Contract shall be:

Year	Facilities Charge ($000/Month)	
2002	$ 35,440	(excludes Palo Verde)
2003	$ 63,600	
2004	$ 67,120	

3.2.2.2 For Contract Years following 2004, the Facilities Charge in the Pinnacle West Energy Contract shall be calculated as provided in Attachment 1 to this Service Schedule.

3.2.2.3 The Base Fuel Charge in the Pinnacle West Energy Contract shall be $0.0210 per kWh for 2002 and $0.0174 per kWh for 2003 and thereafter for the remaining term of this Agreement, as provided in Attachment 2 to this Service Schedule.

3.2.2.4 Beginning March 1, 2003, a Fuel and Purchased Power Adjustment to the Base Fuel Charge will be applied each month to the billing for Dedicated Units Energy Products. The Fuel and Purchased Power Adjustment in the Pinnacle West Energy Contract shall be calculated annually prior to March of each calendar year as provided in Attachment 2 to this Service Schedule.

3.2.2.5 For billing purposes, the Base Fuel Charge and the Fuel and Purchased Power Adjustment shall be applied to the Dedicated Units Billing Energy.

3.2.3 Minimum Availability of Dedicated Units.

3.2.3.1 Capacity. At a minimum, PWCC shall make Capacity from the Dedicated Units available as follows: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 3440 MW at system peak or actual load at system peak; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 4720 MW at system peak or actual load at system peak, subject to adjustment as Dedicated Units are retired.

3.2.3.2 Energy. At a minimum, PWCC shall have available Energy from the Dedicated Units in the amount of: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, 15,370 GWh annually; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, 21,090 GWh annually, subject to adjustment as Dedicated Units are retired.

3.2.4 Dedicated Contracts Energy Products. Dedicated Contracts Energy Products shall be priced at the actual cost incurred by PWCC under the provisions of those contracts, including transmission, losses, and Ancillary Services to the Delivery Point. In the event of a default on a Dedicated Contract, PWCC shall obtain Replacement Energy Products pursuant to Section 3.4 of this Service Schedule.

3.3 Supplemental Energy Products. If APS' Full Load Requirements exceeds the Energy Products provided under Sections 3.1 and 3.2, or if there are insufficient qualified bidders to supply the required level of Competitively-Bid Energy Products under Section 3.1 of this Service Schedule, then PWCC shall use commercially-reasonable efforts to obtain the additional energy requirements in the market. APS shall be responsible for any and all costs and expenses incurred in the acquisition of any Supplemental Energy Requirements supplied including PWCC's administrative expenses incurred for procurement.

3.4 Replacement Energy Products. In the event of non-performance by parties that are under contractual commitments as a result of APS' Supplemental Energy Requirements, PWCC shall use commercially-reasonable efforts to obtain Replacement Energy Products for the benefit of APS. PWCC shall also obtain Replacement Energy Products when requested under Section 8.1(B) of the Agreement. APS shall be responsible for any and all costs incurred for the acquisition of Replacement Energy Products including PWCC's administrative expenses incurred for procurement. In consultation with APS, PWCC shall pursue all commercially legal remedies for defaults under contracts entered into to

acquire Supplemental Energy Products. APS shall be responsible for all costs and fees associated with the pursuit of such remedies, and APS shall receive all monies awarded as a remedy.

Calculation of the Facilities Charge in the Pinnacle West Energy Contract

1. **Facilities Charge (FC).**
The FC for 2002-04 as specified in Section 3.2.2.1 of the Service Schedule was derived using the method below. Effective January 1, 2005 and every three years thereafter the FC shall include the reasonable costs of owning and operating the Dedicated Units as recalculated below:

$$\text{FC \$/Month} = \frac{[[(\text{ROR \%}) \times (\text{Net Dedicated Units Assets \$})] + (\text{Dedicated Units Operating Annual Expenses \$}) - \text{Annual Ancillary Service Revenues}^{1}]}{\text{12 Months}}$$

Where:

Rate of Return (ROR) is 9.12% which is the cost of capital assuming a 50/50 debt-equity capital structure, at a 7.5% cost of debt and a 11.25% return on equity.

Net Dedicated Units Assets[2] = Original Plant-in-Service Cost[3] – Accumulated Depreciation – Accumulated Deferred Income Taxes + Material & Supplies + Prepayments + Working Cash

Dedicated Units Operating Expenses[4] = Operation & Maintenance Expenses[5] + Administrative & General Expenses + Depreciation & Amortization Expenses[6] + Ad Valorem Taxes[7] +Income Tax Expense[8] + Other Taxes or Assessments[9] + Miscellaneous Deferred Credits

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[1] Includes revenues paid to PWCC by APS for ancillary services pursuant to the terms of a separate contract.
[2] Projected three year average of year end balances. Each component shall be defined pursuant to the FERC system of accounts or if no applicable FERC system of accounts exists, then on General Accepted Accounting Principles (GAAP). All A&G related expenses, not directly charged, shall be allocated on wages and salaries for the Dedicated Units as a percent of total Pinnacle West Energy wages and salaries.
[3] Original Plant-in-Service Costs will include all capitalized costs of the Dedicated Units plus improvements including common and intangible.
[4] Projected three year average. Each component shall be defined pursuant to the FERC system of accounts or if no applicable FERC system of accounts exists, then on General Accepted Accounting Principles (GAAP). All A&G related expenses, not directly charged, shall be allocated on wages and salaries for the Dedicated Units as a percent of total Pinnacle West Energy wages and salaries.
[5] Costs and expenses associated with the Dedicated Units excluding fuel and purchased power.
[6] Costs and expenses associated with the Dedicated Units, including related common facilities.
[7] Costs and expenses associated with the Dedicated Units, including related common facilities.
[8] Based on the statutory tax rate, both state and federal, for PWEC on stand alone basis.
[9] Taxes and assessments based on generation or gross revenue.

Calculation of the BFC and FPPA in the Pinnacle West Energy Contract

1. **Base Fuel Charge (BFC).**
The BFC shall be set at $0.021/kWh for the calendar year 2002, and at $0.0174 /kWh effective January 1, 2003 for the remainder of the Agreement, and is the Average Fuel Costs associated with the Dedicated Units (AFCDU) for 2002-2004.

Where:

AFCDU $/kWh = (Total fuels cost of Dedicated Units[1] $)/(Total generation of the Dedicated Units MWh)

2. **Fuel & Purchased Power Adjustment (FPPA).**
Beginning March 1, 2003 a FPPA to the BFC will be applicable each month to the billing for Dedicated Units Energy Products. The FPPA shall be calculated annually prior to March of each calendar year as follows:

$$\text{FPPA \$/kWh} = [(\text{Projected AFCDU}^2 - \text{BFC})\ \$/\text{kWh}] + \left[\frac{((\text{Actual AFCDU}^3 - (\text{BFC} + \text{FPPA}^4)\ \$/\text{kWh}) \times \text{Actual kWh}) - \text{Off-System Sales Margin \$}}{\text{Projected kWh}}\right]$$

Where:

"Actual kWh" is the actual Dedicated Units Energy Products purchased by APS on a kWh basis for the prior contract year.

"Projected kWh" is the kWh projected by APS pursuant to Section 2 of this Service Schedule, less the Energy Products acquired under Section 3.1, Section 3.2.4, Section 3.3, and Section 3.4 of this Service Schedule, for the period March 1 of the current Contract Year through the last day of February of the next Contract Year.

Off-System Sales Margin[5] = [(Off-System MWh X (Price[6] $/MWh –AFCDU[7] $/MWh)) - Other Costs[8]] X .25

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[1] Total fuels costs of Dedicated Units shall include all coal, gas including transportation, oil, nuclear fuel expenses, costs and benefits of fuel-related financial instruments, nuclear spent fuel costs, any applicable surcharges, purchased power costs associated with economic dispatch of the Dedicated Units, nuclear decommissioning expense to the extent it is not recovered from the System Benefits charge authorized by the Arizona Corporation Commission, and any other fuel related expenses, including but not limited to costs associated with emissions allowances.
[2] For current Contract Year.
[3] For prior Contract Year.
[4] For prior Contract Year.
[5] For prior Contract Year for Energy Products delivered and sold into the wholesale market for third-party purchases.
[6] The Price will be based upon the Dow Jones Palo Verde Daily On and Off-Peak Index as applicable to the specific sales. In the event this index ceases to exist or a more representative index is developed for Arizona or the southwest portion of the U.S.A. then the index will be replaced.
[7] For prior Contract Year.
[8] Includes transmission costs and losses, and Ancillary Services, if applicable, and other out-of-pocket costs associated with the sales.

1 BEFORE THE ARIZONA CORPORATION COMMISSION
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4)
SPECIAL OPEN MEETING)
5)
)
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7 At: Phoenix, Arizona
8 Date: April 25, 2002
9 Filed:
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15 REPORTER'S TRANSCRIPT OF PROCEEDINGS
16
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18
19
20 ARIZONA REPORTING SERVICE, INC.
Court Reporting
21 Suite Three
2627 North Third Street
22 Phoenix, Arizona 85004-1103
23 By: CAROLYN T. SULLIVAN, RPR
Prepared for: Certified Court Reporter
24 Certificate No. 50528
25

EXHIBIT
S-2
admitted

AGENDA

1. Panda Gila River, L.P.'s Request for Order to Show Cause (E-01345A-01-0822)

2. Motion of Arizona Public Service Company for Determination of Threshold Issue Concerning Retail Electric Competition

3. In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues

BE IT REMEMBERED that a Special Open Meeting was held at the Arizona Corporation Commission, 1200 West Washington Street, Phoenix, Arizona, commencing at 1:30 p.m., on April 25, 2002.

BEFORE: WILLIAM A. MUNDELL, Commissioner - Chairman
JIM IRVIN, Commissioner
MARC L. SPITZER, Commissioner

ALSO PRESENT:
ARIZONA PUBLIC SERVICE COMPANY
JACK DAVIS

ARIZONA CORPORATION COMMISSION
ERNEST JOHNSON

APPEARANCES:

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Electric Cooperative, and Duncan Valley Electric
7 Cooperative:
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For Arizona Community Action Association:
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CAROLYN T. SULLIVAN, RPR
24 CCR No. 50528
25

1 CHMN. MUNDELL: Let's go ahead and go on the
2 record. We have three matters on the Open Meeting
3 Agenda today.
4 — No. 1, the Panda Gila River, L.P., Request
5 for Order to Show Cause.
6 And we have the motion of APS for a
7 determination of the threshold issue.
8 And then lastly, we've put on the docket the
9 generic docket proceedings concerning electric
10 restructuring.
11 So we can discuss all three of those matters
12 and comply with the open meeting statute.
13 Why don't I go ahead and -- and I don't know
14 where to start. I'll start over here, and let's take
15 appearances. Since we have two motions before us,
16 it's a little different type of open meeting procedure
17 than we would ordinarily have. So I'll start with
18 Mr. Kempley. He looks excited to pull that mike over
19 and announce himself.
20 MR. KEMPLEY: Thank you, Mr. Chairman and
21 Commissioner Spitzer, Christopher Kempley and Janet
22 Wagner appearing on behalf of Commission Staff.
23 MR. FERLAND: Mr. Chairman, Commissioner
24 Spitzer, Roger Ferland of the law firm of Quarles &
25 Brady Streich Lang, appearing here on behalf of the

1 Harquahala Generating Company.
2 I want to introduce my client. We need to
3 have at least a token real person up here, Tom
4 Broderick.
5 MR. MEEK: Mr. Chairman, Commissioner
6 Spitzer, Walter Meek, president of the Arizona Utility
7 Investors Association.
8 MR. SULLIVAN: Mr. Chairman, Commissioner
9 Spitzer, Bill Sullivan, Martinez & Curtis, on behalf
10 of Reliant. Our real client is also here today, David
11 Greeson, vice president of business development, as
12 well as Aldie Warnick, vice president of regulatory
13 affairs.
14 MR. MUMAW: Thomas L. Mumaw, after more
15 punishment, from the law firm of Snell & Wilmer
16 representing APS.
17 And hopefully more than just a kind of real
18 person here with Mr. Jack E. Davis, president of APS.
19 COM. SPITZER: We'll be the judge of whether
20 it's punishment.
21 MR. SHAPIRO: Good afternoon, Chairman
22 Mundell, Commissioner Spitzer, Jay Shapiro from the
23 law firm of Fennemore Craig on behalf of Panda Gila
24 River, L.P. With me here today is my co-counsel,
25 Mr. Larry Eisenstat, sitting to the right of me from

1 Dickstein Shapiro.
2 Also with us today are several members of the
3 Panda Gila River team: Mr. Richard Lehfeldt,
4 Mr. David Crabtree, Mr. Bill Gehlen, and Mr. Pat
5 Burnett.
6 Thank you.
7 MR. ROBERTSON: Mr. Chairman, Commissioner
8 Spitzer, my name is Lawrence V. Robertson, Jr.,
9 appearing today on behalf of Sempra Energy Resources.
10 Seated to my right is my co-counsel, Theodore E.
11 Roberts.
12 And seated behind me I'd like to introduce
13 Leesa Nayudu, origination manager of energy supply
14 with Sempra. She came in from California.
15 I'd also like to enter the appearance of
16 myself on behalf of Southwestern Power Group.
17 Thank you.
18 MR. MOYES: Good afternoon, Chairman Mundell,
19 Commissioner Spitzer, Jay Moyes with the Moyes Storey
20 law firm here in Phoenix on behalf of the PPL
21 entities. I also have seated behind me my associate
22 Steve Wene.
23 And also we have a representative of PPL
24 today, Ms. Dana Diller, director of development for
25 PPL.

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1 MR. ROBERTSON: Mr. Chairman, Commissioner
2 Spitzer, also an oversight on my part, seated directly
3 behind me is Mr. David Getts, who's one of the
4 executives with Southwestern Power Group.
5 Thank you.
6 CHMN. MUNDELL: You don't want to forget who
7 your clients are.
8 MR. WAKEFIELD: Scott Wakefield on behalf of
9 the Residential Utility Consumer Office.
10 CHMN. MUNDELL: Mr. Wakefield, there's an
11 extra seat there. You can certainly pull up a chair.
12 We certainly want RUCO's input on this very important
13 matter facing the state of Arizona.
14 Is there anybody else that's not in the front
15 row here that is an intervenor in this matter that
16 needs to at least acknowledge for the record that
17 they're here?
18 I see Mr. LaSota is moseying up to the
19 microphone.
20 MR. LaSOTA: Thank you, Mr. Chairman. Jack
21 LaSota of Miller, LaSota & Peters. I'm counsel for
22 the Arizona Competitive Power Alliance.
23 MR. CURTIS: Mr. Chairman, Commissioner
24 Spitzer, Michael Curtis. And if Bill Sullivan doesn't
25 do an adequate job on behalf of Reliant, I'm here to

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1 help.
2 CHMN. MUNDELL: Commissioner Spitzer said
3 earlier on whether it's pleasure or not, we'll decide
4 whether or not he's done a good job.
5 MR. DUFFY: Mr. Chairman and Commissioner
6 Spitzer, Steve Duffy with the law firm of Ridge &
7 Isaacson on behalf of Duke Energy North America and
8 Duke Energy Arlington Valley.
9 MR. LYNCH: Mr. Chairman, Commissioner
10 Spitzer, Bob Lynch on behalf of the Arizona
11 Transmission Dependent Utility Group.
12 COM. SPITZER: And it must be an important
13 proceeding for Mr. Lynch to have a jacket.
14 CHMN. MUNDELL: He dressed up for today.
15 MR. GRANT: Mr. Chairman, Commissioner
16 Spitzer, Michael Grant on behalf of AEPCO, Duncan, and
17 Graham in the electric competition docket. We are not
18 participating in the variance request.
19 MR. MIRICH: Mr. Chairman, Commissioner
20 Spitzer, Gary Mirich on behalf of the Arizonans for
21 Electric Choice and Competition.
22 CHMN. MUNDELL: Thank you, sir.
23 MS. KANE: Good afternoon, Chairman and
24 Commissioners, Mary Ellen Kane on behalf of Arizona
25 Community Action Association.

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1 CHMN. MUNDELL: Thank you.
2 MR. HEYMAN: Good afternoon, Chairman,
3 Commissioner Spitzer, Ray Heyman from the law firm of
4 Roshka Heyman & DeWulf on behalf of Tucson Electric
5 Power Company, to the extent that we do -- matters
6 that are involved in the generic proceeding. We're
7 not intervenors in the APS proceeding.
8 Thank you.
9 CHMN. MUNDELL: Thank you.
10 Anyone else?
11 (No response.)
12 CHMN. MUNDELL: Commissioner Spitzer, do you
13 have some opening comments?
14 COM. SPITZER: Thank you, Mr. Chairman. And
15 to some degree, since I bear some responsibility for
16 assembling all the suits and the skirts today, I want
17 to make a few prefatory comments.
18 This is obviously a proceeding that is
19 difficult from a procedural context with three
20 different matters pending and probably more motions
21 and papers. And I actually tried to create a matrix
22 and was unable to do so. It's so complicated. And I
23 should point out, I've gotten some e-mails and faxes
24 this morning.
25 And for those counsel out of town, this is

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1 not myself. This is my cousin -- distant cousin
2 Elliott, who went to Harvard, which I did not, from
3 New York. He's the black sheep democrat of the
4 Spitzer family.
5 CHMN. MUNDELL: You went to Michigan, didn't
6 you?
7 COM. SPITZER: I did. We had a better
8 football team than Harvard, at least. I won't say
9 about the law school.
10 I think there are a few issues that are
11 commonalities that run through as a common thread in
12 this case, and I want to identify them. But before I
13 do that, we have this side of the utility business --
14 and I just spent three days at a conference on
15 telecommunications. And the Wall Street folks talk
16 about doom and gloom. It was beyond doom and gloom in
17 the telecom industry and just a chaotic environment
18 that has great peril for ratepayers and for consumers
19 attendant to federal statute in that case in 1996 and
20 then an unprecedented collapse of an industry. And it
21 was pointed out by a Wall Street bond analyst, you've
22 got investment grade bonds that are trading for 6
23 cents on the dollar. And that's created a situation
24 where the regulators and the citizens want enhanced
25 broadband capability for this essential industry, Wall

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1 Street demanding reductions in net expenditures and a
2 real crisis and, of course, fierce competition on top
3 of that between the incumbents and the competitors.
4 And in the electricity issue, although this
5 industry has had some unprecedented volatility as
6 well, largely we have a success story in this country
7 and with this industry. And, in addition, we've had
8 proceedings where there was I think a very,
9 Mr. Chairman, high degree of civility and the briefing
10 was first class by all the parties that intervened.
11 And you've had numerous instances in proceedings
12 before this Commission and at the FERC a great deal of
13 cooperation between the so-called merchant plants or
14 competitors and the incumbent companies. And that I
15 find appreciative, and the high level of work that's
16 gone into this is also appreciated by me.
17 A couple points I want to make to at least
18 show where I'm coming from, Mr. Chairman, and how I
19 would frame this issue. And it was highlighted to
20 some degree by the recent very helpful pleading filed
21 by Arizona Public Service Company.
22 Do we go back to rate of return regulation?
23 Do we cut our losses and put the genie back in the
24 bottle? And the company quite rightly wants to know
25 if that's the case. If that's going to be the law in

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1 Arizona, that ought to be decided as a threshold
2 matter. And it was helpful to me in formulating my
3 views of this.
4 Rate of return regulation was not a great
5 panacea to the ratepayers, I don't think it was good
6 for the companies, and it was not good for the
7 environment. And even if you disagree with my
8 analysis, the simple fact is that rate of return is
9 dead. The recent Supreme Court ruling on FERC Order
10 888 was the nail in the coffin. You cannot put the
11 genie back in the bottle. Rate of return regulation
12 is dead.
13 We are reaching a situation where electricity
14 at the wholesale level has been ordained by the
15 federal government and, in my view, also the
16 marketplace to be a commodity just like the interstate
17 trucking. And I think that's where we're headed.
18 Even if you wanted to put the genie back in the
19 bottle, in my view, you simply cannot because to do
20 so, to say Arizona would act as an island and sever
21 all ties with all other jurisdictions, would simply be
22 a violation of federal law.
23 Now, I know, Mr. Chairman, when I was in the
24 legislature dealing with air quality issues,
25 frequently people in my caucus would rail and rave and

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1 rant against the federal government, but the federal
2 law had clearly preempted in the area of air quality.
3 As Mr. Ferland knows, we may on occasion quarrel with
4 the implementation of a particular federal rule or
5 suggest that the federal government and EPA abused its
6 discretion or did not follow the statute. I think,
7 Mr. Ferland, you understand that the federal
8 government has preempted the area generally and the
9 states were not free to ignore the Clean Air Act nor
10 to ignore the federal government's regulatory
11 authority over that issue.
12 I don't think it is -- even if we were to
13 consider possible benefits, and, again, I don't think
14 there are possible benefits of this, I think it's in
15 the interest of the ratepayers and the state that
16 electricity become a commodity and that we have a
17 viable, effective, active wholesale market. To simply
18 raise our fists and scream at the federal government
19 doesn't -- it is not the law. It's not the law of the
20 United States. A unanimous Supreme Court so held.
21 Secondly, the federal government, through the
22 FERC, is moving forward in its efforts to deal with
23 the concept of market power. That is a concern. That
24 was a concern raised as part of the APS variance
25 request. It's a concern that has been raised by

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1 Staff. I think it's a legitimate concern. And it may
2 give the Commission some pause to reflect how
3 ultimately we enter into this competitive wholesale
4 environment and to make appropriate precautions to
5 protect the ratepayers of the state of Arizona.
6 Nevertheless, that is an area within federal
7 authority. And in some of the pleadings that I've
8 seen and some positions taken by some folks, including
9 the views of the Staff, that I've carefully
10 considered, I don't think that the state of Arizona
11 can go against this tide of interstate commerce
12 preemption of federal authority and assume that the
13 federal government will not do what the law says it
14 should do, federal statutes, federal regulations, and
15 the expressed intent of the United States Congress.
16 And I think it would be inappropriate for
17 this Commission to blithely assume that the market
18 power issue will not be handled adequately by the
19 federal government. This Commission has intervened in
20 a number of federal proceedings to ensure that the
21 state of Arizona is treated fairly, and I don't think
22 there's any reason for this Commission to assume that
23 it won't be ultimately, when the day is done, properly
24 dealt with.
25 Obviously I was intrigued by the concept of

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1 an RFP process. I don't have any opinion to express
2 on how that is conducted. I know Mr. Mumaw does not
3 want a free-for-all that disadvantages the ratepayers
4 of Arizona. And speaking for myself, neither do I,
5 and I'm sure my colleagues wouldn't want to do
6 anything to be concerned about that. We've gone on
7 and on and on about the California analogy, and I've
8 got research and statistics on a wide panoply of
9 issues relevant to the possibility of the wholesale
10 market emerging vigorously and vibrantly in Arizona,
11 and I don't think -- we all know those materials, and
12 I don't think they need to be in excruciating detail.
13 I do think, though, that the time has come
14 for the people of Arizona in terms of this Commission
15 to analyze the impact on the people of Arizona. In
16 terms of the environmental impacts of a wholesale
17 market, these are potential benefits for clean energy
18 that are not considered in rate of return regulation
19 that we today are free to consider. The issue of
20 price again is something that we are free to consider.
21 I'm mindful of the fact that when California went out
22 into the market, as the governor said, with a gun to
23 his head, that the conditions were highly adverse.
24 This environment is a much stronger one to bring some
25 benefits to the ratepayers.

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1 So we'll obviously hear the views of my
2 colleagues and the views around this table. But I
3 think -- and I have no time frame for the ultimate
4 disposition of an RFP process, if that's ultimately
5 what this Commission determines to approve. And I
6 think I'm willing to defer this until the safeguards
7 are appropriately put into place so that we have
8 questions of to the extent there's liaison work with
9 the federal government, to ensure that market power
10 does not exist and to ensure reliability concerns and
11 transmission concerns and congestion and transmission
12 pricing and those other issues.
13 I don't have a time frame for that other than
14 have the final result be in the best interest of the
15 people of Arizona. But I do feel this Commission has
16 sited power plants consistent with environmental
17 considerations that were necessary to create a
18 positive situation with respect to supply and demand.
19 This Commission has made the hard decisions on siting
20 transmission lines to ensure that this product that
21 may not have been at commodity status in the past is
22 now treated as a commodity. And the ultimate end of
23 that was not to cast hard votes that made a lot of
24 people angry. The purpose of that process of siting
25 the plants that were needed to create an electricity

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1 supply that was needed for the people and the siting
2 of the transmission lines that were needed to get the
3 power where the load pockets would be served was to
4 provide that where cheaper and cleaner energy was
5 available for the people of Arizona to be brought to
6 market, that would in fact be the case.
7 And I would like with all deliberation --
8 appropriate deliberation to see to it that the parties
9 collaboratively can work together to create a process
10 whereby the rules that were put in place in this
11 jurisdiction -- and maybe they weren't the rules that
12 I would have voted for. I wasn't around. But I do
13 think that in this system of government, we have an
14 obligation to see to it that the continuity of the
15 process goes forward. To not continually revisit the
16 rules. To not have delay after delay after delay
17 where Mr. Mumaw's client has the risk of being
18 disadvantaged to the degree that he's filed papers.
19 And all the other participants, including the consumer
20 groups, are entitled as well to some certitude. And
21 if the prices are low and it's possible to enter into
22 long-term bilateral contracts, which are no stranger
23 to this state under old rate of return regulation --
24 we've had bilateral contracts where you can lock in
25 prices advantageous to the ratepayer -- it's my

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1 recommendation that we go forward.
2 Three, there's a famous line from FDR: The
3 only thing we have to fear is fear itself. And there
4 is fear of the unknown, no question about it. And
5 there is a different sense of fear underlying the
6 current deliberations because of the situation in
7 California that did not exist when the settlements and
8 the rules were established by this Commission. But
9 simply the fact of fear is not an excuse or a
10 justification for this Commission to prevent the
11 ratepayers of Arizona from obtaining the benefits of
12 all the hard work that this Commission's done. And I
13 do think we ought to move forward on that basis,
14 Mr. Chairman.
15 Thank you.
16 CHMN. MUNDELL: Thank you, Commissioner.
17 Commissioner Irvin.
18 COM. IRVIN: Thank you, Mr. Chairman. I
19 apologize for being a few minutes late. I'll be very
20 short, as I'm anxious to hear the comments from the
21 parties.
22 Just a couple things that I will note. I was
23 here when the rules were drafted, and I was here when
24 the rules were changed. I voted against those
25 changes. I voted in favor of the rules overall

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1 because we're going to move to a restructured utility
2 market whether Arizona wants to or not. I think
3 that's a given. We all have to be prepared to accept
4 that. And it's a national trend. And it started in
5 California and New York, and now it's been stopped in
6 California, but it's clearly moving from the East and
7 will eventually evolve the West. And what California
8 does, who knows. And I'm not sure that at this
9 particular point in time we're interested. However,
10 we do have to keep an eye on them.
11 When I helped -- and I was one of the authors
12 of the original rules that are about 80 percent -- 90
13 percent were intact prior to the changes which I
14 opposed. I made a point of saying that these rules
15 are done based on assumptions. Assumptions that were
16 best guess based on the information we had, but yet we
17 were still moving in the blind. And from that day to
18 this very day, I have called on the Commission to say
19 that we need to continually look at these rules as we
20 get more information to make sure that what the rules
21 are are fair, are just, are truly in the public
22 interest, and first and foremost, they protect
23 consumers because we're the last line of defense for
24 those consumers. And there's got to be a benefit for
25 consumers. California, there was no benefit.

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1 Montana, there was no benefit. Other states, they've
2 seen some minor benefits that are being questioned.
3 I still believe there are many questions that
4 have to be answered before we can have a fully
5 competitive market in both the wholesale and retail.
6 But I still stand on statements that I have made in
7 the past, and I will reiterate them again today. They
8 are not new. We need to first and foremost develop a
9 wholesale market before we can move to retail
10 competition. I think that's a given. California's a
11 perfect example of what happens when you don't have a
12 wholesale market and when you have a complete
13 imbalance in the supply and demand curve.
14 California's a perfect example of what happens when
15 you have price caps in effect and the market rate is
16 highly above the rate of what the price caps are. We
17 get bankruptcies. We don't need that in Arizona.
18 The utilities here have pledged and have done
19 an excellent job in protecting and seeing that Arizona
20 consumers' lights come on when they flip those
21 switches. Last summer it was a little tight a couple
22 times, but we got through that. The utilities have
23 assured Arizona consumers that the lights will be on
24 this summer, the air conditioning will work barring
25 any major catastrophes or weather. And I have every

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1 reason to believe based on what I've seen that that
2 will come true.
3 The questions raised by APS I think are good
4 ones. Questions raised by Panda I think are good
5 ones. And we can't simply -- and I agree with
6 Commissioner Spitzer -- continue to put these things
7 off to infinitum and move no place. By the same
8 token, I believe a rush to judgment is equally a gun
9 to our head and bad. I believe that what the
10 Commission has to do is set up that wholesale market,
11 determine what is a distribution company going to look
12 like.
13 I spent last year working in Washington,
14 D.C., with not only my colleagues but industry
15 officials, which a white paper will be coming out next
16 month, middle of next month, on what we believe a
17 distribution company should look like. I'm very proud
18 of that work. It's going to try to cover every aspect
19 that we can do. There was a tremendous amount of
20 debate and differences on it, and we had input from
21 all sectors in the country and both stakeholders,
22 consumers, and regulatory interests on that. I think
23 it will be interesting. I believe one reason I wanted
24 to work on that paper is because I wanted for the
25 first time to have somebody put forth something that

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1 said: Here is a blueprint. Here is a copy. Here's a
2 plan. Here's an idea of what a transmission company
3 should look like. If we're going to allow companies
4 to create wholly owned unregulated generation
5 corporations and we're going to have regulated
6 companies that are going to be in the distribution
7 end, we need to know what those are going to look
8 like. We need to have an idea. I think this paper
9 will help give that.
10 The other thing that I have called upon --
11 and we still haven't got an answer and there's not
12 much we can do except continue to call. I know it's a
13 problem with my colleagues around the country -- is
14 what the hell is FERC going to do. Right now, the
15 Supreme Court, as Commissioner Spitzer has alluded,
16 has given them a tremendous amount of power. It makes
17 a tremendous difference in what this Commission does
18 with regards to what FERC's jurisdiction is going to
19 be. Are they going to take complete full jurisdiction
20 of all the wires right down to the delivery to one's
21 home and be basically regulating distribution. Or are
22 they going to back out, which I believe they should,
23 and allow states to regulate distribution and let them
24 take the traditional role of the interstate commerce
25 facility. Those are questions we don't have answers

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1 to until FERC gives us some idea.
2 We don't have the formation of an RTO.
3 Whether we like it or not, an RTO is going to happen.
4 I think that's another given. We have to look at and
5 work with the constraints that -- with the
6 transmission that we have and with the constraints
7 that the FERC has put out on their game plan. They're
8 getting better giving us a game plan now. We've seen
9 some successes.
10 We still have the issue of if we go, have we
11 answered the question in our rules. I don't believe
12 they did. Provider of last resort. That rule -- that
13 question has not been answered in my opinion
14 adequately.
15 We have not answered the question of how do
16 we assure that we don't get what we have in telecom,
17 underserved or unserved areas in power. Another
18 critical question that needs to be answered and goes
19 along the lines of provider of last resort.
20 We haven't answered the questions of
21 demand-side management, of indigence, of other things.
22 We've brushed on these topics, but we haven't talked
23 about them.
24 We haven't talked about the case of what
25 happens if a California scenario comes up, what do we

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1 do. The worst thing we can do would be react like
2 California and overregulate. Equally bad, do we sit
3 back and do nothing.
4 I think, you know, APS has got a legitimate
5 concern. 2003 is approaching us. I've asked that the
6 Commission -- because I don't believe it was
7 adequately discussed in those first hearings whether
8 divestiture is in the public interest. I think the
9 Commission needs to make a finding. The rules have
10 called that the company can do that if they choose to
11 do that. But the Commission never said it was in the
12 best interest of the state. If it's not, what do we
13 do. If it is, let's move forward. Let's get the show
14 on the road because without the economic -- or without
15 power, the economic viability and the quality of life
16 of this state is at risk. Economic recovery is at
17 risk, I believe.
18 And, therefore, I think it's time. We've got
19 -- Commissioner Spitzer is right on. These are not
20 easy choices. These are tough decisions. But then
21 again, that's why the Commission Staff gets paid all
22 those big bucks, to try to work with us and resolve
23 those issues along with the stakeholders and what is
24 truly the best interest of the state of Arizona.
25 So I still believe there's a lot of work to

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1 do. The answer might be to put temporary -- move this
2 thing back and buy more time for us. The answer might
3 be a stay. The answer might be to proceed. It will
4 be interesting, and that's what we're starting here
5 today. But by hearing these comments today, we are
6 not -- these answers aren't going to come overnight.
7 I agree wholeheartedly with Commissioner
8 Spitzer. Whether I support the rules or don't support
9 the rules is immaterial. To go back and redo the
10 rules is absolutely stupid. And I don't think anybody
11 on the Commission is calling for that, but a review of
12 the rules, a quick review to make sure what we have
13 done. Those rules that are good, let's leave them in
14 place. Those rules that are not, let's make some
15 changes. And let's proceed in the interest of Arizona
16 so that we can assure an adequate market and
17 ultimately someday get to retail competition.
18 It's not going to happen because the rules
19 say. Perfect example is the Telecommunications Act of
20 1996. It called for competition in
21 telecommunications. Year 2000, we don't have it. We
22 have some elements of it. We don't have it.
23 We have to ensure consumer benefits on this
24 thing. We have to ensure the viability. Our
25 Constitution requires that we ensure the viability of

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1 those regulated entities and such.
2 So I look forward to the discussions that are
3 here. There's a tremendous amount of work going on
4 back in Washington. There's work going on here. We
5 know on Capitol Hill -- we don't know what Congress is
6 going to do. I think we all have an idea and a
7 thought what they're going to do with regard to this
8 issue. And my thought is and my prayer and hope is
9 they do nothing. That would be probably in the best
10 interest of the United States as a whole, but that
11 probably won't happen, either.
12 So I do look forward to these comments and
13 the remarks, and I just ask that all parties -- all
14 parties keep in mind that the responsibility of this
15 Commission is to protect the interests of Arizona
16 consumers, not the interests of shareholders of
17 various corporations, although I will acknowledge that
18 the shareholders are also consumers, so those
19 interests from that standpoint must be protected.
20 Thank you, Mr. Chairman.
21 CHMN. MUNDELL: Thank you, Commissioner
22 Irvin. I appreciate your comments.
23 One of the reasons why I started this process
24 -- and Commissioner Spitzer talked about how the
25 process got started. I wrote a letter back on

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1 December 4th, 2001, to my colleagues suggesting that
2 we needed to at least look at what we had done in the
3 past. And I, in fact, as I said in that letter, voted
4 for the rules and for the settlements. But I thought
5 that as a --from a public policy perspective and not
6 putting our head in the sand perspective that we
7 needed to at least look at what we had done, why we
8 did it, whether things had changed as a result of the
9 California experience or what's going on on the
10 federal level at FERC or whether the Supreme Court
11 case that Commissioner Spitzer alluded to makes us
12 have any pause for reflection. And as I said in that
13 letter, I indicated that we ought to at least look to
14 see if we needed to make any minor adjustments or
15 major policy shifts.
16 And I appreciate Commissioner Spitzer's
17 responsive letter of the next day saying that he
18 thought it was important, along with Commissioner
19 Irvin, that we ought to look at these things to make
20 sure what we did was correct. We can debate whether
21 or not we can put the genie back in the bottle or not,
22 but if we assume that we can't and there's some
23 disagreement as I understand from legal scholars on
24 the impact of the Supreme Court case on whether or not
25 if you rebundle or not, if you go back to the

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1 old-fashioned rate of return regulation.
2 But in any event, assuming that we can't put
3 the genie back in the bottle, we ought to at least
4 make sure that that genie doesn't fly freely and roam
5 freely without any oversight. So from my perspective,
6 we need to go slow and take into consideration what is
7 happening on the federal level at FERC, and there are
8 five or six items that I will mention later that I
9 think gives me pause for reflection, and my colleagues
10 have alluded to those.
11 And I disagree a little bit, I think we do
12 have a little bit more to fear than fear itself. That
13 doesn't mean that we're so frightful or fearful that
14 we do not act in a positive manner to protect the
15 ratepayers of Arizona, but I do think that we need to
16 make sure that whatever we do, we're not just falling
17 on the Holy Grail of deregulation for the sake of
18 deregulation if in fact that is not the appropriate
19 path to follow in order to protect the people of
20 Arizona.
21 And I don't necessarily think it's an
22 all-or-nothing proposition. If you look at what's
23 happening throughout the Western states -- and when it
24 comes time for the parties to address it, I asked this
25 question last time we were here. I said, explain to

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1 me why -- if every state around us has either put
2 deregulation on hold or back pedaled on deregulation,
3 what will be the impact on the people of Arizona if we
4 proceed forward and do nothing and just go forward
5 with the way the rules and the settlements have been
6 enacted? And so I'd like some discussion on that.
7 But I do believe that we need to be very
8 careful how we proceed because we obviously have the
9 people of Arizona to be concerned about. We have the
10 investors of the different companies that have come to
11 Arizona based on our prior rulemaking.
12 So I look forward to the discussion by the
13 different parties. All the briefings I think were
14 helpful in making sure that whatever decision we make,
15 it is the correct decision for Arizona. And so I
16 think at least from my perspective, and I'll look to
17 my colleagues, it seems to me that the motion by APS
18 asking us to make a determination on the threshold
19 issue needs to be decided first because everything
20 else really at least flows from that decision.
21 If we decide that we want to go full speed
22 ahead or half speed ahead but we want to continue on
23 the path towards the deregulated market in Arizona,
24 then so be it. If we decide we want to delay or stay
25 the application of the rules, that's an alternative.

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1 But I think from my perspective, that determination
2 needs to be made before we get to the Panda Request
3 for an Order to Show Cause and before we move into the
4 generic proceeding docket. And I have some thoughts
5 on that at the appropriate time.
6 But unless I hear differently from my
7 colleagues, it seems to me we ought to have a
8 discussion on: Do we move forward with no changes.
9 Do we suggest that we have the rules looked at in the
10 generic docket to make sure that what we've done is
11 correct based on change of circumstances throughout
12 the Western United States and take into consideration
13 what FERC is doing. Or do we do nothing and say, this
14 was a great intellectual exercise, everything is fine.
15 The rules the way they are are perfect. But based on
16 what I'm hearing from my colleagues, we at least ought
17 to look at whether what we've done is in the best
18 interest of the people of Arizona.
19 Any thoughts on that? I've suggested that we
20 go to Item No. 2 and discuss that and --
21 COM. IRVIN: You want to discuss APS' motion
22 or Panda's OSC?
23 CHMN. MUNDELL: I just said that. I thought
24 that the threshold issue, No. 2, we need to decide
25 that because everything else I think flows from that.

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1 Again, if we decide to continue on the path that we're
2 on, that will lead us one direction. If we decide
3 that we want to pause, that will lead us in another
4 direction or if we want to totally go back to where
5 things were prior to the settlements and the rules.
6 COM. SPITZER: Mr. Chairman, I think APS has
7 quite correctly stated that the Commission, if you
8 want to go back to cost-based regulation in return for
9 monopoly service territory, let us know. And I think
10 that's appropriate. And I will say that you have to
11 start someplace. And I think that's an appropriate
12 place to start.
13 The only caveat -- and I think we ought to go
14 forward. The other issues on the table are to some
15 degree modifications or ameliorations of those. And
16 if you are to decide for one reason or another that we
17 ought to have a divestiture -- and I know Staff has
18 concerns about the divestiture that I don't share
19 again because I feel that there are avenues of redress
20 with respect to market power under existing federal
21 law.
22 But, again, I think you're right. You've got
23 to start someplace, so let's start there.
24 COM. IRVIN: Let's start at the beginning.
25 CHMN. MUNDELL: Mr. Mumaw, it's your motion,

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1 so I'll let you start the discussion.
2 MR. MUMAW: Thank you, Mr. Chairman, Members
3 of the Commission. Hopefully the bruises aren't
4 showing too much from the beating we took yesterday.
5 I also hope that the type of hotly contested
6 discovery dispute that we have between buyers and
7 sellers --
8 COM. IRVIN: Mr. Mumaw, you weren't here
9 yesterday, were you?
10 MR. MUMAW: I was here.
11 We have between buyers and sellers and
12 competitors. And I think Judge Farmer correctly noted
13 that apparently part of the growing pains that we have
14 in a restructured industry doesn't obscure the fact
15 that I think there are common threads between the
16 merchant generators and APS. I think we all support
17 the development of a robust competitive wholesale
18 market and the infrastructure improvements that are
19 necessary to support that type of market.
20 We do disagree largely on where we are in
21 that process and who should bear the risk if we don't
22 get there or, perhaps more precise, don't get there as
23 quickly as we anticipated. That's why we requested a
24 variance last October, and that's what we hope to be
25 able to prove to you the beginning of next week.

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1 The motion that APS filed last Friday was a
2 simpler and less ambitious document. It was simply
3 asking this Commission to determine whether it intends
4 to go forward in implementing the 1999 settlement
5 agreement and the framework of the Electric
6 Competition Rules that have been in place for at least
7 the last four years, or is the Commission signaling a
8 retreat from both that settlement and the rules to the
9 status quo.
10 If it's the former, this doesn't require a
11 formal order of the Commission or a round of hearings
12 or a series of workshops or frankly even more
13 jabbering from us attorneys. It's a mere indication
14 from the bench that we are going to stay the course I
15 think would be sufficient.
16 If it's the latter, if the Commission does
17 not wish to proceed in accordance with the settlement
18 or the framework of the Electric Competition Rules as
19 they currently exist, just say so, and the parties
20 will work through the various repercussions of that
21 decision.
22 Now, APS is aware that some have alleged that
23 APS requested a retreat from the settlement and the
24 Electric Competition Rules by merely filing for a
25 variance. We respectfully disagree, and we believe

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1 the Commission will disagree after it's heard all the
2 evidence. But if I'm wrong and we fail to convince
3 you, deny the variance.
4 APS has said all along, and it reiterated in
5 our motion filed on Friday, that the company will
6 proceed with a competitive bid for at least 50 percent
7 of its 2003 retail load on September 1st unless it is
8 for some reason no longer required to do so or the
9 Commission alters that requirement as a result of this
10 proceeding.
11 On its own, APS has operated for the past two
12 and a half years on the assumption that we were going
13 to move forward as agreed. We've seen or heard
14 nothing from the Commission stating otherwise nor did
15 it anticipate anything other than following the course
16 begun in 1999.
17 CHMN. MUNDELL: Mr. Mumaw, I did write a
18 letter on December 4th that I alluded to that
19 suggested that we may want to at least think about
20 what we did. So I don't know what you mean by heard
21 nothing from the Commission.
22 MR. MUMAW: Nothing from the Commission as a
23 body, Mr. Chairman.
24 Again, we agree with Commissioner Spitzer
25 that the siting decisions we've seen from the

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1 Commission are consistent with the paradigm of moving
2 forward towards a vibrant and hopefully competitive
3 wholesale market.
4 COM. SPITZER: And, Mr. Mumaw, the Chairman's
5 letter of December to which I believe I responded as
6 well as Commissioner Irvin, there was nothing in there
7 to suggest that this Commission had any fear of the
8 consequences to the ratepayers from a transfer of
9 assets where the jurisdiction would be under FERC as
10 opposed to this Commission.
11 MR. MUMAW: I think there's some -- and the
12 letter -- they certainly wish to discuss the issue.
13 As the replies have indicated to the Staff Report and
14 to other documents in this case, that's not a new
15 issue. It's an issue that the Commission was aware of
16 back in 1998 when it first made the requirement for a
17 divestiture. The FERC's jurisdiction over wholesale
18 rates has been exclusive since the 1930s. So it was
19 clear that the Commission wanted to look at that
20 issue, but we didn't look at it as a new issue.
21 Certainly it was an issue that existed at the time of
22 the settlement, and we didn't interpret that as being
23 any prejudgment on whether we should or should not go
24 forward with the settlement.
25 When Staff came out with their

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1 recommendations in the generic docket and in their
2 testimony in the variance docket, it created
3 tremendous uncertainty. Uncertainty in the financial
4 community, uncertainty amongst the company management
5 and employees as to whether we were going to continue
6 along the course that we began in 1999. And it's that
7 uncertainty that the company attempted to address in
8 its motion of last Friday.
9 Now, with the Chair's indulgence, I would
10 like to have Jack Davis speak on this issue of
11 uncertainty. Mr. Davis is fresh from the trenches of
12 Chicago and New York and can probably give you more
13 pointed and better observations on the impact of the
14 uncertainty than I can.
15 When Mr. Davis is finished, I would like to
16 say a few words about the Staff and Panda counter
17 motions requesting a stay of the variance proceeding.
18 CHMN. MUNDELL: Before we get to Mr. Davis,
19 let me ask you a question, Mr. Mumaw. You made it
20 sound like it's an all-or-nothing proposition. And I
21 think one of my colleagues indicated that -- and I
22 think I indicated in my opening remarks that there are
23 options in between the other two, you know, go back to
24 the old days or go full speed ahead. And I guess my
25 question is: Representing your client, do you see any

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1 middle ground there where we either stay or delay the
2 divestiture and to see what happens at FERC and to see
3 what happens with the follow-up case to the New York
4 case that the Supreme Court decided? You made it
5 sound like it's all or nothing and one way or another
6 and no in-between.
7 And at least from my perspective, I'd like to
8 go as slow as we can go because once -- to use the
9 analogy that Commissioner Spitzer used, once we get
10 the genie out of the bottle, at least as I understand
11 his perspective, there's no going back. And mine is a
12 little different that I'd like, as I said, if the
13 genie gets out of the bottle and can't be put back in,
14 we ought to have some oversight to make sure the
15 people in Arizona are protected. And I'm not saying
16 that I don't agree with that, also.
17 But is there some in-between that your
18 company would think would be reasonable? And then
19 when I hear your answer, I've got a couple follow-up
20 questions.
21 MR. MUMAW: There's probably always some
22 in-between that could be reasonable to the company and
23 frankly to the other people in this room. What we
24 don't think there's an in-between on, there's no
25 in-between on whether we follow the terms of the 1999

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1 settlement and we don't think there's an in-between as
2 to whether we resolve this uncertainty.
3 Again, as hopefully Mr. Davis can tell you,
4 this uncertainty as to what direction we're going and
5 where we intend to end up is severely impacting the
6 company at the present time, and it will only grow if
7 it looks like that uncertainty is going to stretch for
8 another year or year and a half.
9 COM. IRVIN: Mr. Mumaw, Mr. Chairman, if I
10 could, currently, we're also at somewhat of a loss.
11 As you are aware, the courts have ruled the
12 deregulation rules are illegal as they currently
13 stand. They're on appeal. They're on appeal to the
14 Arizona Supreme Court. Now, they could rule a lot of
15 different ways. They could rule that the settlement
16 agreement is a legal document that the Commission
17 entered into and it's in full force and effect but the
18 rules are invalidated because the Commission didn't
19 follow procedures or whatever.
20 And I went back -- I think it was Judge
21 Campbell. I went back to Judge Campbell's decision.
22 It was before these two colleagues got on board. And
23 he said, we ought to address and correct those
24 problems before now. Now, we haven't done that.
25 The settlement agreement is totally and

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1 completely predicated on the rules. If the rules are
2 deemed illegal, then how can the settlement agreement
3 hold up?
4 MR. MUMAW: First of all, the company
5 certainly has always taken the position that the
6 settlement and the rules are independent of each
7 other. And, in fact, that's why we were somewhat
8 insistent that the settlement contain a specific
9 provision addressing divestiture of our assets to an
10 affiliate or affiliates. We were certainly aware that
11 the litigation was pending against the rules. In
12 fact, as Commissioner Irvin remembers, we were part of
13 that litigation at that time.
14 COM. IRVIN: You and a host of other people.
15 MR. MUMAW: And frankly, with all due respect
16 to the Commission's legal counsel, we were fairly
17 confident that the parties opposing the rules would be
18 successful on at least the Attorney General
19 certification issue, although that's an easily
20 correctable deficiency in the rules. We believe, and,
21 of course, we've indicated as much in numerous filings
22 with the SEC and so forth, that the settlement
23 represents an independent and separate basis of the
24 company's assets. So it would be nice to have the
25 rules litigation behind us one way or another. I

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1 don't think it impacts on what we believe is a
2 threshold decision that we would urge the Commission
3 to make.
4 COM. IRVIN: Mr. Mumaw, does the settlement
5 agreement -- and I don't have it in front of me. Does
6 it not on numerous occasions refer to the rules on
7 numerous occasions throughout the settlement agreement
8 as the rules are contemplated?
9 MR. MUMAW: Yes, it refers to the rules in
10 several different contexts. Sometimes it refers to
11 the rules and specifically incorporates in its
12 definition of rules any amendments or variances
13 granted to those rules in the future, which I think
14 would encompass certainly any changes that would be
15 required by the Court to the Electric Competition
16 Rules. As I think we've learned by the final
17 resolution of U S WEST 2 at the Supreme Court, that
18 the Commission can fashion competition rules that are,
19 at least in the Court's opinion, consistent with our
20 competition. So I don't deny that that litigation may
21 require changes to the Electric Competition Rules --
22 COM. SPITZER: Mr. Mumaw, you said fashion
23 rules consistent with the -- did you mean to say
24 Constitution?
25 MR. MUMAW: Constitution of Arizona, yes. In

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1 other words, the fair value requirement is not
2 necessarily inconsistent with the idea of moving
3 forward to competition. We'll see whether that as a
4 practical matter can work, but at least our Supreme
5 Court believes that they can.
6 COM. SPITZER: And, Mr. Mumaw, you're
7 basically here trying -- make it as simple for my
8 little mind as we can. The rules say -- excuse me.
9 The settlement stipulates that APS is to transfer
10 generation assets --
11 MR. MUMAW: On or before December 31st.
12 COM. SPITZER: You have the discretion. It
13 can go to a third party. You've proposed an
14 affiliated entity.
15 MR. MUMAW: The rules would give us -- the
16 rules would give us the option of divesting to either
17 a third party or an affiliate. I believe the
18 authority granted to the Commission in the settlement
19 is restricted to an affiliate or affiliates. And, in
20 fact, I think it specifies that the affiliate has to
21 be a subsidiary of Pinnacle West rather than a
22 subsidiary of Arizona Public Service Company.
23 COM. IRVIN: I believe that's a correct
24 interpretation.
25 COM. SPITZER: So it's a subsidiary of

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1 Pinnacle West and, therefore, brother/sister of the
2 wire company?
3 MR. MUMAW: That's correct.
4 COM. SPITZER: And your concern is the Staff
5 has a fear of those assets leaving the regulated
6 entity?
7 MR. MUMAW: Well, Staff certainly has raised
8 some concern about that. But I guess in our mind,
9 they haven't raised any concerns which didn't exist in
10 1999. From the moment the Commission opposed the
11 divestiture -- and, again, as we've tried to remind in
12 the motion, it was not a company proposal. It was
13 originally a Staff proposal. From the moment that
14 proposal surfaced, I have to presume that the
15 Commission was advised by legal counsel that once that
16 transfer was made, the Commission would lose
17 ratemaking jurisdiction over any subsequent wholesale
18 transactions in those facilities, whether they be with
19 APS or Salt River or whoever. Although I understand
20 Staff's concern, it's not a new concern and one that
21 we have frankly tried to address, perhaps
22 unsuccessfully, but have tried to address through the
23 proposed buy back agreement, the PPA.
24 COM. SPITZER: And you've got the variance
25 that you feel deals with that issue, and Panda's filed

1 a motion that they feel deals with that issue. And to
2 some degree, if we're in a situation such as
3 California where demand significantly -- the curve for
4 demand rachets up and the supply curve does not match
5 and, therefore, you have an increase in the price,
6 that would be disadvantageous to consumers. But based
7 on the evidence from Mr. Hieronymus that I've seen so
8 far in the variance issue and based on the evidence
9 submitted by Panda, it's your feeling that that
10 concern -- let me get off the word fear -- the concern
11 that the ratepayers of Arizona would somehow be harmed
12 by virtue of that transfer you feel is unfounded?
13 MR. MUMAW: In large part, we agree,
14 Commissioner Spitzer. We proposed the PPA as a safety
15 net for standard offer customers. If the Commission
16 doesn't believe that safety net is necessary, again,
17 like I said, deny the variance, and we will proceed to
18 competitively bid as required by Rule 1606(B). We
19 have no fear of that.
20 COM. SPITZER: But assume for sake of
21 argument we have to adopt today the framework of an
22 RFP. And assume that the RFP model -- under the RFP
23 model, your PPA were the winning bid. We'd be in the
24 same place, would we not?
25 MR. MUMAW: As we've hopefully tried to make

1 clear but apparently not successfully, the PPA would
2 not be our bid under such a structure. Pinnacle West
3 would probably submit a bid, but it certainly would
4 not be the PPA.
5 COM. SPITZER: Fair enough.
6 CHMN. MUNDELL: Who do you represent here
7 today?
8 MR. MUMAW: Arizona Public Service Company.
9 That somewhat encompasses its sister companies. As
10 you're probably aware, APS requires their attorneys to
11 take an entity representation. So if you represent
12 one Pinnacle West entity, you are deemed to represent
13 all of them.
14 CHMN. MUNDELL: Mr. Mumaw, let me ask you
15 this question. And not only does the Staff have a
16 concern -- let's not use the word fear -- but this
17 Commissioner has at least some questions and concern
18 about the transfer of the assets. Having watched what
19 happened in California with having the holding
20 companies and the different entities and having, you
21 know, the UDC and having the transfer the funds from
22 the holding company to the distribution company, is it
23 your position and your company's position that the way
24 the rules are drafted that we in Arizona don't have to
25 worry about that same thing occurring where you have,

1 you know, the holding company up here out of the
2 regulation of the public utility as in California with
3 the California PUC -- let me just be blunt about it.
4 That's my concern. You spin off the assets, they go
5 to Pinn West, and we no longer have jurisdiction to
6 regulate that entity. And is it your position that we
7 don't have to worry about the same thing happening in
8 Arizona that happened in California when that Public
9 Utility Commission lost their ability to regulate the
10 holding company?
11 MR. MUMAW: Mr. Chairman, let me address
12 that. And I was very careful in my remarks to
13 Commissioner Spitzer to talk about rate regulation
14 over wholesale transactions. As much as Pinnacle West
15 or Pinnacle West Energy may like to characterize
16 themselves as unregulated, they are far from
17 unregulated. The Commission has passed an extensive
18 series of Affiliated Interest Rules, including some
19 kind of generic ones that give the Commission
20 certainly carte blanche to investigate books. The
21 Commission has in the past imposed dividend
22 restrictions on APS. The Commission has imposed
23 various restrictions on the transfer of cash and
24 non-cash assets between affiliates.
25 Now, I realize we have received some waivers

1 on some of those provisions, but I will tell you the
2 company has always believed that those waivers could
3 be withdrawn by the Commission if there were ever an
4 instance where the company abused it.
5 CHMN. MUNDELL: Let me ask you this question,
6 Mr. Mumaw, just so I'm clear about what you're saying:
7 You believe that under the current rules, we have the
8 ability to carte blanche, to use your terminology,
9 look at the books of Pinnacle West and Pinnacle West
10 Capital Corp?
11 MR. MUMAW: It specifically states in Rule
12 804(A) that as a condition for doing business with
13 APS -- and it's fair to say that Pinnacle West Energy
14 and Pinnacle West Capital do business with APS -- as a
15 condition for doing business with APS, and that's one
16 of the rules we haven't received a waiver from, the
17 other parties have to provide -- the other party,
18 meaning in the case Pinnacle West Capital or Pinnacle
19 West Energy -- would have to provide the Commission
20 access to their books and records for any Commission
21 investigation or any Commission proceeding or -- I
22 won't say for idle curiosity, but I assume it has to
23 be related to your role.
24 CHMN. MUNDELL: Well, you said, carte
25 blanche.

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1 COM. SPITZER: This Commission would always
2 behave reasonably.
3 MR. MUMAW: The AZT decision, it's not really
4 clear whether the Commission does have to have a
5 reason. But clearly under Rule 804(A), it allows full
6 access as regards certainly any transactions with APS
7 and so forth. And as I said, outside of the affiliate
8 rules, the Commission has from time to time imposed
9 specific limitations. And I've raised the dividend
10 limitation because that would specifically address the
11 type of situation that occurred in California. Again,
12 I'm not saying that what PG&E did was in any way
13 unlawful, but I'm saying that that sort of restriction
14 was aimed at precisely that concern which the
15 Commission had at one time. Ours was a bank and not a
16 power crisis, but the same type of concern. I think
17 that dividend limitation has been lifted because I
18 think this Commission has come to believe that APS is
19 not going to abuse -- or Pinnacle West is not going to
20 abuse its position with APS to bleed the company.
21 COM. SPITZER: And Pinnacle West, of course,
22 has other holdings other than electricity or energy
23 holdings. There's a real estate entity within the
24 corporate umbrella as well, and that's the case
25 notwithstanding this transfer.

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1 And another -- I want to just spend a moment
2 on another side of the coin here to show that this --
3 although this is a significant issue, and I appreciate
4 you raising it, there are limits to how concerned we
5 ought to be over this issue.
6 Under the status quo, prior to divestiture,
7 energy was being sold within the corporate structure
8 to California, was it not?
9 MR. MUMAW: That's absolutely true.
10 COM. SPITZER: And this Commission, under
11 predivestiture rules, had no authority to regulate the
12 price at which that electricity was sold, did they
13 not?
14 MR. MUMAW: They did not have that authority.
15 In fact, if you recall, the Federal Power Act was put
16 in place to fill a gap in state authority. In fact,
17 the states have never had that authority.
18 COM. SPITZER: It's the hypothetical New
19 England in the '30s.
20 MR. MUMAW: The Attenborough Gap.
21 COM. SPITZER: Referenced in the Supreme
22 Court decision. And then the tribunal where I assume
23 for the sake of argument the California purchaser
24 would be aggrieved with respect to a wholesale
25 transaction from APS into California, it has always

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1 had -- always was the law, is the law, and post
2 divestiture would be the law that it would be the FERC
3 that would adjudicate an allegation of market power.
4 MR. MUMAW: That is absolutely correct. And
5 as the Commission is probably aware, states can and do
6 interject themselves into that process on one side or
7 the other, either in favor of a domestic buyer or in
8 favor of a domestic seller.
9 COM. SPITZER: And I guess Mr. Davis will
10 speak to -- I guess there were financial aspects to
11 this uncertainty attendant to this uncertainty that he
12 wants to discuss, but I want to make it clear that --
13 and you certainly have a reasonable right to request
14 certainty and this Commission obviously has the duty
15 to consider that, but preeminent is the -- is how --
16 and I think although we may disagree on how we
17 approach this issue, all three of us are interested in
18 the well-being of the ratepayers. The divestiture
19 issue is not the be-all and end-all and is simply one
20 facet of federal wholesale regulation that's gone back
21 60 years.
22 MR. MUMAW: That's true. It's one facet, but
23 it's certainly an extremely important facet to the
24 company. As we've tried to indicate, we've spent an
25 awful lot of money to get to this point, and we will

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1 be spending an awful lot more in the next couple of
2 months. And if that apparently is not in the cards,
3 we'd just as soon know that before we spend the money
4 rather than after we spend the money.
5 COM. IRVIN: I don't blame you, but I also
6 recall that in the settlement agreement any money you
7 spend on divestiture you're allowed to collect from
8 ratepayers.
9 MR. MUMAW: Only two-thirds. Again, that was
10 one of the bits of our scalp that we had to give up.
11 COM. IRVIN: We won't go into that. I
12 objected to that.
13 Let me ask a couple of questions. And
14 correct me -- I don't have the rules in front of me.
15 It seems to me that we have codes of conduct that the
16 companies were allowed to direct or develop along with
17 the ASIA, but Affiliated Transaction Rules were
18 deleted from the rules.
19 MR. MUMAW: The specific Affiliated
20 Transaction Rules dealing with electric affiliates,
21 the Commission still has its general affiliate rules
22 in place, the 800 series, 801, et cetera, that have
23 been in place. And I think we argued, apparently
24 successfully, that those rules, along with the
25 individual orders that the Commission has from time to

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1 time imposed to handle specific situations, like APS'
2 dividend limitation, et cetera, were sufficient and
3 that we didn't need to have that level of detail.
4 COM. IRVIN: As I recall, because we had --
5 originally in the '98 rules, there were some more
6 Affiliated Transaction Rules were put in, and then
7 they were subsequently removed in '99. And the reason
8 for that and the reason I voted against that removal
9 is one of the lessons that was learned from
10 California. And that was the stranded cost lesson
11 that myself and many of my colleagues -- fortunately
12 we didn't do it here. Everybody knows my position on
13 stranded costs.
14 But one of the problems with stranded costs,
15 especially as we saw in California, is that the
16 utilities in California received literally billions
17 and billions of dollars from California ratepayers,
18 and there was absolutely no requirement that those
19 utilities reinvest those monies into quote-unquote
20 stranded costs, that they were therefore -- and, in
21 fact, those companies invested those into
22 quote-unquote foreign. Hence, we have a major company
23 building a power plant here in Arizona with some of
24 that stranded cost money. We've seen companies from
25 the East look at buying assets in Arizona using

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1 stranded cost money.
2 And I know I've talked to many of my
3 colleagues, and they say on the next round, should
4 they ever get to this, they will definitely put in a
5 requirement that will require any monies received on
6 quote-unquote stranded cost must be reinvested into
7 the state and for the benefit of ratepayers, unlike
8 they had in California.
9 Now, we do not have a stranded cost provision
10 for any of the affected utilities under these rules
11 should they be deemed legal. And certainly APS and
12 the other companies that are affected by these rules
13 would in fact be allowed to take their $1 billion and
14 make quote-unquote investments wherever they choose.
15 Now, I don't know where those investments will be,
16 whether they will be reinvesting here in the state of
17 Arizona, taking out some of the old power plants that
18 are obsolete or maybe old coal-fired diesel burning
19 plants that are inefficient and put in some modern
20 plants or if they're going to buy assets in other
21 states. I don't know where they're going to go, and I
22 don't know that our rules restrict that money. And
23 that is a concern of mine. And, again, that has to
24 look -- I don't know where that issue plays in. I'm
25 not so much on the issue whether the company's

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1 entitled to stranded costs or not -- I don't want to
2 redebate that. To me, that's not a critical point in
3 the argument that we face today that. It may be
4 something that will come up in the future.
5 But I still have a concern with the rules
6 with regards to the codes of conduct and the
7 Affiliated Transaction Rules. And should we allow
8 this divestiture, do we have enough safeguards in
9 place to protect against cross-subsidization to
10 protect the consumers. It's an age-old question, and
11 I don't know that we've adequately answered that
12 question. I know we have -- I know what you're
13 referring to, and I know we have the codes of conduct.
14 I mean, everybody knows my view on the ASIA. If we
15 blew it up yesterday, it wouldn't have been too soon.
16 But regardless, I mean, I've still got those concerns.
17 MR. MUMAW: I understand that issue. I'm
18 sure you'll recall when we submitted our policies and
19 procedures to implement the code of conduct approved
20 by the Commission, those policies and procedures do
21 have extensive discussion on intercompany accounting
22 policies and intercompany transferring policies and
23 the like, many of which frankly were borrowed from the
24 portions of the rule that weren't adopted. And as I
25 think I've indicated, the Commission has in the past,

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1 when there are specific issues that they're concerned,
2 tailored orders to individual utilities. I can recall
3 at the height of the MeraBank unpleasantness, the
4 Commission --
5 COM. SPITZER: I thought you were going to
6 say fiasco.
7 CHMN. MUNDELL: That sounds like the story of
8 your life, Mr. Mumaw. Unpleasant yesterday,
9 unpleasant today.
10 MR. MUMAW: Unfortunately, I was on this side
11 of the unpleasantness.
12 COM. SPITZER: Usually that's a reference to
13 a divorce.
14 MR. MUMAW: I was part of the clean-up crew
15 on that mess.
16 I remember a specific Commission order that
17 detailed precisely what types of transfers APS could
18 make to Pinnacle West. And it addressed precisely --
19 again, in a different context, precisely the concerns
20 that I think regulators felt that there was in
21 California.
22 CHMN. MUNDELL: Mr. Mumaw, let me ask you
23 this question. It sort of goes back to my opening
24 remarks and my December 4th letter where I talked
25 about whether we make major adjustments to the rule or

1 major policy shift. And obviously the question on the
2 threshold issue is major policy.
3 But some of these other issues -- and
4 Commissioner Irvin brought up a good point, and I had
5 it to ask, also: Is it your position that we don't
6 need to look at the code of conduct, we don't need to
7 look at the Affiliated Interest Rules again -- because
8 we've seen what's the experience in California, we
9 know what happened with El Paso Natural Gas and their
10 holding company and FERC's investigation on that. It
11 would seem to me, again, that -- and that's why I put
12 in my letter that we need to look at these things.
13 I'm not hearing what your position is on doing that.
14 And, again, that's why I put in my letter, major
15 changes -- minor's all in the eyes of the beholder, I
16 guess, like beauty. But in order to protect the
17 consumers of Arizona, do we need to revisit those
18 things?
19 And also, and I know this is going to rub you
20 and your company the wrong way and your client, but as
21 I recall, when we put in there on who could do what in
22 each company, we put it at a certain level of, you
23 know, president, vice president, et cetera. And then
24 what's happened is folks have been promoted, and now
25 there's all this interrelationship. That's why I

1 facetiously asked you, who do you represent today.
2 And then there's some testimony that we'll get to
3 about it's really hard to see what hat we're wearing
4 when we're discussing what issue. So I think there's
5 a lot of things we need to do, and I hope my
6 colleagues will agree with me that the rules are not
7 etched in stone. And as I said at the start, I'm not
8 willing to fall on the Holy Grail of deregulation for
9 deregulation's sake. I think we need to really think
10 about what we're doing.
11 COM. SPITZER: Mr. Chairman, if I may -- and
12 Mr. Mumaw doesn't need me to come to his defense, but
13 I would point out, however, that a number of the
14 parties here, the intervenors, the so-called
15 merchants, are, in fact, affiliates of regulated
16 entities where this exact transaction has taken place.
17 And there are no objections to the status of APS or
18 this proposal to create the affiliate raised to my
19 knowledge by any of the intervenors. And they're the
20 ones who have capital that's in the ground spent at
21 risk in the transaction.
22 Similarly, in other -- I understand you've
23 got a California situation and there were lots of --
24 there are lots of issues with respect to resources
25 that might have fled the state for one reason or

1 another attendant to those transactions, but there
2 have been many examples of jurisdictions mostly in the
3 eastern part of the United States where we've had the
4 spin-off transactions. And, again, for virtually
5 every one of the merchants here, this is a regulated
6 entity that is a wire company in a home jurisdiction.
7 And the regulators in some of those jurisdictions
8 where the ratepayers have gotten the benefits of
9 competition in terms of economic benefits and the
10 state has received environmental benefits,
11 particularly in New England, where acid rain is a huge
12 issue with some of the coal-fired plants versus the
13 new natural gas-fired plants, none of those
14 circumstances has as an issue been raised with respect
15 to No. 1, any impropriety, and No. 2, any disadvantage
16 to competition or the ratepayers.
17 CHMN. MUNDELL: Just to follow up on that, I
18 used the example of Mr. Mumaw's client because that's
19 the one I'm most familiar with. Having said that,
20 though, if we're talking about Affiliated Interest
21 Rules or code of conduct, those are going to be
22 generic in nature, so they would apply not just to
23 Mr. Mumaw's client.
24 And additionally, this Commission -- I mean,
25 I've heard us on numerous times say here at the bench,

1 just because a party hasn't raised an issue or they
2 haven't thought of an issue, we've thought of it
3 ourselves and thought it was appropriate to talk about
4 and discuss. So I would just say that it's something
5 to talk about. Maybe they don't need to be changed.
6 I'd like to hear from the other parties on
7 this matter, whether it's Staff or RUCO or anyone
8 else, to hear their thoughts on it. I don't claim to
9 have the answer. All I'm doing is try to ask
10 questions as I did in my letter to see what their
11 thoughts are.
12 Again, Mr. Mumaw, I wasn't just picking on --
13 it was generic in nature because that's what rules are
14 by their very nature, is that they would apply to
15 other folks, also.
16 MR. MUMAW: We're not certainly suggesting
17 any change in the affiliate rules and the code of
18 conduct section in this proceeding. That's not to say
19 that they couldn't be examined or couldn't be changed
20 by the Commission. As I'm sure the Chairman recalls,
21 at one time APS fought mightily to have the code of
22 conduct provisions in the rules apply to entities
23 whose regulated utility was in another jurisdiction.
24 We lost that battle.
25 CHMN. MUNDELL: That's another good example.

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1 MR. MUMAW: Well, and I'm not planning to
2 start it again now. When we did the affiliate rules,
3 we made a similar suggestion. We also suggested that
4 to the extent that Salt River has affiliates that at
5 least the legislature ought to address that issue if
6 not this Commission. We pretty much lost some of
7 those fights, too, and I'm not planning on picking
8 another one of those today.
9 So I'm not saying the company's never
10 suggested that there ought to be changes in either the
11 code of conduct section or the affiliates rules. We
12 don't see that that is one of the threshold issues,
13 but if this Commission is -- doesn't believe that the
14 current rules are either extensive in scope or aren't
15 in sufficient detail or need to apply to more than the
16 transactions that are listed within the rule, that's
17 certainly the prerogative of this Commission to open
18 up a new rulemaking on either the code of conduct
19 rule, which I believe is 1616 -- I may stand corrected
20 on that -- and the generic Affiliated Interest Rules,
21 the 800 series to which I previously referred.
22 But I don't believe that those are threshold
23 issues that affect either the settlement or the basic
24 framework of the Electric Competition Rules, as I'm
25 sure -- the Chairman and Commissioner Irvin were here.

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1 We opposed the more detailed provisions of the code of
2 conduct rule not because we substantively disagreed
3 with a lot of them. We just thought it was too
4 inflexible to put those in the rules and preferred to
5 have those in the policies and procedures that could
6 be changed a little bit more flexibly than having to
7 go through the Administrative Procedure Act every time
8 we wanted to fine tune a policy or procedure.
9 And I think --
10 COM. IRVIN: And on that note, I would concur
11 with you because I think Mr. Davis even testified as
12 to the flexibility of those at that time.
13 MR. MUMAW: And to date, I think it's
14 actually worked pretty well. But obviously, if the
15 Commission disagrees with us and thinks that the
16 policy and procedures haven't worked well or haven't
17 been sufficient or aren't in enough detail or don't
18 cover enough transactions under the order that
19 approved those, they're kind of automatically
20 revisited every year if either the company or for that
21 matter anybody else wants to propose a change to them.
22 I don't think anybody has, but, I mean, they have --
23 that opportunity rolls up at least for APS every July.
24 CHMN. MUNDELL: Mr. Mumaw, we were going to
25 let Mr. Davis speak, then.

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1 We need a break. The court reporter needs a
2 break, so let's take five minutes.
3 (Recess taken.)
4 CHMN. MUNDELL: Let's go ahead and go back on
5 the record. I think when we left off, we were going
6 to have Mr. Davis at the microphone.
7 MR. DAVIS: Chairman Mundell, Commissioner
8 Irvin, Commissioner Spitzer, I'll be very brief
9 because I know time is of the essence.
10 I did just get back last night from meetings
11 from the rating agencies and the analysts in both
12 Boston and New York. And, of course, ever since 1999,
13 we have been telling those analysts and rating
14 agencies based upon our settlement that we were moving
15 our generation assets in accordance with the rules and
16 the settlement into an unregulated affiliate. And
17 we've been financing that unregulated affiliate based
18 upon that assumption.
19 Essentially, what we've done at the
20 affiliate, Pinnacle West Energy, is we have structured
21 the financings into two- and three-year blocks so that
22 when the assets are moved, we can go to the long-term
23 financing. And, in fact, the financing is done at the
24 holding company, not within Pinnacle West Energy.
25 There is a certain amount of anxiety in the financial

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1 markets over that arrangement since the assets of
2 which we were borrowing money for do not sit with
3 who's borrowing money, and that causes them a lot of
4 concern.
5 We built those assets to serve APS' load, but
6 because the rules do not allow a distribution company
7 to own generation other than the generation through
8 the Environmental Portfolio Standard, we had to build
9 them within Pinnacle West Energy. We made the filing
10 last October in recognition of several factors, one of
11 which was the financing aspect of it.
12 But No. 2, Chairman Mundell, I think it also
13 answers your question, we, too, were concerned about
14 what happens if you just go wide open to the market.
15 But we also believe that we should live up to the
16 competition rules and we should live up to our
17 settlement. So our variance and the corresponding PPA
18 is quite simply a way to have the best of both worlds.
19 And quite frankly, that's the way we see that.
20 For instance, you as Commissioners will have
21 lots of say in that contract; unlike the contracts
22 that we will be signing with the other parties in this
23 room over time, you will not have a say. We're giving
24 you a say today. Going back to Commissioner Spitzer's
25 and Commissioner Irvin's comments, the contracts that

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we'll be signing with other parties, be they either through RFP or short-term buying arrangements, will all be under the jurisdiction of FERC. In fact, in the year 2008, our proposal says that about 25 percent of APS' load at that time will be under RFP. But I have a great deal of certainty that a significant -- more of that will be under other kinds of arrangements, not just an RFP.

So what is happening irrespective of our request for variance or our PPA is that over time -- and I think there's one thing we all agree here is that over time, we should be moving toward a competitive brass ring. That over time, in terms of the jurisdiction of this Commission, we'll lose jurisdiction over those wholesale agreements.

COM. SPITZER: Mr. Davis, you've got a long history of successful bilateral contracts by your company as well as other incumbents in Arizona, and, of course, they were done under the rubric of pass-through under the rate of return regulation. But they were entered into for the same reason that the wire company of the future will be entering into hypothetical either RFP or bilateral, which is to best protect the ratepayers. That is a constant between the old machine and the new, is it not?

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MR. DAVIS: That would be a constant. In fact, I would expect that when Arizona Public Service would come before this Commission in order to look at how to pass those contracts through to our customers, the wire customers, I'm sure there will be a lot of discussions on prudence and how you did that and those kind of things. I fully expect that to happen.

COM. SPITZER: And in the hypothetical future, whether it would be a variance as you requested or an RFP which Panda requested, which may ultimately result in an agreement among affiliates for a large percentage, again, use of long-term bilateral contracts to hedge against volatility is a factor that attained under the old regime or the new regime.

MR. DAVIS: That's correct.

COM. SPITZER: And in areas where we've had forms of deregulation, gas, for example -- and I don't want to get into the El Paso thing. The Chairman doesn't want to hear any more about it, I'm sure, but it was long-term contracts. And in this case, it was a long-term contract created by a FERC docket in '96 led APS and the other companies within a deregulated environment to enter into long-term contracts to protect the interests of the people of Arizona. So the format of bilateral agreements to protect

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ratepayers to lock in advantages from a competitive environment is something that existed under the old rate of return regime and you would continue to expect under a new regime under any formulation that we would adopt.

MR. DAVIS: Yes, I would agree. Even our own request for a variance fits into the model of a bilateral agreement. And, in fact, a combination going forward would -- the Arizona Public Service would only have bilateral arrangements. And the bilateral arrangements would be half of it would be non-RFP, half would be RFP. My point was over time, even though our proposal has almost 25 percent by 2008 being RFP, it will be a lot more than that on the capacity basis. It will probably not be more than that on the energy basis.

And just the last comment I want to make is we filed our motion last Friday because we find ourselves in a position of it looked as though there wasn't a course set to answer the threshold issues. And we find ourselves in the financial situation that we've got to have something known. We need to put the assets where the borrowings are, and you can't continue to borrow money for Pinnacle West Energy with no assets sitting there. So we have to do something

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else with those assets.

Quite frankly, if this Commission's choice is to -- as we stated in our motion, to deny the variance, the sooner we know and I'm sure the sooner these parties know, the better off we'll all be, and we'll move forward. We do not intend not to follow the rules of this Commission, and we'll move forward with a 50 percent request for proposal and move forward with the divestiture of our assets into Pinnacle West Energy. So the long and short of it is the sooner we can get an answer to that question, the better off we'll be.

We believe our hearing that begins on Monday will provide significant information and data that can be used by this Commission in order to answer those threshold issues. You're going to be talking about transmission issues within that hearing, you're going to be talking about market power issues in that hearing, you're going to be talking about pricing issues in that hearing. All those issues and the information you need to make your decision will be discussed in that issue.

I tell you, if you said no today, I would have a nice weekend. I'm not looking forward to a nice weekend. I'm looking forward to sitting there

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1 next week -- looking forward is a little -- I will be
2 sitting there next week, helping you get the data and
3 information to answer those questions. So that's a
4 great avenue to get answers that you need to make your
5 decision.
6 COM. IRVIN: Would you please put his last
7 comment in bold, please, looking forward to sitting in
8 this seat.
9 Mr. Davis, if I could, Mr. Chairman, a couple
10 of things that you -- and I'll just point them out,
11 and I haven't made a determination. I know with the
12 white paper that I came up with, one of the comments
13 that you mentioned is you stated that you want to move
14 your generation out because a generation company
15 cannot own wires I believe under our rules.
16 MR. DAVIS: A wire company can't own any
17 generation other than the generation that's put in
18 place in accordance with the Environmental Portfolio
19 Standard.
20 CHMN. MUNDELL: Run that by me again.
21 MR. DAVIS: I believe 1615 of the competition
22 rules will not allow the wire company to own
23 competitive assets. And competitive assets under the
24 rules happens to be generation.
25 COM. IRVIN: Wait a minute. That's not

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1 entirely true because I remember the debate which
2 wasn't answered was what about must-run units or
3 peaking units. And it wasn't determined. And, in
4 fact, it was the interpretation, I believe, by APS
5 that in fact they could own must-run units or peaking
6 units in order to meet peak demand, which would then
7 give them generation.
8 MR. DAVIS: Commissioner Irvin, there were
9 probably arguments along those lines at the time, but
10 the way the rules ended up and the way the settlement
11 agreement ended up was we would divest ourselves of
12 our generation assets in accordance with 1615 of the
13 rules where we're ordered as a wire company not to own
14 generation and move it to Pinnacle West Energy. In
15 terms of the must-run issue, that is an issue that we
16 need to be concerned about since today, as we sit here
17 today, there is not a market structure under which the
18 market will function in the first place. What we have
19 today is we're moving toward strictly a bilateral
20 market under which that market will perform under APS'
21 open access transmission tariff.
22 COM. IRVIN: And I don't disagree with you,
23 and I was -- in my opening remarks mentioned that we
24 need to answer that. And, again, the question isn't
25 answered whether a wires company can, should be

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1 allowed to own that generation. And that is still
2 open. Your interpretation is that it is -- or your
3 intention is that you would put all your generation
4 into a wholly owned affiliate of Pinn West.
5 MR. DAVIS: That is our intention, and that
6 is explicit in the rules itself.
7 I would maintain, though, that the wire
8 company has to have rights to certain kinds of
9 generation just to maintain voltage on the system.
10 COM. IRVIN: Repeat that.
11 MR. DAVIS: A wire company has to have rights
12 to generation in certain areas just to maintain
13 voltage on the system.
14 COM. IRVIN: And then it comes back to should
15 they own generation in order to maintain that voltage.
16 And those are key, critical questions that we must
17 develop.
18 Could you ask -- or answer real quick and one
19 of the things that I -- it causes me some problems
20 is -- and we'll get into it, and I suppose maybe --
21 well, I'll ask it, and I can defer it to next week, if
22 you wish. The viability of APS' request on 15-year or
23 30-year PPA agreement.
24 MR. DAVIS: Okay. First of all, there has
25 been some confusion on our agreement. I think I've

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1 answered in my rebuttal testimony. It is a 13-year
2 agreement. There was some confusion whether or not
3 APS could unilaterally go forward with the agreement.
4 And in my rebuttal testimony, I agreed that this -- we
5 should come before this Commission and get approval
6 from this Commission before that first option is
7 exercised. So from that view, it's a 13-year
8 agreement without this Commission's review of that.
9 COM. IRVIN: It's a 13-year agreement.
10 Let me ask this question: You and I have had
11 this conversation more than once, and I still don't
12 have the answers. We still need to develop in my
13 opinion -- and I trust you're still in agreement -- we
14 need to develop a wholesale market if we're going to
15 create the competition that we're talking about. Is
16 that a fair statement?
17 MR. DAVIS: Yes. In fact, that's one of the
18 reasons we filed our variance in October.
19 COM. IRVIN: And I understand that.
20 I have a problem in that which we haven't had
21 debate and argument on, and I think it's ripe, is the
22 RFP the best method to go. I don't know. In New
23 Jersey, they had a very successful bid -- auction, bid
24 process. The question is, long-term versus
25 short-term. The question is how much. Let's make an

1 assumption that the 50 percent rule stays in effect.
2 And 50 percent of your load is now going to go out to
3 some sort of competition. Is it best that maybe 20
4 percent of that goes to an auction, 20 percent of that
5 50 percent power goes to an RFP, 20 percent goes to a
6 long-term load and balances just open market and fill
7 it in. I don't know.
8 These are -- in setting up wholesale markets,
9 I would hate to see us at this juncture of the game
10 lock into just one method, saying or presuming that
11 the RFP is the most effective for IPPs to get into the
12 market. Maybe it is today, but if it is, what avenues
13 of recourse do we have down the road to look at other
14 methods to do that. And maybe I'm getting ahead of
15 myself and premature. But, again, the goal is to
16 develop the wholesale market in the best manner that
17 is going to provide incentive and benefit to the
18 consumer. Otherwise, I see absolutely no reason to
19 proceed, and I would say we go back to standard offer.
20 Having -- fully understanding my opening remarks as
21 saying that something of this nature is going to come
22 down the road.
23 And the RTO also opens up the possibility,
24 assuming that ever gets formed, that not only the
25 power companies that are building in Arizona, the

1 independent power producers in Arizona, and knowing
2 full well that APS will also have some independent
3 power products, some you're building now, you'll be
4 able to bid in theory most anywhere in the Western
5 United States and presumably anywhere in the United
6 States to provide load.
7 Again, is that RFP the best way or is there
8 some other means of doing that? And that question
9 hasn't been answered yet, and I don't know if the
10 industry has the best answer.
11 MR. DAVIS: I would agree with you, the issue
12 of how an RFP should be performed has not been
13 addressed in great detail, and there are several ways
14 to do it.
15 In conjunction with the RFP itself, you also
16 need to address the issue of transmission. And I
17 think each of you -- as I've stated to each of you
18 individually and collectively, in my mind that is one
19 of the bigger issues that is not being addressed by
20 the industry. And quite frankly, as a man who spent
21 30 years of his life in the transmission side of the
22 business and operating and building and designing
23 transmission, I am embarrassed to tell you I don't
24 have an answer to that question.
25 COM. IRVIN: I don't, either, so I'm glad to

1 hear you don't have one, either.
2 MR. DAVIS: That's a difficult question. I
3 get asked that when I go back to New York and Boston.
4 On behalf of my brethren here, we have thousands of
5 megawatts being built in Arizona and we have one 500kV
6 line that someone has committed to build. We have
7 other things on the drawing board, but no one has
8 committed to build it, though we have approval from
9 this body, which will probably be appealed to the
10 court, I imagine.
11 COM. IRVIN: Tell them to get in line.
12 MR. DAVIS: And to actually put some wire in
13 there. And that concerns me more than anything. We
14 do not have the envisioned open market I think that at
15 least I envisioned in 1999. I'm not sure what the
16 Commission or the Commission Staff's vision was, but
17 we as a company certainly envisioned something that's
18 more liquid and open and viable and structured than
19 exists today.
20 CHMN. MUNDELL: Mr. Davis, let me ask you a
21 question, then, I asked your attorney earlier: If
22 that's the case, then wouldn't it make some sense to
23 slow down until we have a viable wholesale market?
24 MR. DAVIS: Chairman Mundell, that is the
25 essence of our variance request, the very essence of

1 our variance request.
2 CHMN. MUNDELL: I guess we're talking like
3 two ships in the night. You're saying that's the
4 essence of your variance request, and I'm looking at
5 divestiture, also. And let me ask the question: Can
6 we have a -- I know what the rules say. Because I
7 know Mr. Mumaw will come back and say, the rule says
8 this. And I'm saying, forget about what the rule says
9 if we're talking about what we should do going forward
10 because we can always change the rule. Can we have an
11 RFP or bid process without divestiture?
12 MR. DAVIS: I'm going to answer that question
13 directly, yes.
14 COM. SPITZER: Because he's not a lawyer. A
15 direct answer to the question.
16 MR. DAVIS: Let me qualify that question.
17 I've been in the business for 30 years. All aspects
18 of the business. Run power plants, transmission
19 systems, the whole match. What you just described is
20 what I call an incremental market. And the reason I
21 say that is the market has functioned quite readily
22 for 20 years on an incremental market. That being the
23 assets that were built to serve load or are dedicated
24 to the load first and foremost, and then what's left
25 is dedicated to the market. That's the incremental

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1 market. That is not a robust -- that is not a robust -
2 wholesale market. That's not one where people can be
3 assured there will be supply there because most of
4 that is short-term in nature, non-firm in nature in
5 many cases. But you can do that.
6 But you've got to realize that what you've
7 got to do first, you have a set of assets that are
8 actually dedicated to the load, the assets built for
9 the load, and then we have the incremental market.
10 We've had that for years. In fact, I actually helped
11 design the first experiment of that in 1982.
12 COM. IRVIN: Was it a good one? Don't answer
13 that.
14 MR. DAVIS: If good means it proved
15 something, it was a bad one.
16 COM. SPITZER: Mr. Chairman, Mr. Davis, I've
17 got a follow-up on the Chairman's question trying to
18 establish the degree to which we can ascertain whether
19 the wholesale market is sufficiently robust to yield
20 benefits to Arizona ratepayers from the decisions made
21 by the private interests as well as by this
22 Commission.
23 If there were to be a -- and it doesn't have
24 to be an RFP. I'm not wedded to that. I like
25 Commissioner Irvin's comments that there are many,

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1 many ways to have contractual relationships. You have
2 auctions, you have bilateral, you have request for
3 proposal. Many ways in which that could be done. But
4 if such a scheme were to be created to the
5 satisfaction of from the wire company's perspective
6 one that would yield adequacy and reliability, that
7 would provide -- and the process were undertaken,
8 again, whether it be RFP, auction, whatever, that
9 would provide the demonstration case, would it not?
10 MR. DAVIS: It would be in the wire company's
11 best interest to have the best designed RFP bilateral
12 process, bid, or auction as long as it had the
13 following characteristics:
14 First of all, you are already constrained by
15 what you have in front of you. I've got five
16 injection points where you can inject massive amounts
17 of power. You can have an auction all you want, but
18 you have to inject that power into these points --
19 COM. SPITZER: You could design a process to
20 deal with that, can't you?
21 MR. DAVIS: Yes, you can. The problem is
22 going to become when you design that process, some
23 ugly things are going to raise their head. Certain
24 assets at certain injection points may possess a
25 certain amount of market power.

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1 COM. SPITZER: That would be demonstrated,
2 though, would it not, by the process? And granted, to
3 remedy the market power -- and I think this is the
4 Staff's problem. We can undertake this process and
5 it's ultimately determined that market power exists,
6 the remedy to the existence of the market power lies
7 outside of this Commission. That's -- I think when
8 you really analyze it, that's the Staff's concern.
9 But we don't -- where we sit, we don't know whether
10 that is --
11 MR. DAVIS: We never built the transmission
12 system to support an open and liquid wholesale market.
13 They found out in California big time on Path 15. Big
14 time. And so when you tried to go an open and liquid
15 market like everybody envisions and layer it on the
16 transmission system that we have today, you're going
17 to find pockets of problems. Problems will pop up we
18 don't even know about. But, also, we'll find some
19 nuggets. I'm not saying you won't find some good
20 nuggets somewhere.
21 That's why we're suggesting, as we did in our
22 proposal, since we all have the same vision apparently
23 of going to a competitive market -- I haven't heard
24 anyone here today or in all the paper I've read over
25 the last week that says that that's not our vision.

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1 All we're talking about is how much, how fast. And to
2 make sure -- the same thing I said back in 1998 and
3 '99 is to make sure we don't have any unintended
4 consequences. And by that, I mean unintended
5 consequences for my company or unintended consequences
6 for my customer.
7 COM. SPITZER: Thank you.
8 COM. IRVIN: One other question as long as
9 I've got you. And, again, if it's going to be
10 answered, and you certainly can reserve the right to
11 answer it. Under your variance request, you're asking
12 for a 95 percent for 13 years. Have I got that
13 correct?
14 MR. DAVIS: No. It would be approximately 75
15 percent in 13 years. And actually should be less than
16 that.
17 COM. IRVIN: 75 percent. Then strike that.
18 I was on to something else.
19 MR. DAVIS: And I'd put that in terms of
20 capacity, by the way.
21 COM. IRVIN: Thank you, Mr. Davis.
22 CHMN. MUNDELL: Briefly, Mr. Mumaw, so we can
23 get to somebody else.
24 MR. MUMAW: Very briefly.
25 CHMN. MUNDELL: Let me just ask you a

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1 question: Is it your position that we should go
2 forward with the variance hearing on Monday as opposed
3 to doing something else that has been suggested by --
4 some of the other parties have suggested we stay that
5 and go to a bidding -- I'm trying to cut to the quick
6 here. We can talk intellectually about all this stuff
7 from now till the cows come home, but I just want to
8 make sure we understand what your position is.
9 MR. MUMAW: Our position is we should go
10 forward Monday as planned. We think -- and we agree
11 with Staff response that a hearing could produce
12 information that would be helpful to the Commission in
13 resolving some of these threshold issues.
14 I did want to note for Commissioner Irvin if
15 he wanted to look it up in one of the 1998 orders, I
16 think there were three of them on the Electric
17 Competition Rules, and I frankly can't remember which
18 one, but one of those rules, there's a discussion of
19 whether the Commission's use of the term "competitive
20 generation" meant to imply that there was some form of
21 generation that was non-competitive, essentially
22 must-run.
23 And I believe the Commission resolved it by
24 saying, no, that meant to include all generation. And
25 the Commission then put a provision in the rules

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1 requiring that the UDC obtain the rights that
2 Mr. Davis referred to prior to divesting any of its
3 generation. In other words, they had to make sure
4 they accounted for the must-run situation before they
5 divested. And I think as we noted in our original
6 filing, APS, in fact, has done so. There's a separate
7 agreement dealing with must-run in the ancillary
8 services.
9 COM. SPITZER: Mr. Mumaw, I understand the
10 precaution is appropriate, but are you -- has this
11 Commission ever entered an order compelling the
12 operation of a plant, or was that something that the
13 industry did to maintain load and maintain service?
14 MR. MUMAW: Did the Commission ever enter an
15 order compelling the operation of a plant?
16 COM. SPITZER: I'm not saying the precaution
17 of the rule. I'm just suggesting -- we have enough
18 hard issues to face. Let's not go chasing squirrels.
19 MR. MUMAW: I don't recall there ever being
20 such an order, and I don't think there's been
21 suggestion that there needed to be such an order. I
22 would say that we think the Staff response raises
23 essentially the same threshold issue as the company.
24 They've given a different name to it, but we think
25 it's essentially the same issue. And we agree, as

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1 I've said, with Staff that we think the hearing could
2 produce some useful information.
3 We were kind of surprised that they wanted to
4 go ahead and stay the hearing. We think that Panda's
5 response and through a counter motion again suggests
6 that the Commission needs to address the threshold
7 issue. Their threshold issue is called bid procedure
8 and bidding procedures. I do think that there is a
9 proposal that we had suggested and that if the
10 Commission is believing that the threshold issue that
11 we've identified is not the threshold issue or is only
12 one of several threshold issues or there may be
13 threshold issues that they currently aren't aware of,
14 that they could set up a process by which parties
15 could essentially file a response indicating if they
16 had other issues that they believed had to be
17 addressed -- I think the date in Staff's is August 1st
18 -- and propose a procedure for resolving those issues
19 by August 1st. And then if the Commission wishes to,
20 they could schedule a subsequent open meeting to
21 address all those issues.
22 We think that we have kind of put our finger
23 on what we believe is the problem, and we believe
24 Staff has the same issue with a different name. And
25 whether it's at this open meeting or a subsequent open

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1 meeting, we certainly encourage, as Mr. Davis
2 indicated, that we have a resolution of that threshold
3 issue as quickly as possible.
4 COM. IRVIN: Mr. Mumaw, thank you. I
5 remember the conversation. I don't remember how it
6 resolved, but I will tell you this. In the white
7 paper that I worked on, I did concur with the majority
8 that the UDC or the DISCO should not own any
9 generation. Let's not go there.
10 MR. MUMAW: It's one of those orders. I just
11 can't remember which one.
12 COM. IRVIN: Anyway, we debated it, and I'm
13 not sure we solved it.
14 In the white paper I worked on, I concur that
15 the UDC or the DISCO should not own generation.
16 Thank you, Mr. Chairman.
17 CHMN. MUNDELL: And I appreciate that,
18 because I looked at the definition, and I didn't see
19 where it said it couldn't own generation. And then I
20 wanted maybe some help from Staff.
21 COM. IRVIN: I don't believe we ever made an
22 actual determination on it, but it was implied that
23 the UDC would not own generation. And I think --
24 CHMN. MUNDELL: Mr. Kempley's going to
25 enlighten us. Let Mr. Kempley cite us -- I was just

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1 looking at the definition of utility distribution
2 company, but maybe you've got something else.
3 MR. KEMPLEY: Mr. Chairman, I think the place
4 to look is in Rule 14-2-1615(A). And it says: All
5 competitive generation assets and competitive services
6 shall be separated from an affected utility prior to
7 January 1st, 2001.
8 That is the specific rule that was waived or
9 extended in the APS settlement agreement that created
10 the December 31, 2002, date that they rely on for
11 separation of generation assets from APS.
12 CHMN. MUNDELL: Mr. Kempley, then how does
13 the definition of non-competitive services fit into
14 that where it talks about must-run generating units?
15 Because then we get into the question of how many are
16 must-run? And how is that defined?
17 COM. IRVIN: That was the issue. The
18 must-run and the peak was a key issue.
19 MR. KEMPLEY: Mr. Chairman, I think
20 Commissioner Irvin's recollection and the discussion
21 that I heard between Mr. Davis and Commissioner Irvin
22 is fairly accurate. I do not think that must-run
23 generation has been defined at this point. The rule
24 specifies separation of competitive generation. And I
25 gather from Mr. Davis' comments that APS is taking the

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1 view perhaps as the safest course of action that
2 rather than argue about certain generation facilities,
3 they'll separate all of them. I don't know whether
4 they have some other basis for that separation.
5 MR. MUMAW: Just to respond, as I say, I do
6 think the Commission had some discussion in the '98
7 order as to whether that reference "competitive
8 generation" meant to imply that there was
9 non-competitive generation, i.e., must-run, that a UDC
10 could continue to own. And they indicated, no, it
11 didn't. But I guess in point of fact, that's why in
12 the settlement agreement issue, you recall, we listed
13 all the generating assets that were covered by that
14 agreement.
15 COM. IRVIN: Mr. Mumaw, you're going to hear
16 one of my lawyer jokes in a minute. We're going to
17 get to the other side because you must be paid by the
18 word today.
19 MR. MUMAW: I hope so.
20 CHMN. MUNDELL: Mr. Kempley -- I'm going to
21 go to the merchants in a second. What I'm going to
22 ask you to do is not everybody repeat the same thing.
23 If you want to pick somebody to be the lead person --
24 and we'll certainly let everyone talk if you want to.
25 But we've got the threshold issue we need to sort out,

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1 and then we have whether we go forward on Monday or
2 whether we do the request that Panda has requested in
3 their Order to Show Cause, and that's to go to a bid
4 process and stay the variance hearing on Monday,
5 figure out how to do a bid process, et cetera. But
6 before I go to the merchants, Mr. Kempley, do you have
7 any thoughts that you want to -- I'd like at least --
8 well, let me just see what you have to say, and then
9 maybe we'll get to the merchants.
10 MR. KEMPLEY: Mr. Chairman, Commissioners,
11 rather than try to do an oral argument form, let me
12 just make some comments based on what Mr. Mumaw and
13 Mr. Davis said. And I think that in the course of
14 those discussions, Staff's concern and the reason we
15 believe that the threshold issue to be addressed is
16 the question of separation of assets emerged.
17 It is true that in 1999, the Commission
18 approved a set of Electric Competition Rules and the
19 settlement that APS and other parties proffered. It
20 is also true, as at least Mr. Davis and I suspect both
21 Mr. Davis and Mr. Mumaw indicated, that at that time
22 those orders were entered with the anticipation that a
23 robust wholesale or retail -- actually, I think at the
24 time, we were thinking retail -- competitive market
25 would emerge prior to the date that APS would transfer

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1 its assets. It's also true that that hasn't happened.
2 And so in examining the question of where we
3 go in the short term, Staff is very concerned and
4 believes that the preeminent issue that this
5 Commission should consider is the circumstances around
6 which APS should be allowed to transfer assets -- the
7 generation assets to a separate affiliate.
8 The market power concerns that have been
9 alluded to are real. And Mr. Davis and Mr. Mumaw made
10 several comments that demonstrate the reality of the
11 problem. Mr. Mumaw said that if a bidding process
12 were approved, the Purchased Power Agreement that's
13 proposed in the variance proceeding would not be
14 Pinnacle West Energy Corporation's bid into the
15 bidding process. He didn't say what it would be, and
16 he doesn't have to. The point is that if the assets
17 are transferred, the Pinnacle West Energy would own
18 the assets, would be free to participate in the bid
19 process, not participate in the bidding process, bid
20 at a level that that generation owner deemed
21 appropriate. And given some other things that
22 Mr. Mumaw and Mr. Davis indicate, you can see what the
23 nature of the problem is.
24 Mr. Davis indicated -- and I think it's
25 universally agreed in the room -- that we don't have a

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1 market structure in place that is capable of dealing
2 with a liquid commodity market in electricity in the
3 APS service territory. The must-run plants would be
4 owned and presumably bid into the process by APS --
5 well, I can't even remember the name of the subsidiary
6 now.
7 COM. SPITZER: Pinnacle West Energy.
8 MR. KEMPLEY: In addition, there are
9 financial constraints that would prevent the other
10 potential competitors from bidding on equal terms.
11 Now, the Pinnacle West family of companies has been I
12 think very forthcoming about their desire on APS'
13 behalf to act in a way to try to protect the APS
14 captive customers. It's Staff's view that in the
15 future, rather than rely on the good intentions of
16 unregulated entities, that the Commission should
17 instead examine the question and devise a structure
18 that will act to protect customers and yet do our best
19 to facilitate the creation of a competitive market on
20 an ongoing basis.
21 It is true -- and I just have a couple more
22 things to say. It is true, although I had to be
23 reminded and go look at it, that in the Staff's
24 response, we did indicate that the variance proceeding
25 would provide information that might prove useful in

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1 devising a competitive bid process and information
2 that might prove useful in examining the other market
3 power and related issues.
4 But the problem is that APS has indicated,
5 and it is their right to do so, that they intend to
6 provide the 30-day notice to transfer assets on August
7 1st. It is, therefore, Staff's view that what the
8 Commission should do is to undertake proceedings that
9 will most efficiently let the Commission examine the
10 question of whether and to what extent that transfer
11 should be permitted and do it in a time frame that
12 will allow an answer before the transfer would take
13 effect on -- based on an August 1st proposed date for
14 the notice.
15 And then finally, I just want to indicate one
16 thing with respect to the market power concerns that
17 Staff has and specifically Commissioner Spitzer's
18 remarks that our concern is that the market power
19 concerns aren't addressed in this forum. And I think
20 that's a part of our problem. But our real problem
21 and our major problem is that we're concerned that in
22 the short term there isn't anyplace, any forum, where
23 the market power concerns can or will be addressed.
24 COM. SPITZER: In terms of our -- in terms of
25 this Commission's deliberative process?

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1 MR. KEMPLEY: No, in terms of the prices that
2 APS will have to pay and ultimately charge its
3 standard offer customers in order to obtain the power
4 that it needs to accomplish that.
5 When you transfer these assets into the
6 unregulated affiliate, that unregulated affiliate
7 immediately has tremendous market power in the APS
8 certificated area. And it's our concern that there is
9 no forum in which to litigate control over that once
10 the transfer is allowed to take place in the short
11 run.
12 COM. SPITZER: But, Mr. Kempley -- well, let
13 me first say that I think within the response filed by
14 Staff, there is, interestingly enough -- and maybe
15 this is wishful thinking. There is within your
16 response a way -- a means of dealing with the APS
17 issue, their threshold issue that they filed and also
18 a means of disposing of the Panda suggestion that we
19 examine and try and construct an RFP process that
20 would be in the interest of the ratepayers.
21 So it's possible that, Mr. Kempley, based on
22 your motion, we could have all the parties -- I don't
23 know if happy is the right word -- but we would have a
24 response to the concerns of the parties and then the
25 facts would be addressed in a timely manner and the

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1 chips fall where they may.
2 I would agree that if the intent -- and,
3 again, I was not here. If the intent of the rules of
4 the settlement were that we would have a retail market
5 that has not come, that is not going to come in at
6 least my time horizon, and regardless of the vision of
7 the proponents of that measure, that's not on the
8 table. But that does not mean that the ratepayers
9 could not benefit from again the plant siting
10 decisions and the transmission siting decisions that
11 this Commission has made both in terms of price and in
12 terms of impact on the environment, of having more
13 efficient, less-polluting energy be delivered to
14 Arizona consumers.
15 The market power issue, it is more than
16 theoretical remedy. There is 60 years of law on the
17 books where there is an exercise -- and it's not -- I
18 guess there's two things: A theoretical possibility
19 that market power may be exercised in the future is
20 not under the rightness doctrine subject to litigation
21 at the FERC or the federal courts. It is only the
22 exercise of market power that is recognizable as a
23 claim under federal law. And to the extent Pinnacle
24 West Energy Corporation were to exercise market power
25 with respect to APS, wholly apart from whether this

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1 Commission would approve the rates of the wire
2 company, there would be recognizable action under
3 federal law attendant to the exercise of market power.
4 At this point, though, that's speculation.
5 And it seems to me what I would like to do is start
6 with the -- your proposal and incorporate -- and,
7 again, I'm not going to be judged whether it's an RFP
8 or an auction or a series of bilateral contracts or --
9 under the current situation, to the extent there is
10 potential demands for power in excess of forecasted
11 supply, APS and the other incumbents enter into -- I'm
12 trying to think of the right term -- contracts for
13 power not on the spot market but for supplemental
14 power. Supplemental supply agreements as a way of
15 protecting Arizona ratepayers against -- first of all,
16 to make sure they get the power they need in the
17 summer months, and they do it at reasonable prices
18 rather than speculate on whether this conveyance of
19 assets leads to a hypothetical market power situation
20 where there would not be an immediate remedy available
21 to this Commission or to the ratepayers or to the
22 competitors.
23 Let's start with the Staff's proposal, do it
24 in a time frame so that APS gets a prompt response to
25 its -- and it may ultimately be the APS variance

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1 request would be what would be entered into. If
2 that's the case -- and I just want the best deal for
3 the ratepayers. If the APS variance request is the
4 best deal for the ratepayers of Arizona, so be it. If
5 it's a combination of merchants and domestic load with
6 supplemental agreements, so be it. Whatever it is, it
7 is. Let's enter into this quickly, and I think your
8 motion provides for a timetable.
9 And let me say that I'm not for deregulation
10 just for the sake of deregulation nor am I, though,
11 for regulation just for the sake of regulation. I
12 don't think we ought to go back and regulate
13 stockbrokers' commissions and say, e-trade, you can't
14 offer $5 trades, you have to go to a Wall Street
15 broker and pay $200 for a trade. Nor do I want to
16 reregulate natural gas nor do I want to reregulate
17 trucking. So while I'm not for deregulation for the
18 sake of deregulation, I think we have to knock on the
19 trap of saying, let's regulate just to regulate less.
20 Let the chips fall where they may.
21 And hopefully we'll hear from some of the
22 other parties, including APS and the merchants, start
23 with the Staff proposal. And if the facts ultimately
24 show, based on a proceeding of how we put together
25 supply to the wire company, that it is inexorable that

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1 we'll have a market power situation and we'll have a
2 problem, we will have time to deal with that issue.
3 And if the facts show that something akin to what
4 Panda proposed is the result or whether it's an APS
5 variance, that would be the result.
6 So I don't think what the Commission ought to
7 do is to punt. We can move forward and be
8 deliberative and answer the questions the Chairman has
9 proposed and answer the questions that Commissioner
10 Irvin has proposed and answer the questions I have,
11 but today establish a framework for solving the
12 problem.
13 CHMN. MUNDELL: Go ahead, Mr. Kempley, and
14 then I have a couple comments.
15 COM. IRVIN: Let me before -- on that,
16 Mr. Kempley.
17 What I'd like to do is add a couple things to
18 Commissioner Spitzer and throw them out, and then,
19 Mr. Kempley, you can answer them as well.
20 First of all, I totally concur with
21 Mr. Kempley in that the settlement agreement was based
22 on customer choice, retail competition. In fact, I
23 cite as one of the reasons I voted against the
24 settlement agreement because even at the height of
25 California competition, they had 1 percent

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1 penetration. And then the thing blew up.
2 But I think we need to go one step further in
3 developing what we're going to do in order to bring
4 and give the consumers benefits out of this. And that
5 is, we need -- because if we don't do it, I think
6 we're going to be behind the curve. I think Arizona
7 has a great opportunity to develop a wholesale market.
8 And I think that has to be part of the equation, is to
9 develop a wholesale market.
10 Now, maybe we're not ready, and certainly APS
11 deserves the answer to their questions. And it may
12 come that ultimately, if -- and we go with a variance
13 and we get those answers in there, I think the
14 Commission needs to define two questions: Either
15 we're going to move to a competitive market and the
16 first thing is a wholesale market, or we're going to
17 go with standard offer and we're going to be in a
18 regulated entity.
19 And I concur with you, Mr. Spitzer, and I'm
20 sure Commissioner Mundell the same, that it's not a
21 matter of regulation, who regulates or what. In fact,
22 to me, it's not even a matter of whether this
23 Commission has regulatory authority, FERC has
24 regulatory authority, or it's set up that some unknown
25 third party such as the WECC or one of the new

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1 entities we're trying to develop has authority over
2 the piece of the puzzle. The bottom line is we have
3 to protect the interests of Arizona and the consumers.
4 And, Commissioner Spitzer, bring in, as you said, the
5 benefits of some of these power plants to Arizona
6 consumers, I believe the best way to do that is
7 develop the wholesale market.
8 And, Mr. Kempley, what Chairman Mundell was
9 asking you on that, should that be part of our
10 equation as we look into answering these questions
11 that Panda and APS have asked?
12 MR. KEMPLEY: Mr. Chairman, Commissioners,
13 first, directly responding to Commissioner Spitzer,
14 the point of view you're espousing I think is exactly
15 why Staff's response took the tack we took with regard
16 to defining the threshold issue. We do not have the
17 sense that there is a sentiment at the Commission to
18 go back -- to try to go back to a regulated
19 environment. But we are concerned that as we go
20 forward towards a competitive environment that we do
21 that in a measured manner and that we do that with
22 full consideration of the issues that are presented.
23 COM. SPITZER: And, Mr. Kempley, I agree with
24 that. And just to make perfectly clear, at least how
25 I view this, I appreciate that. And there are many

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1 aspects, as I've already said, how the Staff proposal
2 could move forward. And, again, the only thing I
3 would amend to it would be among the issues to be
4 looked at -- and I won't deal with the RFP because
5 it's -- Commissioner Irvin's right, there are a lot of
6 ways to skin a cat here, a process by which APS, the
7 wire company, would receive offers to provide capacity
8 and energy to the wholesale market and a broad
9 analysis of that. My only response to the concerns of
10 the Staff with regard to market power is I do not -- I
11 understand the financial issues with respect to APS.
12 And they were mandated, and they undertook actions in
13 good faith based on this divestiture principle.
14 If I were to know and it were to be
15 established that the ratepayers would be harmed by the
16 exercise of market power, then I would be inclined to
17 move in one direction. However, mere supposition that
18 there is a hypothetical exercise of market power out
19 there, that, as you point out, is not recognizable
20 under the Federal Power Act, which would not give it
21 rise to an action in federal court or with the FERC,
22 that supposition is not sufficient for me to deny APS
23 the request their relief.
24 MR. KEMPLEY: Mr. Chairman, Commissioner
25 Spitzer, I think that the Staff's position in response

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1 to APS -- to the APS motion provides a vehicle to
2 ensure that your -- that you don't have to face that
3 problem. And I certainly don't -- didn't mean to
4 imply in the response that other issues, specifically
5 the question of what means and amounts of competitive
6 power should be introduced into the system akin to the
7 Panda Request for Order to Show Cause should be
8 ignored. But we're proposing a time frame that is
9 relatively brief, extremely concentrated, I would
10 think, and the object is to let APS be released from
11 the uncertainty that they've been facing and at least
12 know what it is that the Commission's going to say
13 about those issues and immediately thereafter or
14 possibly on a trailing track as it goes along, one of
15 the next issues to be looked at is the mechanism by
16 which to allow participation in the competitive
17 market.
18 We don't intend to lose the benefits of the
19 siting decisions the Commission has made. And while
20 we've talked a lot about APS' reliance on the Electric
21 Competition Rules and their settlement, these merchant
22 generators have also relied in some measure on the
23 Commission's pronouncements of its intention to go in
24 this direction, and we don't want to lose that,
25 either.

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1 COM. IRVIN: So we want our cake and we want
2 to eat it.
3 MR. KEMPLEY: Well, we want to have as much
4 of our cake as we can get and eat as much of it as we
5 can and not gain any weight.
6 COM. SPITZER: Counsel was using the royal
7 "we" referring to the Arizona ratepayers.
8 COM. IRVIN: Even Mr. Ferland agrees.
9 MR. KEMPLEY: Mr. Chairman, Mr. Johnson
10 reminds me that I should have mentioned along the way
11 that one of the benefits of the approach that Staff
12 has presented is that the proceeding we suggest will
13 allow the identification of any potential market power
14 that may exist and the opportunity to introduce
15 mitigating measures before the fact.
16 CHMN. MUNDELL: That's what I was going to
17 comment on. And I heard Commissioner Spitzer talking
18 about hypothetical market power situation in the
19 future, but that doesn't mean that we can't construct
20 rules or statutes that can try to prevent it from
21 happening or lessening the possibility of it
22 happening. I guess that would be something I'd want
23 to look at in this docket that you're talking about.
24 I also said earlier that I wanted some
25 comment about whether we needed to revisit the code of

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1 conduct rules and the Affiliated Interest Rules.
2 Things have changed since 1999 when we voted on this.
3 When I voted on this -- and we saw what happened in
4 the market, whether it was in California or with El
5 Paso Natural Gas Company, all of those allegations.
6 And whether they turn out to be true or not, it seems
7 to me we ought to look at our rules and statutes to
8 try to prevent that from happening. I guess that
9 would be a question.
10 Are we preempted -- as Commissioner Spitzer
11 said, we have 60 years of case law built up, and I
12 don't know if he's talking about the generic antitrust
13 statutes that exist or whether we need to look at our
14 statutes in Arizona to see if they deal with this
15 modern era of merchant facilities in the state of
16 Arizona and this modern era that we're going from from
17 the old-fashioned regulation to this new era. We need
18 to look at all of these things to try to prevent --
19 assuming we determine that we're not concerned about
20 market power presently today that we make sure that it
21 doesn't occur in the future. And so you don't have to
22 comment, Mr. Kempley, but --
23 MR. KEMPLEY: I have a comment.
24 COM. IRVIN: Does the word antitrust spill
25 into market power anyplace?

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1 MR. KEMPLEY: It does, Commissioner Irvin.
2 Mr. Chairman, the only reason I have a
3 comment is because one of the things I was going to
4 mention in the course of my comments was the code of
5 conduct provision and simply to mention that the rule
6 that we have in place was put in place in anticipation
7 of development of retail competition. And the code of
8 conduct rule addresses in APS' case the conduct
9 between APS and its what we called the ESP affiliate.
10 And so it was anticipating a completely different
11 structure than is developing. And so we would
12 certainly want to go back and look at that issue,
13 among others. And I guess that's why we think that
14 behind all of this is the generic proceeding to deal
15 with these other kind of issues.
16 CHMN. MUNDELL: Thank you, Mr. Kempley.
17 I don't know where to start with the
18 merchants. Whoever.
19 MR. EISENSTAT: Thank you, Chairman Mundell.
20 Good afternoon, Commissioners. My name is Larry
21 Eisenstat. I'm here on behalf of Panda Gila River.
22 I was trying to think of a way to cut to the
23 quick, as you suggested, so I'll try to be brief.
24 There are in fact, as Mr. Mumaw suggested,
25 some common threads between what APS has suggested

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1 other than moving forward with the variance and what
2 we suggested in our response to APS.
3 I think the problem that we've had here today
4 is precise to the point that the issues that you
5 raised in your open meeting notice are all linked.
6 The Order to Show Cause is linked to the APS request
7 for the threshold determination. It's linked to
8 whatever may occur in a generic proceeding. So the
9 question is how best to resolve this thicket.
10 We can summarize our position in two
11 sentences that I think relates both to the Order to
12 Show Cause and to our response to the motion for
13 determination and for that matter to the generic
14 proceeding. I tried getting it into one sentence, but
15 it was too long.
16 In our view, which we believe Commissioner
17 Mundell already has endorsed in the competition rules,
18 it is not appropriate to deregulate a monopoly and for
19 the Commission to lose its jurisdiction going forward
20 as a consequence of a divestiture without first doing
21 an RFP. Otherwise, there would be no way to address
22 the very market power concerns that Staff raises and
23 has so well delineated. The issue is not who will
24 address market power abuses going forward. I agree
25 with Commissioner Spitzer that the FERC has the

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1 jurisdiction to address market power abuses at
2 wholesale going forward. Of course, until things
3 change -- and there was another order yesterday on
4 this precise point, but it only applied to RTO areas
5 for the most part. But until things change, the best
6 the FERC can do is go under its complaint authority,
7 which requires a refund effective date, which requires
8 a lag time. And so you're not going to get the kind
9 of immediate relief that you might want.
10 So I agree with Chairman Mundell and I
11 believe it was Staff's comment that the goal then is
12 to do what you can up front to reduce the likelihood
13 that there will be a market power problem in the
14 future. And our -- the predicate for our Order to
15 Show Cause and the predicate for our saying you've got
16 to stay the variance and proceed with an RFP, or at
17 least stay the variance and undertake a process to
18 resolve some of these issues, the very predicate is
19 that you won't know whether market power has been
20 cured or at least mitigated until you see what the
21 results of that RFP are.
22 It's not an accident that the Commission
23 initially provided in the competition rules that
24 divestiture will occur at the same time as deliveries
25 were to begin pursuant to the RFP. That was the whole

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1 point, as the Commission correctly noted. Presumably,
2 if the RFP results were insufficient, the Commission
3 would have known that before the divestiture was to
4 have closed. The deliveries were to have begun on
5 January 1, 2003. The divestiture was to have closed
6 by year end 2002. Obviously, the RFP would have been
7 issued prior to that, and the results would have been
8 in prior to that. And if any changes would have been
9 made, they could have been made prior to the actual
10 divestiture. So the link was anticipated. The link
11 between an RFP -- between a competitive solicitation
12 and a divestiture was already anticipated by the
13 Commission.
14 If the RFP is successful, one need not be too
15 concerned about APS' market power over its customers.
16 If the RFP is unsuccessful, this only can mean that
17 there's not sufficient competition so as to mitigate
18 any potential for market power abuse. That's the
19 connection between the RFP and the market power issue
20 and the divestiture issue.
21 COM. SPITZER: And then, counsel, on that
22 case, the Commission would obviously take a hard look
23 at the variance proposed by APS, which would at some
24 point become -- assuming there's market power in the
25 relationship between Pinnacle West Energy and APS

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1 becomes the main economic transaction.
2 MR. EISENSTAT: I'm sorry. I don't follow
3 you.
4 COM. SPITZER: If APS has the market power,
5 then the Commission's only inquiry is the relationship
6 between Pinnacle West Energy and APS.
7 MR. EISENSTAT: You mean the generic -- in a
8 threshold determination?
9 COM. SPITZER: No, no, no, from an economic
10 point of view. They're the supplier. So if
11 they're -- if their buyer's out there, which is the
12 retail load in the APS service territory, and there's
13 only one -- for sake of argument only one wholesale
14 provider, then the inquiry of the Commission moves
15 from setting forth the RFP, bid, auction, whatever, to
16 the economic relationship between the supplier and the
17 load.
18 MR. EISENSTAT: I think that's -- if I
19 understand you correctly, I think that's the point.
20 If you were to do an RFP, you would determine whether
21 there was a predicate for allowing the kind of
22 separation that would allow for market power to be
23 exercised if there indeed was not sufficient
24 competition. Is that responsive to your question?
25 COM. SPITZER: Yes.

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1 COM. IRVIN: I just have one problem. What
2 market? We don't have a market.
3 MR. EISENSTAT: Well, that's a good question.
4 Let me try and respond.
5 The predicate for the variance is sort of a
6 reverse field of dreams: That if we bid it, they
7 won't come.
8 We don't buy that.
9 COM. IRVIN: But what -- are you talking
10 wholesale?
11 MR. EISENSTAT: I'm talking --
12 COM. IRVIN: This is all predicated on retail
13 sales. We don't have a wholesale market.
14 MR. EISENSTAT: Actually, my comments go to
15 the wholesale side of the equation. They go -- they
16 can apply to the retail side, but retail competition
17 is not necessary in order to require or in order to --
18 COM. IRVIN: But our rules are contemplated
19 on retail.
20 MR. EISENSTAT: Yes, sir. But the question
21 before us is: As a matter of going forward, do we
22 proceed with a variance? Do we proceed to determine
23 various generic issues going forward? Do we do an RFP
24 immediately?
25 COM. IRVIN: Why is the RFP the best method?

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1 MR. EISENSTAT: Because there is no better
2 method to determine --
3 COM. IRVIN: Says who?
4 MR. EISENSTAT: If I can just finish.
5 There's many states have already decided that
6 the best way to provide for standard offer service
7 requirements is to pursue an RFP. You yourself raised
8 a New Jersey situation where I believe in February of
9 this year, they issued an order for 18,500 megawatts
10 of capacity from four utilities, at least, I believe
11 -- I don't want to do any disservice to APS -- at
12 least three of whom were considerably larger than APS,
13 possibly all four. I just don't recall. That's a lot
14 of megawatts.
15 So you say, why is it the best way? Because
16 it's the only way -- short of trying to determine
17 through a litigated process, it's the only way to see
18 if people will make bids.
19 COM. IRVIN: That's your opinion. I haven't
20 heard a counter to it. There may be. I mean, I'm not
21 saying you're not entitled to your opinion, counselor,
22 but what I'm saying, as you heard, that issue hasn't
23 been debated. And I for one -- while an RFP is one
24 method, I for one cannot conclude that the RFP is the
25 best method. I will concede it is a method. I will

1 concede it may be a good method. But I will certainly
2 not concede it is the only method or the quote-unquote
3 best method.
4 COM. SPITZER: Counsel, do you include -- and
5 Commissioner Irvin referred to the auction. An
6 auction can be part of an RFP process, can it not?
7 MR. EISENSTAT: Yes, sir.
8 COM. SPITZER: So by using RFP, you are not
9 excluding what Commissioner Irvin suggested there are
10 other methods of bringing a buyer and a seller
11 together.
12 MR. EISENSTAT: I'm really saying a
13 competitive solicitation. Your rules contemplate no
14 less than 50 percent through RFP.
15 I think what one has to realize is the
16 variance proceeding itself will, if fallen through on,
17 undertake an RFP through litigation. That's what has
18 to be done. If APS wants to argue that its variance
19 and its PPA are in the public interest and are
20 prudent, then the way for it to show that is is that
21 there would be no supplier or group of suppliers that
22 individually or collectively could give the Arizona
23 ratepayers a better deal.
24 So in order to sustain that burden, they
25 basically have to do a -- we have to prove that were

1 they to do a competitive solicitation, the results
2 would be meager. If they can't prove that, then they
3 can't sustain their burden because there would be no
4 way to show that the prices that Arizona ratepayers
5 would pay couldn't be lower or -- if competition were
6 solicited.
7 COM. SPITZER: Counsel, I actually think
8 there's a difference, and that is in terms of the
9 nature of the resolution of the dispute or the
10 demonstration of the case, in a process that -- I
11 don't want to use RFP because the language I've come
12 up with is a process by which APS, the wire company,
13 would receive offers to provide capacity energy from
14 the wholesale market, which is broader, I think, than
15 RFP. It gets to what Commissioner Irvin was
16 suggesting with an auction, maybe one permissible
17 method.
18 But in the hearing process, you don't have
19 the actual response by the economic folks. You have a
20 bunch of arguments by lawyers and, ultimately, a judge
21 and perhaps this Commission approving an order. And,
22 you know, I've only been a lawyer for 20 years, and
23 I've seen dispositions of cases not in accord with
24 economic reality by judges, and I've seen political
25 decisions that are not in accord with economic

1 reality, unfortunately. And so for an economic
2 disposition, I would prefer the economic process to be
3 the result, which is why I found the original Panda
4 pleading somewhat compelling.
5 And if we could devise a framework where we
6 deal with the concerns that Staff's raised -- and the
7 fact remains that tens of millions of dollars worth of
8 electricity are being traded right now. You open The
9 Wall Street Journal, and you will find trading of Palo
10 Verde electricity at the Palo Verde hub in Arizona.
11 That's about the only place in The Wall Street Journal
12 where we have little Arizona in there, is electricity.
13 So it's trading right now. This Commission isn't
14 doing anything about that. The only question is: How
15 do we adapt that economic reality. Right now, the
16 Arizona ratepayers aren't benefitting from that
17 phenomenon. Let's find a way for the ratepayers to
18 get some of the cake.
19 MR. EISENSTAT: A few other points:
20 Obviously, our view was that the best way to
21 proceed was to do an RFP. But if there is any
22 question about how best to go forward, certainly at
23 least in our judgment -- and it's just our opinion --
24 in our judgment, there's no reason to pursue the
25 variance proceeding right now since this would

1 prejudge the very issues to be examined.
2 COM. SPITZER: Counsel, would you support
3 what Staff has proposed with the additional language
4 that I've proposed?
5 MR. EISENSTAT: With the additional language?
6 COM. SPITZER: That language being, in
7 addition to the items requested by Staff, as part of
8 this docket: a process by which APS would receive
9 offers to provide capacity and energy from the
10 wholesale market.
11 MR. EISENSTAT: What I was going to say
12 later, I was going to talk about the compromise that
13 we had originally proposed in our response, which I
14 think is very similar to Staff. Staff said in its
15 paper that --
16 CHMN. MUNDELL: Was that a yes or a no?
17 MR. EISENSTAT: I think it's a yes. I just
18 want to understand what Commissioner Spitzer is
19 getting at and what Staff is getting at.
20 CHMN. MUNDELL: I think we said competitive
21 solicitation. I think that was the key word.
22 MR. EISENSTAT: Staff says all parties would
23 know the terms upon which APS would be allowed to
24 transfer its generation assets. It says: Including
25 any measures necessary to protect against a potential

1 for market power abuses.
2 As long as the threshold issue includes that,
3 includes a way to determine whether in fact the
4 divestiture will make sense from an economic/market
5 power perspective, then the answer is yes, we would
6 agree with Staff's proposal because it's very, very
7 similar to the one we made. Very, very similar.
8 CHMN. MUNDELL: Thank you.
9 COM. IRVIN: Counselor, there's one question
10 which you have cleverly avoided. APS is entitled to
11 have a hearing on their variance request. How do you
12 respond? According to both our Staff Report and the
13 APS motion, the Staff indicated that they are entitled
14 -- based on the rules, they're entitled to have a full
15 hearing on their variance.
16 MR. EISENSTAT: Well, I think even if APS
17 were entitled to have a hearing on their variance --
18 and I'm not sure if I do agree with that. But for the
19 sake of argument, let's assume they are entitled to
20 have a hearing on their variance. They are not
21 entitled to have a hearing when they want it. They
22 are entitled to have a hearing at best when the
23 Commission decides it's in the interest of the Arizona
24 ratepayers to go forward.
25 And our whole argument is it is not in the

1 interest of the Arizona ratepayers to go forward right
2 now on the variance request. We're happy to have
3 Pinnacle West bid into a competitive solicitation,
4 happy to have that. If we lose, that's life. That's
5 what competition is all about. What we don't want to
6 do is be cut out from the competitive market and
7 relegated to I believe it's 270 megawatts per year for
8 the first 18 years for a total of 1,620 megawatts.
9 That's not an open market.
10 COM. IRVIN: I'm a lot more comfortable with
11 having the Commission have all the facts before making
12 a decision, period.
13 MR. EISENSTAT: That's our whole point,
14 though. We're not disagreeing, sir. We're of the
15 view that the facts aren't determined yet. And we
16 agree with Commissioner Spitzer that about the worst
17 way to determine some of these facts is through a
18 litigated process. Chairman Mundell had the pleasure,
19 maybe it wasn't so pleasurable, to sit through a
20 discovery dispute yesterday on confidential
21 information. And one of the points we made was: If
22 you're going to do an RFP, this is the kind of
23 information that is routinely provided pursuant to
24 confidentiality agreements.
25 (Discussion off the record.)

1 MR. EISENSTAT: So, anyway, the bottom line
2 on your question, Commissioner Irvin, is even if you
3 assume they might be entitled to a hearing, we're of
4 the view that there are sufficient open issues at this
5 point so as to make the hearing either prejudicial to
6 the ultimate disposition of those issues or simply a
7 waste of time, given that it's a litigated proceeding
8 rather than having a considered process through a
9 generic proceeding.
10 COM. IRVIN: I would certainly disagree that
11 the proceeding conducted by this Commission would be
12 prejudicial.
13 MR. EISENSTAT: I wasn't saying that, sir. I
14 misspoke, then. What I was saying was a litigated
15 proceeding in the hearing, the variance proceeding, as
16 Commissioner Spitzer mentioned, is not the best way to
17 set public policy.
18 COM. IRVIN: I agree, counselor, and I'll
19 tell you what. I've been trying to have hearings done
20 without lawyers as long as I've been on the
21 Commission. I'm still unsuccessful.
22 COM. SPITZER: Admirable goal.
23 CHMN. MUNDELL: We want to get to anybody
24 else that feels the need to talk, so go ahead.
25 COM. IRVIN: That's why I appreciate

1 Mr. Davis.
2 MR. EISENSTAT: If I could just make a couple
3 other points, I guess. I guess two things:
4 First of all, there's been a lot of
5 discussion on jurisdictional issues and whether the
6 Commission will continue to have jurisdiction over the
7 PPA with respect to the PPA or with respect to PWCC or
8 not.
9 Certainly with respect to the PPA, state
10 jurisdiction would be preempted. That's the law. The
11 rule that Mr. Mumaw cited to, Rule 804, dealing with
12 Commission review of transactions between public
13 utilities and affiliates, has zero to do with the
14 rates, terms, and conditions of a wholesale power
15 agreement. And if it did have anything to do, it
16 would be preempted. Now, it doesn't have to do with
17 that, so --
18 COM. IRVIN: I would agree with that under
19 especially the Supreme Court. But, again, the issue
20 isn't who has jurisdiction. The issue is what's best
21 for Arizona.
22 MR. EISENSTAT: Which gets back to the
23 threshold question, which is, stated another way, if
24 you're going to lose jurisdiction over the PPA --
25 which you will do -- if you're going to lose

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1 jurisdiction over that PPA, then you want to do
2 everything possible to make sure that it was the right
3 deal for Arizona ratepayers. And we would
4 respectfully submit that you can't make sure it was
5 the right deal for Arizona ratepayers without doing
6 one of two things: Either do the RFP as we've
7 suggested and have a market test, a real market
8 test, or some other type of -- you call it an auction.
9 To me, they're synonymous.
10 COM. IRVIN: We'll call it market
11 solicitation.
12 MR. EISENSTAT: That's great. Do the market
13 solicitation. Or at a minimum, stay the course,
14 resolve some of these threshold issues, try to do it
15 on an expedited way so that the divestiture can
16 proceed.
17 We're not opposed to the divestiture. We are
18 opposed to a divestiture that doesn't have protections
19 and that preempts a market.
20 COM. IRVIN: Mr. Chairman, if I could, just
21 for clarification, you are talking strictly about a
22 wholesale market, not a retail market.
23 MR. EISENSTAT: Well, on the --
24 COM. IRVIN: Because we don't have a retail
25 market.

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1 MR. EISENSTAT: Right. The solicitation that
2 we're talking about would be entirely a wholesale
3 transaction, sure.
4 COM. IRVIN: And Chairman Mundell has
5 mentioned it, and part of the problem -- Mr. Kempley
6 has alluded to it -- is the rules were drafted in
7 contemplation of retail competition. And so that's
8 part of the problem that we have to look at.
9 MR. EISENSTAT: The only other point I would
10 make -- actually, I have -- does anyone else want to?
11 (No response.)
12 MR. EISENSTAT: Then I'll make a few more
13 points, then. Just a few more.
14 In response to specific questions that you
15 all --
16 COM. IRVIN: Can we put that to an RFL,
17 request for lawyers?
18 COM. SPITZER: Commissioner Irvin, you need
19 to know that lawyers charge by the hour whether or not
20 they speak. I don't know if you were aware of that.
21 COM. IRVIN: I wasn't, and so, therefore,
22 it's a moot point.
23 MR. EISENSTAT: So given that, it's actually
24 quite a risk to open one's mouth. We'll find out just
25 how much later.

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1 Just very briefly, there may not have been
2 objections to the spin-off. Frankly, I wasn't around
3 back when all this was initiated. But certainly, as
4 Commissioner Irvin points out a couple times, the
5 assumption was that the resulting competition would be
6 fair. I mean, that, I think, is common ground, that,
7 yeah, there was discussion under divestiture, there
8 was agreement that it would be divestiture, but it was
9 always divestiture in the context of a fair standard
10 offer service requirement process. One was linked to
11 the other. The affiliate PPA in our judgment is not
12 fair because it hasn't been market tested. Therefore,
13 the fact that these folks may not have objected to the
14 divestiture is sort of irrelevant to the fact that
15 they are objecting to the variance and the PPA.
16 A couple points on the financing issue, which
17 we think is a red herring, on the PPA and the
18 variance. The financing issue, from what we
19 understand of it -- and we read the 8-K that was
20 recently filed. The financing issue goes to where the
21 assets are. It goes to the divestiture. It doesn't
22 go to whether they can lock up a 13-year or an
23 extended-year Power Purchase Agreement. They're not
24 project financing this deal. And that's not the basis
25 upon which -- from my understanding and hearing the

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1 comments of Mr. Davis, that's not the basis for their
2 funds, if you will.
3 So we're of the mind that we should --
4 COM. SPITZER: Counsel, I don't think
5 Mr. Davis was suggesting that the threshold issue
6 subject to their motion was somehow contingent or
7 dependent upon the request for variance. I think
8 they're just saying, look, the Commission said, you
9 should do a certain thing by such and such time, and
10 we want to know if that's where you're headed. And
11 they're entitled to know that. And I for one haven't
12 said anything to the contrary, just speaking for
13 myself. My colleagues can speak for themselves. And
14 if we need to clarify that for them, then that's what
15 Mr. Kempley's designed to do.
16 But I don't think it's fair to say that
17 there's a linkage on the request for variance.
18 MR. EISENSTAT: I'm pleased to hear that.
19 That wasn't my understanding. I thought that they
20 wanted the request for variance to go forward because
21 of the financing issue in part.
22 CHMN. MUNDELL: We'll let Mr. Davis speak.
23 MR. EISENSTAT: I'm done.
24 CHMN. MUNDELL: Thank you.
25 COM. IRVIN: Mr. Davis, now you know how Sol

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1 Trujillo felt at U S WEST all these years.
2 CHMN. MUNDELL: Thank you, counsel, for your
3 presentation.
4 MR. DAVIS: Commissioner Spitzer, our
5 financing issue is a separate issue than the PPA. The
6 financing is -- quite frankly, we financed those
7 assets in PWEC on the anticipation that all the assets
8 would be there. We would convert short-term financing
9 to long-term financing and go about our business.
10 That's why we said in our pleading, if you decide to
11 deny our variance, we need to know, we'll move the
12 assets into Pinnacle West Energy, and we will do the
13 50 percent bid.
14 There's one other comment I want to make, and
15 then I'll sit down. There seems to be and at least
16 I'm understanding to be that there's a belief that our
17 RFP is something that someone's bidding against. Our
18 RFP is not our bid. And I don't mean it in a bad way.
19 It means that it's our proposal we think to protect
20 our customers.
21 COM. SPITZER: You're referring to your
22 variance?
23 MR. DAVIS: Our variance. But let me give
24 you a specific example. And I should stand over here
25 so my lawyers can't reach me because I'm going to

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1 provide something today that you guys argued about all
2 day yesterday.
3 Let me give you a very simple example. The
4 busbar costs at Four Corners power plant is about $28
5 a megawatt hour. Now, if you asked us to go to an
6 RFP, we wouldn't bid $28 a megawatt hour most likely.
7 So I've already revealed some things that you argued
8 all day yesterday about because if we're going to go
9 to an open and free market, we'll bid what the market
10 will bear. It will not be $28 a megawatt hour.
11 COM. IRVIN: Do I hear 26?
12 MR. DAVIS: So I want to make sure --
13 CHMN. MUNDELL: Let me ask a serious
14 question, then: I went back and read all the
15 testimony at the legislative hearings, and everyone
16 came into the legislature and they came in here, and
17 they said, hey, go forward with deregulation, because
18 if you do, it's going to mean lower prices, consumers
19 are going to benefit, the company's going to become
20 more efficient. And I want to throw that out because
21 that's the premise of everything that's been occurring
22 since deregulation was first introduced at the
23 legislature. And all the executives -- Mr. Post came
24 in, Mr. Silverman, Mr. Pignatelli. Oh, yeah, you pass
25 this deregulation bill, you're going to have lower

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1 prices, the customers are going benefit, et cetera,
2 et cetera.
3 COM. IRVIN: One point, Mr. Davis. Let me
4 add to that not only the people you mentioned, but all
5 the IPPs came in and said the same thing.
6 CHMN. MUNDELL: I wasn't sure what you were
7 alluding to there, saying the market --
8 MR. DAVIS: I'm a free market person
9 generally. What I'm alluding to is markets are
10 efficient but not timely. We have found that out
11 already in several markets.
12 Secondly, the market will never always be the
13 cheapest thing. Never. Markets vary. I mean,
14 markets vary over time. In fact, I think you'll find
15 in my testimony, part of my testimony here today,
16 we're not saying that our PPA will always be less than
17 the market. There will be times it may be more than
18 the market.
19 But what it does do for our customers, it
20 provides a steady, known price. And that's why I use
21 the example that our RFP -- I mean, our PPA is not our
22 bid. I mean, I run a business. And I've got an asset
23 sitting out there that's deep in the money. Deep in
24 the money. Would I on a real bid, bid that at $28?
25 Probably not.

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1 In fact, what will happen to those who inject
2 at that injection point will look at that and say --
3 if I showed you the forward curve today that we have,
4 and everybody here has a forward curve that will be
5 less to each other, if I looked at the forward curve
6 we have today, then the price of power on the average
7 for the remainder of this year is $36. I can go
8 out -- not all day long because liquidity in the
9 market has been seriously damaged with several things.
10 Chairman Mundell, you referred to The Wall
11 Street Journal and Palo Verde -- or Commissioner
12 Spitzer. It's a very thin market. I'll be more than
13 willing to supply to you that volumes that were traded
14 there each day, but the market is pretty thin. But it
15 is traded. And by the way, it's so thin that NYMEX
16 canceled their contract. So NYMEX doesn't have a
17 contract at Palo Verde anymore because they didn't
18 want to sustain the cost of sustaining the contract.
19 So it's not that liquid of a market yet.
20 COM. SPITZER: Mr. Davis, I understand your
21 argument that you've got the agreement or the proposed
22 request for variance or the Purchased Power Agreement
23 between Pinnacle West and APS provide some certitude.
24 I think the test of this process hopefully we endorse
25 today when we look at whether such certitude could

also be achieved through other means. Right now, you have supplemental contracts that you've got forward to provide certitude and stability as hedging for Arizona ratepayers. And I understand that.

Let's have a cocktail party and we're interested in bananas. And I'm trying to decide how many bananas do I need to buy. And if I buy ten and everybody shows up and everybody wants a whole bunch of bananas and I have to go to you and I need the bananas and you know I need the bananas, I'm going to pay a hell of a lot more for those bananas.

On the other hand, if when I'm putting together the party, and I say, let's -- give me an option to buy bananas at a certain price, maybe a little bit more than the market price right then, but I know that I'm not going to get stuck if everybody shows up and wants bananas. That's what your company's been doing for many years for Arizona ratepayers, and that is all I'm suggesting, is that the same process ought to be tried again.

MR. DAVIS: As our motion suggests, if this Commission believes it's not in the interest of ratepayers not to have the variance, we basically said in our motion, then deny the variance and we'll go to 50 percent -- actually, we'll go to 100 percent

because what the rules say is 100 percent from the market. 50 percent of capacity.

COM. SPITZER: And, Mr. Davis, right now sitting here, I don't know the answer to that. But I'll tell you that going through a hearing on the variance request doesn't just -- I've given this a lot of thought. And Mr. Post came to see me a long time ago with this concept, and the idea of stability in a very volatile world for the ratepayers is something that I'm sympathetic to. I'm just not satisfied that the legal process by which we reach the adjudication of the variance is the best way to go and lo and behold, when it came around we could have a real test case, that's the answer.

And sometimes a little bit of levity is good. The ratepayers that we're in this Commission interested in promoting and protecting and there are certain other interests, certain environmental interests that I've gotten into as well in terms of getting the best price, they don't -- and particularly since we're out of the retail situation, they're not real interested in all the esoteric methods by which we get there. We just need to get them the best price. There are certain things that they understand. I tried to explain to my wife demand side management

when she was running the dishwasher at 6:00. I tried that. And when I explained demand side management to Mrs. Spitzer, Mrs. Spitzer said, I demand clean dishes.

MR. DAVIS: Just one last comment. And I appreciate the fact that you believe that Pinnacle West Energy ought to be able to bid in this, but we can't bid until we divest the assets. And I was pleased to hear Mr. Eisenstat's comments they also believe in that.

If we're going to go forward, we need to divest our assets, and we'll go forward.

CHMN. MUNDELL: I must have misunderstood what you said earlier when I asked you the question about do you need divestiture in order to issue an RFP and you talked about incremental marketing. So I may have missed what you said earlier.

MR. DAVIS: I thought you asked me the question: Could you have RFPs without divestiture? And my answer was: Certainly you can. You take all the assets first that are dedicated to the load, they serve the load, and then you do the RFP for the incremental piece. In our case, that's what we have in our PPA. It's 270 megawatts -- it's actually more than 270. We're conservative in the estimate there.

That's what I meant when I answered the question.

CHMN. MUNDELL: Thank you.

Anybody else that -- first of all hasn't been heard?

MR. ROBERTS: I'm Ted Roberts representing Sempra Energy Resources. I just wanted to finish one thought that I thought Mr. Eisenstat was going on until he was corrected. It seems to me if the finance issue and the variance issue are not related that there ought not be any prejudice to APS in regard to that finance by staying the variance hearing.

CHMN. MUNDELL: Thank you.

MR. SULLIVAN: And I heard the tone, and I will keep it short.

COM. IRVIN: Mr. Sullivan, you're right now on borrowed time.

MR. SULLIVAN: What I have heard is a desire to move forward and how to go from here to the end of the year and get this process done. I've heard that Staff has put a seed before you that it has a possibility of working, and we agree. We believe that it's not in your best interest to go forward with the variance because not that it's a waste of time totally, but it's not the most productive use of your time today. There are legitimate issues that Staff

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has raised that the Commissioners talked about today that should be reviewed and that the competitive solicitation process needs some framework. And so in addition to what Staff has proposed, the Alliance has proposed -- and Reliant's is a supporter of the pleading that was filed yesterday -- to go forward --

COM. SPITZER: Which pleading are you referring to?

MR. SULLIVAN: There was a 3:00 response filed by the Alliance to --

COM. SPITZER: Oh, the Alliance.

COM. IRVIN: Mr. Sullivan, I have a proposal that's going to incorporate that. And I'll offer it here, and hopefully we'll get to the bottom of this and we can all go home.

MR. SULLIVAN: I'll sit down.

COM. IRVIN: Thank you, Mr. Curtis, for kicking him.

Mr. Chairman, and I'm not sure and I'll ask counsel or the hearing officer. And, again, I don't know. We've got several issues. But personally, what I'm hearing and what I'm feeling, and I will offer this, and I don't know the proper way to do it.

I would recommend that the Commission deny the OSC by Panda, stay the variance, and adopt Staff's

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recommendation along with Commissioner Spitzer's additional language as -- Staff's recommendation they mention in their motion for determination of threshold issue would be I think the best way to proceed. It would be the most judicious way of utilizing our time and answer the questions and do that in a timely manner, as Mr. Kempley has outlined.

CHMN. MUNDELL: Let me ask a question of Mr. Kempley or Staff. My thought on it -- I was thinking about this the last couple days. Do we need -- if we do what Commissioner Irvin is suggesting, do we need any for lack of a better word outside help or consultant, someone that has an expertise in -- if we assume that we're going to go to a bid that has expertise that has done this in the past, or do we not have to cross that bridge today because we don't know which mechanism we're going to use.

And that was my first -- when I read the suggestion by Panda and the responses, I said, yeah, that's fine. But I sat through the discovery discussion yesterday, and I thought, to get these folks to agree on anything is going to be very -- I mean, no offense, but I sat through the discovery dispute yesterday. So it seems to me you would need

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sort of like we did in the 271 process, some kind of expertise to establish the parameters if we go to a commercial solicitation or bid or whatever term we use.

MR. JOHNSON: Mr. Chairman, Commissioners, I believe that issue has been raised by at least one of the parties in this case. And they did it in the context of some independent evaluator for an RFP or something like that. And I think that the Commission and certainly the Staff could benefit from that sort of assistance.

I think what's important to the Staff is that we recognize that this is a staged process. A phased process. We think initially we need to deal with the issue of transferring separation as well as the market power, market monitoring. So there's a question of timing. At what point do we actually take up the issue of the competitive -- the procurement process and the necessary expertise associated with that.

So the bottom line is yes, I think we could all benefit from that at least as it relates to the competitive solicitation part, but we might have some need to dialogue the other aspects.

CHMN. MUNDELL: And then let me follow up because I mentioned earlier, and maybe you decide that

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that -- whatever process first. But at some point in time fairly close to making that determination, as I said earlier, I think we need to -- whatever the proper mechanism is, we need to look at the code of conduct, look at the Affiliated Interest Rules. And I understand the Federal Power Act preempts us greatly in this area, but I was really looking more at are there statutes that we can deal with from a perspective of preventing abuses in the future, not after they've occurred, whether those are criminal statutes, additional civil statutes, et cetera, or rules. And so that's what I was looking at. I know we've given you a lot on your plate, so first thing's first, but I don't want that to be overlooked.

And then also we want to look at that rule that says we think we have sufficient authority to look at the books and records of the holding companies and whether we're preempted by PUCA from doing that or any other federal statute.

MR. JOHNSON: Mr. Chairman, I'm somewhat familiar with the issue of -- that you're addressing.

CHMN. MUNDELL: Commissioner Spitzer said it was just --

COM. SPITZER: I think PUCA is no more. We may have to wait until the House/Senate Conference

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1 Committee, but they may make it disappear.
2 CHMN. MUNDELL: In any event, we need to look
3 at those issues.
4 MR. JOHNSON: I think it's important,
5 Mr. Chairman, Commissioners, to make sure there's
6 clarity relative to the specific authority the
7 Commission has. There has been great debate as to
8 what you can -- what the Commission can actually
9 review and how they can utilize that information, what
10 remedies are going to be available to the regulatory
11 body. So I think it bears examination.
12 CHMN. MUNDELL: Thank you.
13 COM. SPITZER: And, Mr. Chairman, one of
14 the -- if there are any beneficial aspects of the
15 collapse of retail, it is that ultimately, the
16 incumbents are going to need to come to the Commission
17 with regard to the wire companies with respect to
18 pricing issues, and that gives the Commission a lot of
19 authority. If we were going straight retail direct
20 access, then I agree there would be a big gap in
21 jurisdiction. But given the failure of retail, we
22 have some remaining authority.
23 And what, Mr. Chairman, I would do is just
24 state my support for what Commissioner Irvin proposed,
25 which would be to deny the Panda motion, to stay the

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1 APS variance, and adopt what Staff has proposed. And
2 the language, to repeat for the court reporter and the
3 parties, is my language alluded to by Commissioner
4 Irvin: a process by which APS -- okay. I wonder if
5 we change that to the retail -- what was the term?
6 COM. IRVIN: Retail solicitation.
7 Competitive solicitation.
8 MR. SHAPIRO: Market solicitation.
9 COM. IRVIN: We don't know what a market is,
10 so solicitation.
11 COM. SPITZER: Offers for competitive
12 solicitation of energy for the wholesale market.
13 MR. KEMPLEY: Commissioner Spitzer, I think
14 we know what you have in mind and are prepared to move
15 forward in that way.
16 COM. SPITZER: And I am not wedded to any one
17 particular procedure. And it may be through
18 consultation with Staff and/or experts. There may be
19 a range of possibilities by which we get the power to
20 the wire company. And I'm not -- I'm certainly not
21 prejudging any one method.
22 COM. IRVIN: And the only other thing I added
23 is obviously -- and, Mr. Kempley, you alluded to --
24 it's got to be a time-appropriate schedule because I
25 think there are certainly some sensitive issues with

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1 respect to Arizona Public Service that the Commission
2 needs to answer.
3 CHMN. MUNDELL: Back to my issue, the --
4 again, the independent entity consultant, et cetera.
5 And then I guess the other issue is who pays for that.
6 My thought would be that the merchants and -- well,
7 Panda, but --
8 COM. IRVIN: Panda.
9 CHMN. MUNDELL: Well, Panda, but -- you
10 earned your payday, Mr. Ferland.
11 MR. SHAPIRO: It cost us a few dollars.
12 MR. KEMPLEY: Mr. Chairman, let me just
13 comment a little bit on that topic. I think that what
14 I see emerging is consistent with what we've proposed,
15 that we move forward with haste, if you will, on the
16 issues related to the divestiture and in as rapid a
17 manner as we can consistently with thoughtful
18 evaluation on questions of competitive power
19 acquisition.
20 I'd rather, I think, leave the question of
21 what consulting expertise is necessary and whether
22 some of that might be something that Mr. Johnson wants
23 to acquire for his own purposes and there may be other
24 consulting expertise or facilitation expertise that we
25 would try to get all of the parties to acquire. I

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1 think it would be difficult to define that too
2 narrowly right now.
3 CHMN. MUNDELL: And I didn't intend to do
4 that. I just want to make sure it's in the motion, at
5 least if not specifically, that you all understand
6 what we were directing you to do.
7 COM. IRVIN: Since it's my motion,
8 Mr. Chairman, I'll follow your direction -- yeah, and
9 all that stuff.
10 CHMN. MUNDELL: Deny, stay, and all that
11 stuff.
12 [See page 113, lines 8-10; page 130, line 24,
13 through page 131, line 4; page 134, line 23, through
14 page 135, line 12]
15 COM. IRVIN: That's a term of art.
16 CHMN. MUNDELL: Is that clear for the court
17 reporter?
18 All those in favor say aye.
19 Aye.
20 COM. IRVIN: Aye.
21 COM. SPITZER: Aye.
22 CHMN. MUNDELL: Ayes have it. So ordered.
23 Any further business?
24 (No response.)
25 CHMN. MUNDELL: We'll stand adjourned.

(Discussion off the record.)
CHMN. MUNDELL: If we could go on the record just for a second. The chief hearing officer reminded me to tell the parties to remember we have the public comment on Monday. The hearing itself is stayed, but we do have public comment on Monday because it's already been scheduled, and the people of Arizona may want to attend. So I just want to let the parties know if they want to be here, it's still going forward for that portion.
Now we'll stand adjourned.
(The Special Open Meeting adjourned at 5:05 p.m.)

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, CAROLYN T. SULLIVAN, Certified Court Reporter No. 50528 for the State of Arizona, do hereby certify that the foregoing printed pages constitute a full, true and accurate transcript of the proceedings had in the foregoing matter, all done to the best of my skill and ability.
WITNESS my hand this 29th day of April, 2002.

CAROLYN T. SULLIVAN, RPR
Certified Court Reporter
Certificate No. 50528

EXHIBIT
S-3
Admitted

REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-01-0822, et al.

April 22, 2002

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ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-01-0822

Rebuttal Testimony of Cary Deise

Director, Transmission Operations and Planning
Arizona Public Service Company

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Cary Deise. My business address is 502 South Second Street, Phoenix, Arizona 85003. I am Director of Transmission Operations and Planning for Arizona Public Service Company ("APS" or "Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will discuss APS' current and planned transmission system and how that system affects the various proposals for competitive bidding in intervenor testimony, as well as compliance with Rule 1606(B) as written. I will respond to the interim proposal for competitive bidding contained in the testimony of Staff witness Jerry Smith and Staff witness Matthew Rowell, and discuss why that proposal is ill-advised and based on inaccurate assumptions. I will also respond to errors in the testimony of several other intervenor witnesses relating to APS' transmission system and its capabilities.

II. WITNESS QUALIFICATIONS

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, PROFESSIONAL BACKGROUND, AND YOUR RESPONSIBILITIES AT APS.

A. I have a Bachelor's Degree in Engineering from California State University–Long Beach, and I am a registered Professional Engineer in the state of Arizona. I have over 32 years of experience in transmission planning and operations, and have worked for APS in numerous different positions relating to transmission system planning and operations continuously for the last 30 years. I am Chair of the WestConnect Interim Committee, and serve on the Western Electricity Coordinating Council's Reliability Compliance Committee, Planning Coordination Committee and Operation Transfer Capacity Policy Group.

In my current capacity as Director of Transmission Planning and Operations, I am responsible for all of the transmission system planning for APS, as well as the overall operation of APS' transmission system. Among other activities, I oversee all technical study work on APS' system, all scheduling over the APS system, the operation of APS' Open Access Same-Time Information System, merchant generator interconnections, and the preparation of the Company's 10-Year Transmission Plans.

III. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Many of the intervenor witnesses suggest, either explicitly or implicitly, that there are few or no system-related impediments to competitively bidding 50 percent of APS' Standard Offer Service load, as currently required by Rule 1606(B). They fail to appreciate that APS' complex transmission system was

designed over the last 75 years to deliver power from APS' generating plants to APS' diverse loads in a cost-effective and reliable manner. The system simply was not designed, nor should it have been designed, with large amounts of surplus capacity to accommodate unplanned generation additions (competitive or otherwise) within a relatively concentrated area, let alone allow unconstrained access to all of APS' loads or to loads in other regions or states. The nature of APS' existing transmission system, as well as the uncertainty of future regulatory and technical developments relating to that system, does not support an immediate transition to 50 percent competitive bidding as apparently envisioned by some intervenors, and certainly not without significant reliability risk to APS' customers.

In fact, Staff witness Jerry Smith agrees that the current transmission system would not support the immediate transition to competitively bidding 50 percent of APS' Standard Offer Service load, and that there are "risks and uncertainties" associated with any transition to competitive bidding. He proposes an "interim" competitive bidding system for APS as a "starting point for discussion." That interim proposal, however, is based on several incorrect assumptions and does not present an acceptable alternative to the phased-in competitive bidding process that is provided in the proposed Purchase Power Agreement ("PPA"). I also disagree with Mr. Smith's suggestion that transmission owners like APS could control transmission constraints and must-run generation to affect market prices, and with his analysis of how a competitive supply margin of generation is emerging given the configuration of APS' transmission system.

Additionally, I will address errors in the testimony of those witnesses who assert that there is adequate transmission infrastructure to support the rapid transition to competitive bidding contemplated by Rule 1606(B). For the most part, these witnesses simply fail to understand the critical limiting factors that necessarily exist on APS' transmission system. APS is committed to working closely and cooperatively with merchant plants to assist in interconnections to APS' system, and our track record shows that commitment. But simply interconnecting to the grid does not resolve the complex operational and reliability issues that will accompany a radical "redesign" of how the system is expected to operate. Nothing in the intervenor testimony supports jeopardizing continued reliable service to APS' Standard Offer Service customers while Regional Transmission Organizations ("RTOs") such as WestConnect, other market institutions, and the physical infrastructure evolve and a competitive bidding program is prudently phased in under the proposed PPA.

IV. APS' TRANSMISSION SYSTEM

Q. PLEASE DESCRIBE HOW APS' TRANSMISSION SYSTEM WAS DESIGNED.

A. Essentially, APS' transmission system has been designed and constructed over the last 75 years or so with two principal concepts in mind: (1) integrated resource planning to serve load; and (2) the interconnection of the APS system with the area transmission grid for reliability purposes.

Integrated resource planning has caused the system to evolve incrementally by selecting over time cost-effective solutions to meet APS' load serving requirements. In some cases, that involved the construction of generation; in

others it meant building transmission capacity. The interconnections of the APS system to the regional grid were made primarily for reliability purposes and reserve sharing. By interconnecting to the Western transmission grid, APS' system is made more reliable because it can take advantage of other resources on the integrated system should elements of the APS system fail. Also, the interconnection of transmission systems has allowed utilities to share reserves (through organizations such as the Southwest Reserve Sharing Group) in a more cost effective manner than if each separate utility had to provide all of their own reserves.

Because the system was designed with a focus on integrated resource planning and with interconnections mostly to support reliability and reserve sharing, the system was never meant to support all resources being able to serve all loads at all given times. Thus, those intervenors who suggest or imply that system constraints and related issues can be ignored in favor of a massive shift to competitively bidding an uncoordinated assemblage of new resources that were not designed with the present system in mind are vastly underestimating the risk to system operation and APS' customers.

Q. FOR BACKGROUND TO YOUR TESTIMONY, COULD YOU DESCRIBE APS' TRANSMISSION SYSTEM.

A. APS' transmission system ties together several relatively remote areas of load, including Yuma, Northern Arizona, and Southern Arizona, with the portion of the Metropolitan Phoenix ("Valley") area that is served by APS. Essentially, there are four injection points where APS' transmission system ties to the Extra-High Voltage ("EHV") grid and from which APS imports bulk power to its

system and exports to other systems. These are: (1) Mead, near the Arizona border in Nevada, (2) Navajo/Moenkopi, which is several hundred miles north of Phoenix, (3) Four Corners, which is in northwestern New Mexico, and (4) the Palo Verde/Hassayampa switchyard complex west of Phoenix. A simplified diagram of this system is attached as Schedule CD-1R. Of these injection points, Mead, Four Corners and Palo Verde could be considered market hubs, in that there is trading occurring among suppliers at these hubs. Although Navajo/Moenkopi is an injection point to APS' system, there is not currently significant trading activity at either Navajo or Moenkopi.

By far the largest part of APS' system from a load standpoint is the Valley, where the expected summer peak for 2003 will be 4112 MW. The Valley is itself a complex transmission system that is partly shared with Salt River Project ("SRP"). APS' Valley 230 kV system is served from four bulk switchyards that electrically form a square around the Valley—Westwing to the northwest, Pinnacle Peak to the northeast, Southwest Valley (now called the Rudd Switchyard) to the southwest, and Kyrene to the southeast. A simplified diagram of the Valley system is attached as Schedule CD-2R. While there are several interconnections to other systems, such as to the Western Area Power Administration ("WAPA"), geographically located near or in the Valley, these interconnections are electrically outside of what is known as the Valley "cut plane" which determines APS scheduling capability on the Valley system.

In addition to Phoenix, APS serves the Yuma area; Northern Arizona including communities such as Flagstaff, Prescott and Payson; Southern Arizona including communities such as Gila Bend, Casa Grande, and Douglas; the Eastern Mining

Area including Globe and Miami; and several smaller remote loads. All together, the APS retail system peak for 2003 is estimated to be 5911 MW.

V. TRANSMISSION CONSTRAINTS AND MARKET POWER

Q. STAFF WITNESS SMITH ASSERTS THAT THERE ARE TRANSMISSION CONSTRAINTS ON APS' SYSTEM. DO YOU AGREE?

A. Of course. Transmission constraints—which emerge as load growth occurs and retreat as additional resources are brought into service to meet that load growth—are inherent aspects of any complex transmission system like APS' during certain peak hours of the year. Unless there is massive and uneconomic overbuilding of both transmission lines and local generation, I expect that transmission constraints will continue to be a factor that must be considered when looking at the capabilities of APS' transmission system. I also believe that constraint issues will likely be appropriately addressed by an RTO in the future. The Federal Energy Regulatory Commission ("FERC") itself recognizes that it is neither practical nor desireable to eliminate all transmission constraints, and through its Standard Market Design initiative intends to manage constraints using physical and financial protocols. Currently, both Yuma and the Valley are transmission constrained areas on APS' system at peak hours during the summer.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW TRANSMISSION CONSTRAINTS ARE INHERENT ASPECTS OF APS' SYSTEM?

A. The history of Yuma offers a good illustration of both how transmission constraints ebb and flow and how the current APS transmission system developed under integrated resource planning. In the 1960s, loads in Yuma

could generally be served by the steam turbine at the Yucca power plant and local transmission. In the early 1970s, loads in Yuma were increasing to the point that additional load serving capability was needed. At the same time, APS needed additional generating capacity for its system. Given these needs, the logical and economical choice was to install new generating capacity at Yucca to meet both needs, rather than construct both a power plant in Phoenix and a transmission line to Yuma. When the Yucca combustion turbines were added, the local generating capacity increased, eliminating the need for new transmission at that time. That outcome was the most cost effective solution to the situation.

By the mid-1980s, load in Yuma was again reaching the point where additional load serving capability was required. Now, however, a California utility was proposing to construct the North Gila 500 kV transmission line from Phoenix (i.e., Palo Verde) into Southern California to allow it access to the Arizona and New Mexico systems and markets. Given those circumstances, the logical choice was for APS to partner with that utility for a share of the capacity on the North Gila line, which allowed more transmission import capability and thus provided more load serving capability in Yuma. And, after the North Gila line was constructed, the Yuma local generation requirement was significantly reduced.

Today, however, load growth in Yuma has again reached a point where additional load serving capability will soon be necessary. Thus, APS has included a new transmission line in its 10-Year Plan from Gila Bend to Yuma, which will provide more transmission import capability and, accordingly, more

load serving capability. For a time, that new line will relieve transmission constraints into Yuma.

The point of this example is that the displacement of transmission by local generation is neither "bad," nor indicative of "poor planning" by the incumbent utility. Instead, it is simply the byproduct of least cost planning to meet load serving requirements. In some cases, the least cost solution is to build local generation. In fact, some local generation is always needed to provide voltage support and reactive power to a system regardless of how much transmission is built. Sometimes, the least cost solution is to construct new transmission lines. And again, in most cases transmission constraints only exist for a small portion of the year and for a relatively small amount of an area's overall load requirements.

However, it is never least cost to redundantly construct both transmission and local generation, or to overbuild the transmission system so that APS customers have to pay for significant unused transmission capacity. Thus, I disagree in concept with Staff witness Smith when he states that merchant generators outside a constrained area "<u>may</u> be more cost-effective than generation available locally." (emphasis added) In fact, they are likely <u>not</u> more cost-effective given the need to build additional transmission to allow them to reach load during the relatively few hours per year when an area is constrained. Mr. Smith has certainly not presented any evidence supporting the accuracy of this statement when the cost of siting and constructing additional transmission lines through an urban area is compared to the incremental generation costs for a limited period

of time during the year. This is one critical area where Mr. Smith does not account for how APS' system was planned and constructed.

Q. DO YOU AGREE WITH STAFF WITNESS SMITH WHEN HE STATES ON PAGE 7 OF HIS TESTIMONY THAT OWNERS OF CONSTRAINED TRANSMISSION CAN USE THE CONSTRAINTS TO EXERCISE MARKET POWER?

A. Absolutely not. Like Mr. Smith, I am an engineer and not an economist, but it is clear that Mr. Smith makes several inappropriate inferences and conclusions in his evaluation of market power and transmission constraints. First, I disagree that a utility can exercise "market power" simply because they own or operate must run generation. In the Valley, for example, APS is not preventing any merchant generator from siting competing local generation. Any competitive supplier (including an ESP) is perfectly free to construct its own local generation or fund transmission upgrades to supply capacity within transmission constrained areas. Further, the prices that must run generation can charge during constrained periods are capped using a cost-based rate. Because the price is regulated during constrained periods, the utility operating must run generation cannot manipulate the market price. So Mr. Smith is simply incorrect when he claims that utilities with local generation "control" the market.

Mr. Smith also does not discuss various regulatory requirements currently in place that would preclude FERC-regulated transmission providers like APS from exercising market power due to transmission constraints. The Open Access requirements set forth in FERC Orders 888 and 889 were developed in large part to mitigate the potential for market power. APS' OATT includes specific FERC-approved protocols regarding cost-based pricing for must run generation and the

allocation of APS' network transmission service to suppliers of Direct Access loads. FERC Orders 888 and 889, coupled with APS' OATT, require transmission providers such as APS to make available transmission capacity accessible to other users on a non-discriminatory basis, which also prevents market power abuse such as Mr. Smith suggests can exist.

Finally, Mr. Smith's discussion of how must run generation could adversely impact Direct Access customers of Electric Service Providers is also faulty. Although APS' retail rates are capped today as a result of the 1999 Settlement Agreement, once the purchase power adjustment mechanism provided for in that agreement is incorporated into APS' rates 2004, regulated cost-based prices resulting from the operation of must run generation would presumably be passed through equally to both Direct Access and Standard Offer customers. In this case, because there would be no relative difference in costs between Standard Offer and Direct Access customers, there would be no impact on the "shopping credit."

Q. **DO YOU BELIEVE THAT APS SHOULD CONSTRUCT ENOUGH TRANSMISSION SO THAT IT NEVER HAS TO RELY ON LOCAL GENERATION?**

A. No. In its recent Biennial Transmission Assessment, Staff essentially took the position that there should be enough transmission constructed into "constrained" areas so that local generation was never required. If adopted, such a policy would dictate considerable and unwise overbuilding of transmission capacity and would ignore the unquestionable value to the system of local generation resources. For example, constructing new transmission lines through urban areas is expensive, both in terms of money and impacts to property and the

environment. If local generation is needed due to transmission constraints for the 300 to 400 hours per year projected for the Valley, or less than 5 percent of the 8760 hours in a year, the hundreds of millions of dollars and environmental impacts it would take to fashion a 8760 hour solution to relieve a 400 hour "problem" would be a real waste of resources. This is particularly true when during constrained periods, the price that a local must run generator can charge is regulated. Further, local generation offers a significant reliability advantage compared to 100 percent dependence on transmission imports.

Local generation requirements must be considered hand-in-hand with the load service obligations of a company like APS. When it is necessary to construct load serving capability to meet APS' load serving requirement, as I discussed in my Yuma example above, it may be appropriate to construct new transmission lines. It is not appropriate to just ignore local generation resources and overbuild transmission lines.

Q. IS STAFF WITNESS SMITH CORRECT IN ASSERTING THAT TRANSMISSION CONSTRAINTS AT THE PALO VERDE HUB ALSO GIVE RISE TO MARKET POWER CONCERNS?

A. No. APS did not tell Duke, Sempra or PG&E National Energy Group to construct plants at the Palo Verde hub. If too much capacity has been constructed at that location so that some capacity is "stranded" due to inadequate transmission away from the hub, that is in no way attributable to any action, let alone "market power", of the transmission owners in that area. Further, I don't see how Mr. Smith can claim that the over-construction of capacity at Palo Verde by merchant generators somehow "protects" higher pricing at other non-merchant generating sources. And, even if it had such an effect, why would that

be the fault of a transmission owner, who was not responsible for the merchant generator's selection of its plant site?

No merchant generator interconnecting at Palo Verde asked for firm transmission capacity to serve APS' load (and only PWEC's Redhawk Project asked to be designated as a network resource). Thus, it would have been foolish and imprudent for APS to construct additional transmission capacity from Palo Verde for, say, Sempra's Mesquite power plant, at APS ratepayer expense only to later find out that Sempra contracted to serve California or some other non-APS loads unless the merchant plant owner were willing to purchase sufficient firm transmission rights over such additional capacity. Indeed, APS generally does not know where a given merchant plant intends to sell its output over the life of a project.

Finally, Mr. Smith is incorrect in suggesting that there is at present, or will be in the future, some ability to "bid" for transmission rights in a way that would affect delivered energy prices so as to give an incumbent transmission provider and its generation affiliates a competitive advantage. I cannot tell you today what will ultimately be adopted, but it certainly will not be driven by transmission owners attempting to manipulate constraints, given that each one of the merchant generators at Palo Verde freely selected that location and made whatever transmission service requests that it felt were appropriate. If such congestion management arrangements are implemented, I expect them be administered by a FERC-authorized and independent RTO and not controlled by individual transmission owners. I can also tell you that, even absent an RTO, the FERC Code of Conduct between transmission owners and generation affiliates

would prohibit the improper leveraging of generation by using affiliated transmission.

Q. IS APS FRUSTRATING THE EFFORTS OF MERCHANT POWER PLANTS TO INTERCONNECT TO THE TRANSMISSION GRID?

A. Of course not. I am proud of APS' track record, which includes the development of a pro forma interconnection tariff and process while FERC is still in the pre-rulemaking stage on a similar effort; the siting and permitting of Panda/TECO's interconnection on a significantly faster pace than has historically been possible for 500 kV transmission line projects requiring National Environmental Policies Act ("NEPA") review; and the proactive resolution of transmission constraints at Reliant's Desert Basin plant when it was discovered that WAPA had facility limitations on its 115 kV system.

Q. IS APS TAKING APPROPRIATE STEPS TO ADDRESS TRANSMISSION CONSTRAINTS ON ITS SYSTEM?

A. Yes. As Mr. Smith recognized in his testimony, APS and other Arizona transmission owners have made plans to construct additional transmission capacity in Arizona. He also mentioned several planned transmission enhancements by APS that have been identified in our 10-Year Plan. I appreciate and agree with his comments that "...Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions..." and that this represents a "...good faith demonstration of Arizona utilities commitment to respond favorably on a forward looking basis." Also, PPL witness Saline confirmed in response to a discovery question that he was not alleging that APS had been deficient in planning or constructing transmission to serve APS' load. These statements

further contradict any notion that APS is taking advantage of transmission constraints, particularly when merchant generators are simply not siting their plants inside any constrained areas nor offering to construct transmission into such constrained areas.

Generally, the additional transmission that APS is planning is being driven by load requirements or when reliability issues require additional transmission capacity. There currently are no established and proven mechanisms to provide for cost recovery to construct transmission capacity that is not needed for load serving capability or system reliability, but which might still be appropriate for economic reasons in the long term. That issue is one that I expect will be addressed after WestConnect becomes operational in the Desert Southwest and more flexibility towards system planning is introduced, including transmission lines that on a "stand-alone" basis might not be economic for a single transmission provider or load serving entity to construct, but which may be economical on a regional basis.

I would also note, again, that the resolution of transmission import constraints and local generation requirements through the construction of new resources is rarely a permanent fix. To use my earlier discussion of the Yuma area, the construction in 2006 of a 230 kV transmission line from Gila Bend to Yuma will reduce the amount of local generation that is necessary to run in Yuma to meet load serving requirements. So initially, it can be said to reduce transmission constraints at Yuma. But as load growth occurs in Yuma, we will likely reach "constrained" status again at some point in the future until yet another resource, whether a transmission line or generator, is added to serve load.

Q. ARE THERE OTHER WAYS THAT WESTCONNECT MAY HELP ADDRESS TRANSMISSION ISSUES IN THE FUTURE?

A. Yes, I think WestConnect will go farther than Mr. Smith suggests in addressing even perception problems arising from transmission limitations of the various systems in the Desert Southwest. Under the WestConnect model, which was submitted to FERC for approval on October 16, 2001, WestConnect would be responsible for transmission planning and expansion across its region. WestConnect proposes a planning process that is active, hands-on, and open to all stakeholders. WestConnect proposes to coordinate those efforts with all appropriate state and federal regulatory authorities and, additionally, in coordination with the WECC, ensure that expansion efforts do not interfere with the expansion of other facilities within the Western Interconnection. The stakeholder transmission planning group would also be responsible for developing regional transmission expansion plans. However, all of these measures are still some time in the future, which leads me to concur with Mr. Smith's assessment that the time is not yet ripe for the immediate transition to competitively bidding 50 percent of APS' Standard Offer Service requirements, as if all of these market and infrastructure issues were already resolved.

VI. STAFF'S "INTERIM" COMPETITIVE BIDDING PROPOSAL

Q. IS STAFF'S "INTERIM" COMPETITIVE BIDDING PROPOSAL ACCEPTABLE?

A. No, certainly not in its entirety.

Q. WHAT AREAS OF THE INTERIM COMPETITIVE BIDDING PROPOSAL DO YOU AGREE WITH?

A. First of all, I appreciate Staff's acknowledgement that their proposal is intended as a starting point or "straw man" for further discussion. So although I have significant substantive disagreements with much of Staff's proposal, I understand that it was developed in the spirit of searching for creative solutions to the inherent problems associated with a 50 percent competitive bid requirement on APS' system. However, I don't believe that the significant risks of implementing creative solutions—risks that Mr. Smith admits—are appropriate when balanced against the phased-in approach to competitive bidding set forth in the proposed PPA.

I specifically agree with Staff's suggestion that load growth can be served through competitive bidding. In fact, this is what the increasing competitive bid component of the proposed PPA was itself intended to capture. I also understand that competitively bidding new load serving requirements or load growth is being done in several other states, so I do not believe that it is a totally untested proposal. I also agree with Staff that there should be exceptions to any mandatory competitive bidding requirements for emergency or short-term purchases.

Q. IS STAFF'S PROPOSAL FOR COMPETITIVELY-BIDDING UNCONSTRAINED LOAD APPROPRIATE?

A. As a <u>theoretical concept</u>, Staff's notion that unconstrained load on APS' system <u>could</u> be competitively bid is correct. I do, however, have corrections to Mr. Smith's analysis of this component of Staff's interim proposal and I have

concerns over whether competitively bidding this remote load is either practical or economical.

Specifically, Mr. Smith concludes that there is roughly 1600 MW of unconstrained load that could be competitively bid under the interim proposal. To reach that figure, he subtracted APS' Valley load and Yuma load (the two transmission constrained areas noted in his testimony) from APS' overall load requirement reported in the 2001 Biennial Transmission Assessment. This calculation method, however, improperly includes APS' wholesale loads and transmission losses in the 1600 MW and does not reflect the most current estimates for APS' system. The correct and more accurate way to determine APS' unconstrained loads is to look at the system from the bottom up, rather than the top down. At system peak, such an analysis would yield the following loads for APS' unconstrained system:

Northern Arizona (Flagstaff, Prescott, Payson, etc.)	250 MW
Southern Arizona (Douglas, Casa Grande, etc.)	350 MW
Eastern Mining Area and other remote loads	100 MW
Total	700 MW

While I think it is theoretically possible to competitively bid this 700 MW of unconstrained loads, I have serious reservations on the feasibility of such an approach. First, serving this load would require delivery and interconnection to the local 230 kV system at one or more remote points on the APS system, which may potentially exclude some suppliers and further limit the size of the bidding pool. Second, the figures provided above are at system peak and would usually be significantly lower during the remainder of the year. Thus, for example, a generator serving the Southern Arizona load would often be supplying much

less than 350 MW and would have to be capable of supplying baseload, intermediate and peaking capacity for this load.

Further, if a merchant generator were to be the "sole supplier" of the power requirements to one of these communities, as the Staff proposal appears to contemplate, the merchant generator would have to essentially devote a unit (or possibly two, when reserves are considered) to serving a relatively small load. Even assuming the metering technology to integrate the generator into APS' overall control area to serve the remote loads were available, Staff's proposal may also require the merchant generator to install Automatic Generation Control ("AGC") for load-following, and require related system control and telemetry equipment. Therefore, I do not believe that it would be appropriate or practical to require competitive bidding for all, or even a significant portion, of this unconstrained load as suggested by Staff.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL ON MAKING "NEW ATC" AVAILABLE FOR COMPETITIVE BIDDING?

A. No. The proposal for competitively bidding new Available Transmission Capacity ("ATC") has a number of serious flaws and includes several inaccurate assumptions, so I do not believe that this component of Staff's interim proposal can work at all in practice. Even as a theoretical construct, I do not believe it could work to the extent suggested by Mr. Smith.

Mr. Smith begins by assuming that there is 1840 MW of new generation being constructed inside the Valley constrained area, including Reliant's 520 MW Desert Basin plant, SRP's 250 MW Kyrene expansion, PPL Sundance's 450

MW peaking plants, and Pinnacle West Energy Corporation's ("PWEC") 620 MW West Phoenix expansion. Of these plants, however, both Desert Basin and Sundance are interconnected to the transmission grid outside of the "cut plane" which determines APS' Valley scheduling capability, so neither Desert Basin nor Sundance could increase APS' Valley scheduling capability by <u>any</u> amount under <u>any</u> circumstances.

I also disagree with Mr. Smith's assertion that the location of new generation inside the Valley "has the net effect of addressing the transmission import constraint irrespective of who owns, operates or purchases the output." This error is based on a misunderstanding of APS' scheduling capability versus load serving capability. APS' Valley scheduling capability is 3685 MW—a figure that represents the amount of power that can be imported to the Valley on transmission lines expected to be in service by system peak in 2003, and specifically including the Southwest Valley Project. With no local generation running, 3685 MW can be imported to serve load requirements in the Valley. If APS' load increases to 4185 MW, there is not enough transmission scheduling capability on the system to bring in more generation, so local generation must be used to meet APS load serving requirement. In this case, 500 MW[1] of local generation from, for example, West Phoenix would be required. However, the presence of generation in the Valley only increases APS' load serving capability but does not increase scheduling capability. Thus, the operation of the local generation in this example meets APS' 4165 MW load serving requirement, but does not change the transmission scheduling limit of 3685 MW into the Valley.

[1] 4185 MW load – 3685 import = 500 MW

Moreover, the fact that SRP might be running the Kyrene plant to meet its load serving requirements would neither entitle APS to any more transmission scheduling capability on its (or SRP's) system nor meet APS' load serving requirements unless the Kyrene plant's output was being sold to APS. That project is already included in the calculated Valley import capability. Further, because both companies serve the Valley, APS and SRP have apportioned the total scheduling capacity into the Valley on the basis of 41% to APS and 59% to SRP. Any additional transmission import capacity from system improvements is added on a pro rata basis to this baseline. In the case of the Southwest Valley Project, where each party is paying for 50% of the Project, that means that each party receives 50% of the additional transmission import capability resulting from the Project, which is then added to the base amounts from the initial allocation. In the case of Kyrene, any additional scheduling capability from that project would be allocated only to SRP, since APS did not participate in it.

It is not the case, as suggested by Mr. Smith in his testimony, that APS and SRP simply divide the total import scheduling capability for the Valley in half for any system improvements. APS' transmission import scheduling capability for the Valley after the Southwest Valley Project is in service will be 3685 MW, irrespective of other plants in the area or SRP's local generation or improvements that SRP makes to the system.

The only theoretical concept that could allow for some "new ATC" from local generation consistent with Mr. Smith's proposal appears to me to be wholly impractical. The Arizona Independent Scheduling Administrator's ("AISA")

protocols do allow increased transmission import schedules, but only when the amount of local Valley generation exceeds the Local Generation Requirement ("LGR") for the Valley. Using the example above, if West Phoenix were generating 620 MW, with 500 MW going to the LGR and 120 MW being sold outside of the Valley, it is possible to schedule an additional 120 MW into the Valley. This is a concept known as "counter-scheduling," and means that 120 MW of new scheduling into the Valley is essentially "netted out" by the 120 MW being sold from West Phoenix to outside the Valley.

While under these limited circumstances, it may be theoretically possible to schedule into the Valley the amount of local generation that is being sold outside the Valley, I certainly do not believe that this concept could practically be subjected to competitive bidding. To do so would require that a bidder be solely dependent on those times where PWEC was choosing for its own economic reasons to sell local generation off system, and then only for the amounts of those off-system sales, and then only to the extent that the amount sold off-system exceeds the LGR. I cannot see how this concept would result in any firm ability of a bidder to reach the APS system, or allow APS to rely on such a bidder being able to schedule into the Valley whenever APS needs the power.

Also, the amount of capacity that could be subject to this theoretical concept of counter-scheduling would be far less than the 1840 MW that Mr. Smith estimated would be available by simply adding the capacity of four new power plants, and would also decline each year, until additional scheduling capability into the Valley is constructed, as APS' load serving requirement and the LGR increased. A table illustrating the relationship between LGR, transmission

import scheduling capability and the theoretical limits to "counter-scheduling" for APS' Valley system is attached as Schedule CD-3.

Q. CAN MR. SMITH OR ANYONE ELSE TELL THE COMMISSION HOW MUCH POWER CAN BE COMPETITIVELY BID GIVEN TRANSMISSION CONTRAINTS AND APS' TRANSMISSION SYSTEM?

A. Not without making a number of critical explicit or implicit assumptions. For example, how are the Dedicated Units being used, how specifically will the bid be structured, where will the required delivery points be located, and for what capacities at each delivery point? The bid amount also cannot be determined without knowing the exact location and operational characteristics of all the generation resources that would operate on APS' system following the competitive bid.

I can tell you that resources to serve APS' load would have to be delivered at all of APS' four EHV injection points—Four Corners, Navajo/Moenkopi, Mead and Palo Verde—and that there are potential reliability or contractual impacts based on which units are running or what is being delivered at each location. For example, if Cholla Unit 4 is off line, Pacificorp has transmission rights to 200 MW from Four Corners to Westwing or Palo Verde, which would in turn curtail the amount of transfer capability available to APS on the transmission path from Four Corners. Also, if certain existing generating units are not running on APS' system, the transfer capabilities on each of these paths may change due to voltage limitations or other operational constraints. For example, if energy is delivered to APS at Four Corners from Craig/Hayden in Colorado, the transfer capabilities along the Four Corners path may well be different than if energy is

being delivered from Four Corners itself. Of course, it also depends on what one considers to be a "competitive" bid.

Q. DO YOU AGREE WITH STAFF WITNESS SMITH'S CONCLUSION THAT A "COMPETITIVE SUPPLY MARGIN" IS EMERGING IN ARIZONA?

A. Again, like Mr. Smith I am not an economist, so I look at these issues more from an engineering and transmission operating perspective. I certainly agree that significant amount of new generating capacity is being constructed in Arizona and is currently planned for future construction in Arizona. I would also agree that this new capacity should allow Arizona to contribute to the supply needs of the Western Interconnection.

However, much of this new capacity is relatively concentrated around the Palo Verde hub—something that is certainly not surprising given the amount of trading there and the fact that direct interconnections by generators to the "common bus" at Palo Verde reduce transmission costs to the generators. Because APS' system cannot physically take delivery of all its power requirements from one location like Palo Verde, I do not believe that the analysis of whether there is an adequate "competitive supply margin" for delivery to APS' transmission system can be performed by simply adding up all the new and planned capacity in the state and comparing it with load requirements. For APS, power would have to be delivered at all the injection points that I discussed in Part IV of my testimony, which requires a more involved analysis than the additive process that Mr. Smith appears to have performed in his testimony on this issue. Thus, while I agree that there is a significant amount of new generating capacity being added in Arizona and to the

Western Interconnection generally, I don't believe that new capacity can simply be summed to determine whether there is an adequate "competitive supply margin" for APS' system, as Mr. Smith appears to suggest.

VII. TRANSMISSION ISSUES AFFECTING 50 PERCENT COMPETITIVE BIDDING REQUIREMENT

Q. OTHER INTERVENOR WITNESSES HAVE STATED THAT APS SHOULD SIMPLY PROCEED WITH COMPETITIVELY BIDDING 50 PERCENT OF ITS STANDARD OFFER SERVICE REQUIREMENT. DO YOU AGREE?

A. As I discussed earlier in my testimony, from a transmission operator's perspective, competitively bidding 50 percent of APS' Standard Offer Service in January 2003 is not as practical or efficient as such witnesses appear to believe. Put simply, I believe that there are too many emerging regulatory and market issues to reduce the risk of such a change to an acceptable level for APS customers. I also believe that APS' transmission system and transmission constraints on serving Valley loads make implementing such a large competitive bid requirement in such a short period of time much more complicated and risky than is being suggested by these intervenor witnesses, and certainly more risky than the phased-in approach offered by the proposed PPA.

Q. PPL WITNESS SALINE ARGUES IN HIS TESTIMONY THAT COMPETITIVE BIDDING WOULD PRODUCE RESULTS EVERY BIT AS RELIABLE AS THE PROPOSED PPA. DO YOU AGREE?

A. No. Mr. Saline too easily dismisses many critical issues relating to the impacts of competitive bidding on the practical operation of APS' system. In general, he attempts to argue that reliability is limited to literal compliance with NERC and WECC reliability criteria. The reliability issue that APS has discussed in its

Request for a Partial Variance is not whether an individual merchant power plant is "reliably" interconnected at an individual point in APS' or any other party's transmission system. The fact that minimum criteria are met for interconnection does not mean that those plants can serve APS' loads with the same overall reliability as the plants that were designed and built as the system evolved.

For example, Mr. Saline states at page 7 of his testimony that "APS would not allow electrical interconnection of a generator [at Palo Verde] unless APS' system could safely accommodate that generation into the transmission network if that generator were dispatched to serve load." That statement misstates the reliability analysis that APS is required to perform for an interconnection under FERC rules. Under these rules, a generator may request interconnection to APS' system without asking for any transmission service. Thus, many generators interconnected to the Palo Verde hub without requesting any transmission service to reach APS or any other load serving entity. To approve such an interconnection, APS (and SRP in the case of Palo Verde) would look at the interconnection component, but would not at all "guarantee" that every generator can be simultaneously accommodated on the transmission system, as Mr. Saline's testimony seems to infer. Rather, it would be the responsibility of the interconnected generator to secure transmission rights, which might require system upgrades, or use a load serving entity's existing network transmission if it actually sought to serve a specific load.

Similarly, Mr. Saline goes to great lengths to argue that receiving network transmission service from APS guarantees the same ability to serve load as

under APS' current system. However, network transmission service has never meant that any generator is entitled to reach any APS load at any time. Thus, his assertions on page 10 of his testimony regarding the "conclusions" one must reach with respect to network resource transmission service are simply not supported.

Q. ARE THERE OTHER ASPECTS OF PPL WITNESS SALINE'S TESTIMONY THAT ARE INCORRECT?

A. Yes. He also suggests that his firm has studied the ability of Sundance to deliver its output to serve the Valley without being limited by current import constraints. While I agree that Sundance's interconnection into the WAPA 230 kV system at Coolidge allows it a different delivery path than the generators interconnecting at the 500 kV system at Palo Verde, the interconnection still does not change APS' scheduling constraints to serve Valley load. Thus, Sundance perhaps could deliver power over the 230 kV system to APS at the Westwing substation, but that does not at all change the 3685 MW transmission import capability that APS has to serve the Valley. And Mr. Saline's suggestion that there may be 500 MW of firm transmission rights to substations accessing Valley loads (page 19) also ignores APS' Valley import limitation, which is independent of whether PPL or another party can deliver to one of these substations.

Q. PANDA WITNESS SCHUYLER SUGGESTS THAT PANDA'S INTERCONNECTION AT THE JOJOBA SWITCHYARD AND RIGHTS TO DELIVERY AT PALO VERDE GIVE IT BETTER ACCESS TO APS' SYSTEM. DO YOU AGREE?

A. Not really. Because the Jojoba switchyard is outside the Valley cut plane, Panda's interconnection (whether at Palo Verde or Jojoba) does nothing to

increase APS' Valley scheduling limits of 3685 MW that I discussed above. While using additional capacity on SRP's Kyrene line coupled with the 333 MW of firm transmission rights Panda has from APS may allow Panda flexibility to deliver power to Palo Verde and from Palo Verde to California, it doesn't increase the amount of power that APS can schedule into the Valley.

Q. PG&E NEG WITNESS DE ROSA STATES THAT NEG AND OTHER INDEPENDENT POWER PRODUCERS ARE TRADING SIGNIFICANT VOLUMES OF POWER AT PALO VERDE, AND THUS APS HAS OVERSTATED THE PRACTICAL BARRIERS TO COMPETITIVE BIDDING. DO YOU AGREE?

A. No. Like most of the merchant generators, NEG has also focused on trading at Palo Verde, and not the necessary delivery points on APS' transmission system other than Palo Verde. There could be another 20,000 MW at Palo Verde, but that wouldn't alter the limitations of APS' system that preclude all of APS' Valley load from being served from a single injection point like Palo Verde. Simply getting power to Arizona does not necessarily make it possible to serve APS' system.

Q. NEG WITNESS TAYLOR IS SUGGESTING THAT THE COMPETITIVE BIDDING COULD BE DONE BY SPECIFYING RESOURCES TO BE CONSTRUCTED IN THE FUTURE. WOULD YOU AGREE?

A. I agree that there appears to be some uncertainty about what Rule 1606(B) actually means. I would also agree that competitively bidding 50 percent of APS' Standard Offer Service load could theoretically include the construction of additional local generation and transmission resources. However, given the relatively long lead times to construct new transmission resources in Arizona, I believe that there would be significant development risk associated with any

additional transmission required under the model that Mr. Taylor appears to recommend. Also, his comments that simply getting power to Palo Verde resolves the problem demonstrates the same misunderstanding and oversimplification of APS' transmission system that I addressed earlier.

Q. RELIANT WITNESS KEEBLER STATES THAT APS HAS IGNORED PLANNED TRANSMISSION PROJECTS IN ARIZONA OVER THE NEXT SEVERAL YEARS THAT WOULD PROVIDE RELIABLE TRANSMISSION PATHS FOR NEW GENERATION. DO YOU AGREE?

A. No. My discussion earlier assumes that the Southwest Valley Project is in service by the summer of 2003, which does provide more scheduling capability to APS Valley loads. Even with that project in service, the ability to deliver to APS' loads in the Valley is limited because of the underlying 230 kV system.

VIII. CONCLUSION

Q. WHAT CONCLUSIONS HAVE YOU REACHED BASED ON YOUR REVIEW OF THE INTERVENOR AND STAFF TESTIMONY?

A. In general, I believe that the intervenors and Staff vastly oversimplify the complexities of APS' transmission system and the difficulties associated with immediately "redesigning" that system to accommodate a competitive bidding model that does not recognize how the system evolved under regulated least cost planning principles. It is not possible to simply drop off half of APS' power supply needs at Palo Verde, where most of the merchant generators have constructed their plants, and let APS and its customers worry about how to deliver that power. There are limitations on deliverability that result from the transmission system that APS has developed over the last 75 years that must be considered.

Additionally, Mr. Smith and Mr. Rowell agree that there are "risks and uncertainties" associated with competitive bidding and that APS' system cannot currently support the 50 percent requirement embodied in Rule 1606(B). While I agree with those points, the interim competitive bidding proposal developed by Staff is mostly impractical and based on incorrect assumptions. The Staff interim competitive bidding proposal does not present a superior alternative to the phased in competitive bidding in the proposed PPA. From a transmission system perspective, I believe that the proposed PPA is the most reasonable way to provide continued stable and reliable service to APS' Standard Offer Service customers, while allowing the transmission system and related market institutions like the WestConnect RTO to evolve and while phasing in competitive bidding on a reasonable schedule.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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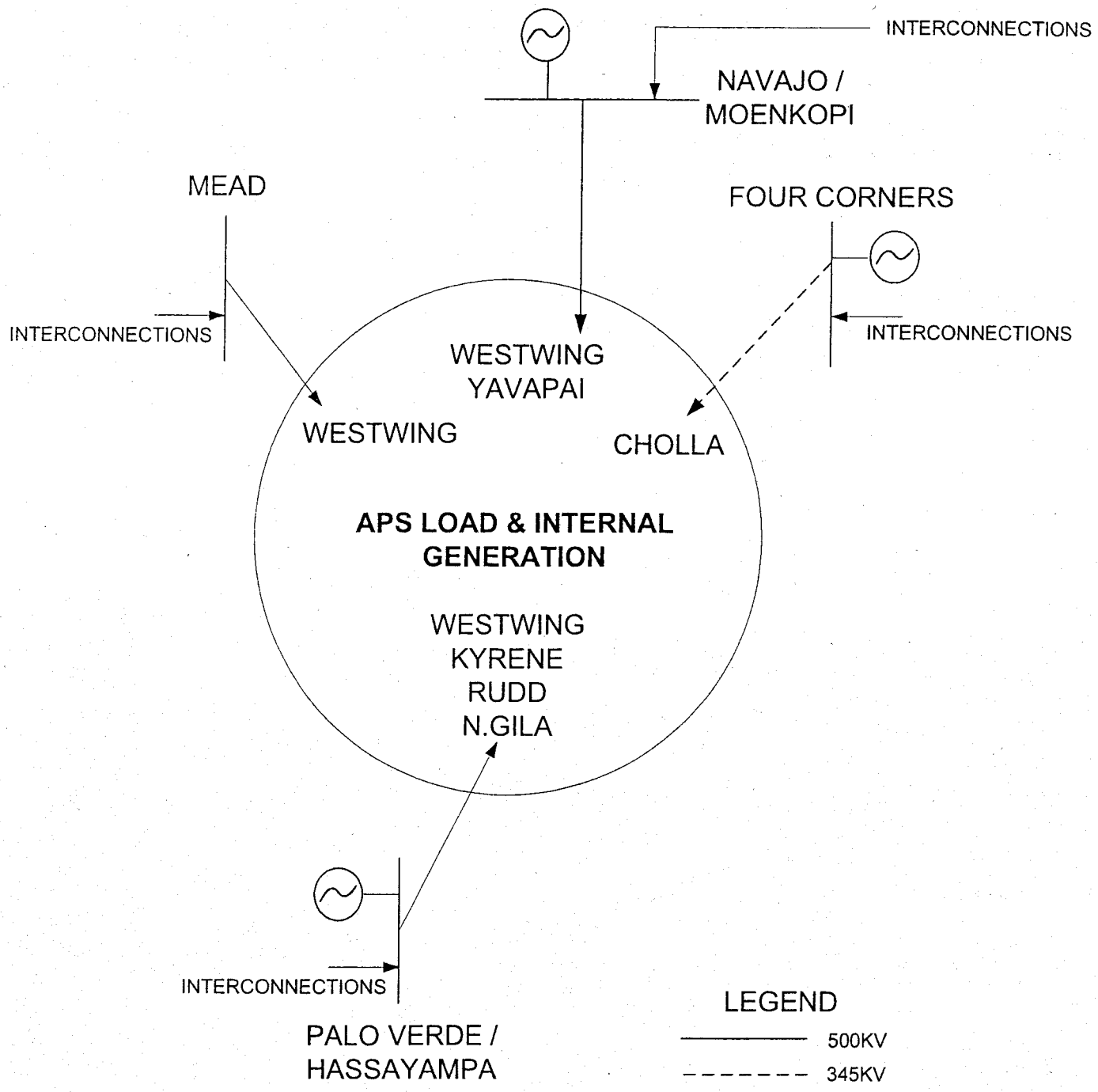
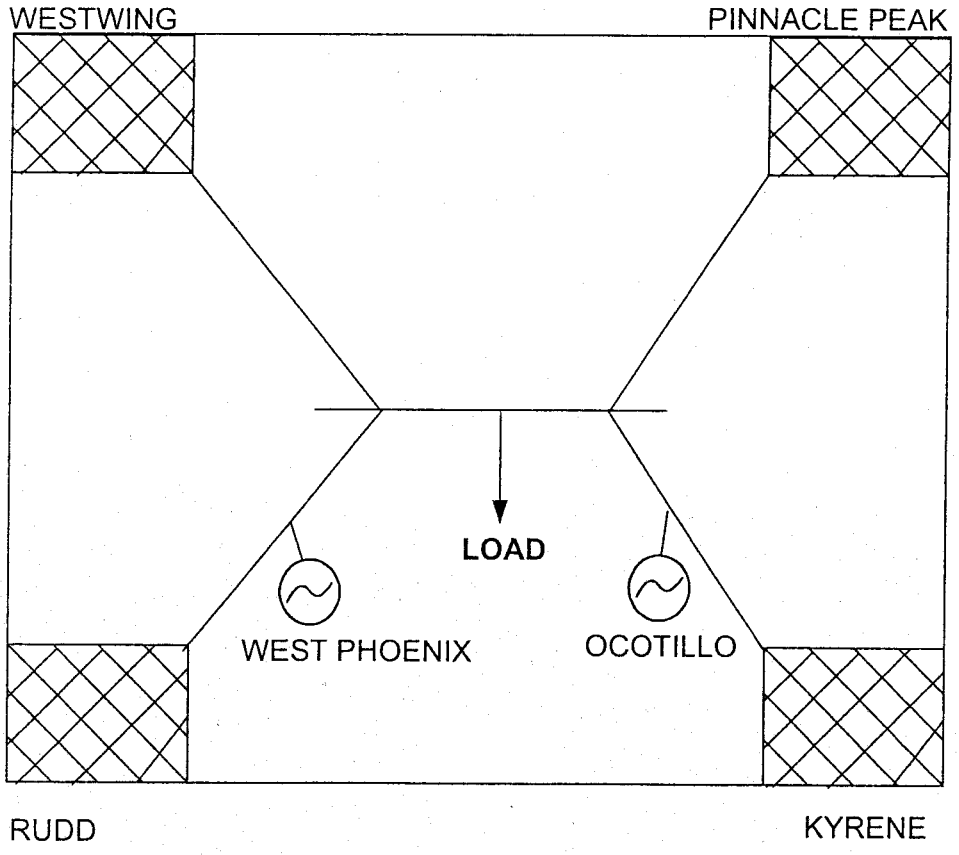
SCHEDULE CD – 1R
SIMPLIFIED APS EHV DIAGRAM



SCHEDULE CD-2R
SIMPLIFIED APS VALLEY 230KV DIAGRAM



Schedule CD-3R

APS Valley Import Analysis

Year	APS Valley Load	APS Transmission	APS Valley Local Gen Reqmnt	APS Valley Gen-Reqd Margin(2)	Theoretical Limit of Counterschedul-ing(3)
2003	4112	3685	427	1080	653
2004	4256		571		509
2005	4405		720		360
2006	4559		874		206
2007	4719		1034		46
2008	4884	4685 (1)	199		881
2009	5055		370		710
2010	5232		547		533

(1) Palo Verde – Table Mesa 500kV,1000MW

(2) Gen includes WP CC 4 & 5, but not WP St 4 & 6
Required margin = 250MW

(3) Assumes all Valley units can be sold off system

(All values in MW)

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

PAUL R. PETERSON

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF UTILITIES DIVISION

MAY 29, 2002

EXHIBIT
S-4
admitted

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Exhibit PRP-4 Best Practices in Market Monitoring (November 2001)

1 **I. QUALIFICATIONS**

2 **Q. Please state your name, business position and address.**

3 A. My name is Paul R. Peterson. I am a senior associate with Synapse Energy
4 Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts 02139.

5 **Q. Please describe your educational and occupational background.**

6 A. I have twenty-two years of experience with energy efficiency policy issues
7 through work with the University of Vermont Extension Service, the Vermont
8 Public Service Board, and, most recently, ISO New England, the operator of the
9 regional electric grid for New England. Over the last 7 years, I have worked on
10 electric restructuring issues directly related to the six New England states,
11 regional wholesale power markets, and Federal Energy Regulatory Commission
12 ("FERC") initiated proceedings. I have a BA from Williams College and a Juris
13 Doctor degree from Western New England College School of Law. My
14 qualifications are described in detail in Exhibit PRP-1.

15 **II. INTRODUCTION AND RECOMMENDATION**

16 **Q. What is the purpose of your testimony?**

17 A. My testimony identifies critical structures and rules that are necessary to
18 minimize market manipulation and exercises of market power in restructured
19 electric markets. Although problems in California's wholesale markets have
20 garnered most of the headlines, there have been significant problems in the New
21 York, New England, and PJM markets due to market design flaws and the abusive
22 behaviors of market participants. The consequences of many of these behaviors
23 have been unreasonably high wholesale market prices that can translate into
24 higher costs for consumers. My testimony supports the testimony and
25 recommendations of Staff witnesses, including the testimony of Mr. Schlissel and
26 Mr. Talbot, by providing additional information for the Arizona Corporation
27 Commission ("Commission") to consider in the instant docket.

Q. Please summarize your recommendations to the Commission as they pertain to this Docket.

A. The Commission should proceed cautiously with restructuring in Arizona in light of the significant problems that have been experienced in competitive, bid-based wholesale markets around the country. Until specific structures such as RTOs and well-designed markets that are subject to appropriate monitoring and mitigation oversight are established and are demonstrated to be effective, Arizona electricity consumers will be exposed to the risk of market manipulation, abuse, and gaming that may lead to requests for sudden and dramatic increases in retail electricity prices. Under current market models, the Commission will have little immediate recourse other than to grant the price increases, and then petition the FERC for prospective changes to avoid future high prices. My testimony supports Staff's general recommendation that if APS is confident that the transfer of its assets is the best course of action at this time, then it is appropriate to assign to APS the financial risks associated with such a decision.

III. DISCUSSION

Q. What guidance has the FERC provided regarding market monitoring in wholesale electric markets?

A. FERC's guidance has evolved over the years in response to the events that have occurred in wholesale electricity markets. In the mid-1990s, in Orders 888 and 889, the FERC required companies that sought market-based rates to file studies documenting the likelihood of market power issues in the wholesale market in which they intended to operate, and to file plans for addressing any potential exercises of market power. As Independent System Operator ("ISO") administered wholesale markets were implemented in the late-1990s, market monitoring requirements and activities expanded in response to the discovery of market design flaws and the experience of market abuses. In a series of Orders on RTO formation beginning in July of 2001, the FERC has initiated proceedings and provided extensive guidance and recommendations on many design elements of wholesale bid-based markets. In November 2001, FERC announced a new "test" (the supply margin assessment or pivotal test) that companies seeking

1 market-based rates must satisfy. In March 2002, FERC provided the first outline
2 for standardization of RTOs and market designs; a process that FERC believes
3 will assist a rapid implementation of RTO structures. The days of "open
4 architecture" may have passed.

5 **Q. What do you mean by "open architecture"?**

6 A. Until last summer, the FERC had encouraged transmission owning entities to file
7 RTO proposals that meet the four characteristics and eight functions specified in
8 Order 2000[1] through any business structure, market design, and transmission tariff
9 that was reasonable and likely to be effective; the shorthand term for this was
10 "open architecture". In its numerous Orders on RTO filings of July 12, 2001, the
11 FERC emphasized that the time for experimentation was over. Experience with
12 ISO business structures, market designs, and transmission tariffs had established
13 preferred approaches or "best practices" that should become standards for RTOs.
14 Subsequently, FERC has announced several initiatives to develop standard
15 designs and processes for wholesale markets, transmission tariffs, interconnection
16 rules, and market power tests. While not explicitly repudiating the "open
17 architecture" concept, FERC appears to be favoring proven approaches over
18 untested or innovative ideas.

19 **Q. What are the implications for the development of RTOs in the Western**
20 **Interconnection?**

21 A. It is likely that RTO proposals will need to conform to the standardization process
22 that FERC is conducting. The design of wholesale electric markets, including the
23 monitoring and mitigation functions for those markets, will need to be consistent
24 with the results of FERC's NOPR proceeding which is scheduled for this summer
25 and fall. The same is likely to be true for wholesale tariffs, interconnection rules,

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[1] The four characteristics are (1) independence from market participants, (2) appropriate scope and configuration, (3) operational authority, and (4) short-term reliability. The minimum functions pertain to (1) transmission service and tariff, (2) congestion management, (3) parallel path flow, (4) ancillary services, (5) transmission availability information, (6) market monitoring, (7) transmission planning and expansion, and (8) interregional coordination. Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999).

and a host of other procedures both large and small. All the current RTO filings before the FERC will probably need substantial modification.

Q. What have been the experiences in bid-based wholesale markets?

A. I have excluded California from my discussion because its problems have been well publicized and analyzed, and because its market structure was unique. Less well known are the numerous design flaws and indications of anti-competitive behavior that have resulted in significant price distortions in all of the Northeast markets. PJM has had problems with its capacity cost-allocation system, New York has had problems with its reserve markets, and ISO-NE mitigated bids in its Installed Capacity market (before filing to abolish it). All three of the Northeast ISOs have experienced enormous variances in energy bids under certain circumstances and they all currently have $1,000 bid caps in place. Independent studies of PJM and New England suggest that prices average 5 – 20 percent above cost.

Q. Please describe the extent of market monitoring and mitigation incorporated in early ISO filings.

A. New England provides a good case study because it filed for market-based rate authority subsequent to California and PJM, but before New York. In December 1996, the New England Power Pool ("NEPOOL") filed for market-based rate authority and the creation of an Independent System Operator ("ISO-NE") to dispatch the bulk power system and administer the new bid-based markets. New England had been operated for over twenty-five years as a tight power pool with centralized dispatch and a shared-savings mechanism to facilitate least-cost resource utilization. NEPOOL's filing was designed to retain most of the system operating procedures developed over the preceding years and to substitute a bid-based dispatch for the existing cost-based dispatch.

Q. How did NEPOOL address issues about market power?

A. As part of its overall filing, NEPOOL included a study that determined that congestion problems were rare in New England, except for certain load pockets during times of seasonal (summer) high demand. Based on that study, NEPOOL initially proposed minimal market monitoring activities with no specific

1 mitigation procedures. Other parties, including the New England Conference of
2 Public Utilities Commissioners ("NECPUC"), challenged NEPOOL's rosy
3 assessment and asked FERC to require NEPOOL to be more proactive. In a June
4 1997 Order approving NEPOOL's overall plan, FERC directed NEPOOL, the
5 just-formed ISO-NE, and NECPUC to engage in discussions to create a specific
6 market monitoring and mitigation plan and to file it with the FERC.

7 **Q. What was the result of this effort?**

8 A. Over the next year, the parties engaged in a collaborative process that resulted in
9 Market Rule and Procedure17 ("MRP 17", attached as Exhibit PRP-2), which
10 FERC approved in November 1998 and further modified in April 1999 when it
11 gave final approval for the implementation of market-based rates. Market Rule
12 17 included specific procedures for addressing congestion due to reliability
13 concerns (reliability-must-run units) and a separate section for evaluating bids that
14 deviate from competitively established levels. It also established mitigation
15 options and referenced penalty and sanction options that could be applied for
16 improper behavior. MRP 17 authorized ISO-NE to collect cost data from market
17 participants and required ISO-NE to file monthly, quarterly, and annual reports
18 with Federal and state regulators, as well as making redacted versions available to
19 the public.

20 **Q. Why is MRP 17 important to this proceeding?**

21 A. All jurisdictions where consumers are subject to prices that flow from wholesale
22 markets need to implement a rule similar to MRP 17. There also needs to be an
23 entity responsible for implementing it. The Commission should evaluate the
24 protections available to Arizona consumers if APS goes forward with its market-
25 based proposals.

26 **Q. How have higher costs been passed on to consumers in the Northeast**
27 **wholesale markets?**

28 A. One significant component of higher consumer costs is congestion costs. These
29 costs arise due to both transmission congestion (reliability uplift) and bid-based
30 congestion (energy uplift). In general, reliability congestion costs are socialized
31 among all market participants. Energy congestion costs are currently allocated to

1 specific zones in PJM and NY, and will be done in a similar manner in New
2 England in the near future.

3 **Q. Are congestion costs an unanticipated expense?**

4 A. Since the markets were implemented in New England in May 1999, congestion
5 costs have far exceeded the predictions of NEPOOL's study. This is due, in part,
6 to the requirements of several New England states that traditional utilities divest
7 their generation assets and serve their customers through standard offer contracts
8 from marketplace suppliers or reliance on the wholesale spot market. One result
9 of divestiture is that generation that had traditionally served native load is now
10 contracted to provide power to distant customers; the delivery of that power is
11 subject to available transmission capacity that may not be sufficient under certain
12 seasonal load conditions. As a consequence, more expensive generation is
13 dispatched by ISO-NE to maintain reliability, thereby incurring a "congestion"
14 cost (the portion of the unit's bid-price that exceeds the market clearing price).
15 These costs are then shared by all market participants based on a load allocation
16 formula. Another reason for higher congestion costs is that bids appear to be
17 exceeding the cost-based pricing that prevailed prior to May 1999. A study
18 released in March 2002, which covered the start of the markets in 1999 through
19 the summer of 2001, suggests that bids have been four to twelve percent higher
20 than a cost-based dispatch. These higher bids are another reason that congestion
21 occurs more frequently and at higher amounts than NEPOOL's study anticipated.
22 Load suppliers try to deliver lower priced generation into areas with high local
23 bids. Overall, congestion costs total hundreds of millions of dollars on an annual
24 basis, despite ISO-NE's aggressive efforts to mitigate bids where appropriate and
25 negotiate fixed-price contracts for reliability-must-run generation.

26 **Q. How are congestion costs relevant to this proceeding?**

27 A. The Arizona utilities, as recommended in other testimony, need to conduct studies
28 to evaluate the potential constraints on their systems that could lead to congestion
29 costs or the potential to exercise market power. As a conservative measure, the
30 Commission should independently review these studies. Several of ENRON's

California strategies, as reported in the press, appear to have used congestion as a mechanism for raising prices.

Q. How has MRP 17 changed over the years in New England?

A. There have been numerous changes to MRP 17 since the implementation of bid-based wholesale markets in May of 1999. Most importantly, MRP 17 has been revised in ways that reflect FERC's efforts to balance market participants' needs for predictability and price certainty with the responsibility of ISOs to administer competitive and efficient markets. In July 2000, FERC ordered ISO-NE to revise its bid-mitigation procedures to eliminate the "excessive discretion" it had to decide when to mitigate bids. Pursuant to that FERC Order, ISO-NE adopted bid-mitigation thresholds similar to those implemented by NYISO: bids that exceed reference prices by 300% or $100 per MWH (whichever is lower) and raise the market clearing price by 200% or $100 per MWH (whichever is lower) are automatically lowered to the reference price. Recently this spring, ISO-NE has been revising its procedures for establishing prices for reliability-must-run generation. Instead of the current process of negotiating a price with each generation owner, which has been criticized as inconsistent and unfair, ISO-NE is trying to establish a formula that generation owners can select as a bid ceiling; if their bids do not exceed the ceiling threshold, they will not be reviewed for bid mitigation. Generation owners will still have the option of negotiating a long-term contract price with ISO-NE as an alternative.

Q. What is your assessment of these changes?

A. Although there is some value in providing clear boundaries and expectations for participant behavior, particularly bidding, the rules need to be carefully drafted to not provide "safe zones" within which participants can engage in abusive behavior without concerns about monitoring and accountability. I have some concerns that the thresholds that FERC considers appropriate are far too high, and can serve to sanction manipulative behavior. A popular comment about markets, in general, is that they work best when market participants struggle with equal emotions of greed and fear. Greed to encourage them to bid into the market in order to maximize earnings and fear that other bidders may force them out of the

1 market with a lower bid. Until competitive pressures in the wholesale electricity
2 markets (abundant supplies and load response) can provide the appropriate
3 amount of fear, market monitoring needs to provide an alternative "fear", a fear
4 that abusive behaviors will be detected and corrected.

5 **Q. Are there other market rules that relate to market monitoring activities?**

6 A. Yes. In New England MRP 15 provides ISO-NE with the authority to revise
7 market prices under certain specific conditions. The NYISO has a similar
8 authority in its rules and procedures. At the start of the markets, both ISOs had
9 the authority to revise market prices after the fact due to market design flaws or
10 prices that were inconsistent with a workably competitive market. This authority
11 was utilized frequently during the first three months of market operation in NY
12 and New England due to numerous market design flaws that were discovered after
13 market operations began. These flaws produced prices during certain hours that
14 were hundreds of dollars higher (per MWH) than competitive prices. FERC
15 granted ISO-NE a sixty-day extension of this authority in August 1999, but
16 refused a similar request at the end of September. NYISO's authority was
17 temporary as well. FERC stated that market participants needed to have some
18 certainty regarding posted hourly clearing prices and stated FERC's preference
19 for *prospective* changes to market rules, rather than *retroactive* price corrections,
20 to address market design flaws. Nonetheless, FERC left intact both ISOs'
21 authority to correct prices for errors, such as improper data entry or
22 miscalculations, provided that the prices were flagged for correction within a
23 narrow timeframe of 24 hours to three days.

24 **Q. Why are MRP 15 and similar authority important to this proceeding?**

25 A. It is another factor that needs to be considered in terms of balancing protections
26 and risks. A wholesale market place that seeks bid-based authority from FERC
27 should have such a rule in place.

Q. In light of its experience with wholesale electricity markets, is the FERC considering comprehensive policy changes in regard to market monitoring and mitigation?

A. Yes, in March 2002, FERC released a Staff Working Paper on Standard Market Design ("SMD") that includes specific comments on Market Power Monitoring and Mitigation.[2] FERC has invited comments on the Working Paper and stated its intention to issue a Notice of Proposed Rulemaking on SMD this summer. The Working Paper makes some general comments as well as some detailed recommendations that reflect FERC's experience with bid-based wholesale markets. The results of this FERC proceeding will need to be reflected in the RTO filings currently pending.

FERC observes that structural solutions are more effective than behavioral solutions for mitigating market power. FERC notes that many problems in the early years were due to market design flaws and that the first priority should be to establish efficient market designs. FERC believes that SMD will help limit the problems that occur at the start of market implementation. In addition, FERC wants to see regional transmission organizations ("RTOs"), a large number of suppliers, and effective demand response programs in place as safeguards:

> RTOs and independent transmission operators are structural mitigation for vertical market power because they remove the control of transmission access from transmission companies that also compete in generation markets. With respect to generation market power, market forces such as supply and demand responses are the most potent and lasting means of mitigating market power, so solutions that increase the potential number of suppliers or increase price-responsive demand must be promoted. If market power is not mitigated through structural solutions, market rules need to be designed to mitigate market power.[3]

FERC identifies several principles that should guide the development of market power mitigation rules and a market monitoring plan. These include bid caps as a

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[2] FERC Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, 3-13-02. Attached as Exhibit PRP-3.

[3] Id., at 21.

1 proxy for demand response, mitigation of reliability-must-run generation,
2 assessing the overall efficiency of the market, and a preference for ex-ante
3 mitigation instead of ex-post price changes. FERC then discusses the general
4 structure of the market monitoring unit ("MMU"), stating that it must be
5 independent of RTO management and report directly to the RTO Board of
6 Directors and to FERC. In addition, the MMU should monitor all markets and
7 conduct periodic reviews and analyses of the markets. While acknowledging that
8 MMUs will be the first line of defense, FERC states that, ultimately, it has the
9 responsibility for monitoring and to take corrective actions when needed.

10 **Q. Do you concur with FERC's general principles and recommendations?**

11 A. On many issues, I am in complete agreement. My own research confirms that
12 market monitoring should become a more intensive endeavor in the near term;
13 this is not a time to assume that markets will be self-correcting. An MMU needs
14 to have an adequate budget, access to all market information, and the
15 independence to make recommendations to both the RTO Board and the FERC.
16 In the near-term, bid caps and other special rules (such as requirements to bid all
17 capacity into the market every day) will provide safeguards against some forms of
18 blatant manipulation. The RTO's authority to manage the daily power flows over
19 the grid and through the market system will also provide significant protection
20 against market power abuses. In a report I co-authored, commissioned by the
21 consumer advocate offices of the Mid-Atlantic states (part of the PJM ISO service
22 area), we chronicled in detail the market monitoring practices of the three
23 northeast ISOs (PJM, NYISO, and ISO-NE).[4] We developed a list of 14
24 recommendations in that report, many of them similar to and consistent with the
25 recommendations in FERC's Working Paper.

26 **Q. Are you in disagreement with any of the FERC comments?**

27 A. Not so much disagreement as a matter of different emphasis. I think FERC
28 underestimates the need for the RTO market monitoring staff to make near-real-

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4 *Best Practices in Market Monitoring*, Peterson, Biewald, Wallach, Johnston, and Gonin, November 2001. Attached as Exhibit PRP-4.

time decisions in response to the behavior of market participants. FERC almost naively assumes that the market monitoring plan will cover all possible contingencies and that the MMU staff will just need to implement the plan. My experience at ISO-NE indicates that there are many occasions when quick action is needed. I would give the MMU the authority and discretion to act immediately to implement rule changes. I also support a limited authority for the MMU staff to flag prices for evaluation and to correct prices as warranted within a few days based on possible design flaws or market manipulation.

In addition, FERC talks almost exclusively about its concerns over the exercise of market power. I do not want to get into a word game, but "market power" is too narrow and limited a concept to encompass all the areas of market participant behavior that need to be monitored. Evaluating one company's overall market share is less helpful than evaluating each company's relative market position for each hour that it bids. That is one reason why the FERC's new pivotal test is an improvement over the traditional "hub and spoke" or HHI analyses. I prefer to think of monitoring for market abuses and manipulation, of which market power is certainly a primary concern and example. But on a day-to-day basis, there are many "behaviors" in which market participants engage, ranging from competitive to manipulative to abusive to corrupting. I am convinced that many market participants approach wholesale electricity market bidding and trading as a set of rules that they can "game" in an effort to improve their company's bottom line. A much discussed study by Cornell University shows how relatively unsophisticated "energy trader novices" can quickly learn how to manage and bid a portfolio of wholesale market electricity resources to maximize profits when they are given incentives to do so.[5] Recent revelations about trading practices in California illustrate the pervasiveness of these strategies; it is highly likely that strategies similar to those utilized by Enron in California are being utilized in other wholesale electricity markets.

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[5] *Testing the Performance of Uniform Price and Discriminative Auctions*, Mount, Schulze, Thomas, and Zimmerman (July 16, 2001).

Q. What is the significance of proposed market design changes in California and recent actions of the California legislature?

A. As I stated earlier in this testimony, the FERC is indicating that it is going to be much more prescriptive in regard to the design of wholesale bid-based electricity markets. I expect that FERC is unlikely to approve significant changes to existing bid-based markets or grant market-based rate authority to any new entities until it completes its NOPRs on standardization. The market design proposals filed on May 1, 2002, by the California ISO would create substantial changes to the California wholesale market system. There is still a great deal of debate and discussion around the proposals by California stakeholders, due to the technical detail and the complexity of the proposed rules. There could be considerable delay before the FERC acts on the proposed changes. Anything approved by the FERC prior to the completion of its NOPR process will probably be conditioned on making a subsequent compliance filing that would conform to the NOPR results. Given recent revelations about the extensive and pervasive market manipulations that occurred under the previous bid-based wholesale market system in California, -- manipulations that appear to have escaped detection by the California market monitoring process and two separate FERC investigations -- I would be surprised if the FERC approved any major changes to the California markets in the next six to twelve months. While it is important to monitor the developments in California, I expect that the proposals currently being discussed are likely to be modified over the next year.

The California legislature has implemented a proposal to make California owners of generation resources subject to reporting requirements and oversight as a condition of participation in the California markets. These initiatives are designed to enhance reliability of power supplies and eliminate some of the opportunities for egregious market manipulation through the physical withholding of resources. The bill also creates a California Electricity Generation Facilities Standards Committee to perform the oversight function.

Q. Are you concerned that the removal of price caps for the Western Interconnection will produce adverse impacts for Arizona electric consumers?

A. First, I doubt that the FERC will fully remove the current price caps in September and allow unrestricted bidding in the Western Interconnection. There is just too much uncertainty about how the markets will react and the problems of 2000 and 2001 are all under the spotlight again due to the ENRON discovery documents. It is much more likely that FERC will propose some modifications or easing of the current restrictions. FERC needs to proceed cautiously and slowly to rebuild confidence in bid-based market structures in general, and in the West in particular, given the debacle in California. Regardless of FERC's actions (or inaction), Arizona consumers can remain relatively insulated from the adverse impacts of the wholesale markets through actions that can be taken by the Commission. Those actions would include many of the Staff recommendations, such as requiring a market power study before any transfers occur and ensuring that structures, safeguards, and mitigation measures are in place before "competition" should be implemented.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT PRP-1

Paul R. Peterson

Senior Associate
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(617) 661-3248 • fax: 661-0599
www.synapse-energy.com

EMPLOYMENT

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, March 2001 - present.
Provide consulting services on a variety of energy and electricity related studies.

ISO New England Inc., Holyoke, MA.

Coordinator of Regulatory Affairs, 2000 – 2001.
Coordinate regulatory activities with individual state public utility commissions, the New England Conference of Public Utilities Commissioners (NECPUC), and the Federal Energy Regulatory Commission (FERC). Assist the General Counsel on a variety of specific tasks and documents; draft letters and reports for the Chief Executive Officer.

Public Information and Government Affairs, 1998 – 1999.
Worked with all ISO-NE constituencies including NEPOOL Participants, regulatory agencies, and stakeholder groups in large-group and small-group formats. Developed and presented materials that described ISO-NE's functions, special projects (including Year 2000 rollover issues), and future evolution.

Vermont Public Service Board, Montpelier, VT. Senior Associate, March 2001 - present.

Policy Analyst, 1997 - 1998.
Monitored House and Senate legislation on electric restructuring; helped coordinate the passage of Senate Bill S.62 in 1997. Coordinated the New England Conference of Public Utilities Commissioners (NECPUC) activities regarding NEPOOL restructuring; assisted in drafting documents to create an Independent System Operator (ISO) for New England. Worked on New England task forces to develop a model rule for electric disclosure projects for consumer information and regulatory compliance.

Utilities Analyst, 1990 - 1997.
Reviewed regulated utility filings for changes in rates; judicial Hearing Officer for contested cases on a wide range of topics; wrote all decisions regarding annual utility applications for Weatherization Tax Credits. Focused on integrated resource planning and electric industry restructuring; initial Hearing Officer for the Energy Efficiency Utility docket. Chaired the Staff Energy Committee of NECPUC.

Energy Analysis, Burlington, VT. Consultant, 1990.
Energy-efficiency program design and evaluation.

UVM Extension Service, Burlington, VT.

Area Energy Agent, 1985 - 1990.
Performed tasks pursuant to an annual contract with Vermont Department of Public Service to conduct energy research, design energy efficiency programs and provide public education (see attached list of publications).

Home Energy Audit Team (H.E.A.T.), 1978 - 1985.
Home energy audits; energy surveys for commercial, municipal, and non-profit buildings; energy education and information.

The Close-Up Foundation, Washington, D.C. Program Administrator, 1975 - 1978.
Directed weekly government studies program for 200 high school students and teachers; supervised a staff of fifteen; coordinated curriculum and logistical aspects of program.

EDUCATION

Admitted to Vermont Bar, February 1992

Western New England College School Of Law, Springfield, MA.
- Juris Doctor degree, cum laude, May 1990
- American Jurisprudence Award: Remedies, 1989
- Merit Scholarship recipient
- Student Bar Association Representative

Williams College, Williamstown, MA
- Bachelor of Arts degree, cum laude, June 1974
- Political Science and Environmental Studies
- Tyng Scholarship recipient

National Judicial College, Reno, NV
- Administrative Hearings, Sept., 1994
- Civil Mediation, March, 1996
- Civil Mediation, July, 1997 (faculty assistant)

American Inns of Court, Northern Vermont Chapter
- 1995-1996, member
- 1996-1997, member

Continuing Legal Education, Vermont Bar Association
- Americans with Disabilities Act, April 1992
- Ethical Issues/Governmental Agencies, October 1992
- Advance Medical Directives, May 1993
- Family Law Workshop, September 1993
- Negotiating Settlements, May 1994
- Physician Assisted Suicide Symposium, October 1996
- Electric Industry Restructuring, March 1999
- Advance Medical Directives, May 1999
- Tax Law for Non-Tax Law Attorneys, May 2000
- International Law Update, June 2000

UVM Continuing Education, Brattleboro, VT
Small Computer Course, Spring 1983
Communications Workshops, Spring 1983 & Spring 1984

PUBLICATIONS & PROJECTS

Residential Construction Survey, Survey of Vermont new home construction for construction techniques, energy-efficient design, appliance loads, etc. 1986, 1989.

Vermont Vacation Home Energy Study, Survey of vacation home energy consumption and impact on Vermont statewide electrical demand. 1989.

Dairy Farm Energy Use, A detailed examination of electrical energy consumption on forty Vermont dairy farms to identify opportunities for improving energy-efficiency. 1987.

Mobile Home Booklet, A fresh look at energy saving opportunities for mobile homeowners. Specific problems of cold climates are addressed. 1987.

Dairy Farm Energy Project, Implemented $400,000 grant from Vermont Department of Agriculture for installation of milk-cooling equipment that also produced hot water. 1989.

Vocational Building Trades Instructors, Annual workshops on energy-efficient construction practices for the teachers of Vermont building trades students. Classroom presentations on selected topics. 1986 - 1989.

Brattleboro Community Energy Education Project, Coordinated a Central Vermont Public Service Company funded project to promote energy-efficiency awareness through community programs. 1985.

PROFESSIONAL CONFERENCES

Federal Energy Regulatory Commission Conference, Philadelphia, PA. March 2001.
National Association Of Regulatory Utility Commissioners, Washington, DC. 1998 - 2000
Advanced Integrated Resource Planning Seminar, Berkeley, CA 1995
ACEEE Summer Study, Pacific Grove, CA 1992 & 1994
1991 DOE Low-Level Radioactive Waste Conference, Atlanta, GA

Resume dated March 2001.

EXHIBIT PRP-2

17 MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

This Rule provides for monitoring and, in specifically defined circumstances, mitigating behavior that interferes with the competitiveness and efficiency of any or all of the NEPOOL Energy, AGC and Operating Reserve markets.

Section 6.4 of the Interim ISO Agreement states:

> **Market Assessment.** The ISO shall have the authority to independently assess the competitiveness and efficiency of the NEPOOL Market and shall convey its findings and recommendations to NEPOOL. The ISO may propose or adopt such new System Rules or Procedures as it may deem necessary or desirable to implement any such recommendations, subject to and in accordance with the procedures set forth in Section 6.17.

The ISO and NEPOOL are committed to ongoing consultation and cooperation to develop appropriate Market Rules. Consistent with the Interim ISO Agreement and this Rule, the ISO will work with the Federal Energy Regulatory Commission (the "Commission") and other jurisdictional agencies and with NEPOOL Participants to monitor for design flaws in the market, to monitor and evaluate any additional patterns of anomalous market behavior that may be detrimental to the efficient and workably competitive operation of the markets, and to determine whether they can be corrected by market design changes or improved mitigation standards.

This Rule also provides for reporting of information about the markets, including analysis based on the ISO's monitoring activity and reporting of mitigation activity.

This Rule is intended to protect and foster competition. In market monitoring and mitigation the ISO will, to the extent possible, avoid interfering with competitive price signals. Prices will be allowed to rise and fall to levels determined by competition.

This Rule provides administrative guidelines and procedures for identifying and modifying certain behaviors that may interfere with the competitive and efficient operation of the market. No action taken or report made by the ISO under this Rule 17

constitutes a finding that any party possesses market power or is exercising market power, nor a conclusion that any party has violated any law or government regulation.

17.1 MONITORING OBJECTIVES

The ISO is authorized to monitor any aspect of the NEPOOL markets to the full extent permitted by the Interim ISO Agreement. The following list of objectives is not exclusive, and is presented for the guidance of the ISO, NEPOOL Participants and others interested in the NEPOOL markets.

A seller with market power can profit by withholding its output either partially or temporarily and raising prices. Withholding may take one of two forms: physical withholding (such as declaring a Resource unavailable) and economic withholding (such as raising a Resource's bid so high it is effectively no longer available to the market). The ISO shall monitor the markets for indications of such withholding.

A seller with market power can also profit by raising the price of the Resource that actually sets the clearing price in a market or by raising its price or changing its unit characteristics to receive excess uplift in a market. The ISO shall monitor the markets for conduct that suggests the exercise of market power, including opportunistic price-setting, behavior, and attempts to receive excessive uplift payments.

In monitoring the market and implementing the mitigation procedures the ISO will recognize that the same behavior that might under some conditions suggest the abuse of market power is often, under other conditions, normal, beneficial and pro-competitive. In particular, restricting unit operation through redeclaration, operating parameters or bid prices in order to protect the safety of persons or equipment or ensure compliance with environmental licenses and permits is prudent behavior consistent with a competitive market. In addition, actions to efficiently utilize resources (including, but not limited to, fuel and emissions) in the highest value market, whether geographic, intertemporal, or component commodity market (e.g., natural gas market, or emission trading) are competitive activities and would not be subject to mitigation under this Rule. The ISO will work to ensure that these distinctions are clearly understood and that all monitoring and mitigation activities are implemented fairly and consistently in accordance with this Rule 17. Further, difficulties in accurately reflecting generator economics caused by

lack of a day-ahead market, some unit commitment without consideration of operating reserve bids, and some real-time dispatch without consideration of operating reserve bids may result in the need to vary unit characteristic and bid price submittals to avoid uneconomic operation.

17.1.1 Monitoring for Physical Withholding

Physical withholding of a Resource may include, but is not limited to, (i) falsely declaring that a Resource has been forced out of service or otherwise become unavailable, (ii) submitting an unjustifiably inflexible set of operating parameters so that the Resource is not or will not be dispatched or scheduled when it would be in the economic interest, absent market power, of the withholding entity for the Resource to be dispatched or scheduled, or (iii) operating a generating unit in real-time to produce an output level that is significantly less than the ISO-NE's dispatch instruction.

In monitoring for physical withholding the ISO will consider a number of factors and perform a number of tasks, including the following:

Require the entity responsible for operating a Resource (whether or not it is the same entity that decides the bid) to certify confidentially to the ISO the reason for failure of a unit to be available (forced outage, derating, change in operating characteristics, etc.) as recorded in the operator's log.[1] This review will include review of the unit's compliance with the bidding requirement for Low Operating Limit set forth in Appendix 3A to Market Rule 3.

Compare current and historical outage data to determine changes in patterns of unit availability, recognizing the transition from a regulated to a market-based environment.

If the ISO detects possible physical withholding (or possible physical withholding combined with possible economic withholding), the ISO will use its best efforts to provide each seller with an opportunity to explain or justify its conduct as provided in

[1] The ISO's consideration of patterns of energy unavailability on limited energy Resources would not require routine certification of reasons for actual bid price and self-schedule strategy. The ISO will, however, investigate anomalous behavior as it arises.

Section 17.2.5 before the ISO takes corrective action. However, the ISO should not delay if the affected seller does not provide an explanation in a timely manner. There

may be other unusual circumstances in which the ISO determines it needs to act before consulting with an affected seller.[2]

17.1.2 Monitoring for Specific Mitigation Thresholds

The ISO shall monitor for all the specific mitigation thresholds set forth in Sections 17.2.2 and 17.2.3. Monitoring for these thresholds may serve as the basis for mitigation under Section 17.2.4.

17.1.3 Other Monitoring Objectives

The ISO will conduct such additional monitoring as it deems necessary. Among other objectives, the ISO will monitor for:

- Behavior that may constitute economic withholding.
- Behavior consistent with an attempt to set the clearing price.
- Other price anomalies that appear inconsistent with competitive markets.
- Flaws in market design or software that reward a strategy of raising bids or overstating operating parameters in any market.
- Actions in one market that affect price in another market.
- Other aspects of market implementation that prevent competitive market results.

The ISO will include significant results of such monitoring in its reports under Section 17.6. Monitoring under Section 17.1.3 cannot serve as a basis for mitigation under Section 17.2, 17.3 or 17.4. If the ISO concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it can proceed under Section 17.5.

[2] This includes, for example, situations where the ISO determines it must act immediately to assure the reliability and security of the system, or the efficiency and competitiveness of the market.

17.1.4 Thirty Day Average Monitoring

The ISO shall investigate the reasons for and market impact of any bids that exceed the following threshold:

A Resource's Out of Merit Order bid average for Energy Bids, AGC Bids or Reserve Bids exceeds the unit's corresponding Out of Merit Order Average Threshold as defined in Appendix 17-C.

17.2 GENERAL MITIGATION PROCEDURES

The ISO shall proceed to mitigation whenever one or more of a Participant's bids or declared unit characteristics (i) exceeds the thresholds described in Section 17.2.2, and (ii) exceeds the market impact thresholds described in Section 17.2.3, and (iii) is not explained by the Participant in accordance with Section 17.2.5 or by other information available to the ISO. The ISO shall notify the Designated Entity that it is subject to mitigation at or before the imposition of mitigation. The ISO also will disclose publicly (in its Monthly Reports) the fact of mitigation and the kind of action taken, but not the Participant or specific Resources involved. Mitigation under this Section 17.2 that affects unit commitment or dispatch shall be imposed only prospectively.

17.2.1 Market Rules to Prevent Physical Withholding

Market Rule 13 governs the imposition of sanctions for physical withholding. Other Market Rules may provide additional remedies for physical withholding or noncompliance with dispatch instructions. Nothing in this Rule limits the ISO's authority to act under Market Rule 13 or other Market Rules in the event of physical withholding. If the ISO determines that a mitigation remedy for physical withholding is necessary over and above the existing Market Rules, it may seek such authority in accordance with Section 17.5.

17.2.2 Mitigation Thresholds for Economic Withholding and Attempts to Affect Price or Uplift Payments

The following thresholds shall be employed by the ISO to identify economic withholding that may trigger mitigation:

17.2.2.1 Reference Price Screens

The ISO shall calculate a Reference Price separately for the Hot Startup Price, Cold Startup Price, No-load Price, each 10 MW block of the Energy Block Price, and each 10 Reg-hr AGC block price, of each Resource bidding in the NEPOOL markets. The block prices shall be determined as the average of the prices submitted for each MW or Reg-hr within the block.

(a) For (1) a block that has run for 15 hours or more (in the aggregate) during the past 30 days[3] for Energy, excluding (A) the megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power and (B) megawatthours priced above the Energy Clearing Price ("ECP") that were not eligible for Uplift compensation, or (2) a unit that has been designated for Operating Reserve or AGC for 15 hours or more (in the aggregate) during the past 30 days, the Reference Price for that block or unit shall be calculated using the formula in Appendix A.

(b) For (1) a block not covered by subparagraph (a) above that has run at least 15 hours during the past 90 days for Energy, excluding (A) any bid of zero or less than zero, (B) the megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power and (C) megawatthours priced above the Energy Clearing Price that were not eligible for Uplift compensation, or (2) a unit's No-Load Price or a unit that has been designated for Operating Reserve or AGC for at least 15 hours during the past 90 days, the Reference Price for that block or unit shall be the arithmetic average of those in-merit bids, adjusted for changes in fuel prices.

[3] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, this screen will evaluate the number of in-merit hours in the most recent 30 days when the unit was operable.

(c) For a unit that has started up for at least 15 times during the past 90 days for Energy, excluding (A) any bid of zero or less than zero, (B) days when the megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power and (C) days when megawatthours priced above the Energy Clearing Price that were not eligible for Uplift compensation, the Reference Price for Hot Startup Price or Cold Startup Price shall be the arithmetic average of those in-merit bids, adjusted for changes in fuel prices.

(d) For any bid not covered by subparagraphs (a), (b) or (c) above, the Reference Price shall be the first of the following measures that can be calculated:

(i) A level agreed on between the ISO and the Participant submitting the bid or bids at issue, provided such a level has been agreed on prior to the occurrence of the conduct being examined by the ISO; or

(ii) A reference level determined on the basis of an appropriate average of competitive bids of one or more similar units.

17.2.2.2 Investigation Thresholds

The ISO shall investigate the reasons for and market impact of any bids that exceed the following thresholds:

(a) Energy Block Price Bids: A 300 percent increase or an increase of $100 per MWh above the Reference Price, whichever is lower, but excluding bids under $25;

(b) Startup and No-load Price Bids: A 200 percent increase above the Reference Price.

(c) AGC Bids: A 300 percent increase or an increase of $100 per Reg-hr above the Reference Price, whichever is lower, but excluding bids under $5;

(d) Reserves Bids: A 300 percent increase or an increase of $100 per MW above the Reference Price, whichever is lower, but excluding bids under $5.

(e) Unit Characteristic Bids: An increase in a unit bid physical characteristic greater than 2 hours for any time based unit characteristic (e.g., minimum run time, minimum down time, cold start time, hot start time) or greater than six hours for any combination of such time-based unit characteristics,[4] or an increase greater than 20% in low operating limit, compared to the smallest (or shortest) historical bid value for the unit since May 1, 1999. Following the unit's first 89 operable days after the implementation of three-part bidding, the smallest historical bid value for the unit will be determined from bids during its first 89 operable days when three-part bidding is effective. If historical bid values are unavailable or inappropriate for a specific unit, the ISO will use historical bid values from like units.

(f) Short Notice External Transactions across the NYISO-NEPOOL interface or a transaction across other NEPOOL interfaces with a control area with published spot prices where the published price in the buyer's market is less than the published price in the seller's market will be evaluated as described in Appendix 17D. If the market impact of these transactions results in greater than an aggregate $100 per MWH change in the ECP over a day, and the Participant does not provide a satisfactory explanation to the ISO, the ISO may limit the quantity of Short Notice External Transactions the Participant may submit in the future.

If bids, pursuant to (a) through (e) above, exceed these thresholds, exceed the market impacts described in Section 17.2.3 and are not explained to the satisfaction of the ISO in accordance with Section 17.2.5, the ISO shall impose mitigation as set forth in Section 17.2.4.

[4] A decrease in one time-based characteristic shall not offset an increase in another time-based characteristic for purposes of this screen.

17.2.3 Hourly Market Impact and Uplift Thresholds

Before taking any mitigation action with regard to bids identified in accordance with Section 17.2.2 (a) through (e), the ISO shall investigate the reasons for the change in accordance with Section 17.2.5. If the bids in question are not explained to the satisfaction of the ISO the ISO will determine whether the bids in question would, if not mitigated, cause a material effect on market clearing prices in any NEPOOL market or uplift in excess of either of the following thresholds:

(a) An increase of 200 percent or $100 per MWh, Reg-hr, or MW, whichever is lower, in the hourly clearing price in any NEPOOL market for Energy, AGC or Operating Reserves.

(b) An increase of more than 100 percent in Net Commitment Period Compensation (NCPC) Energy Market component uplift payments to the Participant facing mitigation in a dispatch day, provided that the increase also exceeds $10/MWh, compared to the uplift payments calculated using Reference Prices as determined in Section 17.2.2.1 and the smallest historical bid characteristics for the Resource simultaneously for each hour. This calculation is as follows:

$$NCPC_e = Startupprice + \sum_t [NoLoadprice_t + (SE_t \times EBB_t) - (SE_t \times ECP_t)]$$

Where:

$NCPC_e$ = Net Commitment Period Compensation Energy Market Component

Startupprice = Bid Startup Price (or Reference Price)

NoLoad Price = Bid No-Load Price (or Reference Price)

SE = Supplied Energy (or Reference LOL)

EBB = Energy Bid Block Prices (or Reference Prices)

ECP = Energy Clearing Price

t = Operating Hour of the Unit associated with one continuous start-up/dispatch period when Energy was Supplied (or as determined by Reference Unit Characteristics)

The ISO shall determine the effect of questioned conduct on prices and uplift using the best available data and such models and methods as it deems appropriate.

If the bids would have an effect in excess of either of these thresholds, and has not been satisfactorily explained in accordance with Section 17.2.5, the ISO shall impose mitigation pursuant to Section 17.2.4.

17.2.4 Mitigation Remedy

If the ISO identifies bids in excess of the thresholds described in Section 17.2.2 that have the material impact on price or uplift described in Section 17.2.3, the ISO shall substitute a Default Bid in place of the bid submitted by the Participant, unless the Participant has demonstrated to the satisfaction of the ISO that mitigation is unnecessary, using the procedure described in Section 17.2.5. The Default Bid shall be 100% of the applicable Reference Price determined in accordance with Section 17.2.2.1, and with regard to uplift, the Resource shall receive uplift based on the smallest (or shortest) historical bid characteristics for the Resource, and with regard to uplift, the Resource shall receive uplift based on the smallest (or shortest) historical bid characteristics for the Resource.

Whenever a Resource is subjected to a Default Bid, the Participant responsible for deciding the bid may, if it chooses, submit a bid lower than the Default Bid, as long as the lower bid is otherwise consistent with the NEPOOL Market Rules.

17.2.5 Consultation With Affected Participant

If through its monitoring of thresholds set forth in this Section 17.2, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, the ISO shall contact the Designated Entity responsible for submitting the bid or bids identified to request an explanation. In requesting an explanation, the ISO will identify to the Designated Entity which thresholds have been exceeded. If the explanation, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. The ISO will consider all information a Designated Entity chooses to submit, but is not required to delay mitigation while waiting for information. The ISO will, in every case, consider explanations of bid behavior based on a Participant's cost of providing any market product, including any relevant opportunity costs and will recognize that bids for a limited energy Resource may need to be shaped to maximize the economic value from that Resource over time given the unique characteristics of the Resource.

17.2.6 Timing of Mitigation

Mitigation under this Section 17.2 that affects unit commitment or dispatch shall be imposed on the day a bid is received or used for commitment or dispatch purposes and before the bid is used to determine the hourly clearing price in any market. Mitigation affecting the amount of the uplift to which a unit is entitled may be undertaken in connection with settlement.

17.3 MITIGATION PROCEDURES FOR RESOURCES THAT ARE RUN OR USED OUT OF ECONOMIC MERIT ORDER DURING TRANSMISSION CONSTRAINTS

17.3.1 Defining the Constraint

For each hour in which the ISO designates or uses one or more Resources or portions of Resources for non-economic operation,[5] so that the Resources in question will neither set nor receive the NEPOOL Clearing Price ("CP"), the ISO will, as soon as possible after the hour:

(a) Identify each Resource or portion of Resource run or used out of economic merit order in the hour;

(b) Define and record the specific system requirement (*e.g.*, a particular transmission constraint) that caused the Resource or portion of a Resource to be run or used out of economic merit order in the hour; and

[5] "Non-economic operation" and "out of economic merit order," as used in this document, refer to Resources dispatched and committed by the ISO that neither set nor receive the CP. *See, e.g.,* Section 14.8 of the Restated NEPOOL Agreement, which describes the Resources that set and receive the Energy Clearing Price. *See also* Restated NEPOOL Agreement §§ 14.9 (Operating Reserve Clearing Prices), 14.10 (AGC Clearing Price). As indicated earlier, Resources operated out of economic merit order neither set nor receive the CP. They receive their Bid Price for each megawatthour if the Bid Price is appropriately paid pursuant to market operations rules governing out-of-merit generation approved by the Markets Committee prior to the activation of the Participants Committee or the Participants Committee thereafter. *Id.,* § 14.5.

(c) Identify each alternative Resource, including supply Resources as well as any dispatchable demand, which was reasonably available to the operator in the hour and could have been used to satisfy that requirement.

In addition, the ISO will, as soon as possible after the dispatch day, determine if the 30-minute reserve requirement (OP8 TMOR + replacement reserves) for the system was met for all hours of the dispatch day. If the 30-minute reserve requirement was met for all hours in the day, then the ISO will apply the Market Power Screens prescribed in Section 17.3.2. If the reserve requirement was not met for any hour in the day, then the ISO will proceed to Section 17.3.1.1.

17.3.1.1 Pool-Wide Competition Screen

For a dispatch day when the system 30-minute reserve requirement was not met, the ISO will evaluate the energy bid supply stack used in the day-ahead Unit Commitment and determine for each bid block of each Resource dispatched and used for non-economic operation for transmission congestion for each hour:

(a) The cumulative MW of Resources or portions of Resources that were dispatched and used for non-economic transmission congestion;
(b) For the bid block being evaluated (the "Subject Bid Block") the cumulative MW of Resources or portions of Resources, lower priced than the Subject Bid Block, but priced above the ECP;
(c) For each Subject Bid Block, if the value determined in (a) exceeds the value determined in (b), the Subject Bid Block will receive its bid price under the congestion pricing rules. If the value determined in (a) is less than or equal to the value determined in (b), go to Section 17.3.2.

17.3.2 Market Power Screens

Each Resource or portion of a Resource identified in step (a) of Section 17.3.1 will be subjected by the ISO staff to two market power screens: (1) a structural screen, which estimates the amount of immediately available competition, and (2) a price screen, which compares the Resource's bid behavior to available competitively-based Reference Prices. The price screen recognizes the importance of frequency, severity and foreseeability to the issue of whether a particular Resource can exercise market power by raising its price significantly, and profitably above competitive levels.

17.3.2.1 Structural Screen

Could the ISO meet the requirement identified in step (b) of Section 17.3.1 without running the selected Resource (*i.e.,* are complete substitutes, including economically dispatchable or interruptible load, available to be used to meet the requirement)? *If so*, identify the alternatives. *If not*, go to Section 17.3.2.2.

(a) Identify the entity or entities that decide the bids for the selected Resource and each alternative identified in Section 17.3.1(a).

(b) If there are three or more independently controlled competing bidders that could satisfy the requirement specified in Section 17.3.1(b), the Resources run or used out of economic merit order in the hour will receive their bid price(s) under the congestion pricing rules.[6] If there are fewer than three competitors, go to Section 17.3.2.2.

(c) In circumstances where the ISO determines that the occurrence of a constraint is reasonably foreseeable to the affected Participants, and that the existing structural screen listed in item (c) above is not sufficient for that occurrence, the ISO may substitute the following structural screen for that occurrence: If there are five or more independently controlled competing bidders that could satisfy the requirement specified in Section 17.3.1(c) , the Resources run or used out of economic merit order in the hour will receive their bid price(s) under the congestion pricing rules. If there are fewer than five competitors, go to Section 17.3.2.2.

Whenever the ISO considers raising the structural screen threshold from three to five as provided for in the preceding paragraph, it will balance the need for mitigation with the risk that mitigation pricing might interfere with competitive market incentives for investment or other market response that would tend to relieve the constraint, including but not limited to transmission expansion. Mitigation shall not interfere with or substitute for the ISO's responsibilities under Section 15.5 of the Restated NEPOOL Agreement.

17.3.2.2 Price Screens

The price screens distinguish between Resources that regularly compete in the unconstrained NEPOOL market, such as units that regularly run in economic merit, and Resources that seldom run except under constrained conditions and therefore must recover their fixed costs while running out of economic merit in a relatively small number of hours.

(a) Price Screen for Resources that Regularly Run in Economic Merit Order

[6] ISO has developed procedures for counting the number of competing bidders and has posted such procedures on its website.

This screen compares a Resource's bids in constrained periods to the Resource's Reference Prices as determined in Section 17.2.2.1. The Energy Block Reference Price is the weighted average of the Resource's in-merit bids (excluding any bids of zero or less than zero) during the most recent 30 calendar days for comparable hours. "Comparable hours" means the same day type (weekday or holiday/weekend) and the same time of day (on-peak or off-peak hours). The average of comparable hours will be weighted more heavily towards the more recent hours during the 30 day period to reflect short-term changes in market conditions. The most recent quartile of hours is weighted 40%, the next most recent quartile of hours 30%, the previous quartile 20% and the most aged quartile 10%. A formula for calculating the Energy Block Reference Price is set forth in Appendix 17-A. The No-Load and Start-Up Reference Prices are those determined in Section 17.2.2.1.

The ISO will proceed as follows:

1. Identify each Resource identified in Section 17.3.1 that has run in merit in more than 15 hours (in the aggregate) during the past 30 days.[7]

2. Compare each of the three-part bid prices for each such Resource in the current (constrained) day and hour with the corresponding screen prices from Table 1.

3. If the Resource's bid price was equal to or less than the screen price, the Resource will receive its bid price. If the bid price was higher than the screen price, go to Section 17.3.3.

(b) Price Screen for Resources that Seldom Run in Economic Merit Order

There may be some Resources that lack a history of operation in economic merit order. For example, some generators were built primarily to ensure transmission system stability. Each such Resource is likely to present a unique situation. The ISO may determine that some of these Resources should be entitled to receive a very high bid price or have a special contractual arrangement to ensure their availability when needed to support system reliability and security. Normally

[7] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, this screen will evaluate the number of in-merit hours in the most recent 30 days when the unit was operable.

such arrangements will be negotiated prospectively. The price screen for Resources that seldom run in economic merit order is designed to create a powerful incentive for such generators to come forward and negotiate an appropriate contract with the ISO. The price screen itself is a default case designed to ensure that the ISO has sufficient bargaining leverage in such negotiations. Until the Resource owner and the ISO reach agreement, the default price screen will enable the Resource to be paid for running in the short term, while providing a strong incentive to negotiate an appropriate arrangement with the ISO (or another willing buyer) as the screen price for Energy Blocks rapidly and progressively drops to just 5% above the higher of the same-hour CP or applicable Reference CP in the unconstrained market. A formula for calculating the Reference CP is set forth in Appendix B.

The ISO may disclose details of these negotiated arrangements if and when appropriate to ensure competitive and efficient market operation.

For Resources that lack a history of operation in economic merit order, the default case is to compare their constrained-on Energy Block bids to a screen derived from the higher of the current hour CP or applicable Reference CP and Start-Up and No-Load bids to a screen based on the unit's respective Reference Prices.

1. Compare each of the three-part bid prices in the current (constrained) day and hour for each Resource identified in Section 17.3.1 but *not* selected in Section 17.3.2.2(a)(1) to the corresponding screen price from Table 2.

2. If the Resource's bid price was equal to or less than the screen price, the Resource will receive its bid price as provided for in the congestion pricing rules. If the bid price was higher than the screen price, go to Section 17.3.3.

17.3.3 Mitigation During Transmission Constraints

In place of its bid price, each Resource reaching this step in any hour will receive for the product supplied in that hour:

(a) The applicable screen price from Table 1 or Table 2;[8] *or*

[8] As the ISO and Participants develop experience with the mitigation Procedure, it may become appropriate to revise the screening prices, the mitigation prices, or both.

(b) A price negotiated with the ISO.[9]

The Energy Block mitigation price will never be higher than the Resource's bid for the hour nor lower than the CP in the hour, unless specifically agreed to in advance by the ISO and the owner(s) of the Resource.

17.3.4 Notice to Resources Subject to Mitigation During Transmission Constraints

As soon as reasonably possible after the ISO has determined that a Resource or portion of a Resource will be subject to mitigation, the ISO shall notify the entity responsible for submitting bids for that Resource or portion of a Resource: (1) that mitigation has been imposed; (2) the hour or hours when mitigation applied; (3) the mitigation price in each hour; and (4) all other information about the ISO's determination to impose mitigation on that Resource or portion of a Resource that can be disclosed to that bidding entity under the *NEPOOL Information Policy* if it applies.

17.4 MITIGATION PROCEDURES FOR EXTERNAL ENERGY CONTRACTS SUBMITTED IN CONNECTION WITH EXTERNAL CONTRACTS FOR INSTALLED CAPACITY

17.4.1 Automatic Mitigation

The ISO will mitigate the price of an External Energy Transaction (purchase) submitted in connection with an External Transaction (purchase) for Installed Capacity during OP4 conditions[9A] if the price of the External Energy Transaction (purchase) exceeds the Reference Price. In such event, the External Energy Transaction (purchase) will be given a dispatch price equal to the Reference Price.

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9 The ISO may enter into negotiations with a resource owner for any reasonable payment terms if the ISO reasonably expects the markets will function more reliably, competitively or efficiently as a result.

9A OP4 conditions are defined in the ISO's Emergency Motion for Clarification filed with the Commission on August 9, 2000 in Docket Nos. EL00-83-000, ER00-2811-000, ER00-2937-000 and ER00-2052-000 and in the Special Interim Market Rule Limiting Bids, Sheet Nos. 2201-2203, accepted by the Commission in ISO New England Inc., 95 FERC ¶ 61,184 (2001).

17.4.2 Reference Price

The Reference Price equals the highest price payable during (or if there is no applicable limit, the highest price actually paid to internal NEPOOL resources during the particular occurrence of) OP4 conditions.

17.4.3 Payments to Seller

Any Participant submitting an External Energy Transaction (purchase) that is mitigated pursuant to Section 17.4.1 shall be paid a price equal to the higher of the ECP and the actual marginal cost per megawatt for each hour that such External Energy Transaction is dispatched. The Participant's actual marginal cost per megawatt shall equal the costs incurred by the Participant under the contract supporting the External Energy Transaction plus transmission charges to import the energy divided by the megawatts actually dispatched for the hour.

17.4.4 Uplift

If the Participant's actual marginal cost per megawatt for any hour exceeds the ECP, the difference multiplied times the megawatts actually dispatched during the hour shall be treated as uplift and allocated to Participants with negative ANI for that hour.

17.5 NEW OR REVISED MITIGATION RULES

The ISO will actively seek to identify any additional patterns of behavior that will be detrimental to the efficient and workably competitive operation of the markets. The ISO will, in consultation with jurisdictional federal and state agencies, and NEPOOL Participants, develop any additional monitoring and mitigation procedures necessary to deter or correct harmful behavior and ensure competitive efficiency. This will occur within the framework of consultation with NEPOOL provided for in Section 6.17 of the Interim ISO Agreement, which also describes the circumstances under which the ISO may act unilaterally. In particular, the ISO may develop additional or modified

mitigation measures, including the development of alternative thresholds and Default Bid measures, as needed in the future.

17.6 MARKET INFORMATION AND REPORTS

17.6.1 Data Collection and Retention

Section 7.2 of the Interim ISO Agreement provides:

> The NEPOOL Participants shall provide the ISO with any and all information within their custody or control that the ISO deems necessary to perform its obligations under this Agreement, subject to applicable confidentiality limitations contained in the *NEPOOL Information Policy*.

This would include a Participant's cost information if the ISO deems it necessary, including start up, No-Load and all other actual marginal costs, when needed for monitoring or mitigation of that Participant.

If for any reason the requested explanation or data is unavailable, the ISO will use the best information available in carrying out its responsibilities.

The ISO may use any and all information it receives in the course of administering the NEPOOL markets as appropriate in its monitoring and mitigation activities. Among the most important data to be used for monitoring and mitigation purposes are the following, which ISO staff will regularly collect and maintain, for a running five-year period, preserving its confidentiality consistent with the *NEPOOL Information Policy*:

(a) Clearing Price for each of the five hourly products[10] in each hour.

[10] Energy, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, 30-Minute Operating Reserve, and Automatic Generation Control.

(b) Price bid for each Resource or portion of Resource (whether or not dispatched or used) for each hourly product in each hour. Self-scheduled Resources or self-scheduled portions of Resources will be recorded as bidding zero.

(c) Redeclarations of bids and self-scheduling in the Energy market.

(d) Hours each Resource runs or is used in economic merit order.

(e) Hours each Resource (or any portion of that Resource) runs or is used out of economic merit order (*i.e.,* the Resource in question will neither set nor receive the CP) and associated out-of-merit MWh (or other applicable unit of measure) of each product produced.

(f) Data needed to calculate hourly net purchases and sales of each Participant in the markets.

(g) In addition to the ownership information already collected by the ISO to operate the settlement system, Participants shall provide the ISO with verified statements for each Resource identifying the entity that *decides* the bid prices for each product for such Resource (which may be a different entity than the one submitting bids) and any other entity that was involved in the bidding process.

17.6.2 Periodic Reporting

17.6.2.1 Monthly Report

The ISO will publish a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period. The report will include:

(a) An overview of competitive conditions in the New England markets;

(b) Clearing prices for the period;

(c) A general framework for evaluating those Clearing prices (*e.g.,* system conditions, load, transmission constraints, aggregate unit availabilities);

(d) A listing of frequently occurring constraints that result in out-of-merit generation;

(e) A listing of each mitigation inquiry to a Participant under Section 17.2.5 and the outcome of the inquiry, and each mitigation remedy imposed, in as much detail as is consistent with preserving Participant Confidentiality; and

(f) Rule changes affecting competition in the New England markets.

17.6.2.2 Quarterly Report for Regulators

The ISO will publish a quarterly report that will be made available to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, as well as to NEPOOL Participants. The report will describe transmission constraints and contain an analysis of market conduct and mitigation activities. The entire quarterly report will be subject to confidentiality protection consistent with the *NEPOOL Information Policy* and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The *NEPOOL Information Policy* prevents the inappropriate dissemination of competitively sensitive data to individual NEPOOL Participants. The content of the quarterly reports will include the following items and will be updated periodically through consensus of the ISO and regulators:

(a) Market Clearing Price averages, ranges, and volatilities;
(b) Market Clearing Price comparisons with other deregulated pools;
(c) Magnitude of and changes in size of Residual Energy Market;
(d) Energy Uplift Payments;
(e) System loads and weather conditions;
(f) Resource and Transmission total and net capacities;
(g) Non-Transmission congestion mitigation actions;
(h) Transmission congestion activity and mitigation including unmitigated & mitigated uplift total, average and marginal costs by transmission area;
(i) Participant resource market shares; and
(j) Participant supply curves.

17.6.2.3 Annual Reviews

The ISO will present an annual review of the operations of the New England markets. The review will include a public forum to discuss the performance of the markets, the state of competition, and the ISO's priorities for the coming year. In addition, the ISO will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the *NEPOOL Information Policy*, to the greatest extent permitted by law. The review may include a discussion about whether the ISO should propose any refinement or change in monitoring or mitigation procedures. If any such refinement or change is needed, the ISO will present its proposal to the NEPOOL Regional Market Operations Committee without delay and, if required, to the appropriate regulatory agencies. The ISO may conduct reviews more or less frequently than annually.

17.6.3 Other ISO Communications With Government Agencies

The periodic reviews are in addition to any routine communications the ISO may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets. The ISO is not a regulatory or enforcement agency. However, it will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on the market and mitigation provided in the monthly, quarterly and annual reports the ISO shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the NEPOOL Regional Market Operations Committee, if the ISO determines that a market problem appears to be developing that will not be adequately remediable by Market Rules or mitigation measures;

(b) If the ISO receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the ISO reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market behavior constitutes a violation of law, report these matters to the appropriate state and federal agencies; and

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The ISO will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section 17.6.2.2 of this Rule.

17.6.4 Other Information Available from ISO on Request by Regulators

The ISO will normally make its records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). The ISO shall promptly make available all requested data and information it is permitted under the *NEPOOL Information Policy* to disclose to authorized government agencies. The ISO also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the *NEPOOL Information Policy*, the ISO shall notify each party with an interest in the confidentiality of the information. The ISO shall not disclose the information unless or until (a) the authorized government agency has served the ISO with compulsory process as described above, or (b) the interested party or parties have agreed with the requesting authorized government agency to voluntary disclosure of the data or information subject to reasonable and appropriate terms protecting its confidentiality that are satisfactory to those parties.

17.7 ADR REVIEW OF ISO MITIGATION ACTIONS

17.7.1 Actions That Can Be Reviewed

A Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any ISO mitigation imposed on a Resource as to which that Participant has bidding or operational authority. A participant must seek review within the time limits provided by Section 18.8.2 of Market Rule 18 for billing adjustment requests. Actions subject to review are:

- Imposition of a mitigation remedy.[11]
- Continuation of a mitigation remedy as to which a Participant has submitted material evidence of changed facts or circumstances.[12]

17.7.2 Factual Basis for ADR Review

ADR review will be based on facts and materials presented to the ISO by the Participant, as well as the facts and materials relied on by the ISO in making its mitigation decision. The goal of this process is not to create a separate ADR record, but to provide rapid review by an impartial third party of the basis for the ISO's decision and, if necessary, removal of the mitigation. ADR review is intended to operate only after the ISO and the Participant have made a good faith effort to discuss and resolve their differences.

At a Participant's request, the ISO will promptly provide the Participant with a written explanation of the basis for any ISO mitigation action imposed on one or more Resources for which that Participant has bidding or operational authority. Upon request the ISO will also identify and make available any backup data that has not already been supplied to the Participant. Based on the written explanation, the Participant may wish to submit additional information for the ISO's consideration. If the Participant does not elect to

[11] A mitigation remedy is imposed, for purposes of ADR Review, as soon as the ISO notifies a Participant that its Resource will be subjected to mitigation.

[12] Thus, after a Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR Review on a showing of material evidence of changed facts or circumstances.

submit more information, or if the ISO does not remove its mitigation remedy based on any new information submitted, the Participant may submit the ISO's imposition of the mitigation remedy to ADR review. The written record for the ADR review will consist of (1) all information provided by the Participant to the ISO up to and including the date on which the Participant requests ADR review and identified by the Participant as relevant to the ISO's decision to impose mitigation, and (2) all information submitted by the ISO to the ADR Neutral that supports its prior written determination. The ISO shall provide the Participant with copies of all material submitted to the ADR Neutral.

17.7.3 Standard of Review

On the basis of the written record and the presentations of the ISO and the Participant, the ADR Neutral shall review the facts and circumstances upon which the ISO based its decision and the remedy imposed by the ISO. The ADR Neutral shall remove the ISO's mitigation only if it concludes that the ISO's application of the NEPOOL mitigation policy was clearly erroneous. In considering the reasonableness of the ISO's action, the ADR Neutral shall consider whether adequate opportunity was given to the Participant to present information, any voluntary remedies proposed by the Participant, and the need of the ISO to act quickly to preserve competitive markets.

17.7.4 Parties to ADR Review

The ADR review is confidential. The only parties to an ADR review are the ISO and the Participant or Participants with bidding or operational authority for the Resource or Resources on which the disputed mitigation is imposed. The ADR review and any record are not open to non-parties.

17.7.5 Remedies

The ADR Neutral shall either affirm or remove the mitigation remedy. The decision of the ADR Neutral shall not preclude the Participant from presenting new information or new proposals for voluntary remedies to the ISO, nor shall it prevent the ISO from imposing mitigation on the same Resource in similar circumstances based on new information or further discussions with the Participant. No financial compensation may be awarded in an ADR review.

The decision of the ADR Neutral shall be included as a permanent part of any file or record the ISO maintains concerning the mitigation.

17.7.6 Procedure

17.7.6.1 Objective

It is the intent of the ADR process that disputes be resolved as expeditiously as possible.

17.7.6.2 Confidentiality

All information disclosed in the course of ADR review shall be subject to confidentiality protections that satisfy the requirements of the *NEPOOL Information Policy*.

17.7.6.3 Selection and Compensation of Neutrals

NEPOOL and the ISO shall identify not fewer than three persons who they mutually agree would be appropriate to serve as ADR Neutral under this Section 17.7 and shall obtain the advance consent of such persons to serve as ADR Neutrals for the ADR procedure described in this Section. An appropriate retainer may be paid to such persons in return for their agreement to serve, which retainer shall be made a part of the ISO's budget. The ISO and NEPOOL may from time to time mutually select additional persons to fill vacancies or expand the roster of ADR Neutrals as needed.

When a Participant initiates an ADR process an ADR Neutral shall be selected from the roster within five business days using the following procedure:

- Except as otherwise provided for in Section 17.7.6.7 below, ADR processes shall be assigned to the ADR Neutral whose most recent ADR process handled under this Section 17.7 was longest ago.
- If the schedule of such member of the roster does not permit meeting the required schedule for the ADR process, that ADR process shall be assigned to the member whose most recent ADR process was next longest ago and so forth.

- If two or more members of the roster have not handled at least one ADR process or handled ADR processes as to which hearings were held on the same day, the ADR process shall be assigned among such members by lot.

17.7.6.4 Hearing

The ADR Neutral who is assigned to an ADR process shall receive the complete written record at the time of assignment. The ADR Neutral, in consultation with the parties, shall schedule a hearing to be held not later than 5 business days after the ADR Neutral is selected. The schedule may be altered either by consent of all parties or, if it is clearly not possible to provide a fair review within the schedule given the complexity of the record, at the direction of the ADR Neutral.

After reviewing the written record the ADR Neutral may pose questions in writing or in a conference call with representatives of both parties that he or she would like to have addressed at the hearing. All parties shall be copied on any written communications between the ADR Neutral and any other party. There shall be no telephone calls or meetings between the ADR Neutral and any party unless all parties have been given notice and an opportunity to participate.

At the hearing each party will have up to four hours to present its views regarding the written record. A party may reserve time for rebuttal. There will be no witnesses or cross examination, but a party may choose to have experts or counsel make all or a portion of its presentation. The ADR Neutral is free to question any presenter.

The hearing shall be held in Holyoke, Massachusetts, or such other location as the parties and the ADR Neutral may agree.

17.7.6.5 Decision

The ADR Neutral shall render a decision in writing stating whether the mitigation remedy is affirmed or removed within two business days of the hearing. No statement of reasons for the decision is required. Any party may request a meeting with the ADR Neutral to discuss the ADR Neutral's decision.

17.7.6.6 Costs

The costs of the ADR process (including any fees for the participation of the ADR Neutral in the specific proceeding but not including any retainer for the ADR Neutral) shall be assessed to the Participant if the mitigation remedy is affirmed and to the ISO if the remedy is removed. Costs assessed to the ISO shall be automatically included in the ISO's budget.

17.7.6.7 Related ADR Reviews

ADR reviews involving the same Resource or Resources or Participant or Participants may be determined by the same ADR Neutral and may, in appropriate cases, be consolidated.

17.7.6.8 Effect of ADR Process

The decision of the ADR Neutral is binding on the ISO and the Participant except as specifically provided in this Section 17.7.6.8. The ISO may appeal the removal of a mitigation remedy to the Commission. A Participant may appeal the imposition of a mitigation remedy to the Commission whether or not it has requested an ADR process. Except for this ADR process, a Participant may not seek removal of the mitigation, or any other remedy against the ISO, in any forum other than the Commission, and may not contest the decision of an ADR Neutral in any forum. The ISO may not contest the removal of a mitigation remedy in any forum other than the Commission.

17.8 APPEAL TO THE COMMISSION

A Participant may appeal the imposition of a mitigation remedy directly to the Commission whether or not it has requested an ADR process. Prior to making such an appeal to the Commission, a Participant may request a written explanation of the basis for ISO mitigation as provided under Section 17.7.2 whether or not a request for ADR review has been made. In responding to such an appeal the ISO may provide the Commission with all relevant information regarding its decision to impose a mitigation remedy but shall be under no obligation to request confidential treatment for information specifically identifying the Participant upon whom mitigation is imposed notwithstanding anything to the contrary contained in the *NEPOOL Information Policy*.

APPENDIX 17-A

REFERENCE PRICE

The Reference Price is the weighted average of (1) the bids for block of Energy excluding (a) any bid of zero or less than zero, and (b) bids for megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power, and (c) bids for megawatthours that are above the Energy Clearing Price and were not eligible for uplift compensation, or (2) the bids for Resources that were designated as providing Operating Reserves or AGC during the most recent 30 calendar days[13] for Comparable Hours. "Comparable Hours" means the same day type (weekday or holiday/weekend), and the same time of day (on-peak or off-peak hours). The average of Comparable Hours will be weighted more heavily towards the more recent hours during the 30 day period to reflect short-term changes in market conditions. The most recent quartile of hours will be weighted 40%, the next most recent quartile of hours 30%, the previous quartile 20% and the most aged quartile 10%.

Thus, the formula for calculating the Reference Price is:

$$RP_{DT,PO} = \left[\sum_{n=1}^{N}\left(BH_{DT,PO,W,n} \times WT_{W,n}\right)\right] \div \left[\sum_{n=1}^{N}\left(WT_{W,n}\right)\right]$$

Where:

(For all $BH > 0$)

RP = Reference Price
DT = Day type (2 = Weekday; Weekend/Holiday)
PO = Load Period (2 = On-Peak Hours; Off-Peak Hours)
BH = Historical Hour Bid
WT = Quartile Weights (4 = 4, 3, 2, 1)
W = Quartile (4)
n = Hour
N = Number of Comparable Hours in Previous 30 Days

[13] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, the Reference Price will be based on the number of in-merit hours in the most recent 30 days when the unit was operable.

During the first 30 calendar days following start-up of a new Resource or the implementation of three-part bidding, the Reference Price will be calculated as the simple arithmetic average of (1) the bids for block of Energy excluding (a) any bid of zero or less than zero, and (b) bids for megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power, and (c) bids for megawatthours that are above the Energy Clearing Price and were not eligible for uplift compensation, or (2) the bids for Resources that were designated as providing Operating Reserves or AGC during the most recent 30 calendar days[14] for Comparable Hours. Beginning with the thirty-first calendar day, the Reference Price will be calculated by the formula shown above. If there are no in-merit bids for Comparable Hours, the applicable Reference Price will be calculated using all hours of in-merit bids during the 30-day period.

[14] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, the Reference Price will be based on the number of in-merit hours in the most recent 30 days when the unit was operable.

During the first 89 operable days after the implementation of three-part bidding, and thereafter during the first 89 operable days after a new Resource begins operation, "number of hours" will be converted to percentages of the hours operated (by definition, fewer than 2160)[15] for the cumulative hours test in Tables 1 and 2 using the following conversion.

Cum. Hrs.	Cum. %
≤45	≤2.1%
>45-90	>2.1-4.2%
>90-135	>4.2-6.3%
>135-180	>6.3-8.3%
>180-225	>8.3-10.4%
>225	>10.4%

[15] Percentages are derived by dividing 2160, the number of hours in 90 days, into the number of hours in the 90-day cumulative hours column in Tables 1 and 2. For example, 45/2160=0.021=2.1%.

TABLE 1
(Price screen for Resources that regularly run in economic merit order)

This table contains a test based on the Resource's cumulative number of hours out of economic merit order in the past 90 days.[16]

For example, a Resource that has run out of economic merit order more than 225 hours (just over 10% of the time) in the past 90 days will be subject to a screen price 5% above the Reference Price. If the Reference Price, multiplied by the screening percentage, is less than the current day or hour out-of-merit bid, and the market structure screen identifies fewer than three total competitors, mitigation pricing will apply.

90-day cumulative hours out of economic merit order	Current hour Energy Block Price, No-load Price bid or Startup Price bids as percentage of respective Reference Price to Resources used out of economic merit order during transmission constraints.
≤45	150%
>45-90	125%
>90-135	120%
>135-180	115%
>180-225	110%
>225	105%

[16] Cumulative hours of operation out of economic merit is a measure of past performance and behavior, and will identify Resources that repeatedly run out-of-merit for relatively short periods of time, and therefore would not be identified by the consecutive out-of-merit hours test. Normally the 90-day period will be the most recent, except that when a unit is returning to service after an outage the 90 days will be the most recent 90 days in which that unit was operable. If a unit has operated for a total of fewer than 90 days since the Second Effective Date, the cumulative out-of-merit hours will be prorated as a percentage according to the table in Appendix A above.

TABLE 2
(Price screen for Resources that seldom run in economic merit order)

This table, like Table 1, contains a test based on the Resource's cumulative number of out-of-merit hours in the past 90 days. ***For example, a Resource that has run out of economic merit order more than 225 hours (just over 10% of the time) in the past 90 days will be subject to a screen price 5% above the higher of the current hour CP or Comparable Hours Reference CP for Energy Block Price and above the Reference Price for Startup and No-Load.*** If the screening percentage is less than the current hour out-of-merit bid, and the market structure screen identifies fewer than three total competitors, mitigation pricing will apply.

90-day cumulative hours out of economic merit order	For Energy Block Price, current hour bid as percentage of the higher of the current hour CP or Comparable Hours CP	For Startup Price and No-Load Price bids, current day or hour bid as a percentage of respective Reference Price
≤45	500%	150%
>45-90	300%	125%
>90-135	150%	120%
>135-180	125%	115%
>180-225	115%	110%
> 225	105%	105%

APPENDIX 17-B
REFERENCE CP

The Reference CP is the weighted average of the market clearing prices (excluding any price of zero or less than zero) during the most recent 30 calendar days for Comparable Hours. "Comparable Hours" means the same day type (weekday or holiday/weekend), and the same time of day (on-peak or off-peak hours). The average of Comparable Hours will be weighted more heavily towards the more recent hours during the 30 day period to reflect short-term changes in market conditions. The most recent quartile of hours will be weighted 40%, the next most recent quartile of hours 30%, the previous quartile 20% and the most aged quartile 10%.

Thus, the formula for calculating the Reference CP is:

$$RCP_{DT,PO} = \left[\sum_{n=1}^{N}\left(PH_{DT,PO,W,n} \times WT_{W,n}\right)\right] \div \left[\sum_{n=1}^{N}\left(WT_{W,n}\right)\right]$$

Where:

(For all $PH > 0$)

RCP	=	Reference CP
DT	=	Day type (2 = Weekday; Weekend/Holiday)
PO	=	Load Period (2 = On-Peak Hours; Off-Peak Hours)
PH	=	Historical Hour CP
WT	=	Quartile Weights (4 = 4, 3, 2, 1)
W	=	Quartile (4)
n	=	Hour
N	=	Number of Comparable Hours in Previous 30 Days

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APPENDIX 17-C

DEFINITION OF OUT OF MERIT ORDER THRESHOLD, AVERAGE AND REFERENCE PRICE

A unit's Out Of Merit Order ("OOMO") Average Threshold is calculated over Comparable Hours over the last 30 comparable days for which the unit was operable. For example, an OOMO Average Threshold might be calculated for hour-ending 4pm for the previous 30 on-peak days for which the unit was operable. The formula for calculating the Out Of Merit Order Average Threshold is:

OOMO Average Threshold = [AS*SS*ORP+(OD-AS)*ORP]/OD

AS = Allowed Spikes, lower of TAS and OD.

TAS = Total Allowed Spikes per 30 day period.

OD = OOMO Days, Number of OOMO bids in Comparable Hours for the most recent 30 comparable days for which the unit was operable.

ORP = OOMO Reference Price for Comparable Hours as calculated in this Appendix.

SS = Spike Size, % increase over the ORP.

A unit's OOMO Average is the arithmetic average of its actual OOMO bids over the most recent 30 comparable hours for which it was operable.

The OOMO Reference Price shall be calculated by the ISO separately for each block of 10MW for each generating unit or other Resource submitting bids in the NEPOOL markets. The OOMO Reference Price is the average of the Resource's in-merit bids (excluding any bid of zero or less than zero) during the most recent 30 Comparable Hours for which the unit was operable. "Comparable Hours" means the same market time period (on-peak or off-peak, with off-peak being nights, weekends, and holidays), and the same time of day (e.g. hour ending 4 p.m.).

The formula for calculating the Out Of Merit Order Reference Price is:

$$ORP_{DT,PO} = \left[\sum_{n=1}^{N} \left(BH_{DT,PO,n} \right) \right] \div N$$

Where:

(For all $BH > 0$)

ORP	=	OOMO Reference Price
DT	=	Day type (On-Peak, Off-Peak)
PO	=	Load Period (hour)
BH	=	Historical Hour Bid
n	=	Hour
N	=	Number of Comparable Hours

Sheet Nos. 1787 through 1800 are reserved for future use.

Sheet Nos. 1733 through 1749 are reserved for future use.

Sheet Nos. 1701 through 1732 are reserved for future use.

EXHIBIT PRP-3

Federal Energy Regulatory Commission
Working Paper on Standardized Transmission Service and Wholesale Electric Market Design

To enhance competition in wholesale electric markets and broaden the benefits and cost savings to all wholesale and retail customers, the Commission intends to reform public utilities' open access tariffs to reflect a standardized wholesale market design. The goals of this initiative are to: provide more choices and improved services to all wholesale market participants; reduce delivered wholesale electricity prices through lower transactions costs and wider trade opportunities; improve reliability through better grid operations and expedited infrastructure improvements; and to increase certainty about market rules and cost recovery for greater investor confidence to facilitate much-needed investments in this crucial economic sector. A key challenge will be to balance the need for standardization for a seamless transmission grid with streamlined operations and costs with the need to permit regional differences and market innovation.

The Commission is conducting this effort through Docket No. RM01-12-000 and plans to issue a notice of proposed rulemaking, containing a reformed open access transmission tariff, this summer. The reformed tariff will be filed by regional transmission organizations (RTOs) and other public utilities that own, operate or control interstate transmission facilities.

The Commission's Order Nos. 888 and 889 established non-discriminatory open access transmission services and stranded cost recovery rules for the transition to competitive markets. These rules established a sound foundation for competitive bulk power markets in the United States, but did not address every issue now before us. There is wide consensus today about the need to update the pro forma tariff and the basic elements of wholesale electric market design. On some issues, there is clear consensus about what needs to be done; on others, further policy decisions are needed to move forward. The Commission intends this paper to offer that policy guidance and allow the parties to move forward in a focused process that builds upon Order Nos. 888 and 889, and the institutional innovations of RTOs identified in Order No. 2000, to complete the establishment of robust, seamless competitive wholesale electric markets.

Based on dialogue with a wide array of stakeholders and state commissioners over the past few months, this paper lays out principles and policy decisions on the standard market design to guide the Commission in developing a revised transmission tariff. Most of these reflect consensus voiced by the parties in written comments and in the conferences and workshops held by the Commission with the industry between October 2001 and February 2002. These policy calls are subject to further dialogue with and comment from participants. The Commission will issue a notice of proposed rulemaking this summer and all affected parties will be able to further comment on the notice of proposed rulemaking. The Commission will consider all comments in determining the final rule.

Attached hereto is an Appendix that responds to a number of questions on market design from the Electronic Scheduling Collaborative.

A. The Need for a Single Transmission Tariff

Order Nos. 888 and 889 established the foundation needed to develop competitive bulk power markets. However, it has become clear that the Order No. 888 open access transmission tariff (OATT) contains provisions that, in practice and in conjunction with market design rules that currently exist in the electric utility industry, allow energy suppliers that also provide transmission service to favor their own generation and disadvantage other energy suppliers. For example, a vertically integrated utility determines available transmission capability and the facilities necessary to interconnect a new generator. In both cases, the transmission provider has the incentive to favor its own generation. This creates barriers for other energy providers, raises costs from inefficiency for all grid operations, and often results in higher delivered energy prices to end-use customers. The lack of regional coordination of the grid (for instance, the calculation of Available Transmission Capacity and Total Transmission Capacity on a company basis) contributes to inefficient operations by causing unnecessary transmission congestion and transaction curtailments. In addition, market design issues not addressed by the current tariff impede a seamless national transmission grid and the development of broad, fully competitive electricity markets.

At present there is no single set of rules governing transmission of electric energy. The electrons moving across the grid do not distinguish between bundled retail and other services, and behave according to the laws of physics rather than the laws of a particular jurisdiction. With more non-integrated electricity suppliers and a deeper reliance on wholesale electric markets, there are substantial competitive consequences and higher costs to all retail customers if we do not apply consistent, non-discriminatory rules to all transmission customers. To protect all customers and assure the benefits of competition for all, consistent transmission rules must be applied.

The existing tariff reveals different flaws in different regions of the country. In areas where most energy transactions occur through bilateral contracts without centralized spot markets for energy and ancillary services, more and more transactions are being curtailed under transmission loading relief (TLR) mechanisms that rely on non-price allocation methods. In these cases, congested transmission capacity is not being consistently allocated to the market participants who value transmission the most.

Market design flaws are visible in every regional electric market today under the existing tariff. These flaws are allowing operational problems such as the "socialization" or "uplift" of congestion management prices across all customers in a region, which obscures the potential for price signals to indicate where new generation, demand response or transmission is needed. In other regions, high fees are being collected for the value of generation capacity that do not clearly incent the construction of new capacity. A third type of flaw has been the sequential clearing of energy and ancillary service

markets, which fails to deliver efficient prices for the service delivered. No region has been exempt from market design flaws of one type or another.

Even where market designs appear to be very similar in contiguous regions, "seams" problems have persisted. A seams problem occurs when differences in business practices, market design, reliability rules, or software platforms between regions impedes trade between the regions. When these seams problems prevent the economic exchange of energy, they increase transactions costs.

Even within a region, a poorly designed or inefficiently managed transmission system can result in significant increased costs to customers. It is useful to review the approximate costs of electric generation and transmission to see the impact that transmission can have on energy costs. Consider these approximate costs as viewed by retail customers (excluding distribution and load-serving entities'

(LSEs) operating costs, which represent about 15% or less of the average retail bill) for two regional markets, for the year 2000:[1]

	PJM		NY	
	$ Millions	% of Total Cost	$ Millions	% of Total Cost
Energy Costs	$9,822	92.2%	$7,599	88.6%
Congestion Costs	$134	1.2%	$1,209	14.1%
Line Losses	$491	4.5%	$380	4.5%
Transmission Revenue Requirement	$832	7.8%	$979	11.4%
Total Cost	$10,654	100%	$8,578	100%
Peak Load (MW)	49,417		30,200	

These markets are used because we have information readily available for them. These figures illustrate several important points. First, within the delivered retail bill, the cost of transmission alone is small compared to the cost of generation, but these costs are still large in absolute terms. Second, two elements which are substantially affected by the design and operation of the transmission system have a significant effect on energy costs, i.e., the cost of transmission congestion (which is actually the opportunity cost of having too little transmission) and the cost of line losses (the additional generation that must be produced to make up for energy lost in the delivery of electrons through the grid, averaging about 5% of total electricity produced). Third, the costs hint at the substitutability between generation and transmission – specifically, as the grid becomes constrained, energy costs rise markedly due to the redispatch of more expensive plants to work around the transmission constraints. This can be seen in the higher congestion costs in New York caused by the unavailability of the Indian Point nuclear plant in

[1] Energy Costs for each independent system operator (ISO) are derived from Form 1 data for each of the utilities in the ISO. It is calculated as the sum of Total Power Production Costs (Form 1, page 321, line 80) of each of the utilities in the ISO. Congestion costs are from the websites of each ISO. Line losses are assumed to be 5% of Energy Costs (4.5% of Total Cost). The transmission revenue requirement for each ISO is the sum of the annual transmission revenue requirements of each utility in Attachment H to the OATT of each ISO. Total Cost is the sum of Energy Costs and the Transmission Revenue Requirement. Peak load for PJM Interconnection, L.L.C. (PJM) is from "PJM Interconnection State of the Market Report 2000." Peak load for New York Independent System Operator (NYISO) is from "Power Alert: New York's Energy's Crossroads" (March 2001).

the summer of 2000. Additions to the grid may slightly increase the transmission revenue requirement but yield large reductions in total energy cost per kWh from lower congestion costs and greater access to cheaper bulk power sources.

The table above shows the relative costs of energy and transmission within two areas that have markets designed similarly to the standard market design proposed here. In other areas, where transmission constraints are not managed with similar mechanisms, the impact of congestion on energy costs is likely far greater. Adoption of a standard market design in those areas would improve price signals and encourage more efficient expansion of the transmission grid with corresponding reductions in energy costs. Even if the energy costs reductions are small in percentage terms, there could still be large savings in absolute terms.

In Order No. 2000, the Commission recognized the need to make further changes to its regulations to address these inefficiencies and discrimination problems. However, Order No. 2000 primarily dealt with the structure and independence of the new RTOs. It did not directly address the market rules that were needed to achieve the objective of competitive electric wholesale markets.

We must act now to remedy any undue discrimination and unjust and unreasonable pricing caused by the problems highlighted above and to achieve the reliability and cost-saving benefits of competition. We must restructure electric transmission service to provide comparability for all sellers of electricity, use transmission assets more efficiently, and reduce inefficiencies by standardizing market rules. This should be done by creating a new, flexible transmission service to be offered by all transmission providers to all customers, with a new standard market design for wholesale electric markets.

To assure fairness and transparency for all participants, an entity independent of the market participants must administer the imbalance energy markets that are to be part of the standard market design proposed here. As described below, the Commission is proposing to use Locational Marginal Pricing (LMP) as the system for congestion management. Under LMP, the imbalance and transmission markets must operate together. Thus, it is more efficient to have one entity perform the two functions identified by NERC in its new Functional Model as the Balancing Authority and the Transmission Service Provider. In this document, we use the term "transmission provider" for the independent entity that would perform functions including accepting and processing requests for transmission service, administering the OASIS, scheduling transactions, and administering the imbalance markets. Thus, an RTO or independent system operator (ISO) would meet the definition of transmission provider. However, vertically-integrated public utilities who are not part of an RTO or ISO would have to contract with an independent entity to serve as the "transmission provider" to perform these functions. The question of whether an independent transmission company, i.e., one that has no affiliation with a generator or power marketer, qualifies as a transmission provider requires further consideration.

B. General Principles for Standard Market Design

The lessons learned in existing markets lead us to establish a set of principles to guide the development of standard market design:

1. The objective of standard market design for wholesale electric markets is to establish a common market framework that promotes economic efficiency and lowers delivered energy costs, maintains power system reliability, mitigates significant market power and increases the choices offered to wholesale market participants. All customers should benefit from an efficient competitive wholesale energy market, whether or not they are in states that have elected to adopt retail access.

2. Standardization of market design and business practices reduces transaction costs and reduces "seams issues" that restrict trading. In developing and implementing standard market design, the maximum benefit will be gained by standardizing as much as practicable. Deviations or changes from the standards must be consistent with or superior to standard market design. Such changes must also be compatible with neighboring systems to prevent seams issues.

3. Market rules and market operation must be fair, well defined and understandable to all market participants.

4. Imbalance markets and transmission systems must be operated by entities that are independent of the market participants they serve.

5. Energy and transmission markets must accommodate and expand customer choices. Buyers and sellers should have options which include self-supply, long-term and short-term energy and transmission acquisitions, financial hedging opportunities, and supply or demand options.

6. Market rules must be technology- and fuel-neutral. They must not unduly bias the choice between demand or supply sources nor provide competitive advantages or disadvantages to large or small demand or supply sources. Demand resources and intermittent supply resources should be able to participate fully in energy, ancillary services and capacity markets.

7. Standard market design should create price signals that reflect the time and locational value of electricity. The price signal – here, created by LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission at the proper locations and times. But while price signals should support efficient decisions about consumption and new investment, they are not full substitutes for a transmission planning and expansion process that identifies and causes the construction of needed transmission and generation facilities or demand response.

8. Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for

choice by wholesale and end-use customers.

9. Transmission owners will continue to have the opportunity to recover the embedded and new costs of their transmission systems. Consistent with current policy, merchant transmission capacity would be built without regulatory assurance of cost recovery.

10. Customers under existing contracts (real or implicit) should continue to receive the same level and quality of service under standard market design. However, transmission capacity not currently used and paid for by these customers must be made available to others.

11. Standard market design must not be static. It must not inhibit adaptation of the market design to regional requirements nor hinder innovation.

C. The New Transmission Service

Transmission providers should be required to offer a nondiscriminatory, standard transmission service, "Network Access Service," for all customers, including vertically integrated utilities. Network Access Service would combine features of both of the existing open access transmission services, the flexibility and universal access of network integration transmission service and the reassignment rights of point-to-point service. This allows all customers to have a system of tradable transmission property rights that will expand their transmission options and enable and enhance competition in wholesale electric markets. All transmission services should be performed under a single set of market rules.

To complement Network Access Service and implement the standard market design, transmission providers should manage congestion using LMP. To handle imbalances and the procurement of ancillary services, the transmission provider would operate markets for energy, regulation and operating reserves in conjunction with the markets for transmission services. These markets would be bid-based markets operated in two time frames: (1) a day ahead of real-time operations, and (2) in real time. For both the day-ahead and real-time time frames, the transmission provider would assure that purchases and sales of energy, regulation and operating reserves through the centralized energy, regulation and operating reserves markets, or through self-supply or bilateral contract, are coordinated with transmission services on the grid. The transmission provider would establish schedules for transmission service, and sales and purchases of energy, regulation and operating reserves, to ensure the most efficient use of the transmission grid.

Network Access Service

Network Access Service would give the customer the right to transmit power between two points, a source and a sink. A source is defined here as the location where a transaction originates, and a sink is defined as the location where a transaction terminates. Sources and sinks would be defined to include both individual nodes as well as aggregated points such as trading hubs. Thus, a Network

Access Service customer could use this service to move power from a generator (source) to a load (sink), from a generator (source) to a trading hub (sink), from one trading hub to another, or from a trading hub (source) to a load (sink). A Network Access Service customer would have access to all sources and sinks on the system. An access charge would be used to recover the embedded costs of the transmission system. The manner in which embedded costs will be recovered requires further discussion to be resolved.

Some transactions cannot occur without causing congestion on the transmission system. Network Access Service gives customers two options for how to handle the costs of this congestion, either: (1) a predetermined price, using "transmission rights," or (2) the applicable congestion charge in which the customer bears the full cost of congestion management. The issue of how to allocate transmission rights is difficult and contentious. However, our intent is to preserve the existing rights of current users of the system.

Transmission rights for transmission price certainty

A customer can achieve price certainty for Network Access Service by acquiring transmission rights. A transmission right allows the customer to schedule power from specific source(s) and sink(s) without having to pay congestion for service between those points. Anyone can hold a transmission right. A key implementation issue will be the initial assignment of transmission rights. One option is to directly allocate the transmission rights to customers that pay the embedded costs of the system. Any transmission rights not claimed by these customers would be auctioned. Another option would be to conduct an auction to apportion the transmission rights, with the proceeds from the auction allocated to those customers that pay the embedded costs of the system.

However transmission rights are initially issued, transmission rights holders can sell them into a secondary market so that others can buy transmission price certainty. If a transmission rights holder chooses not to schedule transmission service at a particular time, the transmission capacity will be made available to the market and the transmission rights holder will receive the associated congestion revenue.

The transmission provider must offer to sell transmission rights for all of the capacity on the grid, but it cannot sell more rights than the capacity can accommodate. After the initial allocation of transmission rights, there may need to be a regular reallocation of the transmission rights or the auction revenues to reflect changes in load responsibilities due to retail unbundling or other factors. Over the long term, if a customer (or merchant transmission company) pays to construct new transmission facilities that add transfer capability, the entity that pays for the construction, whether a customer or transmission owner, should receive the transmission rights associated with the new transfer capability (unless they receive credits against the Network Access Service access charge). This issue needs further consideration.

Transmission without price certainty

The alternative to predetermined transmission prices under transmission rights is for the Network Access Service customer to schedule service by agreeing to pay for any congestion costs of a particular transaction. Congestion costs occur when the capacity of the grid is limited and it is not possible to transfer more energy across the grid from the customer's intended source to sink without compromising grid reliability. In this situation, the transmission provider will redispatch a more expensive generator on the other side of the constraint to deliver to the intended sink. The incremental cost of this "out-of-merit" redispatch is charged to customers who have not secured transmission rights. Customers who hold transmission rights would not be charged the redispatch costs.

Day-ahead scheduling

Every day, the transmission operator would develop a schedule for use of the transmission system for each hour of the next day. The schedule would accommodate the requests of customers with transmission rights and those without, as well as transmission needed for delivery of purchases and sales made through the centralized energy spot market (described further below). Customers with transmission rights who want transmission service between their designated source and sink points would schedule their desired service between those specific points, and would be charged for losses but not congestion. Customers without transmission rights (including the transmission provider on behalf of customers purchasing or selling through the centralized energy spot market) would also schedule transmission service, by agreeing to pay the costs of losses and congestion between the desired source and sink points. Transmission rights are either source-and-sink-specific or flowgate-specific (discussed below). If a customer with transmission rights for a specific source-sink pair (from A to B) wants transmission service between a different set of source and sink points (from C to B), the customer would need to pay the cost of congestion and losses for transmission service between those new points (C to B).

Through the scheduling process, customers will be able to react to price signals by indicating how prices affect their demand for transmission service. In requesting transmission service, customers without transmission rights could either: (1) submit a bid stating the maximum congestion charge they are willing to pay for transmission service, or (2) indicate that they desire transmission service regardless of the price. Customers with transmission rights could voluntarily submit bids indicating the price above which they are willing to reduce their purchases of transmission service in exchange for receiving congestion revenues. For example, a customer with transmission rights from A to B may prefer receiving the congestion revenues if the congestion costs between those points is over $150 per MWh. In that case, the customer would voluntarily reduce its demand (for example, through a demand-side response program) for transmission service between those points.

If there is sufficient transmission capacity to accommodate all requested transmission service, then all requests would be scheduled, and all scheduled customers would pay a charge to recover the

applicable cost of losses. However, if the amount of transmission service desired along one or more transmission paths exceeds the transmission capacity (thereby resulting in transmission congestion), then the charge for using each congested path would be raised sufficiently (based on the cost of redispatch and the price bids for transmission service) to alleviate the congestion by reducing the demand for transmission service. The added charge would be paid only by customers without transmission rights along the desired transmission path (or flowgate). As noted above, a transmission rights holder would receive congestion revenues when the path (or flowgate) is congested and the transmission rights holder elects not to schedule all or a portion of its rights.

Real-time transactions

Once all day-ahead transactions have been scheduled, any remaining transmission capacity will be made available for real-time transactions. Transactions that were not scheduled a day ahead would flow at a charge that covers the applicable cost of losses and any congestion associated with necessary redispatch. A customer with transmission rights between a specific source and sink that did not schedule transmission service between those points a day ahead could still obtain transmission service in real time. In that case the customer would pay the real-time congestion costs and losses. The customer would also receive the congestion revenues from the day-ahead market for those points.

Additional features of the standard transmission service

Transmission prices (to recover congestion and losses) developed in the transmission market must be consistent with locational energy prices developed in the energy market. A locational energy price equals the delivered cost of electricity to that point, which equals the sum of the energy price plus its congestion cost plus the value of transmission line losses from the source to the sink. The difference in energy prices between two locations should equal the transmission price that will be paid by customers without transmission rights to transmit power between these two points.

Transmission rights can be defined in two ways: (1) source-to-sink rights, and (2) flow-based, or flowgate, rights. Both source-to-sink and flowgate rights are direction-specific (i.e., a right in one direction is different from a right in the opposite direction). A source-to-sink right is specified by a source (which can be a generator node, an aggregation of generator nodes, an interface, or a trading hub) and a sink (which can be a delivery node, an aggregation of delivery nodes, an interface, or a trading hub), and the total MW that are to be injected and withdrawn from the system at a point in time. It entitles the holder to schedule transmission of the specified MW of energy in the day-ahead market from the source to the sink without paying congestion charges. To the extent that the holder does not schedule its full MW entitlement, the holder is entitled to collect the congestion revenues from the source to the sink for the unscheduled capacity.

A flowgate right is specified by the total MW capacity over a particular transmission facility (or group of facilities, e.g., an interface) rather than just the source and sink points. It entitles the holder to

receive the congestion revenue associated with the specified MW flow over the identified transmission facility in the specified direction.[2]

Transmission rights can be specified as obligations or options. An obligation requires the customer either to (a) physically transmit energy from its source to its sink points, or (b) receive the congestion revenues (either positive or negative) between the points. An option gives the customer the entitlement to transmit energy or collect the congestion revenues, but the customer has no obligation to do either.[3] Currently, the transmission rights offered in ISOs that use LMP are obligations, although there is customer interest for transmission rights that are options. Existing firm point-to-point transmission contracts are similar to transmission rights that are options. At the start of Network Access Service, the transmission provider must offer source-to-sink obligations. Upon the request of market participants, the transmission provider must also offer source-to-sink options and flowgate rights as soon as it is technically feasible.

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[2]Consider, for example, a very simplified transmission network that connects two points, A and B, with two different but interconnected transmission lines, a northern line and a southern line, as shown below:

```
              North Flowgate
A  o-------------------------------------o
   |                                     |
   o-------------------------------------o  B
              South Flowgate
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Each transmission line would be a separate transmission facility or flowgate, and separate flowgate rights could be issued for each line. The holder of a flowgate right on the northern line from west to east would be entitled to the congestion revenues associated with that line in the west-to-east direction. However, holding a flowgate right on the northern line would not entitle the holder to congestion revenues associated with the southern line. Hence, if transmission service results in energy flows over several flowgates, the buyer must obtain sufficient rights on each flowgate to obtain a complete congestion hedge. By contrast, the holder of a source-to-sink right from west-to-east (i.e., from A to B) would be entitled to congestion revenues in the west-to-east direction regardless of whether the northern or the southern lines were congested and thus would have a complete hedge for this transaction.

[3]The difference between obligations and options becomes important when congestion occurs in the opposite direction from the right, that is, when there is congestion from the sink to the source points. In this case, congestion revenues in the direction of the right are negative. "Collecting" negative revenues means the holder pays congestion revenues to the transmission provider. If the rights holder does not physically transmit from its source to its sink when congestion is negative, an obligation holder must pay congestion revenues, but an option holder would not be required to pay.

D. Energy Market Design

One of the problems under the current OATT is the treatment of imbalances. The current rules give a competitive advantage to control area operators because they allow the operator to net out its imbalances over a large load and operate a number of power plants, while charging other sellers and buyers penalties for imbalances. The remedy for these problems is a balancing market with imbalances charged the real-time price for any excess or deficiency of energy.

Unlike gas pipeline systems, electric systems must balance supply and demand in real time. In electric networks, this balance is generally achieved by adjusting generator settings (energy production) rather than controls on the electric transmission network itself (as is done for the gas transmission system). Additionally, electric systems are affected by the operation of other electric systems in the interconnection (i.e., loop flow and parallel flows as externalities affecting all transactions on the grid), while gas pipelines rely on controls on the gas transmission network to balance supply and demand and do not face significant interaction and interdependency effects.

These differences in the operations of the systems argue for different systems for handling imbalances. On a gas system with storage, a small daily imbalance may have little or no operational effect and not threaten service to other customers. But on an electric transmission system, a similar imbalance could threaten service reliability unless the imbalance can be cured in real time. Consequently, while there is no need for centralized regional coordination on a gas system, such a need exists for an electric system, and that coordination is best effected using a real-time market for energy. Such a real-time market will improve system efficiency and lower costs relative to the requirements of Order Nos. 888 and 889.

While a day-ahead market is not strictly necessary for resolving imbalances, experience has shown that the combination of a day-ahead market and real-time market enhances system reliability and efficiency compared to operating only a real-time market. The day-ahead market lets the system operator ensure that sufficient generating units and transmission elements are committed to serve the next day's load. The day-ahead market also provides the opportunity for a generator's bids to better reflect the operational constraints and costs of generating units through multi-part bidding. Additionally, the day-ahead market provides better scheduling opportunities for the demand side to participate in the market. Markets that have operated with both a real-time and day-ahead market are more efficient than those with only a real-time market.

Day-Ahead Energy Market

The transmission provider must operate a day-ahead market in order to develop a joint day-ahead schedule for transmission service, energy, and ancillary services. The day-ahead schedule will be developed so as to maximize the combined economic value of transmission service, energy, and ancillary services, based on the bids submitted.

The energy market component of the day-ahead market performs two functions – through bids evaluated at auction, the market selects those units to be run in the next day and sets the energy prices to be paid in each hour for that energy. Those unit commitments are coordinated with the transmission scheduling operation to assure that energy can be delivered from the generation point to the delivery point, in a secure and reliable fashion.

General Features

1. The transmission provider must run a voluntary, bid-based, security constrained day-ahead market. "Voluntary" means that market participants do not have to buy or sell in the day-ahead market, as explained further below. "Bid-based" means that participants in the energy market may provide prices over the range of quantities that they offer into the market or seek to buy from the market. "Security constrained" means that the market administrator, through the energy auction process, accounts for all transmission system constraints, such as contingency limits, needed for reliable system operations.

2. The day-ahead market should be transparent (i.e., the rules of operation should be clear and understandable, and the software implementing the rules should produce predictable results) so that market participants can offer informed bids and trust market operations.

3. Since the day-ahead market is voluntary for market participants, market participants should be able to schedule bilateral transactions and/or self supply rather than bid into the day-ahead market. Long-term contracts and other means of avoiding price volatility and ensuring generation capacity adequacy should be fully accommodated.

4. Bidding parameters must allow customers the opportunity to reflect the value they place on purchasing in the energy market and allow suppliers the opportunity to reflect the costs and operational constraints of production in the energy market.

5. Demand can best respond by participating in the day-ahead market. Demand response options should be available so that end users can respond to price signals and reduce loads as they feel the price exceeds their individual willingness to pay for delivered electricity.

Scheduling and Bidding Rules

6. The demand side must be able to participate in the energy market. The demand side can participate as buyers or sellers (e.g., offering to sell operating reserves). As a buyer, an entity must be able to submit bids that indicate it is willing to vary the quantities it purchases based on the prices that it may be charged.

7. Sellers (including demand side) must have the option of submitting multi-part bids, e.g., submitting separate but related bids for start-up costs, no load costs and energy. Multi-part bidding allows generators to provide more detailed cost information that can improve the ability of the grid operator to dispatch generators with the lower total cost. Buyers must also be able to submit multi-part bids that indicate the time and price constraints under which they are willing to purchase energy in the day-ahead market.

8. Individual market participants must not be required to submit balanced schedules (where demand and supply are equal), although they may submit balanced schedules if they choose to. The transmission provider will match separate unbalanced supply and demand bids to ensure that aggregate generation and load are matched and the aggregate schedule is balanced. However, as discussed in principle 11 in the Real-Time Energy Markets section below, special rules may be necessary to address deviations in real time from day-ahead schedules that threaten transmission reliability.

9. Bids need not be tied to a physical resource. However, for reliability purposes, bids must indicate whether or not they are tied to a physical resource.

10. Limits may be necessary on bidding flexibility to mitigate market power. For example, suppliers may be required to submit a start-up bid which would remain in place for a period of several months (rather than re-bid every day). As more demand response becomes available in a regional market, limits on supplier bidding flexibility can be relaxed.

11. Additional scheduling options may need to be developed to address the special conditions facing energy-limited resources (e.g., hydroelectric power and environmentally constrained thermal power). However, these additional options should be available to all generators and should not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power that has arisen.

12. Intermittent resources should be able to participate in the day-ahead market on the same basis as other resources.

Price Determination and Settlement

13. Nodal pricing must be used for both buyers and sellers in the day-ahead market. Nodal pricing establishes separate prices at each node (in contrast to zonal pricing, which establishes the same price at all nodes within a zone regardless of congestion). Energy prices incorporate the total value of generation, transmission congestion, and losses at each node on the system.

14. An auction must be run to establish a single market-clearing price at each node. These prices at a minimum are hourly prices. (Smaller time intervals are acceptable.) Buyers and sellers transact at the clearing price. However, if a seller's total bid costs (including startup, no-load costs, minimum run time, and other physical characteristics as well as energy running costs) over the entire day are not fully covered by its revenues from selling at the hourly clearing prices, it will receive an uplift payment for the net revenue shortfall for the day. Hourly energy prices are based only on energy bids; start-up cost bids are not used in calculating hourly energy prices. Thus, a generator may have legitimate start-up costs that are not fully covered by selling at the hourly energy price over the day; paying uplift may be necessary to ensure that generators selected in the auction will receive revenues that fully cover their bid-costs.[4]

15. The results of the day-ahead market must be financially binding on buyers and sellers. In other words, sellers must be paid the day-ahead price for energy scheduled to be sold in the day-ahead market, and buyers must pay the day-ahead price for energy scheduled to be bought in the day-ahead market. In addition, to the extent sellers and buyers fail to produce or take energy according to their respective schedules, such imbalances must be settled at the real-time energy price. Thus, a seller must pay the real-time price for any scheduled energy that it promises but fails to produce in real time. Similarly, a buyer must be paid the real-time price for any scheduled energy that it promises but fails to take in real time.

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[4]For example, suppose that the transmission provider needs to supply an additional 100 MW load in each of 20 hours over the next day. Two generators, A and B, are available. Generator A has energy costs of $30/MWh, but must incur $10,000 in start-up costs before beginning production. Generator B has energy costs of $40/MWh, and has no start-up costs. Generator A's total cost of meeting the load would be $70,000 (i.e., total energy costs of $60,000 [$30/MWh x 100 MWh x 20 hrs] PLUS start-up costs of $10,000). Generator B's total cost would be $80,000, comprised exclusively of energy costs (i.e., $40/MWh x 100 MWh x 20 hrs). Generator A should be chosen because its total costs ($70,000) would be less than Generator B's total costs ($80,000). Suppose that the hourly clearing price in each hour is $32/MWh. By selling 100 MWh in each of 20 hours, Generator A would receive total revenues of $64,000 (i.e., $32/MWh x 100 MWh x 20 hrs), which is $6,000 less than its total bid-in costs of $70,000. Generator A would thus need to receive a $6,000 uplift payment in addition to its energy revenues. Paying $6,000 in uplift is still cheaper for customers than the alternative of dispatching Generator B.

16. Upon request of the market participants, the transmission provider should establish trading hub(s), i.e., a hub price that is the weighted average of prices at selected nodes on the system.

17. The transmission provider must post prices and other market information and settle the markets on a timely basis to provide market participants with reliable information regarding their market transactions.

Real-Time Energy Markets

General Features

1. The transmission provider must run a bid-based, security constrained real-time market. These characteristics are explained above.

2. The real-time market should be transparent so that market participants can offer informed bids and trust market operations.

3. Market participants must be able to revise their schedules for bilateral transactions, including long-term contracts, and self-supply after the close of the day-ahead market. However, all imbalances will be settled through the real-time market, i.e., to the extent a buyer or seller is short, it must purchase power at the applicable real-time price for the shortfall; to the extent the buyer or seller is long, it will be paid the applicable real-time price for the excess amount.

Scheduling and Bidding Rules

4. Bids to sell in the real-time market must be one-part energy bids, i.e., bids for energy only. (Separate bids should not be submitted for start-up and no load costs since the energy suppliers should already be on-line and ready to respond to dispatch instructions. Real-time market bids may, however, include information regarding minimum run times).

5. The demand side must be able to participate in the real-time market.

6. Limits may be necessary on bidding flexibility to address market power issues.

7. Additional scheduling options may need to be developed to address the special conditions facing energy-limited resources (e.g., hydroelectric power and environmentally constrained thermal power). However, these additional options should be available to all generators and should not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power that has arisen.

8. Intermittent resources should be able to participate in the real-time market on the same basis as other resources.

Price Determination and Settlement

9. Nodal pricing must be used for both buyers and sellers in the real-time market. Locational energy prices should reflect transmission congestion and losses.

10. Real-time prices will be established for each node through market clearing price auctions. These prices are generally for five-minute periods within the hour. Buyers and sellers transact at the clearing price.

11. All deviations and imbalances from the day-ahead market will be settled through the real-time market at the real-time price. In addition, real-time imbalances (i.e., individual market participants' uninstructed deviations in real time from their day-ahead schedules or dispatch instructions) that threaten transmission system reliability may require special rules, including penalties.

12. The transmission provider must post prices and other market information and settle the markets on a timely basis to provide market participants with reliable information regarding their market transactions.

Regulation and Operating Reserves to Meet Reliability Requirements

Transmission providers must ensure that ancillary services, including regulation and operating reserves, are provided. Regulation provides moment-by-moment balancing of generation and load on the system. Operating reserves ensure reliable service by covering contingencies such as the failure of a supply source or a transmission line. Order No. 888 envisioned that these would be provided as a tariff service subject to a cost-based rate. With the establishment of markets to provide balancing services, a more market-oriented approach is needed for regulation and operating reserves. (Other ancillary services, such as reactive power, would continue to be procured much as they are today.) The same generators that could be supplying regulation or operating reserves also could be supplying energy for balancing services. Procuring regulation and operating reserves compatibly with the procurement of energy for balancing services will lead to a more efficient and rational price structure for both. As noted below, the technical requirements of regulation service are different from those of operating reserves, so it is likely that some differences in their respective market rules will be appropriate.

General Features

1. The LSE has the responsibility to procure regulation and operating reserves or pay for the regulation and operating reserves procured by the transmission provider on its behalf.

2. Suppliers of regulation and operating reserves must meet specific operational requirements to provide these services. For example, generators offering regulation typically must have equipment providing automatic generation control capability. Suppliers of these services also typically must meet response time requirements; regulation needs to fully respond to a dispatch instruction within 5 minutes, while various categories of operating reserves must respond within 10 minutes or longer. Demand must have the opportunity to supply operating reserves if it meets the necessary operational requirements (which should be designed to enable demand response participation).

3. The transmission provider must have a bid-based day-ahead and real-time market so it can procure regulation and operating reserves on behalf of LSEs. If there are a limited number of sellers for certain operating reserves, then market power mitigation measures may need to be included in the market design.

4. Reliability authorities may establish locational requirements for operating reserves. To the extent they choose to do so, this may require the reservation of transmission capacity. The cost of the "transmission reserves" must be included in the total cost of procuring the operating reserves for the LSE involved.

Scheduling and Bidding Rules

5. LSEs that have a regulation and operating reserve obligation may fulfill this obligation through self-supply, bilateral transactions, or by paying the market-clearing price in the auction run by the transmission provider. LSEs may meet their obligation through combinations of these transactions as long as the full obligation is met.

6. The transmission provider must procure regulation and operating reserves through a bid-based auction for all those who do not self-supply. The financial responsibility for regulation and operating reserves procured through the auction will be borne by those LSEs that did not self-supply.

7. Demand-side supply of operating reserves must have non-discriminatory bidding opportunities in the market.

8. Regulation and operating reserve markets must allow sellers to submit availability bids in addition to energy bids. The availability bid allows the bidder to specify the minimum payment that it requires to be available to provide regulation and operating reserves.

Price Determination and Settlement

9. The day-ahead regulation and operating reserve markets must clear simultaneously with the day-ahead markets for energy and transmission service in bidding and scheduling. The market-clearing prices must be based on winning bids that jointly optimize energy, regulation, operating reserves, and transmission service.

10. Market rules should be structured so that the price of energy is never less than the price of operating reserves and the price of higher-quality operating reserves is never less than the price of lower-quality operating reserves. For instance, the market-clearing price of spinning reserves must never be lower than the price of non-spinning reserves. The price of non-spinning reserves with a shorter availability (e.g., ten minutes) must never be lower than the price of non-spinning reserves with a longer availability (e.g., thirty or sixty minutes).

11. All market-clearing prices must recognize the substitution possibilities among operating reserves and conduct a least-cost procurement of the products. Higher-quality operating reserves bid at lower cost must displace lower-quality operating reserves at higher cost.

E. Other Changes to Improve the Efficiency of the Markets under Standard Market Design

The changes discussed above will require extensive revisions to the current pro forma tariff. The OATT also establishes other rules on the provision of transmission service. Some of these rules also need to be updated to achieve the objective of a competitive wholesale electric market. There are inefficiencies in the application of some of these rules on a company-by-company basis rather than on a regional basis. In others, the OATT does not allocate the costs of reserved capacity to only those customers that have reserved the capacity. The remedy is to update the OATT to correct these problems.

1. Capacity Benefit Margin (CBM), which is a set-aside of transmission capacity by the transmission provider to ensure access to external resources in case of a contingency, ties up valuable interface capacity without a specific reservation and payment by the customers who benefit from the service. Therefore, capacity currently set aside for CBM should not automatically receive a transmission rights allocation, but should be posted on the OASIS and specifically reserved and paid for by the entity requiring the service, whether it be for additional reliability or access to other resources.

2. Calculations of transmission capability and the performance of facilities studies for transmission expansions should be performed by an independent entity. This reduces the ability of an entity to use its transmission system to favor its own generation.

3. The new tariff should recognize the regional nature of today's energy markets. As such, transmission capabilities must be calculated not for one utility's service territory, but regionally to encompass existing trading patterns and power flows, particularly parallel path flows on neighboring systems. All transmission providers that are not part of a Commission-approved RTO must contract with an independent entity to perform transmission capability calculations on a regional basis. Likewise, a common OASIS should be required for the region.

4. Proactive long-term planning and expansion must be done regionally. The RTO, must offer a mechanism for participants to bring long-term planning and expansion needs and proposed solutions to the RTO. The RTO would choose an ultimate solution, whether transmission, generation or demand side, after vetting proposals through an open stakeholder process. The recommended solution(s) must then be put out under request(s) for proposals for construction and/or implementation. If a transmission provider is not part of an RTO, it must participate in regional long-term planning and expansion.

5. To minimize the implementation costs of standard market design, the software should be modular to allow multiple vendors to provide the components of the overall software platform. Standardized data formats and data transfer protocols may also be appropriate to minimize implementation costs.

F. Market Power Monitoring and Mitigation

Market rules, such as poor auction designs, can create or enhance market power by artificially limiting entry, preventing demand response, or providing artificial incentives to withhold. Many of the problems with generation markets identified by market monitors in the first few years of regional market operations have been caused by design flaws. The standard market design will include preventive mitigation measures in the form of bidding rules. The best way to avoid market power stemming from poorly designed markets is to establish efficient designs. Market rules should mitigate market power in the least intrusive manner.

Structural solutions to mitigate market power are generally more effective than behavioral mitigation. RTOs and independent transmission operators are structural mitigation for vertical market power because they remove the control of transmission access from transmission companies that also compete in generation markets. With respect to generation market power, market forces such as supply and demand responses are the most potent and lasting means of mitigating market power, so solutions that increase the potential number of suppliers or increase price-responsive demand must be promoted. If market power is not mitigated through structural solutions, market rules need to be designed to mitigate market power. For example, locational market power in generation load pockets with only one or a small number of generating units will require behavioral mitigation. These load pockets should be identified and the behavioral mitigation measures should be in place before implementation of standard market design.

Market monitoring should focus on two general areas. First, it should identify any problems in the design of the market that lead to inefficient outcomes and should propose prospective market rule changes. Market monitoring should serve as an early warning system for events that are not yet severe, so corrective action can be taken before exercises of market power become significant and sustained. Second, market monitoring should focus on the behavior of the market participants. Market power can be exercised by withholding capacity or output from the market (physical withholding) or raising the price or offer (economic withholding). Therefore, monitoring for withholding will be an important focus of market monitoring activities. Market monitoring units (MMU) within each region will be the first line of defense, but ultimately the Commission has the responsibility for monitoring wholesale energy markets and the authority to take corrective actions when needed. For transmission providers that are not part of an RTO, further thought is required to address market monitoring.

Set out below are some general principles to guide the development of market power mitigation rules and a market monitoring plan, as well as some specific measures that should be included in the standard market design. These are based on the Commission's experience with market power mitigation methods in recent years and are intended to reflect the best observed practices that are compatible with the elements of standard market design.

Principles

1. Market rules should be designed to improve the competitive structure of the markets and to build into the design of the markets customer protections against market power.

2. Market rules should minimize market power by facilitating new entry and increase demand response to improve the competitive structure of the market.

3. The regional transmission planning process should identify opportunities for increasing competition, particularly the elimination of local market power when possible, and should be aggressive about facilitating new demand response, transmission or generation construction as needed.

4. Where behavioral rules are needed to mitigate market power, the mitigation rules should be clear, and not subject to discretionary actions. Effective ex ante mitigation is preferable to retroactive price changes.

5. Market rules should not require offers to sell below marginal opportunity costs of a unit, including the verifiable geographic opportunity cost of selling to other regions and the temporal opportunity cost of selling energy-limited resources in other time periods.

6. Market monitoring should focus on detecting economic and physical withholding (as distinct from the normal operation of supply, demand, and true scarcity) and assessing the efficiency of the market.

Mitigation Measures

7. A bid cap, as a proxy for demand bidding, must be in effect until sufficient demand response develops in the relevant wholesale power market. Mitigation rules that limit bidding flexibility will also be needed. As a region develops substantial price-responsive demand, mitigation rules can be reduced correspondingly.

8. The transmission provider may identify generating units that must run for reliability. Because these units have locational market power, the bids submitted by these units should be subject to mitigation. Similarly, market power in load pockets must be mitigated with on-going behavioral mitigation, such as call options or bid caps, unless structural solutions are possible.

9. Limitations on the flexibility to change bids, e.g., for start-up and no load costs, may be needed. For example, it may be appropriate to limit how often market participants are permitted to change their start-up and/or no load bids.

10. The transmission provider must be able to coordinate maintenance and outage schedules for generation and transmission facilities in order to assist in reliability planning and to monitor withholding. Information on maintenance and outage schedules should be made available to the market on a timely basis.

Monitoring

11. Each RTO should have an MMU that is independent of the RTO management. The MMU should be funded by the RTO, but it should report directly to the Commission and to the independent governing board of the RTO.

12. The Commission will exercise oversight of MMU activities and the impact of RTO operations on the efficiency and effectiveness of the market.

13. An MMU will monitor all markets (including the impact of generation, transmission, and load) in its region, principally for economic and physical withholding.

14. The MMUs will conduct periodic reviews and analyses of the general performance of the markets, and the impact of the market rules, on the efficiency and effectiveness of the markets in the RTO's region and will propose rule changes, when appropriate, to the Commission.

15. The MMUs should work with each other, the states and the Commission to develop market performance measures that are common to all regions.

G. Long-Term Generation Adequacy

Most of the above discussion deals with maintaining reliable day-to-day operations of the system in a market-oriented way. On a long-term basis, for the system to be reliable and the markets to function efficiently, there must be adequate generation resources and transmission resources. To do that, there may be a need to include specific measures to ensure that LSEs maintain a reasonable supply reserve margin. The issue of how to do this is a contentious one that needs further discussion among industry participants. However, there are certain basic principles that should be used in standard market design.

1. Standard market design may include measures to ensure adequate long-term generation supplies. Any such measures should be forward-looking and flexible enough to accommodate changing load obligations.

2. Preferably, state and regional reliability authorities will coordinate with one another to set a regional, long-term reserve margin to be maintained by LSEs subject to their jurisdiction.

3. When load must be curtailed due to insufficient generation, the transmission provider should avoid curtailing LSEs that have procured sufficient generation, if operationally possible.

H. State Participation in RTO Operations

State commissions have an important role in the process of creating an efficient competitive wholesale market for electricity. The Commission has already established state-federal RTO panels as a forum for FERC and state commissions to discuss issues related to RTO development. However, there currently is no formal process for state commissioners to engage in a similar dialogue with the independent entity that would operate the electric grid under standard market design. The standard market design rule will establish a formal role for state regulators to participate on an ongoing basis in the decision making process of these organizations.

Each RTO or other independent entity that operates the grid should have an advisory committee whose members include state representatives reflecting the breadth of retail customers' interests. The specifics of how this advisory committee would be formed and operate could vary regionally and by RTO.

The standard market design rule will require the establishment of an MMU within the RTO. The MMU will provide reports to the independent governing board of the RTO and the Commission on

the efficiency of the markets and the need for rule changes. The MMU should also provide these reports directly to the advisory committee.

Finally, because of the regional nature of these organizations, there are many new issues involving rate design and revenue requirements. We believe the advisory committee can bring a valuable regional perspective to these issues and should play a role in deciding these issues in partnership with the Commission. Once the advisory committees are established, we will work with them to establish protocols for deciding these regional rate issues.

I. System Security

The Standard Market Design and RTO conferences to date have focused on various aspects of market design. System security is critical to the reliable operation of the interstate transmission grid. In this respect, the current OATT defines "good utility practice" as:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. . . .

Similar concerns about reliability led us to require that an RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. In a region lacking a Commission-approved RTO, individual transmission operators must perform the same function. The current OATT will be revised to state more explicitly the obligation of transmission providers to comply with all appropriate standards for ensuring system security and reliability.

Infrastructure security of grid equipment and operations and control hardware and software is essential to ensure day-to-day grid reliability and operational security. The Commission will expect all transmission providers, market participants, and generators interconnected to the grid to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

J. Transitional Considerations

We recognize that implementation of a new transmission tariff and standard market design on a nationwide basis may take some time. Standard market design requires many institutional changes and

software development. Therefore, the rule will require a phased compliance for standard market design changes in order to implement certain changes as soon as possible. The first phase will focus on a few major points that can be implemented within the existing Order No. 888 open access tariffs fairly quickly. Later phases will involve a full tariff redesign to incorporate all of the elements of standard market design. The first phase will include:

1. Physical trading hubs: Flexibility in choosing resources based on hourly marginal costs is an inherent advantage of network service over point-to-point service, particularly with respect to a merchant generator located in a different control area than the load while competing with the host traditional public utility. Transmission providers that do not offer centralized markets should file a proposal to offer physical trading hubs. Suppliers must be permitted to schedule to physical hubs within the transmission provider's system so that load can choose from a variety of resources, and supply can reach a variety of loads. The transmission charge should be commensurate with the cost of providing the service.

2. Clarifications and updates to the tariff: In the six years since the issuance of Order No. 888, the Commission has clarified numerous provisions in the pro forma tariff. These clarifications should be consistently applied to all existing transmission tariffs. Examples of these are "right of first refusal" time frames and the ability to redirect a long-term reservation. For redirects, competing generators or marketers would be confident that they could attain additional flexibility if the Commission were to revise the pro forma tariff to allow partial term redirects of a long-term point-to-point reservation (i.e., permit a long-term firm point-to-point transmission customer to request alternate firm points for a portion of the contract term and return to the original points later in the term).

3. First Phase tariff compliance time frame: Transmission providers must revise their existing transmission tariffs to include physical trading hubs and clarifications to the Order No. 888 pro forma tariff within 60 days of the date the Final Rule becomes effective.

K. Issues that Need Further Discussion

This paper identifies the general vision for a standard market design for wholesale electric markets and a new transmission tariff. It does not attempt to answer all the questions that will need to be answered to implement the standard market design and write a new transmission tariff. Based on the guidance contained in this document, Commission staff will be developing tariff language for further discussion by stakeholders.

There are many issues involved in the transition to the new services, including: (1) transition of customers under existing contracts to the new Network Access Service; (2) allocation of transmission rights; and (3) development of a schedule for phased compliance and implementation of standard market design. Many of these may need to be decided on a regional basis.

As noted in the discussion of the role of state commissions, there are many rate issues associated with these new services. There needs to be further work on transmission pricing issues, such as who pays for embedded transmission costs, whether postage stamp or license plate rates should be used for existing facilities, and cost allocation for new transmission facilities. All of these issues will require further discussion, with the goal of resolving them as soon as possible.

Finally, this paper envisions that RTOs will have significant responsibilities under standard market design. Consistent with the Commission's November 2001 order, the Commission will use a two track approach to resolve RTO issues. Issues of scope and governance will be handled in individual RTO cases, not in the Standard Market Design rulemaking.

APPENDIX

Electronic Scheduling Collaborative Issues

On October 5, 2001, the Electronic Scheduling Collaborative filed a Status Report on OASIS Phase II Business Practices. The report provided an update on the ESC's efforts to standardize a set of Business Practices for implementation of OASIS Phase II and Electronic Scheduling. As part of that report the Electronic Scheduling Collaborative identified certain issues as candidates for standardization or rulemakings and presented some key policy questions that needed to be answered. As part of the description of standard market design elements in this paper, we have provided preliminary answers to the questions on market design. The questions from the Electronic Scheduling Collaborative and the answers that are contained in this paper are summarized below.

1. Congestion Management – When Operational Security Violations occur, how is the system to be stabilized in a fair and equitable manner that is nonetheless efficient? Will LMP based systems be standard, or will there be others that must be accommodated?

   Answer: The transmission provider would use market mechanisms whenever possible to deal with potential Operational Security Violations. Thus, locational marginal pricing will be used as the standard method of congestion management. The transmission provider would also develop a security constrained, day-ahead unit commitment and a security constrained real-time dispatch that account for all transmission constraints, such as contingency limits, needed for reliable system operations. Only if these market mechanisms do not stabilize the system will non-market mechanisms be used.

2. Transmission Service – Are transmission services required to schedule ("covered" schedules only) or are they risk management tools protecting from congestion charges (both "covered" and "uncovered" schedules are allowed)?

   Answer: Anyone wanting to transmit power between two points will need to obtain transmission service. However, Network Access Service could be obtained either well in advance of real time or through the day-ahead or real-time markets. If a customer wants to achieve price certainty (protection from the cost of congestion), it would need to separately procure transmission rights.

3. Loop Flows -- Are contract-path based or flow-based transmission services appropriate? If contract-path based, how are parallel path issues to be addressed?

   Answer: The Network Access Service would be a flow-based transmission service within the RTO. A flow-based system better recognizes the regional nature of the transmission grid.

4. Grandfathered Transmission Service -- Should contracts existing prior to RTO development be transferred, or is there an equitable way to retire those contracts? Are there other solutions?

   Answer: This is a transition issue that needs further discussion and may require different regional approaches. Customers under existing contracts should continue to receive the same level and quality of service under standard market design. However, transmission capacity not used by these customers must be made available to others in the day-ahead and real-time markets.

5. Energy Imbalance Markets -- How are imbalance markets to function? Will they serve as real-time energy markets (support unbalanced schedules), be limited to supplying needs of imbalance service (require balanced schedules) or will they be required at all?

   Answer: The day-ahead and real-time markets will support unbalanced schedules.

6. Ancillary Services -- Will ancillary services be developed in standard ways? Will entities be required to actually schedule ancillary services (required to schedule), or will they be treated primarily as financial instruments (protecting against real-time Provider of Last Resort (POLR) charges)?

   Answer: Ancillary services will be developed in standard ways. Customers will be required to procure operating reserves and schedule ancillary services through self-supply, bilateral transactions, or by paying the market-clearing price in the operating reserves auction(s) run by the transmission provider.

7. Losses -- Can we utilize the imbalance markets to support losses? Can we create specific loss standards that facilitate the scheduling process, or must we support methods that are currently in tariffs, but technically unwieldy?

   Answer: The imbalance markets can be used to support losses. New loss standards will be developed and included in the new pro forma tariff.

8. Non-Jurisdictional Entities (NJEs) -- How are NJEs to be integrated into the new world? Should systems be designed with the assumption that non-jurisdictional entities will be part of an RTO? Or should they be designed to treat each NJE as a separate entity?

   Answer: This question is not specifically addressed as part of standard market design. However, the Commission's policy is that RTOs should be structured to permit non-jurisdictional entities to voluntarily join RTOs. Issues related to the participation of non-jurisdictional entities in RTOs will be addressed in the individual RTO proceedings.

EXHIBIT PRP-4

Synapse
Energy Economics, Inc.

Best Practices in Market Monitoring

A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets

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This report was prepared by Synapse Energy Economics for the five agencies. The authors take full responsibility for the contents. The individual agencies (and their representatives identified above) do not necessarily agree with all of the recommendations in this report.

1. Introduction and Summary

Market monitoring and mitigation is widely recognized as an important evaluative tool for understanding the performance, and ensuring the competitiveness, of bid-based regional electricity markets. Both the physical complexities of the electric bulk power system and the administrative complexity of the market rules for competitive wholesale markets contribute to the numerous market failures that have occurred in the four years since FERC Orders 888 and 889 opened wholesale power markets to widespread competition.

The analysis in this report occurs against the backdrop of Order 2000 and its related follow-on orders on specific proposals for Regional Transmission Organizations (RTOs). Most recently, FERC directed the stakeholders in three existing ISOs to engage in a 45-day mediation process to develop a "business plan" for the development of a Northeast RTO that administers a single Northeast market with a single Northeast transmission rate. While approving parts of the individual ISO filings on RTO formation, FERC found that the "size and scope" criteria, one of the four essential characteristics of an RTO, could only be met through a larger Northeast RTO entity. To guide the mediation process, FERC directed stakeholders to use the PJM system as a "platform" from which to build the Northeast RTO, and to supplement the platform with "best practices" from NE and NY.[1]

While we have examined market monitoring procedures in numerous bid-based wholesale markets, we have focused primarily on the three northeast ISOs and to a lesser extent California.[2] For the United States, these ISOs have had the most substantial experience with bid-based markets. Due to FERC's recent RTO Orders, the three northeast ISOs are a natural focus as plans to implement a Northeast RTO are considered. NY and NE have much more extensive monitoring activities (in part due to their bid-mitigation authority), which PJM may want to consider as enhancements to its own processes, whether in the context of a Northeast RTO, or for direct application to the markets that PJM currently administers.

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[1] On September 17, 2001, the FERC Administrative Law Judge in charge of the 45-day mediation issued his Report together with a Business Plan for the formation of a Northeast RTO. FERC allowed comments on the Report to be filed through October 9, 2001. It is anticipated that FERC will issue an Order on the Report in early November. The Business Plan identifies numerous issues related to Market Monitoring, but does not make any substantive recommendations.

[2] We looked briefly at the Texas ISO and the proposed Midwest ISO but did not evaluate either one in detail due to the limited market experience of Texas and the absence of market experience for the Midwest ISO. Internationally, we examined the markets in the United Kingdom, Nord Pool (Norway, Sweden, Finland, and Denmark), Germany, and Australia. A summary of this review is attached as Appendix B.

responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

Recommendation #1: The MMU must closely monitor, and ideally be physically present or adjacent to, the control room dispatch.

Recommendation #2: The MMU should report within the RTO to the Board of Directors. The MMU should work closely and collaboratively with the CEO and the RTO staff that has market design responsibilities.

Recommendation #3: The RTO should contract with an independent Market Monitor (IMM) or Market Advisor to complement and advise an internal MMU. The IMM should report directly to the Board of Directors of the RTO.

The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

Recommendation # 4: The MMU should be responsible for monitoring all wholesale markets administered or facilitated by the RTO/ISO, including the spot and bilateral energy, ancillary-services, capacity, and transmission markets. The MMU should monitor both supply and load bids in all markets.

Recommendation #5: As part of its ongoing evaluation of market efficiency and competitiveness, the MMU should evaluate the performance of the markets against the outcome of a market where all bids are at marginal cost.

Recommendation #6: The MMU should have the authority to assess the impact on the market of proposed mergers and acquisitions, and be a party to such proceedings.

The market monitor should have authority to mitigate, sanction, and penalize, as well as the ability to identify necessary rule changes.

Recommendation #7: The MMU should have access to all data that will assist it in performing its market monitoring function.

Recommendation #8: The MMU should have authority to mitigate any bid in any market prior to accepting it.

Recommendation #9: Bid caps should be used as an essential component of electricity markets.

Recommendation #10: In addition to its authority to mitigate a bid in advance of accepting it, the MMU should also have the authority to impose sanctions or penalties on market participants for specific behaviors, including the failure to provide information requested by the MMU.

Recommendation #11: The MMU should have the authority to flag clearing prices and make price corrections for a limited period of time after the market clears.

Recommendation #12: The MMU should have the authority to file with FERC for changes to both market-monitoring rules and market rules.

The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

Recommendation #13: In order to improve transparency and enhance confidence in the markets, the MMU should regularly and frequently issue detailed reports on its monitoring activities.

Recommendation #14: Bid data with names should be released on a one-month lag.

In conclusion, our review of current market monitoring and mitigation practice indicates that market monitoring activities need to be broadened and enhanced to guard against significant anti-competitive activities by market participants, including exertions of market power. Of particular importance is our observation that bid-based market systems do not produce prices that are "just and reasonable" when demand approaches or exceeds available supply.[3] The market monitoring improvements identified in this report are needed now and are not dependent upon any specific proposals or alternatives currently being discussed in the context of the Northeast RTO mediation process. In fact, a strong argument could be made that enhanced market monitoring and mitigation practices are a pre-condition for the creation of a single Northeast energy market.

2. Experience and Trends in Market Monitoring

2.1 The Need for Monitoring of Electricity Markets

With economic deregulation of wholesale electricity markets, there is an urgent need for aggressive market power monitoring and mitigation. In markets for other commodities, we rely upon the responsible state and federal agencies to promote workably competitive markets through enforcement of antitrust laws. Actions can be taken by antitrust

[3] Throughout this text we use the term "demand" to mean electrical requirements including reserve requirements, and the term "supply" to mean generation and operating reserves. Our focus on times when demand approaches or exceeds available supply does not imply that market prices are necessarily just and reasonable at other times. Indeed, there may be significant opportunities for market manipulation during less constrained times.

authorities in situations with collusion, proposed mergers, or monopolies. In electricity markets there are several compelling reasons that this customary approach is not adequate or prudent.

First, the electric industry is in a transitional period, with many decades of experience as regulated monopolies. The existing companies are large, with infrastructure designed and built to serve customers in transmission system control areas where there was no need to consider promoting competition. There was an extraordinary degree of industry cooperation – with individuals routinely participating on committees to coordinate system expansion and operation (e.g., the North American Electric Reliability Council). While this was appropriate and necessary in the past, going forward there are inherent tensions between the benefits of coordination and the need for firms in a deregulated market to act competitively. With respect to market power monitoring and mitigation, it is useful to keep in mind that most of the individuals currently working in this industry come from a tradition of cooperating monopolies. Market participants have, for example, played a very active role in designing and modifying electricity market rules in the new ISOs. While this may have occurred for legitimate reasons, it does point to the need for market monitoring and mitigation by an independent entity.

Second, the role of electricity as a fundamental element of the infrastructure supporting the economy as well as basic human activities should be considered. Events in California have illustrated the need for reliable electricity service at reasonable prices, and the implications to local and regional economies of power outages and sustained wholesale prices above competitive levels. It is not an easy task to sort out the specific roles of particular underlying factors (e.g., capacity shortages vs. anti-competitive withholding of generation) in the California debacle. Still, it is clear that the exercise of market power played some substantial role in causing California's problems and that aggressive, timely, and effective market power monitoring and mitigation would have been helpful.

Third, a combination of physical characteristics of electricity generation and transmission make market power a particularly urgent concern in electricity markets. Specifically:

- Electric power must be delivered over a constrained transmission grid,
- Electricity supply and demand must be balanced on an instantaneous basis, and
- Storage of electricity is limited, inefficient and expensive.

Even in electricity markets where generation ownership is not concentrated as a general matter, there are likely to be locations ("load pockets") and times for which there are an insufficient number of competing generators.

Fourth, electricity markets are characterized by repeated organized interaction, with bids typically submitted on a daily basis, and refinement on an hourly basis (in "day-ahead" and "real time" markets). Markets that function as a repeated game are particularly subject to tacit collusion, as participants learn about and react to the bidding strategies of

other participants, or even use the bidding process to communicate and promote cooperation (see, for example, Gibbons 1992).

Fifth, market entry is difficult in electricity markets. It can take several years to get a power plant built, given difficulties in siting, obtaining permits and financing, lining up fuel supply, and construction. Power generation is capital intensive, with new combined-cycle gas plants costing in the neighborhood of $600/kW. In other markets, where market entry is quicker and less costly, actual market entrants or even the threat of entry may be relied upon to moderate the exercise of market power. In electricity markets, the role of market entry must be supplemented by effective market monitoring and mitigation.[4]

And finally, the lack of demand participation in electricity markets is noteworthy and troublesome. In the short run, electricity demand is almost entirely "inelastic." That is, when pool prices spike there is little practical opportunity for customers to cut back purchases. This is changing gradually, with demand-response programs being developed and expanded in all of the operating ISOs (Synapse 2001) but we are still many years – probably decades – away from an adequate demand response in electricity markets. In the meantime, aggressive market monitoring and mitigation supplemented by bid caps will be essential elements of electricity markets.

In electricity markets, the continuing obligation of generators to serve loads (either under contract or as a continuing obligation of a vertically integrated company) can help to decrease or eliminate the incentive for a company to bid above marginal costs in order to raise the market price. In PJM, unlike California and New England, a large amount of the generating capacity has continued to be owned by companies with substantial load obligations. As PJM's 2000 State of the Market Report notes:

> The structural analysis indicates that the PJM control area exhibits moderate market concentration. However, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2000, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those obligations change.[5]

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[4] For a discussion of market entry, as well as an excellent overview of experience in electricity markets through the beginning of 2000, see "Horizontal Market Power in Restructured Electricity Markets" (DOE, 2000).

[5] PJM 2000 State of the Market Report, p. 11.

2.2 Regulatory Context

Orders 888 and 889

In Orders 888 and 889, issued in April 1996, FERC introduced new opportunities for competitive markets to replace traditional cost-based regulation of wholesale bulk power systems. As a result of those Orders, FERC set a series of events in motion that have led to both the need for a report such as this one and to many of the practices that this report recommends. In its April Orders, FERC required that:

- All owners of transmission systems had to file an Open Access Transmission Tariff (OATT) that would provide universal and non-discriminatory access to the use of the bulk power electric system for wholesale electricity sales.

- Electric utilities were allowed and encouraged to develop proposals for "independent system operators" who could oversee the implementation of the OATT on a fair and impartial basis and who could administer a wholesale market in a manner, subject to FERC approval, that would produce "just and reasonable" rates.

Despite FERC's concern that market based rates might provide an opportunity for the exercise of "market power" by owners of generation resources, FERC stated that it would approve market based rates upon satisfaction that the exercise of market power was either unlikely, or that structures had been proposed to guard against such exercises. From this initial posture of "let's see how it goes," FERC has approved a series of increasingly more detailed and complex market monitoring proposals over the ensuing years.

Order 2000: RTOs

In December 1999, FERC issued Order 2000, which required all entities that implement open access transmission tariffs to file proposals for creating a regional transmission organization (RTO) that satisfied the four characteristics and eight functions detailed in the Order.[6] Filings were required in October 2000 for transmission tariff entities that were not part of an existing ISO; the ISO transmission entities were required to make their filings in January 2001.[7] For the purposes of this report, the second characteristic, independence, and the sixth function, market monitoring, deserve particular attention.

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[6] The four characteristics are (1) independence from market participants, (2) appropriate scope and configuration, (3) operational authority, and (4) short-term reliability. The minimum functions pertain to (1) transmission service and tariff, (2) congestion management, (3) parallel path flow, (4) ancillary services, (5) transmission availability information, (6) market monitoring, (7) transmission planning and expansion, and (8) interregional coordination. Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999).

[7] PJM and the transmission owners filed their RTO proposal early, on October 11, 2000.

FERC highlighted the need for RTO independence from market participants to ensure that the wholesale electricity markets and the associated transmission service would not be subject to manipulation or undue influence from entities engaged in profit-making activities. A truly independent RTO would create confidence among market participants that there was a level playing field; it would also encourage new entrants into both the market and transmission functions of the wholesale regional marketplace.

FERC identified market monitoring as one of the core functions that an RTO entity must provide. Since Order 888, FERC has moved toward a more active approach with regard to the need for and benefits of market monitoring. However, FERC still maintains a very flexible approach to market monitoring by allowing RTO participants to identify appropriate market monitoring activities that would meet certain broad standards.

Northeast RTO Orders

In its Orders released in July 2001, FERC discussed how the filings from PJM, NY and New England addressed the "independence" characteristic and the "market monitoring" function. The orders are briefly summarized.

Independence

In the PJM Order, FERC found that PJM meets the independence characteristic except for the establishment of reliability requirements (including capacity resource obligations and capacity deficiency requirements) pursuant to the Reliability Assurance Agreement. For determining reliability criteria under the RAA, FERC stated that PJM can not allow these requirements to be set by a committee of market participants. In this Order, FERC did not specifically address the role that market participants have under the PJM Operating Agreement in proposing and approving changes to the market rules.

In the NYISO Order, FERC found that the authority of market participants, through a governance committee, to review and approve all changes to the wholesale markets system was inappropriate and created "undue influence" on the part of market participants. FERC found that NYISO's RTO proposal failed to meet the independence characteristic.

In the ISO-NE Order, FERC found that market participants' role in governance, through the NEPOOL committee process, was inappropriate. In an RTO, a committee of market participants, such as NEPOOL, should serve a purely advisory role. FERC specifically mentioned NEPOOL's role in approving changes to market rules and stated that this should be the exclusive authority of ISO-NE.

Market Monitoring

The implications of the Orders for market power monitoring and mitigation are not clear. FERC emphasizes that it will be paying close attention to, and will be involved in, on-going efforts to monitor markets. FERC found that all three proposals satisfied the

market monitoring function, although ISO-NE must make a supplemental filing once it has implemented a congestion management system.

It is worth noting that the market monitoring plans of the three Northeast ISOs differ significantly. PJM's market monitoring unit has a small staff and no general authority to mitigate bids or impose sanctions and penalties; it performs primarily a monitoring function, only. However, PJM has the authority to cap bids of must-run units in local load pockets, which is done outside of the market monitoring process. FERC states in the PJM Order that it is not essential for an RTO to have mitigation authority, and accepts PJM's proposal, which does not include a request for mitigation authority.

ISO New England currently has bid mitigation authority that was won with a strong effort on the part of PUCs and AGs in New England. ISO-NE has a medium sized staff and the authority to mitigate bids before the market clears, impose sanctions and penalties, and also mitigate congestion payments for generators in "non-competitive" conditions.

In the New York Order, FERC approved the NYISO's proposal and specifically mentioned the appropriateness of its market mitigation and sanctioning authority. NYISO has the largest staff and the most extensive monitoring and mitigation process of the three ISOs. Furthermore, NY and NE have "outside" market advisors – entities that advise the ISO Board but are not within the ISO corporate organization, while PJM does not.

The disparity in market monitoring authorities and practices is important, and FERC has not given any clear guidance on how the market monitoring function should be designed for the Northeast RTO. Since FERC identifies PJM as the platform upon which the Northeast RTO should be developed, it remains unclear as to whether there will be consistency between the market monitoring functions of the three control areas. While best practices of other ISOs are to be incorporated into the PJM market platform, FERC has not clearly stated how the NE RTO market monitoring function is to be designed nor identified any of the market monitoring "best practices" from NY and NE that should be added to PJM's RTO proposal for market monitoring.[8]

2.3 ISO Experiences

Market Monitoring Concerns during ISO Formation

As the ISO's were established in the Northeast electrical control regions, each took a slightly different perspective on the need for, and implementation of, market monitoring.

PJM's proposal for market based rates for a multi-state tight power pool included a study by independent economists that PJM's markets were not "concentrated" and there was unlikely to be an opportunity for existing generators to have or exercise market power.

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[8] FERC, *RTOs – Administrative Law Judge Mediator's Report to the Commission*, Docket No. RT01-99, September 17, 2001, p. 7.

Despite some protests by intervenors in the FERC proceeding, FERC agreed in large part with PJM's claims.[9] At the time of market implementation PJM had only a small market-monitoring unit with no mitigation authority and no authority to impose sanctions. However, PJM required cost-based bidding for the first year of the markets, as well as a bid-cap of $1,000 that is still in effect. In addition, PJM had the authority to manage prices in load pockets by capping the bids of must-run generation. Furthermore, due to the limited amount of divestiture of generation units, most owners of generation had significant load obligations, which would act as a restraint on bids.

In New England, market participants also asserted that market power concerns were minimal. As part of its filing for market based rates, the New England Power Pool ("NEPOOL")[10] included a study by independent economists that found that under most scenarios, the New England wholesale market was not constrained and that concentrations of generation ownership were not so high as to warrant concerns about the possession or exercise of market power. In response to intervenor comments that challenged NEPOOL's study, however, FERC ordered NEPOOL, the new ISO, and state regulatory agencies to develop a market rule that would allow for appropriate and effective market monitoring and mitigation, including the authority to impose sanctions on market participants.[11]

New York filed its proposal for market-based rates after PJM and New England. As part of its proposal, NY included a market-monitoring unit within the ISO and an independent Market Advisor who sat outside the ISO and reported directly to the ISO Board. FERC approved this arrangement in late 1999.

Post-formation ISO Experiences

As ISOs and market participants have gained experience with electricity markets, and as those markets have evolved over the past few years, ISOs and other stakeholders have modified and sought to improve market monitoring practices and procedures. Comparison of these experiences provides an initial basis for identifying necessary components of effective market monitoring authority and procedures.

In this Section we will discuss key aspects of the experience of the four ISOs in the US that have been up and running. We will also describe some of the more notable market failures and problems that have occurred in each of the four US ISOs. We begin with

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[9] 86 FERC 61,248, March 10, 1999.

[10] NEPOOL consists of the owners of the generation and transmission facilities in the New England control area, as well as the participants in the wholesale markets and various other stakeholder entities.

[11] The immediate result was MRP 17 (Market Monitoring and Mitigation), but MRP 13 (Sanctions) and MRP 15 (Price Correction Authority) also reflect the directives in FERC's Order

California because it was the first to institute a competitive, bid-based wholesale market.[12]

California

There has been an on-going effort to ensure that prices in California's electricity markets are consistent with efficient competition. California experienced problems with its ancillary services markets right from the beginning. Bid-caps were imposed in 1997/98 in an effort to control exorbitant prices. The energy market experienced problems due to the limited transfer capability of the transmission system, particularly between Northern and Southern California. Price caps were relaxed, as the problems were resolved.

In 1999 and 2000, the problems in the energy market became so severe that $1,000 prices and rolling blackouts began occurring with regularity. Since the beginning of the competitive wholesale markets in California, CA ISO (through its Department of Market Analysis "DMA" and its Market Surveillance Committee "MSC") has closely examined the wholesale markets in California. Prior to the spring of 2001, CA ISO primarily identified the potential for market manipulation under a variety of circumstances and sought structural fixes to prevent the potential for exercise of market power. Similarly, FERC staff studies and FERC Orders state in broad terms the potential for the exercise of market power and that it appears market power has been exercised.

In contrast, in spring 2001, CA ISO analysis identified specific evidence of the exercise of market power by specific market participants in filings in docket EL00-95. Simultaneous with FERC's investigation of specific bids above the soft cap established in December 2000, CA ISO analyses established links between bidding behavior of specific market participants and non-competitive prices in California markets. Reports from March 2001 are based on specific findings regarding specific market participants and are the first reports to establish a link between individual bidding actions and their impact on market prices. These findings are supplemented in an April analysis. Both the March and April analyses make allegations against specific market participants (whose identity is held confidential). ISO submitted confidential analysis and data to FERC in support of its conclusions. These analyses are submitted in response to FERC's desire to implement prospective market monitoring, and FERC's Section 206 investigation of just and reasonable rates for the period beginning December 8, 2000; however, the analysis covers a period beginning in early 2000 and the ISO emphasizes the need to consider refunds prior to the period that FERC has identified.

In late spring 2001, FERC developed a prospective market monitoring and price mitigation plan for California. The plan, for real-time California wholesale electric markets, included the following: (1) enhanced ISO ability to coordinate and control

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[12] Nonetheless, California stands apart from the other ISOs due to the uniqueness of its market structure. PJM, NE and NY are much more similarly structured in their market designs, despite the significant differences that do exist between.

planned outages, (2) must-offer obligation for generators, (3) conditions, including refund liability, on sellers' market-based rate authority, (4) price mitigation in California and throughout the rest of WSCC during periods of reserve deficiency; (5) price mitigation in California and the West during periods of non-reserve deficiency, and (6) weekly ISO reports to FERC on schedule, outage, and bid data for all hours.[13] The price mitigation is to be achieved through bid caps. During periods of reserve deficiency, there will be a single market-clearing price established using proxy prices for each generator. Bids above the proxy price are permitted but must be justified and are subject to refund.[14] During periods of non-reserve deficiency, bids cannot exceed 85% of the highest market-clearing price during the most recent period of reserve deficiency.[15] Due to aggressive efforts in early 2001 to encourage conservation, energy efficiency, and develop initial load response programs, the decision by FERC to allow soft price caps, and below average summer temperatures, the summer of 2001 did not repeat the high prices and scarcity problems of the previous winter.

PJM

There are a number of structural and design features of the PJM wholesale market that, in combination, have served to curb systematic abuse of market power since the ISO's implementation of market-based rates in April of 1998. In particular, the opportunity to profit from market abuse has been severely limited by the fact that the bulk of the generation capacity has been dedicated to serving retail load at regulated or capped rates.[16] In addition, the requirement to bid at cost during the first year of operation, along with the phased opening of product markets, curtailed opportunities to exploit design flaws during the initial "shake-out" of the PJM markets. Finally, the PJM market design incorporated at its outset a bid cap in the energy market of $1,000 per MWh, an effective price cap in the capacity market at the Capacity Deficiency Rate, and authority to cap energy bids at cost for generators located in local load pockets.

However, the current relationship between generation ownership and load obligations is changing. More utilities are choosing to divest generation resources and arrangements for providing standard offer service under capped prices are expiring. In addition, the cost capping of bids in load pockets applies only to units built prior to July 1996. Over

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[13] Docket No. EL00-95-012 et al., April 26, 2001, 95 FERC 61,115. Docket No. EL00-95-031 et al., June 19, 2001, 95 FERC 61,148.

[14] 95 FERC 61,115 (April 26, 2001)

[15] 95 FERC 61,148 (June 19, 2001)

[16] The continued obligation to serve load is a significant deterrent to behavior that would raise the market-clearing price. A utility that owns generation and has a significant load obligation is not in a position to profit from raising the market-clearing price to the extent that an independent generation company would be. The additional income for the generation resource would be offset by higher costs to supply its load (generally retail customers) and an inability to pass through those costs due to fixed rates or cost-of service regulation.

time, with new additions, the proportion of capacity exempt from cost capping will grow. However, at the November 8, 2001 meeting of the PJM Energy Markets Committee, the PJM market monitor made a proposal to collect cost data from units built subsequent to July 1, 1996, and there are stakeholder discussions underway in PJM to consider cost capping those units.

Despite the structural relationships that limit the value of manipulating prices, and rules that limit the ability to do so, the PJM markets have not been immune to the exercise of market power or gaming of market rules. Since its inception, the PJM MMU has addressed occurrences of opportunistic bidding in the energy market on high-demand days, efforts to circumvent the $1000 cap in the energy market, abuse of market power in the installed capacity market, and complaints regarding the potential for gaming in the FTR market.

Since 1999, the PJM energy market has experienced price spikes on some days where load approaches or exceeds available supply from internal resources. For example, on July 28, 1999 the market price hit $935/MWh, or more than seven times the $130/MWh marginal operating cost of the highest-cost unit on the PJM system.[17] More recently, real-time prices rose above $900/MWh every day from August 7 through August 9 of 2001. In the former case, the PJM MMU found that

> It appears clear that some generation owners, with an incentive to raise the price, did attempt to exercise market power by economically withholding the output of some units. It is also relatively clear that on July 28 the result was to increase the price of energy above the competitive market level.[18]

In the more recent case, the MMU is continuing to evaluate whether market power was exercised.[19]

In addition to these isolated occurrences of apparently anti-competitive bidding, the MMU has occasionally uncovered evidence of systematic gaming of market-design flaws. For example, the MMU identified attempts to circumvent the $1,000 bid cap with minimum run time bids. In response, the MMU implemented modifications to the rules regarding payments to minimum run time generators that foreclosed further gaming opportunities of this type.

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[17] In fact, prices exceeded $130/MWh in 96 hours, 4.3% of the hours, of the summer of 1999 (source: PJM *State of the Market Report: 1999*, page 11). According to one study, PJM energy-market costs exceeded marginal operating costs by $224 million during the summer of 1999. See Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market", University of California Energy Institute, April 2001, p. 1.

[18] PJM, *State of the Market Report: 1999*, page 36.

[19] PJM, *PJM Prices and Markets: The Week of August 6, 2001*, Preliminary Report, August 21, 2001, p. 1.

PJM administers a separate market for regulation services. Although the regulation market has experienced intermittent price spikes since its inception in June 2000, the MMU has not identified specific instances of bidder gaming of market-design flaws.

Over the last few years, PJM's installed capacity market has been plagued with the problem of daily de-listing of capacity resources. The MMU has consistently determined that such de-listing represents a rational competitive response to high market prices in regional markets bordering the PJM control area. However, because of the potential impacts on system reliability from daily de-listing, the MMU has recommended, and FERC has approved, implementation of a seasonal capacity market beginning in the summer of 2001.

One notable instance of the apparent exercise of market power in the installed capacity market occurred in the first quarter of 2001, when prices rose from approximately $2/MW-day in the prior quarter to $177/MW-day (i.e., the ceiling on capacity prices set by the Capacity Deficiency Rate –"CDR") during a period when there was excess capacity on the system. The MMU identified a flaw in the mechanism for distributing deficiency payments received from load-serving entities that are short on capacity as the cause of the run-up in prices. Since such payments were distributed to capacity owners that were long on capacity, owners that were sufficiently long had a perverse incentive to bid at the CDR. If such bids were accepted, then the market price received by the bidders would be at the CDR. Alternatively, if such bids did not clear, then the pool would be short, and the long owners would be paid the CDR anyway. In response to this design flaw, the MMU devised and implemented a new mechanism for distributing deficiency revenues that eliminated the opportunity to profit from bidding at CDR when the market is long.

Finally, the MMU has received complaints with regard to gaming in the Financial Transmission Rights ("FTR") auctions by transmission owners through the withholding of data on planned transmission outages that can affect FTR prices. Although the MMU has not uncovered evidence of such incidents, it recommended that rules regarding outage notification be strengthened.[20] Revisions to market rules governing outage notification were approved by the PJM Operating Committee.

ISO-NE

Since the inception of ISO-NE in July 1997, there has been an iterative and often very contentious process of refining and modifying ISO-NE's market monitoring and mitigation authorities through a series of market participant votes and FERC proceedings. While ISO-NE began with broad authority to correct prices as markets were launched, that authority has gradually been reduced so that it is currently restricted to revising

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[20] FERC, however, issued a show cause order to determine whether PECO Energy may have given its unregulated affiliates preferential access to information that was helpful to the affiliates in bidding for FTRs (97 FERC 61,009, Docket No. IN01-7, October 3, 2001).

prices for computer software and human errors, only.[21] ISO-NE and market participants have also struggled to determine what circumstances prevent a market from being workably competitive. Specifically, this issue has been argued regarding system-wide capacity constraints, inappropriate market products, and load pockets. ISO-NE has used a variety of tools to address identified concerns with the competitiveness of the markets including recommending changes in market structure and design, recommending changes in market rules, using its emergency rulemaking authority, mitigating bids, flagging and correcting prices, and imposing sanctions on market participants.

The wholesale markets implemented in May 1999 allowed unrestricted bidding in seven markets: an energy market, four ancillary services markets, an operable capability market, and an installed capacity market. In the first weeks there were problems with generation units (mostly hydro) that bid below the Energy Clearing Price ("ECP") but were not being dispatched due to conflicts between bidding and operational (reliability) rules. As that problem was being addressed, unusually warm June weather triggered a series of capacity deficiency events that led to more conflicts between operational rules for reliability and bid-based market rules.[22] ISO-NE filed emergency rule amendments in June and July 1999, to address most of these issues. In August 1999, ISO-NE filed for elimination of the Operable Capability market as a redundant and unnecessary market. Despite vociferous protests from owners of generation, FERC approved ISO-NE's filing. On numerous occasions during that first summer, ISO-NE observed that on days when load approached or exceeded New England supply, prices in its energy, three reserve, and operable capability markets were routinely at levels significantly above those that would be expected from a workably competitive market, the Market Rule 15 standard. In response to this observation, ISO-NE requested and received from FERC a 60-day extension of MRP 15.

In the fall of 1999, FERC denied ISO-NE's request for a second extension of the price correction authority of MRP 15. FERC stated that the extensive price correction authority in MRP 15 was only intended for the initial 90-day market start-up period and that after an additional 60-day extension, it would not be further extended. FERC concluded that any changes to the market designs should be implemented through market rule filings by NEPOOL or, if needed on an emergency basis, by ISO-NE. FERC agreed,

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[21] Prior to the implementation of the markets, FERC approved Market Rule and Procedure (MRP) 15. MRP 15 authorized ISO New England to flag and correct prices that "were inconsistent with a workably competitive market". MRP 15 was an interim rule (90-day sunset provision) to address problems with the design and implementation of market-based rates. Although MRP 15 is still in effect, the scope of the rule has been severely limited and the "workably competitive" standard has been eliminated.

[22] Similar to the problems in the first few weeks, the conflicts had to do with units that were "postured" (held in reserve) due to their quick response capability or limited energy availability (ponded hydro) despite the fact that their energy bids were in merit and under normal circumstances they would be dispatched for energy. The original rules had restrictions on when units were eligible to set the energy clearing price, when they could receive uplift compensation, and the manner in which units could be designated for reserves.

however, with ISO-NE's observation that due to market failures during times of capacity deficiency, the reserve market prices could not exceed the ECP.

In July of 2000, in response to a complaint from a load serving utility (one that has divested all its generation resources) about the $6,000 ECP price spikes in May, FERC capped bids at $1,000 per MWh. The complaint argued, in essence, that a market-based system did not operate properly during a capacity deficiency event. That bid cap continues today, as does a cap on ancillary-service prices.

Just as ISO-NE has gone through several iterations in modifying its price revision authority, it has gone through several stages in determining the appropriate authority and circumstances during which bid mitigation should apply. There are two occurrences that offer a striking example of the obstacles to effective market monitoring and implementation of corrective policies under current MMU rules and ISO practices.

May 2000

The May 2000 event involved dispatchable energy contracts that were associated with installed capacity (ICAP) entitlements. Under then existing rules, a NEPOOL Participant could receive credit in the monthly ICAP market for ICAP entitlements associated with a contract to supply energy even if the energy contract never flowed. The energy contract would have to be bid into the market every day and be available to flow (dispatchable) if called. Due to flaws in the design of the ICAP market, some NEPOOL Participants were removing ICAP offers from the bilateral market and thereby "forcing" other NEPOOL Participants to purchase ICAP requirements through the ISO administered residual spot market (which settles after the month) at significantly higher prices. In January, February, and March of 2000, ISO New England mitigated bids in the spot market after determining that the extremely high bids were, in effect, economic withholding.[23]

Several NEPOOL Participants began submitting external dispatchable contracts with extremely high energy bids in early 2000 as an alternative way to receive ICAP credit, rather than entering into a New England bilateral contract or relying on the post-month spot market. By submitting contracts with high energy bids (some as high as $10,000 per MWh), the Participant was relatively certain that the contract would never flow, but the ICAP value would be credited. ISO New England commented on this "practice" in its FERC filing.[24] In that filing, ISO New England noted that the external contracts with extremely high energy prices could be called if a capacity deficiency event occurred. On May 8th, unseasonably warm weather created extremely high demands at a time when numerous generation units were unavailable due to spring maintenance. That morning, ISO New England had dispatchable contracts in its bid stack at prices as high as $10,000. Around noontime, as New England approached a deficiency in capacity, a $6,000 bid was

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[23] Docket No. EL00-62-000, ISO-NE filing of 5/8/00.

[24] Id. Prior to January 2000, the ISO administered spot market had cleared at $0 per MWh for the previous seven months.

dispatched and set the ECP for the next four hours. In a subsequent report, ISO-NE stated that based on prices in the NY market, it had determined that the $6,000 bid was "reasonable" and accepted it without mitigation.[25]

In response to widespread criticism of the ISO's decision to accept the $6,000 bid, ISO New England maintained that the market rules then in effect had been properly implemented. It described in detail how the rules allowed such contracts, that the contract in question met the rule requirements, and that ISO New England had an obligation to implement the rules without regard to price.[26] ISO New England proposed changes to the market rules to prevent recurrences without resorting to bid or price caps. In July, FERC adopted some of the ISO's proposed changes while installing a $1,000 bid cap and stating that markets are not competitive during capacity deficiency events.[27]

Summer 2001

On June 1, 2001, the NEPOOL Participants Committee (NPC) approved changes to the market rules to prohibit external dispatchable contracts from setting the ECP. Under the new rule, external contracts would be eligible to receive payment based on their bid prices, but would not be eligible to set an ECP that would be paid by all spot market purchasers. On June 14th, several NEPOOL Participants appealed the NPC decision to the NEPOOL Review Board, thus staying any NEPOOL action.[28] On July 10th, ISO New England filed the rules changes with FERC and requested an effective date of September 1, 2001.

On July 23, 2001, the New England bulk power system experienced a sudden loss of generation resources, which coupled with high loads due to warm weather, created an almost immediate capacity deficiency situation. ISO New England accepted all available bids, including an external dispatchable contract bid at $1,000/MWh. The ECP was set at $1,000 by that contract for two hours on Monday, July 23; for four hours on July 24; and for seven hours on July 25. ISO-NE evaluated the significant differences between the ECPs set by the external contracts and the ECPs without those contracts. The total increased cost for spot market energy in the 13 hours of $1,000 ECPs was estimated by ISO-NE to be $80 million.[29] The fundamental issue is how five-minute price increases of

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[25] ISO-NE noted that marginal prices in NY on the morning of May 8th exceeded $3,300 per MWh. Pursuant to agreements with the NY ISO for purchases of emergency power, ISO-NE would be obligated to pay 1.5 times the NY marginal price. ISO-NE reports "Events of May 8-9, 2000" (June 1, 2000) and Supplemental Report on May 8, 2000" (July 28, 2000).

[26] Id.

[27] 92 FERC 61,065 (July 26, 2000).

[28] Pursuant to NEPOOL's rules, an appeal to the NEPOOL Review Board stays the filing of rule changes approved by the NPC until the Board renders a decision.

[29] ISO Customer News, Issue #70, August 15, 2001; NPC Operations Report, August 3, 2001.

500 to 2000 percent can be the result of a properly functioning competitive market. There is also a concern as to why ISO-NE allowed the external dispatchable contracts to set ECPs on the 24th and 25th after being alerted to the situation on the afternoon of the 23rd. Given that a rule change that would have corrected this situation had already been filed with the FERC, ISO-NE could have used its emergency rule-making authority to implement the pending rule immediately.

In a report released in September, ISO-NE determined that the $1,000 prices were appropriate because they were consistent with the rules then in effect. This response is the same as the response to the May 2000 event and does not answer the question of whether the rules themselves are consistent with efficient and competitive markets.

In the two events described above, ISO New England chose not to exercise its explicit authority in the Interim ISO Agreement to ensure the "competitiveness and efficiency" of the wholesale markets.[30] Section 6.17(e) of that agreement states:

> If the ISO determines in good faith that (i) the failure to immediately implement a new System Rule or Procedure or a modification to the existing System Rules or Procedures would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the NEPOOL Market, and (ii) invoking the rulemaking procedures of the relevant NEPOOL Committee would not allow for timely redress of the ISO's concerns, the ISO may promulgate and implement such new or modified System Rule or Procedure unilaterally upon written notice to the NEPOOL Executive Committee, subject to approval by the FERC, if required.

Underscoring the importance of ISO-NE's responsibility to ensure the reliability, competitiveness, and efficiency of the wholesale markets, any rule changes implemented pursuant to this authority can become effective immediately, rather than the mandatory 60-day waiting period associated with rule changes that NEPOOL files with the FERC. While it is important to administer market rules in a consistent and even-handed manner, it is also important to change rules once they are observed to produce anti-competitive impacts.

It is important to note that FERC has not demonstrated consistent support for the ISO's execution of its authority pursuant to Section 6.17 of the Interim Agreement. In November 1999, FERC specifically referred to the ISO's emergency rule-making authority as one of the reasons that price correction authority under MRP 15 for market design flaws should be eliminated.[31] However, in a subsequent Order in July 2000,

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[30] The Interim ISO Agreement is the document in NEPOOL's 1996 FERC filing that details the relationship between NEPOOL, comprised of market participants, and ISO New England, the independent system operator.

[31] 89 FERC 61,209 (November 23, 1999).

FERC criticized ISO New England for having to resort to its emergency authority rather than achieving rule changes through the NEPOOL Committee process. FERC also directed ISO-NE to revise MRP 17 to "reduce the level of ISO discretion in determining when to apply mitigation measures."[32]

The very complex, and often very difficult, evolution of ISO-NE's market monitoring authority and practices has highlighted an increasingly sophisticated understanding of electricity markets and the conditions that permit, or hinder, "workably competitive

NYISO

Perhaps as a result of the decision to implement several bid-based markets simultaneously, there have been some notable instances of opportunistic bidding behavior since the startup of the NYISO in late 1999. In response to these problems, over the last two years the NYISO has implemented bid caps and enhanced bid mitigation procedures in the energy market, suspended market-based pricing and subsequently imposed bid caps in the reserve market, and expanded the scope of the mitigation mechanisms applicable to New York City generators.

In the energy markets, a bid cap of $1,000/MWh was implemented in July of 2000 based on a proposal by the New York PSC and following the filing of a complaint by New York State Electric and Gas that called for imposition of cost-based bidding. Plagued by numerous design flaws in the first few months of operation, the NYISO Board requested FERC approval of a temporary bid cap in expectation of continuing problems in the upcoming summer period. Although initially proposed as a temporary measure, the ISO has repeatedly requested and been granted extensions of the bid cap.

The market-monitoring plan adopted at the end of 1999 authorized the MMU to mitigate energy bids that exceeded certain pre-determined thresholds. When first implemented, the MMU employed a manual procedure for flagging and mitigating bids that was too cumbersome to allow for mitigation of bids prior to their use in determining the market-clearing price for the current operating day. Instead, the MMU was constrained to applying the mitigated bid for determining price for the following day. Because of this one-day lag in mitigation, a generator could reap, and consumers would be liable for, one day's worth of windfall profits, even though the generator's bid was deemed to reflect the exercise of market power.

The events of June 26, 2000 revealed the potential for economic damage from this one-day lag in bid mitigation. On that day, prices spiked to approximately $600/MWh as a result of bids that were subsequently determined to have exceeded the mitigation thresholds. According to the NYISO, consumers bore over $100 million in excess costs

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[32] 92 FERC 61,065 (July 26, 2001).

before bid mitigation could be applied.[33] As a result, and in light of FERC's unwillingness to allow retroactive price corrections, the NYISO subsequently implemented an automated mechanism for mitigating bids prior to setting the market-clearing price. In addition, the NYISO filed for authority to impose penalties and sanctions for repeated anti-competitive behavior.

In March of 2000, the NYISO suspended market-based pricing in the operating-reserve market as a result of evidence of physical withholding and consequent dramatic increase in clearing prices. In compliance with FERC order, the NYISO subsequently restored market-based pricing, but imposed a cap on non-spinning-reserve bids.

In the New York City market, energy prices spiked on a number of high-load days even though a bid-mitigation mechanism was in place for generators that had been divested by ConEd. In response, ConEd proposed, and FERC recently approved, an expansion of the scope of the in-City mitigation mechanism to all generators located within the City.[34]

In summary, all four U.S. ISOs have discovered that their bid-based markets have design flaws that require constant attention ranging from minor adjustments to large-scale overhauls or, in some cases, to complete elimination of the market. Whenever demand approaches the limits of available supply, electricity markets experience price volatility not seen in other markets. FERC has recognized that market based rates may not be just and reasonable under such circumstances.[35] FERC's solution has been to continue the bid caps in PJM and to impose bid caps in the other three ISOs. In fact, the bid caps in NE and NY will remain in effect until the single Northeast market is implemented, at which poitn the continuing need will be reassessed. In an order concerning new bid caps in California, FERC justified the imposition of the bid caps as follows:

> ... as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus sellers have an incentive to offer supply at prices above that which they

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[33] NYISO, "Exigent Circumstances Filing of the New York Independent System Operator, Inc. At the Direction of its Board of Directors to Implement Automated Mitigation Procedure", May 17, 2001, p. 8.

[34] FERC Order on rehearing accepting revised market power mitigation measures, as modified for filing, Consolidated Edison. July 20, 2001.

[35] See, 92 FERC 61,065 (July 26, 2001). In this Order FERC explains why it is imposing bid caps "we believe such a cap is necessary to ensure just and reasonable rates this summer in these markets. We agree with NSTAR that in capacity constrained periods where OP4 conditions apply, the existing New England market does not operate in a manner consistent with a typical competitive market".

See, 97 FERC 61,095 (October 25, 2001). In this Order FERC states: "In our orders approving the previous extension of the bid cap, we noted that if load cannot respond to dramatic increases in prices, then generators can submit very high bids that NYISO must accept when supplies are tight during peak periods, and price spikes can be magnified. We found that these situations can lead to unjust and unreasonable prices if NYISO is forced to accept such high bids and load is not able to reduce its purchases at these prices."

would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable.[36]

3. Assessment of Current Practices

This section presents key aspects of the current market monitoring and mitigation practices of the three northeast ISOs and California. Additional detail is provided in Appendix A. Where relevant, the practices in international markets are mentioned. International practice is discussed in further detail in Appendix B.

3.1 Structure and Budget

In general, market monitoring staff and their budgets have increased significantly each year for the PJM, New England, New York, and CA ISOs. These increases have occurred as a response to the dysfunctions in each of the markets and a growing awareness of the need to monitor, for prospective long-term changes, and mitigate, for immediate correction of short-term problems.

The PJM Market Monitor has had the smallest staff (5). PJM has fewer markets to monitor than the other Northeast ISOs and it does not have the authority to revise prices or mitigate bids.[37] In contrast, New York has the most markets to monitor, the authority to review and revise prices, and the most extensive mitigation process to administer. This is probably why New York, with a current staff of 11 (similar to the staff of ten that New England desires), plans to increase its staff to 23 by the end of this calendar year. New York has acknowledged that its current staff can barely keep up with the "rapid mitigation" thresholds and has spent very little time reviewing the "slow-mitigation" thresholds. New England currently has a staff of 8, with plans to fill two additional positions.[38] New England reviews bids in its energy market and three reserve markets every day prior to accepting bids. New England, which lacks a congestion management system, also has to evaluate all flags for "out-of-merit" generation to determine if individual generator bids should be mitigated.[39]

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[36] 95 FERC 61,148 (June 19, 2001)

[37] Nonetheless, PJM is in the process of expanding its market monitoring staff by two and adding two support staff for a total of nine employees.

[38] In addition, ISO-NE has an internal "price review committee" comprised of ISO-NE employees from market monitoring, markets development, and system operations. This group makes most of the initial decisions regarding the mitigation of bids and the flagging of prices for possible revision later.

[39] This burden has diminished somewhat as reference screens have been developed for many generators to make the bid-mitigation process for out-of-merit generation more mechanical. Also, the NEPOOL Markets

In summary, it appears that as more markets are open to competitive bidding and more extensive mitigation procedures are implemented, market monitoring activities must increase to keep pace.

3.2 Accountability and Independence

The MMUs for PJM, NE, and NY, and the Market Surveillance Unit for CA, are all ultimately accountable to the CEO of their respective ISO and are considered ISO employees. The Market Surveillance Committee, in CA, and the Market Advisors, in NE and NY, are not ISO employees and report to the governing Boards of each ISO. This dual approach appears to be an optimal arrangement for several reasons.

First, having the MMU staffs integrated into the ISO staff structure provides opportunities for informal interactions between the market monitors and the scheduling and dispatch operations at each ISO. As explained by a market monitoring staff person "You can learn much more in a five-minute conversation with a control room operator than you can learn after hours of reviewing print-outs of participant bids and unit commitment reports". This same staff person advocated strongly for "close physical proximity" of market monitoring staff to the scheduling and dispatch functions to allow for frequent and real-time interactions.

Second, having MMU personnel as ISO staff rather than "outside employees" helps lower barriers to communication by allowing all ISO staff to be part of the same team. While some outside observers have concerns that market-monitoring staff will be less vigilant and independent if they are part of the ISO staff, none of the market monitoring staff that we spoke with identified such a concern. It certainly may be appropriate to develop "whistle-blower" protections for ISO market monitoring staff; this would guard against the most egregious forms of management manipulation of market monitoring reports or retaliation for unflattering reports. However, whistle-blower protections are probably needed for all ISO staff, not just market monitoring staff, to ensure the even-handedness, honesty, and independence that are so essential for both market monitors and market administrators.

Third, having an "outside" independent entity reviewing all the market information and reports provides appropriate and useful checks and balances against a dysfunctional MMU (whether due to deliberate concealment or merely incompetent analysis) or an unconcerned ISO management or Board of Directors. Although it appears, to date, that the current ISOs have been quite candid about the problems and failures of their new market systems, it is certainly possible that future managements may become defensive and protective of their market system and be reluctant to identify dysfunctions. An outside independent entity can be very useful if such a scenario develops.

Committee is currently evaluating further changes to MRP 17 to allow for pre-negotiated price agreements for generation units that seldom run in merit, in order to avoid the lengthy after-the-fact settlements.

3.3 Scope of Monitoring and Indices Used

PJM, NE, NY, and CA MMUs are all charged with monitoring all ISO markets and identifying flaws or potential flaws with those markets. Exercises of market power, abuse of rules, and other specific participant behaviors are highlighted. The NY MMU is specifically charged with monitoring the "competitiveness, performance, and economic efficiency" of its markets. The NE MMU is charged with assessing the "competitiveness and efficiency" of its markets and any "aspects that prev
PJM MMU is charged with monitoring "bilateral markets within PJM and regional markets outside of PJM." This last point is worth further discussion. The ability to monitor bilateral contracts, as well as activities outside a particular ISO or RTO boundary, is crucial to understanding the "net" positions of market participants. It may not always be owners of generation resources that can profit from high clearing prices. For example, a load-serving entity that has contracts for resources in excess of its needs will likely be a net-seller in either the day-ahead or real-time market, and, therefore in a position to profit from a high clearing price. In contrast a generator who has contracted to provide more power than its generation units can deliver will likely be a net-buyer in the day-ahead or real-time market, and therefore, in a position to profit from a low clearing price.[40]

Finally, the PJM MMU has the authority to monitor and, with Board approval, intervene in FERC and state proceedings regarding mergers and acquisitions. This is a logical responsibility for an MMU, given its mandate to ensure competitiveness in electricity markets.

The broad scopes of authority granted to MMUs seem appropriate. We did not find any specific enhancements from our review of other MMUs outside the US. However, it is not clear that all the ISOs have been able to structure their activities to meet the broad scope of their general authority. New England and New York have been candid about their inability to implement the comprehensive type of monitoring envisioned in their scopes of authority, in part due to limited staff and resources and in part due to the complexity of developing systems and procedures to do effective monitoring.

Each of the ISOs has developed a variety of indices to use as evaluative tools. Many of them are similar between the ISOs. These include review of concentrations of ownership (HHIs) pool-wide and in specific transmission constrained areas (load pockets); price and cost evaluations using numerous assumptions to simulate a cost-based dispatch; the comparisons of bids and ECPs to fuel-price data; the changes in bid supply curves over time; and changes in generation unit availability as load changes. Appendix C contains even more detailed and specific indices that are used by PJM and CA.

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[40] These are two vastly simplified examples to illustrate a point. In the current markets administered by the ISOs, participants often have numerous "positions"; it is the interaction of all these various positions and the potential for exercises of market power that the ISO MMUs must constantly analyze. Access to bilateral contract within and outside of a particular wholesale market are essential for the MMU staff to see the "whole picture" relative to an individual market participant action.

One evaluative tool that has been particularly beneficial in the UK is the modeling of the dispatch based on marginal cost data provided by the generators. This model is then compared with the bid-based dispatch of the system. While bid-based prices may never actually fall to marginal cost levels, it is extremely useful to compare the differences between the two dispatches as a gauge of the efficiency of the bid-based market. It is also useful to compare the relationship over time (years) as a gauge of overall market competitiveness.

3.4 Data Collection

All FERC approved MMUs have the authority to collect data necessary to perform their market monitoring and evaluation functions. This includes any data collected by their respective ISO and any additional data that the MMU deems necessary. CA requires that data to be collected be published in a "data catalogue" by the ISO and disseminated to market participants.

However, despite this broad authority, none of the ISOs systematically collect marginal cost data from participants on a regular basis. PJM currently collects cost data for generators built prior to July 1996 to support cost capping of bids in local load pockets. New England collects marginal cost data from only those participants who want to negotiate a pre-set bid-price when they are an "out-of-merit" generator due to congestion. New York only collects data from specific generators when requested by the MMU. In California, generators must provide (to CA ISO and FERC) cost data for generation in any month during which the generator submitted a bid that exceeded the proxy price.[41]

Each of the ISOs, except PJM, can penalize participants who fail to provide data upon request. Those penalties can include monetary penalties (CA, NE), restrictions on bids (NE, CA), binding arbitration (NE, NY) and exclusion from the market (CA, NE). PJM is limited to petitioning FERC to enforce its data requests.

3.5 Monitoring Rules and Procedures

The MMUs for PJM, NY, and CA may recommend changes to their market monitoring procedures directly to their governing boards. In addition, NY may recommend changes to its mitigation procedures with the concurrence of the ISO CEO and the Board's Market Performance Committee. The MMU unit in New England can recommend changes after consultation with state regulatory agencies[42] and with NEPOOL approval. All proposed changes would need to be filed and approved by FERC. NE could also invoke its

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[41] 95 FERC 61,115, pp. 15-16. In this order FERC directed that the marginal cost of a generator should be determined using its heat rate, emissions, proxy gas price, proxy emissions cost, and an adder for O&M costs.

[42] This reference to state regulatory agencies is in MRP 17. It is there due to the collaborative process used to develop MRP 17, which involved ISO-NE staff, NEPOOL Participants, state utility regulatory staff, and at least one state attorney general's office.

emergency rule-making authority and implement immediate changes, subject to FERC review; however, to date, NE has never utilized that authority to change market monitoring rules and procedures.

3.6 Market Rules Modifications

The MMUs for PJM, NY, and NE, can make recommendations for changes to the market rules to their respective stakeholder committees. Those committees can then approve the changes, or modify them, and file them with FERC.

In PJM, the MMU also has the authority to file proposed changes directly with FERC, if the changes are approved by the Board of Directors. In NY and NE, the MMU unit can file directly with FERC under each ISO's emergency rule-making authority for exigent circumstances. In CA, the MMU or the independent Market Surveillance Committee can recommend changes to the ISO Governing Board for direct action.[43]

3.7 Corrective Actions

There are a variety of mechanisms that exist within current ISOs for responding to identified competitiveness issues in markets. Some of these tools arise in great part as a result of market flaws that the ISO market-monitoring unit identifies, and some of them are directly within the authority of the ISO to implement.

It is important to note that both the PJM and New England ISO's had more expansive corrective authority during their first year of operations. In PJM, all market participants were required to bid at cost for the first year of operation. In New England, the ISO had the authority in the first five months of operation to revise prices that did not result from competitive forces. In rejecting NE's request to extend that temporary authority in the fall of 1999, FERC stated that the time for such corrections was over; according to FERC, the market participants' need for price certainty outweighed the need to continue to revise prices based on flawed market designs. FERC directed ISO-NE to recommend market design changes on a prospective basis through the NEPOOL committee process, or, if necessary, to make immediate changes using its emergency rule-making authority.

Bid caps

As mentioned earlier, PJM has had a $1,000 per MWh bid cap in place since the start of its markets.[44] CA has had a variety of bid caps in both its reserve and energy markets since the early days of its markets. Most recently, CA had a series of "soft" bid caps ordered by FERC for its energy market in response to the months of high energy clearing

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[43] In CA, as originally constituted, the ISO Governing Board was more similar to a stakeholder committee than an independent Board of Directors. FERC recently changed the composition of the Governing Board to reduce the influence of market participants.

[44] Due to the added cost of congestion, prices may exceed $1,000 per MWh even with a bid cap of $1,000.

prices (and rolling blackouts) that CA experienced in late 2000 and early 2001. The current soft cap in CA for all hours is established in relation to the market clearing marginal cost bid during a reserve deficiency event.[45] NE and NY both have a $1,000 bid cap, that was first approved by FERC in July 2000. Pursuant to recent FERC orders these caps will continue at least until implementation of the Northeast RTO.[46]

In addition to the energy markets, the regulation market in PJM has a $100/MWh price cap; the reserve markets in NE are capped at the energy-clearing price during capacity deficiency events, and the non-spinning reserve market in NY is capped at $2.52/MWh (plus an "opportunity cost" adder).

Bid mitigation

ISO-NE and NY ISO are authorized to mitigate bids prior to accepting them. Until recently, ISO-NE had authority to review any bid and to ask the entity submitting the bid to justify it. NYISO has employed bid screens, or thresholds, for determining which bids are eligible for mitigation since the start of its markets. For automatic mitigation, the threshold is a bid that is 300% or higher than a competitive bid and the impact must raise the clearing price by 200% or more. A second tier threshold allows the NYISO to file a proposed mitigation with FERC if the impact of a bid raises the market-clearing price by 100%. Attempts by market participants to lower such thresholds have been vigorously resisted by the NYISO. In July of 2000, FERC ordered ISO-NE to file mitigation thresholds in order to eliminate the excessive "discretion" that ISO-NE had in deciding which bids to review. In response, ISO-NE developed thresholds that are triggered when a bid exceeds a reference price by 300% or $100, whichever is lower, and the impact on market clearing prices is 200% or $100/MWh, whichever is lower. These are essentially the same thresholds used by NYISO.

If bid mitigation is triggered, bids are reduced to default bids generally set at 100% of a reference price.

In California, FERC has permitted generators to submit bids that exceed the market-clearing price; however, those bids are subject to justification and refund. A generator submitting a higher bid must submit a justification to the ISO and FERC, including a detailed accounting of all of its component costs for each hour where the bid exceeded the market-clearing price. FERC may, upon review of the justification, order a refund.[47]

In the UK, a monitoring group has proposed thresholds that trigger mitigation at significantly lower levels. If a supplier has the ability to raise prices by just 5%,

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[45] 95 FERC 61, 148 (June 19, 2001).

[46] For ISO-NE, see 97 FERC 61,090 (October 25, 2001). For NYISO see 97 FERC 61,095 (October 25, 2001).

[47] 95 FERC 61,115 (April 26, 2001).

mitigation would be applied (the 5% threshold is for a total of thirty days worth of hours over a one-year period). The ability to raise prices by 15% (for a total of 10 days of hours over a one-year period) or by 45% (for a total of about three days of hours over a one-year period) would also trigger mitigation. These thresholds are significantly below the 200-300 % thresholds that NYISO uses, although NYISO is looking at single hour increases and not the cumulative impact over a year.[48]

Price corrections

There are differences in authority for price corrections resulting from errors and those resulting from market-design flaws.

With respect to price corrections resulting from software or data entry errors, it appears that NE, NY, and PJM all have the authority and obligation to correct prices under the filed rate doctrine. As FERC stated:

> ...we believe that it is not necessary to extend NYISO's TEP authority in order to facilitate correction of prices calculated on the basis of computational errors. Under the filed rate doctrine, NYISO already has the authority, and is required, to take corrective actions in a timely manner in order to ensure prices consistent with its Commission-approved tariff.[49]

As a matter of current practice, ISO-NE flags, reviews, and corrects prices within specified time frames. During weekday working hours, prices must be flagged for correction within 75 minutes of being posted and corrections must be made within five days. For all other hours (non-work and weekend), prices must be flagged within 24 hours and revisions made within five days.

With respect to price corrections due to market-design flaws, both NE and NY initially had explicit authority to flag, review, and correct prices. FERC subsequently revoked such authority for both ISOs. PJM has never had authority to correct prices for market-design flaws.

3.8 Sanctions and Penalties

ISO-NE, NYISO, and CAISO have authority to impose sanctions for a variety of participant behaviors. In CA the MMU may recommend fines and suspensions and the ISO Board may impose sanctions. ISO-NE, through specific market rule, may impose sanctions and penalties for physical withholding, failure to perform, failure to follow ISO instructions, inaccurate bid information, and failure to provide requested information. NYISO can impose penalties or sanctions for physical withholding, excess generation,

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[48] See Appendix B for further discussion.

[49] 97 FERC 61,095 (October 25, 2001).

under-scheduling of load, failure to follow ISO dispatch instructions, and failure to provide requested information.

In determining the level of the sanction, ISO-NE uses a series of formulae that increase with each offense. NYISO calculates a market-based penalty for withholding and over-generation. Under-scheduling of load is penalized by a requirement to schedule all load in the day-ahead market, and a penalty factor added to any real-time purchases.

3.9 Congestion Procedures

PJM, ISO-NE, and NYISO have specific monitoring and mitigation procedures for addressing market power related to congestion. PJM and NYISO have congestion management systems that identify locational prices due to congestion. ISO-NE is in the process of developing a congestion management system. For generating units in load pockets, often called out-of-merit generation, all three ISOs impose some form of bid-cap on those generators.

In PJM, generators can choose among three bid caps: incremental cost plus 10%; a reference price based on when the unit was in-merit; or a negotiated price. ISO-NE and NYISO use a reference price for generators who are often in merit. For units that are seldom in-merit, ISO-NE uses a calculated reference price as a staring point for negotiating a price with each generator. ISO-NE has commented that the process of "negotiating" a price with specific generators is a very time-consuming one.

3.10 Reporting Requirements and Data Release

All the MMUs release bid data on a six-month lag. The names of bidders are replaced with identifiers that are supposed to maintain anonymity while allowing bids to be tracked over time. To date, FERC has supported the six-month lag in releasing bid data. The rationale for trying to keep bids anonymous is that competitors will gain an advantage, and be better able to game the market, if the names of bidders are not obscured. Many people have noted that any market participant with a working knowledge of the regional market and generation units can identify individual bidders with a small degree of additional effort. In general it is non-participants, including the public, who are unable to "decipher the code", not market competitors. Consequently, the bid anonymity does little to enhance the competitiveness of the market, and merely makes the markets less transparent to non-market participants.

The six-month lag, too, is intended as a protection against entities trying to game the market. There are some economists, however, who believe that a one-month lag is probably sufficient to prevent anti-competitive behavior. In UK/Wales and Australia markets, bid data is released publicly with only a one-day time lag.

4. Critical issues and recommendations

4.1 Summary

Despite the wide variety of market monitoring approaches that have been developed and implemented by system operators, our research has identified numerous areas of agreement among the market monitors themselves, as well as other market stakeholders, regarding critical structural and functional requirements for effective monitoring, mitigation, and sanctioning of market-participant behavior. This section identifies those areas of agreement. It also looks at some "best practices"[50] that should be adopted for a Northeast RTO, and notes where they are not incorporated into the market monitoring authorities and practices currently in place in PJM. Many of those recommendations could be incorporated in the short-term into PJM's market monitoring practices, pending the development of the Northeast RTO.

In summary, there are four basic themes for effective market monitoring:

1. The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

2. The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

3. The market monitor should have authority to mitigate, sanction, and penalize, as well as the authority to identify and implement necessary rule changes.

4. The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

We will discuss each of these in the following sections.

4.2 Independence and Mandate

The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

Recommendation #1: The MMU must closely monitor, and ideally be physically present or adjacent to, the control room dispatch.

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[50] The term "best practices" has become a much-debated term in the context of developing a Northeast RTO. We use the phrase here in a very broad context to refer to existing practices of the Northeast ISO or other ISO/RTO entities that, in our judgment, should be incorporated into market monitoring activities.

Market monitoring requires constant access to and communication with the operators who are setting day-ahead and hour-ahead power schedules as they respond to dynamic system conditions on a seven-day by twenty-four hour basis. For all practical purposes, this close, daily contact with operations staff necessitates the incorporation of the MMU as a department within the ISO.[51]

Recommendation #2: The MMU should report within the RTO to the Board of Directors. The MMU should work closely and collaboratively with the CEO and the RTO staff that has market design responsibilities.

There should be clear and specific procedures to encourage MMU staff to provide current and accurate information on market conditions and behaviors and to protect the staff from any retaliatory actions by management (whistle-blower protection). Of course, the effectiveness of market monitoring, and the potential for addressing identified market competitiveness concerns, will be significantly affected by the institutional arrangements within which the market monitor and its parent organization operate. For example, where market participants have a mechanism for delaying or preventing market rule changes recommended by the market monitor, the effectiveness of the market monitor in ensuring the competitiveness of markets is hampered. On a day-to-day basis, the MMU should function within the RTO as staff and be subject to the direction of the CEO. However, to help ensure the independence of the MMU, its budget and personnel decisions should be under the direct control of the Board of Directors.

Recommendation #3: The RTO should contract with an Independent Market Monitor (IMM) or Market Advisor to complement and advise an internal MMU. The IMM should report directly to the Board of Directors of the RTO.

The IMM, in consultation with the Market Monitoring Unit, should comment on the overall efficiency of the markets and suggest long-term improvements. The day-to-day market monitoring, rules changes, and periodic reporting should reside with the internal RTO MMU. The IMM can also provide a valuable "second opinion" to the RTO Board on market-design issues and proposed rule changes. For that reason, the IMM should report directly to the Board of Directors and stand outside of the RTO organizational structure that reports to the CEO.

4.3 Comprehensive Scope for Monitoring

The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

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[51] In the context of a Northeast RTO, it may be appropriate to have satellite MMUs at each control area with a central MMU office at the RTO to coordinate inter-control area monitoring and changes to Northeast RTO market rules and procedures. Even under this scenario, the MMU staff at the control areas may perform best as employees of the same entity that employs the operations staff.

Recommendation # 4: The MMU should be responsible for monitoring all wholesale markets administered or facilitated by the RTO/ISO, including the spot and bilateral energy, ancillary-services, capacity, and transmission markets. The MMU should monitor both supply and load bids in all markets.

Other related markets should be monitored (fuel, emissions, and derivative markets) due to their dynamic interaction with, and impact upon, electricity markets. The MMU should, on a routine basis, collect information on bilateral contracts among participants and monitor electricity options markets as they develop. Monitoring should occur in all hours, and account for different market conditions, including congestion, excess generation, low operating reserves, and system emergencies.

There may be additional markets developed and administered by the RTO (such as a resource-attributes market to facilitate compliance with various state regulatory requirements regarding disclosure, renewable resources, and emissions standards) that will require monitoring and evaluation to ensure competitiveness and efficiency. [52] The MMU should monitor and evaluate all markets based on the opportunities to trade in those markets. Thus, as in PJM today, the MMU would look at both day-ahead and real-time markets. If a four-hour-ahead or hour-ahead market is implemented, this should be monitored also.

Comprehensive market monitoring includes technically challenging and time intensive activities. The MMU must be staffed and budgeted at adequate levels to accomplish all of these functions.

Recommendation #5: As part of its ongoing evaluation of market efficiency and competitiveness, the MMU should evaluate the performance of the markets against the outcome of a market where all bids are at marginal cost.

Bids above marginal cost should be evaluated for their impact on the efficiency of the markets.[53] In evaluating the overall performance of the market, the MMU should compare bids with marginal costs, and determine whether and to what extent actual market prices deviate from competitive outcomes.[54] For this analysis, a model based on

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[52] For example, many of the states in the Northeast RTO require retail load serving entities to provide periodic reports to customers on the fuel-mix of the generation resources purchased for those customers. A few of the states also require minimum percentages of renewable generation resources be purchased for each retail customer. A single regional accounting system for the Northeast market that assigns generation resources to specific load accounts, based on systems already being developed in New York, New England, and PJM, is the simplest and most efficient approach. As New York and New England have already determined, any such system will need to be monitored to ensure that potential gaming and anti-competitive activities are addressed.

[53] Where a distinct ISO capacity market exists, energy supply bids in an efficient market should resemble short run marginal operating costs. In California and other ISOs without a capacity market, energy supply bids may be higher than short run marginal operating costs reflecting recovery of fixed costs.

[54] We are not, however, recommending a specific "standard" for quantitatively determining whether a

marginal-cost bidding is an important analytical tool. While we would not expect actual prices to precisely follow a cost-based model, a cost-based model provides critical information regarding the extent to which actual prices diverge from those would be expected in a truly competitive market with marginal-cost bidding.

Recommendation #6: The MMU should have the authority to assess the impact on the market of proposed mergers and acquisitions, and be a party to such proceedings.

Mergers and acquisitions can have significant impacts on market concentration and the potential for market power to be exercised. The market monitoring plan should provide the MMU explicit authority to participate in merger and acquisition proceedings and provide an assessment of the likely market impacts of the proposed consolidations.

4.4 Authority to Act

The market monitor should have authority to mitigate, sanction, and penalize, as well as the ability to identify necessary rule changes.

Recommendation #7: The MMU should have access to all data that will assist it in performing its market monitoring function.

In addition to all the bids submitted into the market place, the MMU should have access to all operational and systems data collected or generated by other RTO staff and market participants.

The MMU should also have authority to collect marginal cost data and operator logs from market participants. The former data would be used to support the assessment of market performance on the basis of marginal-cost bids, as discussed above. Operation logs would support the MMU's investigation of possible market manipulation through physical withholding.

Recommendation #8: The MMU should have authority to mitigate any bid in any market prior to accepting it.

While thresholds for mitigation may provide useful guidelines for the MMU, they should not limit the MMU's authority to review bids below the thresholds at its discretion. The MMU should have the authority to review bids and take specific appropriate action, subject to appeal to FERC.

Recommendation #9: Bid caps should be used as an essential component of electricity markets.

As FERC has recognized, bid caps have an essential role in securing just and reasonable electricity market prices. In a recent order on California market monitoring, FERC justified the need for bid caps as follows:

> Because of the lack of demand response, these prices may not reflect what the market would have established as appropriate scarcity rents and, therefore, may not be just and reasonable.[55]

Bid caps and bid mitigation should both be used. Although uniform bid caps provide a critical restraint on overall market prices in a small number of high-priced hours, they are not an adequate substitute for generator-specific bid mitigation which addresses potential market power in all hours and under all market conditions. At the same time, bid mitigation procedures, as currently implemented, do not appropriately restrain anti-competitive bidding.

Demand response programs are also not an adequate substitute for bid caps at this time. All current bid-based market structures have difficulty functioning when demand approaches or exceeds available supply, and load response should be developed to address this.[56] However, even under the most optimistic and ambitious scenarios for demand involvement in electricity markets, the point at which demand response will be adequate to restrain anti-competitive supply behavior is at least a decade away.

Recommendation #10: In addition to its authority to mitigate a bid in advance of accepting it, the MMU should also have the authority to impose sanctions or penalties on market participants for specific behaviors, including the failure to provide information requested by the MMU.

The behaviors listed in NEPOOL's MRP 13 are a good initial list;[57] however, the MMU should have the responsibility to identify other anti-competitive or gaming behavior and make them subject to sanctions too. The magnitude of penalties and sanctions should be sufficient to at least offset potential gains from anti-competitive behavior.

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[55] 95 FERC 61,115 (April 26, 2001).

[56] In this regard, RTOs should implement procedures that allow load to bid into the market in the same fashion as generators. For example, market rules could permit load to bid in advance a price at which a specific amount of megawatts could be reduced. Such bids could be treated as generation resource in the daily dispatch bid-stack. Market rules could also allow load to respond, in real-time, to market clearing prices as a price-taker. These approaches should not be limited to large consumers, but should accommodate small loads, including residential loads, that could be aggregated by market brokers. In addition to qualifying for energy market compensation, load responsiveness should also be able to qualify for installed capacity payments and reserve payments to the extent that they qualify. Traditional state and utility sponsored energy efficiency programs should also be able to receive compensation for peak load reductions. As with supply bids, load bids and demand response programs will need to be monitored to ensure that anti-competitive practices can be identified and curtailed.

[57] MRP 13 includes sanctions for following behaviors, if not excused: failure to provide energy, failure to provide services, failure to respond to dispatch instructions, failure to perform in markets, inaccurate bid or operating information, failure to follow scheduling procedures, failure to follow transmission instructions, failure to provide information, and failure to comply with market mitigation rule.

Recommendation #11: The MMU should have the authority to flag clearing prices and make price corrections for a limited period of time after the market clears.

As noted in Section 3.7 above, ISOs have the authority and responsibility to correct prices for errors. However, this authority does not extend to corrections for market-design flaws. Although initially ISO-NE and NY had authority to correct prices for market-design flaws, FERC subsequently revoked it.

The issue of whether to allow price corrections for market design flaws is controversial. In considering whether to allow price corrections for market-design flaws, a key issue is how to balance the market's need for accurate prices with its need for certainty of prices. Ideally, at the end of each day market participants need to know where they stand, i.e., at what price and quantity did they buy or sell electricity. On the other hand, market participants need to have confidence that the systems for establishing prices for sales and purchases produce technically accurate results consistent with a competitive market, i.e., are not subject to manipulation or gaming. Striking an appropriate balance between these competing concerns has been a difficult and on-going challenge for the ISOs and FERC.

We conclude that providing a limited time period for correcting prices for market-design flaws is a reasonable compromise.[58] ISO-NE's 75-minute window during business hours (24 hours for non-business hours and weekends) for flagging a price for review is a reasonable approach.[59] If a price is flagged, market participants are on notice that the price may be revised and can make their forward going decisions accordingly. A five-day period for making revisions after a price is flagged seems to be a reasonable amount of time to complete an initial review. As experienced is gained, the authority to correct prices could be curtailed or eventually eliminated.

Recommendation #12: The MMU should have the authority to file with FERC for changes to both market-monitoring rules and market rules.

There should be a standard process for filing changes (which may include review by stakeholders and the concurrence of the RTO Board). The MMU should also have emergency authority to file changes that go into effect immediately, but are subject to FERC review within 60 days.[60]

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[58] The Pennsylvania Office of Consumer Advocate supports market monitoring authority to make after the fact price corrections for computational errors only. However, the Pa. OCA disagrees that the market monitor should make after the fact price or bid changes to remedy market design flaws or other market abuses. The Pa OCA supports the use of other tools to remedy such flaws and abuses, including filings to change market rules and market design, bid caps, before the fact mitigation of bids, FERC investigations and refunds, sanctions and penalties.

[59] These are the requirements in ISO-NE's MRP 15.

[60] ISO-NE's emergency authority under Section 6.17 of the Interim ISO Agreement is a good model.

Finally, it is critical that the MMU be able to respond to new market behaviors in a dynamic fashion. Market participants are continually striving, as any profit-making entity should, to determine profit-making behaviors that are allowed within established market rules. The MMU must not be overly restricted in its ability to respond to the continuous innovations in market behavior by restrictions on the hours or circumstances under which it can monitor the markets and participant behavior. Competitive electricity markets are still relatively new and are undergoing constant change and evolution. The market monitor cannot be given a static and inflexible tool kit with which to ensure the competitiveness of fluid and evolving markets.

4.5 Data Access and Reporting

The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

Recommendation #13: In order to improve transparency and enhance confidence in the markets, the MMU should regularly and frequently issue detailed reports on its monitoring activities.

The MMU, as part of an overall effort, should strive to maximize the transparency of its own actions and the transparency of the markets in general. Absent compelling reasons that specific information will harm the competitiveness and efficiency of the markets, reports on market activities should be posted on the ISO or RTO website. For information that is too sensitive for public release, redacted versions should be provided for posting on the ISO or RTO website. Non-redacted reports, with appropriate confidentiality protection, should be provided to the ISO or RTO Board, FERC, and state jurisdictional entities including state consumer advocate offices.

The type and frequency of reports should be similar to those currently provided pursuant to MRP 17 for the New England wholesale markets.[61] For example, a market monitoring unit should prepare a monthly report that describes activities in each market, compares prices to other markets and previous months, and describes any regulatory actions or rule changes that have occurred. The market monitoring unit should also prepare a quarterly report for regulatory agencies that summarizes the three monthly reports, compares bids and prices to previous quarters, identifies any mitigations and sanctions taken, and an assessment of market efficiency. Finally, the market monitoring units should prepare an annual report that assesses annual market performance against a marginal cost dispatch, assesses the overall competitiveness and efficiency of each market, and describes changes and improvements that were implemented in the reporting year, as well as future refinements to the markets. The annual report should be presented and discussed at an annual forum that is open to the public.

Recommendation #14: Bid data with names should be released on a one-month lag.

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[61] FERC has praised the monthly and quarterly reports produced by ISO New England for their thoroughness, detailed charts, and comparisons to other wholesale markets.

The ISOs currently release bid data on a six-month lag basis and coded to allow tracking of bids without revealing the bidders' names. As a practical matter, coded names are not a barrier to market participants who, with a minimum of effort, can reliably identify the specific bidders. The coded names are an obstacle to non-market participants such as regulatory agencies and the general public who seek to develop a better understanding of participant activities. Therefore, we recommend the release of bid data with the bidders names.

One of the principal reasons to publish bid data is to allow other market participants, regulatory agencies, and the public at large to evaluate the data and comment upon it. Load serving entities, in particular, have a strong interest in uncovering inappropriate bidding activities that raise prices; they are paying those prices to serve their customers. A six-month lag is problematic for two reasons. First, it allows too long a period for gaming activities to go on without detection or correction. Second, it makes detection and correction more difficult due to the long time between an event (such as the $1,000 ECPs in New England this summer) and the opportunity to analyze the bid data that created the event (Summer 2001 data will not be available until January 2002 at the earliest.

There have been proposals to shorten the reporting time from six-months to three-months; a few people have suggested releasing bid data after 24 hours. We are concerned that a 24-hour lag would provide too much detailed information regarding bidding strategies and encourage short-term gaming efforts. However, we believe that the dynamics of the wholesale markets could support a one-month lag of bid data. Bidding strategies are subject to frequent revision based on the changing circumstances of individual participants (for generators this includes outages and other variations to their generating capacity; for load serving entities this includes changes to their customer base) and the market in general (the combined effect of thousands of individual participant factors). Such a dynamic process is likely to diminish the value of one-month old bid information to those entities that would try to manipulate the market based on such information.

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Appendix A
Comparison Tables:
Market Monitoring in PJM, New York, New England, and California

A1 Size and Budget of Market Monitoring Entity

A2 Institutional Arrangements

A3 Scope of Market Monitoring and Indices Used

A4 Data Collection

A5 Changing Market Monitoring Rules

A6 Changing Market Rules

A7 Bid Caps, Bid Mitigation and Market Price Changes

A8 Sanctions

A9 Congestion and Load Pockets

A10 Data Reporting and Release

Table A1: Size and Budget of Market Monitoring Entity

	PJM	NY	New England	CAL ISO
Staff	5 employees	11 employees in 2000; budgeted to increase to 23 employees in 2001 (2001 Business Plan, at 19).	Current staff of 8; when two open positions are filled there will be 10.	MSC: 3 or more independent experts (MMIP 5.2.1).
Total annual budget	NA	NA	NA	MSC: Compensated as established by ISO Governing Board (MMIP 5.4).
Authority to hire outside expertise	Yes, subject to oversight by President and/or Board (MMP V.B).	Yes, in consultation with Market Advisor and subject to oversight by CEO (MMP 3.2).	Yes, with approval of CEO and Board of Directors.	MSU may hire consulting assistance (budget approved by ISO CEO) and seek external expert advice (MMIP 4.6).

Table A2: Institutional Arrangements

	PJM	NY	New England	CAL ISO
ISO Market Monitoring Entity	Market Monitoring Unit staffed by PJM employees, accountable to President and PJM Board (MMP V.B, V.C).	Market Monitoring Unit staffed by NYISO employees, accountable to CEO (MMP 3.2, 3.3).	Market Monitoring & Mitigation Unit staffed by ISO-NE employees, accountable to CEO and NEPOOL (IIA 6.4)	Market Surveillance Unit under management of ISO Chief Legal Counsel and ISO CEO (MMIP 3.2, MMIP 3.3.1).
Independent Market Monitoring Entity	None.	Market Advisor accountable to the CEO and serving at the pleasure of the Board (MMP 4.1). Market Advisor advises and reports directly to the Board (MMP 4.3).	Independent Market Advisor who assists Board of Directors and MMM group (Press Release 5-23-01).	Market Surveillance Committee (MSC). An independent advisory committee made up of 3 or more independent experts -not ISO staff - (MMIP 5.1, MMIP 5.2). MSC advises ISO CEO and ISO Governing Board (MMIP 5.1) and may refer matters directly to ISO Governing Board (MMIP 3.3.2).

Table A3: Scope of Market Monitoring and Indices Used

	PJM	NY	New England	CAL ISO
Practices subject to scrutiny	MMU responsible for monitoring (1) compliance with all rules, standards, and procedures; (2) actual or potential market-design flaws; (3) ability of market participants to exercise market power (MMP III).	MMU responsible for monitoring (1) competitiveness, performance, economic efficiency of electric markets; (2) market-participant conduct; (3) operation and use of transmission system as it effects competitiveness and efficiency; (4) adequacy and effectiveness of tariffs, rules, standards, procedures, mitigation or other remedial measures (MMP 1.1).	MMMG has authority to independently assess the competitiveness and efficiency of the NE markets including physical withholding, bid mitigation, economic withholding, price anomalies, flaws in market design or software, and other aspects that prevent competitive results (MRP 17.1).	Anomalous market behavior, abuse of reliability must-run unit status, gaming, ISO and PX design flaws, market structure flaws (MMIP 2.1).
Markets / products monitored	MMU authorized to monitor all markets administered by ISO, bilateral markets within PJM, and regional markets outside of PJM (MMP I).	MMU authorized to monitor all markets administered by ISO or involving ISO-provided transmission services, and regional markets outside NY (MMP 5.1.2).	MMMG authorized to monitor any aspect of the New England markets (MRP 17.1). IMA authorized to advise on how to improve wholesale markets.	MSU monitors ISO markets and coordinates with PX. (MMIP 2.1).

Authority to select indices	MMU develops and publishes variety of indices used to evaluate collected data (MMP VI.E).	Upon approval of the CEO, and at its discretion the Board, MMU develops and publishes variety of indices used to evaluate collected data (MMP 7.1).	MMMG develops and publishes variety of indices used to evaluate markets.	MSU develop and refine catalog of market monitoring indices (MMIP 4.1.3).
Public review of indices used	MMU required to provide opportunity for stakeholder comment on proposed indices (MMP VI.E).	MMU to give "due consideration" to proposals and comments of stakeholders regarding indices (MMP 7.1, 7.2).	Included in Annual Market Review and part of annual public forum (MRP 17.6.2.3).	Indices are available on the CA ISO website.

Table A4: Data Collection

	PJM	NY	New England	CAL ISO
Authority	MMU has access to all data gathered or generated by ISO during course of normal business operations (MMP VI.A). MMU also authorized to request additional data from market participants (MMP VI.B).	MMU has access to all data gathered or generated by ISO during course of normal business operations (MMP 6.1). MMU also authorized to request additional data from market participants (MMP 6.2).	MMMG has access to any and all data that ISO-NE deems necessary, including cost data from generators (MRP 17.6.1).	MSU develop and refine catalog of data to collect, and procedures to handle data (MMIP 4.1.2). MSC full discretion to specify data types and evaluation criteria (MMIP 6.1). ISO CEO must institute data collection, organization and analytic activities to support MSU (MMIP 3.3.3.2). Data catalog published and disseminated to Participants (MMIP 8.1).
Generator cost data collected	Systematically for all generators on-line prior to July, 1996 (OA, Schedule 1, 6.4; OA, Schedule 2).	No systematic collection. MMU may request specific data from individual generators (MMP, 6.2.1).	Only for generators that seek to negotiate a bid-price with ISO-NE due to congestion.	Generators who submit a bid that exceeds that market-clearing price must submit cost data to ISO and FERC (95 FERC 61,115, p. 15-6).
Enforcement ability	No direct enforcement authority. MMU can petition FERC to	Market participants required to promptly provide data requested	Interim ISO Agreement states that NEPOOL Participants "shall	ISO may impose penalties or sanctions for ISO Participant's failure

	enforce requests. (EDR, at 10).	by MMU, and to submit to binding arbitration in the event that MMU determines that the requested data will not be provided within a reasonable time (MMP 6.2.2).	provide the ISO with any and all information . . . that the ISO deems necessary" (IIA 7.2). Also, MRP 13 provides sanctions for failure to respond to data requests.	to provide information, including exclusion from market (MMIP 4.5.2). MSU may report failure of other entities (e.g. PX) to ISO CEO and Governing Board or to pertinent regulatory agency (MMIP 4.5.1).
Requests for data collected by Market Monitoring entity	No provision.	Upon request, MMU may publicly release data if such data is not confidential and release of such data would not be overly burdensome (MMP 6.4(e)).	Data may be released subject to the confidentiality limitations of the NEPOOL Information Policy (MRP 17.6.1).	ISO CEO has sole discretion whether to provide data it has collected to Participant who requests it (MMIP 4.5.3).

Table A5: Changing Market Monitoring Rules

	PJM	NY	New England	CAL ISO
Authority to change market monitoring rules	MMU may recommend to the PJM Board changes in the MMU or MMP (MMP VII.A)	Market Advisor and MMU may recommend changes to the MMU or MMP as part of its annual report to the Board (MMP 10.1). In addition, Market Advisor and MMU, with approval from CEO and Board's Market Performance Committee, authorized to recommend revisions to existing mitigation measures (MMP 8.2)	MMMG can propose changes to monitoring and mitigation rules for filing with FERC, in consultation with regulatory agencies and NEPOOL, or by ISO-NE in emergencies (MRP 17.1.3 and 17.5)	MSU may recommend to the ISO Governing Board changes to its rules and protocols (MMIP 2.3.2)

Table A6: Changing Market Rules

	PJM	NY	New England	CAL ISO
Market monitor authority to market rules	MMU may recommend changes to stakeholder committees or, with Board approval, file for changes directly with FERC (MMP IV.A)	MMU may recommend changes to stakeholder committees, CEO, or Board (MMP, 11.1(d)). Board may file for changes without committee concurrence only to address exigent circumstances. (ISO Agreement, Article 19)	MMMG reports to VP of Markets Development who can propose market rules changes for NEPOOL consideration, or on its own subject to 6.17 of the IIA (IIA 6.4 and MRP 17)	MSU may recommend changes to rules and protocols of PX, ISO markets, PX markets (MMIP 2.3.2)

Table A7: Bids Caps, Bid Mitigation and Market Price Changes

	PJM	NY	New England	CAL ISO
Bid caps	$1,000/MWh cap on energy bids (OA, Sched 1, 1.10.1A). $100/MWh cap on regulation bids (OA, Sched 1, 1.10.1A). During first year of markets, all generators required to bid at cost.	$1,000/MWh cap on energy bids (Services Tariff, Attachment F). $2.52/MWh plus opportunity cost on bids for non-spinning reserve (FERC order, 11/8/00.)	$1,000/MWh cap on energy bids; reserve prices not to exceed energy price (FERC Order, 10/25/01)	FERC has instituted a soft bid caps, based on proxy marginal costs, for periods of capacity shortage as well as non-shortage hours (95 FERC 61,115,s issues April 26, 2001 and 95 FERC 61,418, June 19, 2001)
Bid-mitigation authority	None, other than in local load pockets.	MMU authorized to mitigate supply bids in day-ahead and real-time energy and reserve markets (MST, Attachment H, Section 4).	MMMG authorized to mitigate Participants' bids and unit characteristics subject to specific thresholds (MRP 17.2).	NA
Bid-mitigation practices	NA	Bid-mitigation triggered only when suspect bid exceeds reference level by threshold amount and only if bid-mitigation would reduce LBMP by threshold amount (MST, Attachment H, 3.1-3.2).	Thresholds for bid-mitigation are specified in reference price screens (17.2.2.1), investigation thresholds (17.2.2.2), and Hourly Market Impact and Uplift Thresholds	NA

		In addition, MMU can file with FERC for mitigation authority in the event that bid has material effect on market prices, but does not exceed standard mitigation thresholds. (MST, Attachment H, 3.2.3).	(17.2.3).	
Corrective actions	MMU authorized to issue demand letters to market participants to cease actions found to be in violation of rules, standards, or procedures (MMP IV.A).	If bid triggers mitigation, MMU authorized to substitute "default bid" based on previous unmitigated bids (OA, Attachment H, 4.2). For day-ahead market, default bid substituted prior to setting, and used to set, LBMP. Default bid applies for six months. (MST, Attachment H, 4.6) In addition, MMU authorized to engage in discussions with, or issue demand letters to, market participants to	MMMG may substitute a default bid that is 100% of the Reference price determined through 17.2.2.1 (17.2.4).	FERC may order refunds upon reviewing justification of bids that exceed the market-clearing price (95 FERC 61,115; 95 FERC 61,418).

		correct actions found to be in violation of rules, standards, or procedures. (MMP, 11.1).		
Authority to Change Market Prices	Can revise prices due to computational errors.	Can revise prices due to computational errors.	Limited ability to change market prices based on human or software error, or due to extreme system emergency (MRP 15) MRP 15 allowed revisions for prices that did not result from a competitive market for first 90 days of new markets. Extended for 60 days; additional extension denied by FERC.	
Practices for Changing Market Prices	NA	NA	Prices must be flagged within 75 minutes to 24 hours and corrections must be made within five days (MRP 15).	

Table A8: Sanctions

	PJM	NY	ISO NE	CAL ISO
Authority	No direct authority.	Authorized to impose penalties or sanctions for occurrences of physical withholding, generation in excess of dispatch signal, or under-scheduling load in day-ahead market (MST, Attachment H, 4.3, 4.4).	Authorized to impose sanctions for a variety of behaviors including physical withholding, failure to perform or follow ISO instructions, inaccurate bid information, and failure to provide information (MRP 13 & 13A).	MSU may recommend actions, including fines and suspensions, against specific entities (MMIP 2.3.2) ISO Governing Board, acting upon recommendation of MSU or MSC, and after audit by MSU, may impose sanctions within its authority, or may recommend sanctions to regulatory agency (MMIP 7.3).
Practices	NA	For physical withholding or over-generation, penalty set at product of amount withheld (or over-generation) and real-time LBMP (MST, Attachment H, 4.3). For load under-scheduling, requirement	Administrative and formula based sanctions for specific behaviors (MRP 13A).	

		to schedule all expected load in day-ahead market, and penalty for purchasing in real-time market in excess of specified allowance level (MST, Attachment H, 4.4).		
Market Participant Recourse			Participant may seek ADR review of any sanctions. Decision from ADR process may be appealed to FERC by participant or ISO-NE. MRP 13.	MSU may institute ADR to resolve differences with market participants over interpretation of behavior and appropriate remedies. (MMIP 2.3.3)

Table A9: Congestion and Load Pockets

	PJM	NY	New England	CAL ISO
Authority	Authority to cap bids of units within load pocket required to be dispatched out of merit for reliability purposes (OA, Sched 1, 6.1). Exception for units relied on to relieve Western, Eastern, Central reactive limits, or other constraints exempted by FERC (OA, Sched 1, 6.4.1(d)).	Authority to cap: 1. Energy bids of units within NYC load pocket whenever (1) transmission constraints limit imports of generation into NYC; or (2) units required to be committed or run out of merit for local reliability purposes. (ConEd Rate Schedule No. 199, Section B [As modified pursuant to 7/20/01 FERC order]). 2. Bids into, and prices received from, NYC installed capacity market (ConEd Rate Schedule No. 199,	Authority to cap bid prices at a reference price for generators in congested areas (defined as less than three competitors). Authority to cap bid prices at a predetermined level (based on cost data) for generation units that are seldom selected, except due to congestion.	

		Section C). 3. Spinning-reserve bids for units committed to meet local spinning-reserve requirements (ConEd Rate Schedule No. 199, Section D).		
Eligibility	All generating units built prior to July, 1996 subject to mitigation. (OA, Sched 1, 6.1)	All generating units located within NYC subject to energy bid cap. ICAP and spinning-reserve caps applicable only to generating units divested by ConEd (ConEd Rate Schedule No. 199, Section A).	Generation units selected as out-of-merit generators.	
Markets subject to mitigation	Restricted to day-ahead energy market (OA, Sched 1, 6.4.1). PJM recently requested authority to apply on real-time basis (6/29/01 filing letter).	Applicable to day-ahead and real-time energy markets, installed capacity market, and spinning-reserve market (ConEd Rate Schedule No. 199).	All markets.	
Bid cap	As elected by generator, bid mitigated to either	In day-ahead energy market, bids mitigated to	Mitigated to reference price (formula based) for	

	(1) incremental cost + 10%; (2) average of LMP at generator bus during hours when unit dispatched in merit order; or (3) amount negotiated with generator (OA, Sched 1, 6.4.2)	"reference price" based on previous unmitigated bids. In real-time energy market, bids set at 10% above reference price. (ConEd Rate Schedule No. 199, Sections B.1, B.2). In installed-capacity market, divested generators' bids and prices received capped at $105/kW-yr (ConEd Rate Schedule No. 199, Section C). In addition, divested generators required to bid all capacity into NYC installed-capacity auction. In spinning-reserve market, divested generators' spinning-reserve availability bids capped at $0 (ConEd Rate Schedule No. 199, Section D).	generators who are often selected in-merit. For generators seldom selected in-merit, a reference price or a negotiated price is used New rules regarding "net commitment period costs", or npcp, provide a method for calculating uplift payments.	

Table A10: Data Reporting and Release

	PJM	NY	New England	CAL ISO
Reporting within ISO	MMU provides periodic reports to the PJM Board (MMP VII.A).	Market advisor and MMU provides reports to the Board on an annual basis (MMP, 10.1) Reports also provided periodically upon request of Board, CEO, FERC, or NY PSC (MMP, 10.2)	Monthly reports to CEO and Board (internal).	MSU must report to ISO CEO and MSC not less than quarterly, and to ISO Board not less than annually, and as needed (MMIP 4.4.1) Director of Department of Market Analysis reports to Governing Board monthly (website) MSU may report directly to MSC (MMIP 4.4.3) MSC must report on its evaluations and recommendations to ISO CEO and Governing Board (MMIP 6.3.1) MSC may require ISO CEO to publish or include MSC reports/findings (MMIP6.4).

Reporting to FERC	MMU provides FERC with all reports to the PJM Board, or any other report requested by FERC (MMP VII.B)	MMU provides FERC with all reports to the Board, or any other report requested by FERC.	All reports to FERC.	MSU reports to FERC annually, reports approved by ISO CEO (MMIP 8.3) MSC may report to FERC (MMIP 6.3.1) Recently FERC has required weekly reports of schedule, outage, and bid data, with identification of bidding behavior issues (95 FERC 61,115, p. 18).

Appendix B
International Approaches to Competitive Markets

England and Wales[62]

The electricity industry was first privatized in 1990 and the Electricity Pool was set up. It was operated under a commercial arrangement: the Pooling and Settlement Agreement, between the generators and the retailers. The pool "was used to determine which generating assets were called on to satisfy demand. The wholesale electricity price was set on a half-hour basis by the most expensive generator used during that period, with all generators receiving that 'marginal' price."[63] There were only two major generators (National Power, now Innogy, and Powergen) at that point, creating a strong potential for the exercise of market power. The main response of the regulator was to force plant sales and divesture. The government also imposed a cap on the pool price.

A new system was set up this year, the New Electricity Trading Arrangements (NETA). It encourages a move towards bilateral contracts signed between generators and retailers and large customers. In addition, five power exchanges have been set up or are in the process of being created. The UK Power Exchange (UKPX) spot market, which started on March 25, 2001, is a 24-hour seven-day market. The owner and operator of the transmission system, National Grid Co. (NGC), a publicly-traded company, "accepts offers and bids from 3 ½ hours ahead of real time, up to real time".[64] This balance and settlement mechanism is managed by Elexon, a non-profit, uncontrolled subsidiary of NGC.[65] This new system seems to have led to a reduction in prices: according to an OFGEM news release in August 2001, "wholesale electricity prices are 20-25 per cent below prices that would have been produced under the Pool" (i.e. the previous system).[66]

The main regulatory agency is Ofgem, the Office of the Gas and Electricity Markets.[67] Ofgem was formed in early 1999, combining formerly separated gas and electricity activities. In terms of market monitoring, Ofgem is charged with overseeing competition of licensees (the market participants) and to refer anti-competitive practices to UK's Competition Commission. Ofgem's Director General (the Director Generator of

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[62] Scotland has a similar framework but there are only two vertically integrated electricity companies. Northern Ireland does not yet have an open market. IEA (2001).

[63] Levesque (2001).

[64] Levesque (2001).

[65] www.elexon.co.uk

[66] "Reviews address NETA's performance and its impact on smaller generators", OFGEM News Release, August 31, 2001 (PN 38). Available at http://www.ofgem.gov.uk.

[67] See www.ofgem.gov.uk

Electricity Supply, DGES) is appointed for 5 years and this mandate can be renewed once. As of March 1997, Ofgem had 233 staff and its running costs for the fiscal year finishing March 1997 were 13 million pounds (UK).[68]

Bower points out, quoting a 1998 report by the electricity regulator, that "[i]n the England and Wales market, strategic capacity withdrawal, especially of marginal plant, has been a major regulatory problem and Ofgem has over the years launched a number of investigations into this kind of behavior by the largest fossil fuel generators PowerGen and National Power".[69] Ofgem has also recently ordered that firms wishing to close plants have to demonstrate that it was uneconomic to operate the latter at the existing market prices. This requirement is likely to lead to spare capacity being put up for sale to competitors.

UK's Competition Commission is the current public independent body, created in 1998, dealing with mergers, abuse of dominant position and other anti-competitive behaviors.[70] Ofgem has been in disagreement with the Competition Commission on the extent of its market monitoring capacity. The Ofgem intended to introduce a so-called Market Abuse Condition in the licenses of generators "capable of exercising substantial market [71] Two generators (out of eight major ones that had been identified) refused the inclusion of the Market Abuse Condition in their license and were referred by Ofgem to the Competition Commission. The Commission found in favor of the two generators and Ofgem had to withdraw the Condition from all the operating licenses where it had been included.

It is worth giving some details on this condition, since Ofgem still pushes for it: Ofgem "has managed to get the Department of Trade and Industry to look at its case again, with a view to getting the [condition] reinstated under the 'Secretary of State's special Neta Power', provided by the Utilities Act".[72]

The term substantial market power was defined in the initial Ofgem guideline as "the ability to bring about, independently of any changes in market demand, a substantial change in wholesale electricity prices".[73] The Competition Commission warned that "[M]ore than one license-holder or interconnected group of license-holders may simultaneously have, and exercize, substantial market power in the Pool".[74] The

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[68] IEA (2001).

[69] Bower et al. (2001), p. 1004.

[70] See UK's competition web site at http://www.competition-commission.org.uk/

[71] UK's Competition Commission (2001), p. 88. This reference is not yet included in the list of References.

[72] "Return of the MALC", http://www.energy-directory.com, August 2001.

[73] *The market abuse licence condition for generators. A decision document.* OFGEM, April 2000.

[74] UK's Competition Commission, 2001, p. 89.

precision with which the criteria for potential market power were defined is interesting. The Ofgem guidelines stated that market power could occur through very large effects on prices which occur over a short period of time, or through a series of lesser effects on prices that occur over a longer period of time. The document stated that a license-holder had the ability to exercise substantial changes in wholesale prices if it has the ability to bring about a change of:

(i) 5 % or more for a duration of more than 30 days in a one-year period;

(ii) 15 % over ten days in a one-year period, or

(iii) 45 % over 160 half-hours (a little less than 1 % of the year) in a one-year period.

These do not have to be considered continuous periods.

The DGES would have a duty to take enforcement action (except in certain specified circumstances when the Competition Act would be the most appropriate way to proceed).[75] Ofgem could ask further information from the generators to come up with its initial findings and provisional orders. After a period for comments by the license-holder at each stage of the investigation, Ofgem would be entitled to issue an order. The penalties could amount up to 10 % of the license-holder's turnover. An Advisory Board of five members would be formed to advise on Market Abuse Conditions matters. If the DGES disregarded the opinion of the Advisory Board, the enforcement order may be subject to a legal challenge – thus ensuring a way of appeal.

It will be worth analyzing how much of these provisions might disappear in the new version of the Market Abuse Condition.

***Nord Pool* (Norway, Sweden, Finland and Denmark)**

The Nordic Power Exchange, or Nord Pool, is "the world's only multinational exchange for trading electric power".[76] It was created in 1993, initially in Norway, and is owned by the two national grid companies, Stattnett SF in Norway and Affärsverket Svenska Krafnät in Sweden. Since 1990, the four Nordic nations (Norway, Sweden, Finland and Denmark) operate in a joint, competitive wholesale market. This is only a power exchange market and the two grids remain owned by the national companies. There is regulated third-party access to the consumers and all consumers may choose their suppliers (except in Denmark, where consumer choice is planned to begin in 2003). Transmission is owned in each country by an independent, usually publicly-owned company (in Finland, there are some private stakeholders in it); there is accounting unbundling of distribution from generation and electricity sales.[77]

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[75] UK's Competition Commission, 2001, p. 91.

[76] www.nordpool.com

[77] IEA (2001).

Most market monitoring was at the national level until recently. However, with the increasing share of electricity traded across borders, the market surveillance of Nord Pool has been reinforced. At the end of 2000, Nord Pool decided to strengthen the monitoring of its physical and financial markets by creating an independent dedicated department. Some of the features of market monitoring include:

- An obligation for Nord Pool participants to "disclose market sensitive information".[78] This type of information (for example about incidents related to the power system, maintenance) is provided first to Nord Pool. The rules are in the process of being defined.

- Flagging bilateral-market agreements. This is a proposal by Norway's parliament: all bilateral market trade in standardized financial power contracts within imposed deadlines would have to be notified.

- Nord Pool tries to obtain full "authority to investigate situations to determine whether there has been undue exercise of market power or insider trading".

- Nord Pool is also considering the creation of an ethics council entitled to make statements and recommendations, but not to impose sanctions.

Australia

The restructuring of the electricity market was initiated in 1995 with the adoption of a comprehensive plan to create a competitive National Electricity Market (NEM). This wholesale market includes, as of the Summer of 2001, five Australian States and territories and was launched on December 13, 1998. One of the distinctive features of the Australian model is that the Australian Competition and Consumer Commission (ACCC) is both the national electricity regulator and the competition authority.[79] Furthermore, the ACCC also covers gas, telecommunications and airports. The states and the central Commonwealth government cooperate through the Council of Australian governments. States have a rather wide responsibility in protecting competition and consumers.

The ACCC investigates market arrangements and behavior that may contravene antitrust laws. Tracking misuse of market power is also one of its roles, according to the Trade Practices Act 1974. The Commission is composed of seven members, appointed by the federal government after consultation with the states. Their five-year term is irrevocable and they can be re-appointed. The ACCC is financed through the Treasury's budget, with a small amount coming from authorization fees and fines. The state regulation authorities also monitor market conduct of retailers and distributors.[80]

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[78] www.nordpool.com

[79] www.accc.gov.au

[80] IEA (2001).

One of the characteristics of the Australian market surveillance system is the very short lag (one day) in releasing bid data in the wholesale electricity market. Anyone can consult this information at the following link: http://www.nemweb.com.au:9080/REPORTS/CURRENT/YESTERDAYS_BIDS_REPORTS/[81]

The ACCC cooperates with the National Electricity Code Administrator (NECA) to ensure the "effectiveness, efficiency and equity of the national electricity market".[82] NECA has a market surveillance program through which "variations between forecast spot prices and actual spot prices" are analyzed. According to the National Electricity Code (Clause 3.13.7), the ACCC predetermines the acceptable thresholds for this gap between forecast and reality. NECA "will report incidents where it finds that significant variations are caused by activities that in its opinion are inconsistent with the objectives of the market" and notify the ACCC. NECA also performs routine monitoring of market participants.[83]

NECA is also entitled to establish reporting requirements from the market participants. NECA can thus obtain data on registration, prudence requirements, market operations, rebidding, and settlements. NECA provides, among other publications, annual public market reports.

Germany

Germany was perceived as a success story of electricity restructuring for consumers when its electricity market was liberalized in April 1998 (following the 1997 EU Electricity Market Directive). It ended 100 years of local monopoly supply and combined a negotiated third-party access model with an optional single buyer approach for small municipalities (to preserve cross-subsidization of other public services). Average industry tariffs dropped by 27 % between April 1998 and the end of 1999.[84]

The main reason for this drop in prices was an intense price war from the incumbents. This predatory pricing strategy of matching or undercutting best prices was intended to preserve market shares and prevent new competition. The downward trend in prices created a benign regulatory attitude towards mergers. Also, before January 1999, energy was not

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[81] Note that similar data is available for the English and Wales' market at http://www.esis.co.uk/market/registration.html

[82] From NECA's web site, at www.neca.com.au

[83] A memorandum of understanding between the ACCC and NECA can be found on the NECA web site (http://www.neca.com.au). The guidelines for NECA investigation can be found at http://www.neca.com.au/SubCategory.asp?SubCategoryID=179

[84] Bower et al. (2001).

covered by the German anti-trust law and monopolies were, thus, tolerated.[85]

However, this first competitive environment may be altered in the coming years, as underlined by Bower et al. (2001) in an article in *Electricity Policy*. There has been a large movement of concentration in the German market, starting in September 1999 when VEBA and VIAG, two German conglomerates with electricity subsidiaries, announced their intention to proceed with the largest merger in German history.

The VEBA/VIAG merger and another major merger between RWE and VEW were authorized in early 2000, but the European Commission insisted that this authorization was conditioned on divestment of shares in commonly-owned generators, scrapping of the transmission tariffs between North and South Germany and agreement to sell or auction cross-border transmission capacity where there appeared to be constraints (Bower et al., page 990).

Germany refused to create an Independent System Operator. The regulation of grid access and transmission pricing was negotiated directly by associations in the electricity industry and heavy industry. The first associations' agreement, reached in May 1998, was modified in January 2000, after some problems with high transmission prices and denial of access occurred. There is no dedicated electricity regulatory body and the German Cartel office deals with concentration issues. The EU anti-trust authority also has authority.

There is thus a continuing potential for the exercise of market power in Germany. Although the market has been rather atomistic in the past, it no longer is. The electricity companies were also vertically integrated up to now, but this may change, too. Thus, although Germany may be considered by some as a platform for an EU-wide model, it does not appear to be equipped with sufficient regulatory tools to monitor market power in the future.

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[85] This illustrates, more broadly, a higher tolerance for concentration in the German economic environment and regulation. This contrasts with more aggressive anti-trust attitude in Anglo-Saxon countries.

Appendix C
Market Monitoring Indices of California and PJM

For PJM (from the PJM MMU Report to the FERC: *Assessment of Standards, Indices and Criteria*, April 1, 2001).

1. Summary statistics for PJM system by hour/day/week/month/year.
    a. PJM system prices and loads: day ahead and real time markets.
        i. Average PJM load weighted price;
        ii. Maximum PJM load weighted price;
        iii. Average PJM load;
        iv. Maximum PJM load;
        v. Correlations between PJM prices and loads.
    b. PJM congestion.
        i. Maximum hourly congestion costs;
        ii. Total congestion cost;
        iii. Number of active constraints.
    c. PJM volumes.
        i. Total MW bid;
        ii. Total MW self scheduled;
        iii. Total bilateral contract MW;
        iv. Hourly net imports and exports including all components.
2. Day ahead market
    a. Total hourly load
    b. Composition of load
        i. Fixed price bids
        ii. Price sensitive bids
        iii. Decrement bids
    c. Composition of supply offers

i. Generation offers

ii. Increment offers.

3. Aggregate relationships between day ahead and real time markets

   a. Hourly aggregate LMP comparisons

   b. Hourly aggregate load comparisons

   c. Hourly aggregate congestion comparisons

4. Comparative prices and loads for PJM and surrounding power markets:

   a. Forward prices for each system by market term;

   b. Forward price spreads by market term;

   c. Real time prices as available;

   d. Real time price spreads;

   e. Loads for each system as available;

   f. Net imports/exports between PJM and each system.

5. Locational prices and loads.

   a. Bus locational marginal prices (LMPs);

   b. Aggregate LMPs;

   c. Bus LMPs less the PJM average price;

   d. Loads and generation by bus;

   e. The distribution of LMP rankings for each bus by bus price and by bus load/generation;

   f. Daily/weekly/monthly price-load comparisons:

      i. Maximum bus LMP by hour;

      ii. Minimum bus LMP by hour;

      iii. Average load LMP by zone, by aggregate load bus, for PJM;

      iv. Average generation LMP by zone, by aggregate load bus, for PJM;

      v. Load/injections by bus, by zone, by aggregate buses, for PJM.

g. Zonal LMPs

i. Zonal daily LMP

ii. Highest bus LMP within zone;

iii. LMP ranking across zones.

6. Congestion by hour/day/week/month/year by bus/zone/bus aggregates.

a. Total congestion costs for period;

b. Peak congestion costs;

c. Percent of time with congestion;

d. Frequency of individual constraints;

e. Frequency of must run price cap implementation;

f. Frequency of constraints without must run price cap implementation.

7. Transmission congestion and FTR revenue adequacy.

8. Congestion comparisons between day ahead and real time markets

a. Total congestion costs for period;

b. Peak congestion costs;

c. Percent of time with congestion;

d. Frequency of individual constraints;

e. Frequency of must run price cap implementation;

f. Frequency of constraints without must run price cap implementation.

9. Offers and dispatch.

a. Unit offer/supply curves;

b. Maximum economic offer;

c. Minimum economic offer;

d. Company aggregate offer/supply curves;

e. Aggregate PJM supply curves;

f. Comparisons of unit offer/supply curves to historical offer curves;

g. Comparisons of company offer/supply curves to historical supply curves;

h. Comparisons of aggregate PJM supply curves to historical supply curves;

i. Deviations from requested dispatch, by unit;

j. Ramp rates by unit, by time period, by company.

k. Comparisons of ramp rates by unit type, by company.

l. Operational constraints on offers: start times; minimum run requirements; minimum down times; maximum starts.

m. Start up costs.

10. Comparisons between day ahead and real time offers

11. Relationship between offers and LMPs

    a. Identification of units which set price;

    b. Identification of fuel type of marginal units;

    c. Frequency of individual units setting price;

    d. Frequency of generation owners setting price.

12. Transmission contracts.

    a. Contract quantities;

    b. Service types;

    c. Contract paths.

13. Energy contracts.

    a. Contract quantities;

    b. Service types;

    c. Contract paths.

14. Regulation

    a. Available regulation

    b. Regulation offers

c. Regulation price

d. Aggregate regulation supply

e. Regulation adequacy

15. Spinning.

a. Condenser bids;

b. Condenser costs;

c. Condenser credits;

d. Total condenser MWs;

e. Total spinning requirements.

16. FTR Auction Market.

a. Total market volume offered and cleared;

b. Total market revenue;

c. Average clearing price;

d. Path specific revenue and volume;

e. Source specific revenue and volume;

f. Sink specific revenue and volume.

17. Available capacity

a. Total capacity resources;

b. Total available capacity;

c. Outage status by unit;

d. Frequency of outages, by type, by unit, by time period;

e. Comparisons of outages across units;

f. Company summary outage frequency;

g. Comparisons of outages across companies;

h. Frequency of unit outages by time period, by demand conditions; by system/bus price.

18. Capacity market

    a. Company supply curves by time period of market;

    b. Company demand curves by time period of market;

    c. Supply/demand balance;

    d. Market prices for each market;

    e. Comparisons of offers to opportunity costs;

    f. Delisting of units by company;

    g. Capacity position by company.

19. Market structure by market

    a. Concentration ratios by hour;

    b. Incremental concentration ratios by hour;

    c. Concentration ratios by transmission defined markets within PJM;

    d. Concentration ratios by zone;

    e. Concentration ratios by interface.

20. Price-cost margins

    a. Unit specific price-cost margins;

        i. Compare unit offers to unit costs

    b. Company price-cost margins;

        i. Compare unit price-cost margins by company.

    c. Price-cost margins for marginal units

    d. Aggregate price-cost margins

For comparison, from the California ISO web site (*ISO Market Monitoring and Information Protocol*, Appendix 2)

Data derived from sources partly or wholly external to the markets administered by the ISO and PX

A. Market Clearing Price Indices

1. The percentage of Settlement Periods in which a Market Participant has set, or has submitted bids close to, the Market Clearing Price in the Energy and Ancillary Service markets overall, and in relation to the following time periods or market conditions:

    a. when such Market Participant is:

        i. a net buyer of Energy and Ancillary Services,

        ii. a net seller of Energy and Ancillary Services;

    b. during on-peak hours and off-peak hours;

    c. in different time periods otherwise of relevance to the state of the markets;

    For each of these situations, bids submitted when Congestion is present and those when there is no Congestion will be compared. These indices will also be examined in relationship to other "vulnerable periods" and bidding strategies;

2. the relationships between the Market Clearing Prices in the various markets administered by the ISO and PX, e.g., between the Imbalance Energy market and the Energy and Ancillary Services markets;

3. the record of Market Participants setting Market Clearing Prices in the context of the inter-market relationships as described in (2);

4. The percentage of Settlement Periods in which a Market Participant has set, or has submitted bids close to, the Market Clearing Price when such price falls into a particular segments of the market price curve, e.g., $20-30/MWh, and $30/MWh and above;

5. A "price mark-up" check that measures the differences in Market Clearing Prices between unconstrained periods and constrained periods.

B. Comparison and Evaluation of Specific Bidding Strategies of Market Participants

1. Correlation between bidding behavior of Market Participants and

their establishing the Market Clearing Price at times when they are:

i. net buyers of Energy and Ancillary Services,

ii. net sellers of Energy and Ancillary Services;

2. bidding and rebidding strategies of Market Participants, especially those that frequently set Market Clearing Prices during iterations in the bidding cycles of each market, both within and between the markets administered by the ISO and PX;

3. comparison of bidding strategies for the same Generation Unit into Day-Ahead Market, Hour-Ahead Market and Imbalance Energy markets;

4. comparison of bidding strategies for the same Generation unit into the Energy, Ancillary Service and Imbalance Energy markets;

5. comparison of Supply Bids of Generation units with similar technology/age characteristics;

6. Supply Bid and Generation Unit withdrawals and redeclarations during bidding cycles;

7. correlation of changes to initial Supply Bids with Market Clearing Prices, e.g., to ascertain if redeclarations cause or lead to increases in such prices;

8. comparison of bidding strategies for the same Generation Unit in relation to the following time periods or market conditions:

. when the Market Participant that owns the unit is a net seller or a net buyer of Energy or Ancillary Services;

a. when congestion is or is not present;

b. when a Reliability Must-Run Unit is called or not called;

c. when "near Congestion" occurs. "Near Congestion" means the final scheduled power flow over an Inter-Zonal Interface is within a few percentage points of the Available Transmission Capacity, or when congestion would occur with the initial Preferred Schedules but is alleviated after rebidding;

9. comparison of bidding strategies of Market Participants in relation to their market share;

10. relationships or correlations between the ability of Market Participants to set Market Clearing Prices or certain type of bidding behavior and periods or circumstances in which such Market Participants may have exclusive or restrictive access to data, e.g., as to costs or availability of Reliability Must-Run Units, or as to expected or actual outages of Generation Units or transmission

facilities;

C. Indices of Market Concentration

The ISO Department of Market Analysis will use dynamic, geographic and product market specific indices based on actual market operation data as indicators of the competitive condition of the ISO and PX markets. The planned indicators are:

1. Market share for the largest supplier.
2. Measure of supply responsiveness. This is a measure of how much additional power would be supplied for a given increase in price.
3. Traditional measures of concentration which might include conventional HHI (Herfindahl-Hirschman Index) analysis.

Indices will be developed for:

4. each of the geographic markets or zones;
5. each of the PX and ISO product markets including Energy, Ancillary Services and Imbalance Energy markets;
6. each of the Day-Ahead, Hour-Ahead and Real Time Markets;
7. each of the market conditions such as on-peak and off-peak periods, periods with Congestion and without Congestion, and periods with and without other constraints;

D. Outages and Other Indices

1. Generation Unit and transmission facility Outage indices in comparison with historical averages, with other similar units or facilities, and with other relevant standards;
2. New or unexpected occurrences of Congestion; and
3. Trend comparisons of Market Clearing Prices with fuel prices and other input prices.

Appendix D: Acronyms and Technical Terms

ADR: Alternative dispute resolution; an option contained in market mitigation procedures that usually allows either party to seek an independent, neutral determination of a disagreement.

Ancillary Services Markets: Markets for services necessary to support the transmission of energy from generators to loads, while maintaining reliable operation of the regional bulk power system; includes reserves, automatic generation service, black-start capability, and installed capacity requirements.

Bid mitigation: Ability of the market monitor to modify the bids entered by the market participants. Bid mitigation is different from price caps: with bid mitigation, only bids are modified, and the price is then set according to the market. With price mitigation, the final price itself is modified.

Bid-stack: The tabulation in ascending order of all the bids submitted; this constitutes the aggregate supply within the market.

Bulk power system: The regional electric supply system administered by an ISO or RTO.

CDR: Capacity Deficiency Rate.

Capacity Market: Generation resources that qualify for installed capacity credit.

De-listing of capacity resources: Removal of capacity and energy from the market.

Day-ahead Market: Part of a multi-settlement market system that provides financial certainty for supply offers and demand bids for energy, at a minimum, and often ancillary services.

ECP: Energy Clearing Price.

FERC: Federal Energy Regulatory Commission, responsible pursuant to the Federal Power Act for ensuring that wholesale electricity tariffs are "just and reasonable."

FTR (FCR): Fixed-Transmission Right (Firm Congestion Right); a financial contract that entitles the holder to a stream of revenues (or charges) based on the reservation level and hourly energy price differences across a specific transmission path

HHI: Herfindahl-Hirschman Index; used to evaluate the level of resource ownership concentration of an industry or sector.

ICAP: Installed Capacity.

IIA: Interim ISO Agreement; the "contract" between NEPOOL and ISO-NE, approved by FERC, that specifies the ISO's duties and responsibilities.

IMM: Independent Market Monitor

ISO: Independent System Operator

LBMP or LMP: Location-Based Marginal Pricing or Locational Marginal Price.

Load Pocket: An area served by out-of-merit local generators when the existing transmission system cannot import sufficient power to meet local demand.

Load Response Program: Program structured to increase the responsiveness of demand to conditions in supply (especially decreasing demand during peak times when supply may fall short of demand).

Loss of load: Other term for rolling blackout or rotating feeders.

MAAC: Mid-Atlantic Area Council; establishes rules and reliability guidelines for the PJM bulk power system.

MAR: MMU Activities Report

MMIP: Market Monitoring Implementation Plan

MMP: Market Monitoring Program:

MMU: Market Monitoring Unit

MPC: Market Performance Committee.

MSC: Market Surveillance Committee.

MST: Market Services Tariff.

MSU: Market Surveillance Unit.

NE: New England.

NEPOOL: New England Power Pool.

NERTO: Northeast RTO.

NCPC: Net Commitment Period Cost; used to determine a value for compensation for out-of-merit generation pursuant to Market Rule 17 (ISO-NE).

NPCC: Northeast Power Coordinating Council; establishes rules and reliability guidelines for the bulk power systems in NY, NE, Ontario, Quebec, and the Maritimes.

OA: Operating Agreement

OATT: Open-Access Transmission Tariff

Out-of-Merit Generation: Generation that is dispatched for system reliability reasons that would not otherwise be dispatched economically.

PJM: Pennsylvania, New Jersey, Delaware, Maryland and District of Columbia bulk power system.

PX: Power Exchange (California)

RAA: PJM Reliability Assurance Agreement

Real-Time Market: An electricity market recognizing actual generation dispatch (e.g., as opposed to the day-ahead market).

RTO: Regional Transmission Organization

Soft Cap: A cap on an energy supply bid which can be exceeded with appropriate cost justification. Bids exceeding the soft cap do not set the market clearing price, however bidders will be paid the bid amount.

WSCC: Western Systems Coordinating Council; establishes rules and reliability guidelines for the entire bulk power system west of the Rocky Mountains, including portions of Canada and Mexico.

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BEFORE THE ARIZONA CORPORATION COMMISSION

JUN 2002
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WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC POWER COMPETITION RULES COMPLIANCE DATES	Docket No. E-01933A-98-0471
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	Docket No. E01933A-02-0069

Rebuttal Testimony Of William Monsen

On behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.

TRACK A ISSUES

June 11, 2002

EXHIBIT
AES-1
Admitted

AES NewEnergy, Inc. and Strategic Energy L.L.C., by and through their attorneys, hereby file the Rebuttal Testimony of William Monsen of MRW & Associates.

Respectfully submitted this 11th day of June 2002.

LAW OFFICES OF DANIEL W. DOUGLASS

By Daniel W. Douglass /m

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Attorneys for AES NewEnergy, Inc. and Strategic Energy L.L.C.

ORIGINAL and **18 COPIES** filed June 11, 2002, with:

ARIZONA CORPORATION COMMISSION
400 West Congress
Tucson, AZ 85701-1347

COPIES mailed and/or sent via electronic mail without a copy of the service list on June 11, 2002 to:

(See Attached Service List)

I. INTRODUCTION

The primary purpose of this rebuttal testimony is to respond on behalf of AES NewEnergy, Inc. ("AES NE") and Strategic Energy L.L.C. ("Strategic Energy") to the initial testimony filed by Tucson Electric Power Company ("TEP") with regard to certain "Track A" issues. In this testimony, I will focus on certain retail electric competition issues raised in TEP's testimony, specifically, TEP's proposal that all residential customers and commercial and industrial ("C&I") customers with loads under 3 MW be "excluded from retail competition."[1]

AES NE is America's leading retail electric provider, serving commercial and industrial customers in California, Texas, Illinois, Ohio, Pennsylvania, Maryland, Delaware, New Jersey, New York, Massachusetts, Rhode Island, New Hampshire and Maine. On April 21, 1999, the Arizona Corporation Commission ("Commission") granted NEV Southwest, L.L.C.'s[2] application for a Certificate of Convenience and Necessity ("CCN") to supply competitive services as an electric service provider. AES NE is a wholly-owned subsidiary of the AES Corporation (NYSE: AES), a leading global power company comprised of competitive generation, distribution and retail businesses around the world.

Strategic Energy is currently providing competitive retail energy services throughout North America and is a potential energy service provider in Arizona and. Founded in 1986, Strategic Energy serves over 19,000 customers across the nation and is dedicated to serving end-users' energy needs.

The Commission should reject TEP's proposal to deny customer choice to all of Arizona's residential customers and to C&I customers with load requirements less than 3 MW. If the Commission were to approve such an anti-competitive proposal, the end result for retail competition in Arizona would be the same as if the Commission acted to repeal the Retail Electric Competition Rules adopted in September 1999 -- it would be the death knell to retail competition in Arizona. AES NE and Strategic Energy are gravely concerned that TEP's proposal is a poorly disguised attempt to derail retail competition before it has been given a fair opportunity to get off the ground. The Commission must do everything in

[1] Initial Testimony of James S. Pignatelli, p. 14.

[2] The initial filing was made under New Energy Ventures Southwest, L.L.C. with subsequent company name changes to NEV Southwest, L.L.C. and then NewEnergy Southwest, L.L.C. The company is in the process of having the CCN updated once more to reflect the current company name, AES NewEnergy, Inc.

its power to ensure the establishment of a healthy retail market to allow all Arizona consumers to realize the benefits of electricity industry restructuring and to protect themselves against incumbent retail market power. Providing all customers with the freedom to choose their own electricity service provider is the very first step that must be taken down the road towards creating a healthy retail market.

II. TEP's Anti-Competitive Proposal

TEP appears to believe customers with less than 3 MW demand do not need to be provided with "choice" since these customers do not possess the knowledge and sophistication to make their own energy decisions. This is evidenced by the following statement by TEP witness DeConcini:

> "I believe that customers below the 3 MW threshold would be better off continuing to receive service from their incumbent utility under the existing tariffs or contracts. For example, if TEP's current customers under 3 MW remain on its system, this would insure that Residential and Small Commercial customers can receive the benefit of TEP's long term, low cost energy supply through 2008."[3]

TEP's assertion that residential and commercial customers would be better off with utility service rather than with an opportunity to choose a competitive provider sounds like a paternalistic presumption that these customers are not sophisticated or knowledgeable enough to make their own decisions regarding an energy service provider. AES NE and Strategic Energy are concerned that TEP's proposal represents an attempt to steer the Commission and consumers back towards the utility-monopoly days when customers were given no choice of electric provider.

As shown in the following table, there is ample evidence from other markets already open to competition that, presented with choice, residential customers and C&I customers of **all sizes** will exercise their choice to switch to a competitive retail provider:

[3] Initial Testimony of Michael J. DeConcini, p. 11.

Direct Access Load and Customers as of April 30, 2002

State	Residential Load	Residential % of Load	Residential Customers	Residential % of Customers	C&I Load	C&I Percent of Load	C&I Customers	C&I Percent of Customers
OH[4]	411,908 MWh	14%	621,716	18%	882,365 MWh	14%	25,960	5%
TX[5]	755 MW	4%	150,929	3%	8,942MW	20%	51,715	5%
PA[6]	1,154 MW	10%	512,380	8%	1,290 MW	7%	22,001	4%
CA[7]	440,201 MWh	.8%	53,692	.6%	22,034,078 MWh	13%	29,430	7%

As one can plainly see from the customer switching data presented in the table above, both residential and C&I customers are finding value when given a choice, i.e., voting with their feet is the best signal of consumers' assessment of value. While definitions of commercial and industrial customers vary from state to state, a substantial proportion, if not the majority, of both customers and load in this category fall below the 3 MW threshold proposed by TEP. Furthermore, evidence that consumers are finding value in retail electricity competition is not limited to the United States alone. According to the United Kingdom's Electricity Association, in England and Wales between 90-95% of customers and load have switched to a competitive provider.

TEP's anti-competitive proposal, if adopted by the Commission, would deny all but a handful of TEP's largest customers (>3 MW) the opportunity to choose a competitive provider. This means that all of TEP's 318,976 residential customers[8] and nearly all of its 31,962 non-residential customers[9] with less than 3 MW demand, such as grocery stores, schools and government buildings, office buildings, and retail businesses such as fast food restaurants, gas stations, drug stores, bank branches, cafes, mini-marts, and dry cleaners, to

[4] Source: Public Utilities Commission of Ohio
[5] Source: Electric Reliability Council of Texas
[6] Source: Pennsylvania Office of Consumer Advocate
[7] Source: California Public Utilities Commission (CPUC). The CPUC suspended direct access as of September 20, 2001. At the peak of direct access in May 2000, residential and C&I load were 2.2% and 17.7% respectively.
[8] UniSource Energy Corporation, Annual Report 2001, p.47.
[9] Ibid, p. 47.

list a few, will be denied the ability to assess the benefits of competition and choose for themselves. TEP is essentially attempting to eliminate choice for nearly 100% of the residential customers in its service territory and the vast majority of its non-residential customers

III. Less Draconian Breakpoint for Restricting Customer Choice

AES NE and Strategic Energy support the continued extension of choice to all Arizona electric customers. However, in the event the Commission is inclined to restrict customer choice based on demand, AES NE and Strategic Energy recommend the Commission reject TEP's 3 MW threshold. As noted above, the breakpoint recommended by TEP would effectively eliminate choice for the vast majority of customers in Arizona.

A less restrictive approach would set a breakpoint that offers choice to a broader spectrum of commercial and industrial users, providing the customer base for an active retail market and allowing businesses and industries to manage their energy costs. AES NE and Strategic Energy suggest that a more inclusive alternative would be to set the breakpoint at 20 kW, consistent with the 20 kW threshold embodied in the Transmission and Ancillary Service charges under the current Direct Access Rate General Service Schedule No. 10. Such a breakpoint would provide choice to customers currently receiving service under Large Light and Power Rate No. 14, Large General Service Rate No. 13, and those customers under General Service Rate No. 10 who meet the 20 kW threshold already in place under that rate.

In addition, customers should be permitted to aggregate multiple accounts to meet the minimum threshold. In fact, any threshold that the Commission might establish should be accompanied by a provision allowing aggregation of accounts to meet the minimum threshold. This would allow customers with multiple accounts or who share billing procurement functions to participate in the direct access option if desired. For example, operators of multiple retail establishments such as chain restaurants or service stations could aggregate their accounts to meet the 20 kW threshold.

This concludes my testimony.

QUALIFICATIONS OF WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, Inc.
(1989 - Present)
Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist
Pacific Gas & Electric Company
(1981 - 1989)
Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff
University of Wisconsin-Madison Solar Energy Laboratory
(1980 - 1981)
Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.
B.S., Engineering Physics, University of California, Berkeley, 1977.

WILLIAM A. MONSEN
PREPARED TESTIMONY

1. CPUC Applications 90-08-066, 90-08-067, 90-09-001
   Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN) (November 29, 1990)

2. CPUC 90-10-003
   Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. (December 21, 1990)

3. CEC Docket No. 93-ER-94
   Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association (December 10, 1993)

4. CPUC Rulemaking 94-04-031 and Investigation 94-04-032
   Prepared Testimony regarding Transition Costs for The Independent Energy Producers (December 5, 1994)

5. D.T.E. 97-120
   Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources (October 23, 1998)

6. CPUC Application 97-12-039
   Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council (June 15, 1999)

7. CPUC Application 99-09-053
   Prepared Direct Testimony regarding PG&E's Proposed Divestiture of its Hydroelectric Facilities on Behalf of the Independent Energy Producers Association (March 2, 2000)

8. CPUC Application 99-09-053
   Prepared Rebuttal Testimony regarding PG&E's Proposed Divestiture of its Hydroelectric Facilities on Behalf of the Independent Energy Producers Association (March 16, 2000)

9. CPUC Application 99-10-025
   Joint Testimony Regarding Auxiliary Load Power and Stand-by Metering Policy on Behalf of Duke Energy North America (July 3, 2000)

10. CPUC Application 99-03-014
    Joint Testimony Regarding Auxiliary Load Power and Stand-by Metering Policy on Behalf of Duke Energy North America (September 29, 2000)

11. CPUC Rulemaking 99-11-022
    Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs (May 7, 2001)

12. CPUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs (May 30, 2001)

13. CPUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area (December 20, 2001)

14. CPUC Application 00-10-045; 01-01-044
Direct Testimony of William A. Monsen on Behalf of The City of San Diego
(May 29, 2002)

15. CPUC Rulemaking 01-10-024
Prepared Direct Testimony of William A. Monsen on Behalf of Independent Energy Producers and Western Power Trading Forum.
(May 31, 2002)

16. CPUC Rulemaking 01-10-024
Rebuttal Testimony of William A. Monsen on Behalf of Independent Energy Producers and Western Power Trading Forum
(June 6, 2002)

JONES, SKELTON & HOCHULI, P.L.C.
ATTORNEYS AT LAW
2901 NORTH CENTRAL AVENUE
SUITE 800
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TELEPHONE (602) 263-1700

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAMS A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	Docket No. E-01933A-98-0471 **NOTICE OF CORRECTIONS TO REBUTTAL TESTIMONY OF WILLIAM MONSEN**

AES New Energy, Inc. and Strategic Energy, L.L.C. submit the following corrections to the pre-filed rebuttal testimony of William Monsen. In the table that appears on Page 3 between lines 4 and 5:

1. The number in row 2, column 3 should be changed from 14% to 12%.

EXHIBIT
AES-2
Admitted

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2. The number in row 2, column 5 should be changed from 18% to 15%.

3. The number in row 2, column 7 should be changed from 14% to 12%.

4. The number in row 3, column 7 should be changed from 20% to 36%.

5. The number in row 4, column 3 should be changed from 10% to 11%.

6. The number in row 4, column 5 should be changed from 8% to 11%.

7. The number in row 4, column 7 should be changed from 7% to 9%.

8. The number in row 5, column 6 should be changed from 22,034,078 to 21,901,709.

9. The number in row 5, column 7 should be changed from 13% to 21%.

10. The number in row 5, column 8 should be changed from 29,430 to 29,011.

11. The number in row 5, column 9 should be changed from 7% to 2%.

In addition,, in the second line of footnote 7 that appears on Page 3, the number should be changed from 17.7% to 23.8%.

Attachment "A" hereto is a corrected version of the table on Page 3 of the direct testimony.

RESPECTFULLY SUBMITTED this 20th day of June, 2002.

JONES, SKELTON & HOCHULI, P.L.C.

By _____

Randall H. Warner
2901 North Central Avenue, Suite 800
Phoenix, Arizona 85012

and

Daniel W. Douglass
Law Offices of Daniel W. Douglass
5959 Topanga Canyon Blvd., Suite 244
Woodland Hills, CA 91367-7313

Attorneys for AES New Energy, Inc. and Strategic Energy, L.L.C.

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ORIGINAL and 18 COPIES filed this 20th day of June, 2002, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

COPY of the foregoing delivered this 20th day of June, 2002, to:

Lyn Farmer
Chief Administrative Law Judge
Arizona Corporation Commission
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Christopher Kempley
Chief Counsel
Arizona Corporation Commission
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Phoenix, AZ 85007

Ernest G. Johnson
Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

COPY of the foregoing mailed this 20th day of June, 2002, to:

All parties in ACC Docket No. E-0000A-02-0051

M. Lowe

Exhibit A

Direct Access Load and Customers as of April 30, 2002

State	Residential Load	Residential % of Load	Residential Customers	Residential % of Customers	C&I Load	C&I Percent of Load	C&I Customers	C&I Percent of Customers
OH[4]	411,908 MWh	12%	621,716	15%	882,365 MWh	12%	25,960	5%
TX[5]	755 MW	4%	150,929	3%	8,942MW	36%	51,715	5%
PA[6]	1,154 MW	11%	512,380	11%	1,290 MW	9%	22,001	4%
CA[7]	440,201 MWh	.8%	53,692	.6%	21,901,709 MWh	21%	29,011	2%

[4] Source: Public Utilities Commission of Ohio
[5] Source: Electric Reliability Council of Texas
[6] Source: Pennsylvania Office of Consumer Advocate
[7] Source: California Public Utilities Commission (CPUC). The CPUC suspended direct access as of September 20, 2001. At the peak of direct access in May 2000, residential and C&I load were 2.2% and 23.8% respectively.

AECC

1 – 3

APS energy SERVICES

EXHIBIT
ACC-1
admitted

Vicki G. Sandler
President

VIA US MAIL and FACSIMILE: (520) 770-2003

April 27, 2001

Ms. Judy Taylor
Direct Access Services Group Coordinator
Tucson Electric Power Company
P.O. Box 711
Mail Stop SC126
Tucson, Arizona 85702

Re: Response to TEP letter dated April 13, 2001

Dear Judy:

This letter is in response to the April 13 letter from Evelyn Dryer to APS Energy Services. Ms. Dryer states that, "it is unclear whether your letter is intended to constitute notice of a bill dispute under A.A.C. R14-2-212.B or to serve another purpose." Let me clarify our intent.

First, as stated in our letter dated April 5, the intent of that letter was to notify TEP that we disagree with the method TEP is using to calculate the Competitive Transition Charge (CTC) on customer bills, but that we would be paying the TEP invoices to avoid any disruption of service to our mutual customers. The letter was not intended to constitute formal notice of a bill dispute under R14-2-212.B, which triggers certain time frames for having this dispute resolved by the Arizona Corporation Commission (ACC). Our intent is to reach agreement with TEP by May 15 before taking formal action.

We are sending you the enclosed invoice representing the amount overpaid by APSES due to TEP's underpayment of the Market Generation Credit on several customer accounts. Based on TEP's billings to date for all 19 accounts that were served by APSES through the time they were returned to standard offer service, we have calculated the amount of our overpayment to be $146,285.82. We expect payment of this invoice, with interest for the time our money was held by TEP, by May 15. In addition to this invoice, we will be negotiating payment of our other damages resulting from TEP's position restricting the viability of direct access as contemplated under TEP's amended settlement agreement.

With respect to your questioning whether APSES has the authority to protest the CTC calculation, we believe it is our obligation as the ESP consolidated billing entity for our customers to bring to the attention of TEP any discrepancy from the rate settlement in the way TEP is calculating the bills for our mutual customers. We are confident that we speak on behalf of all of our customers on this issue. Should TEP require any further written verification of this representation, please advise and it will be forthcoming.

Mail Station: 8103 P.O. Box 53901 Phoenix, Arizona 85072-390 Tel (602) 744-5045 FAX (602) 744-5133 E-mail: http://www.apses.com

Should this issue turn into a formal dispute, we agree that Section 22.2 of the ESP Acquisition Agreement addresses disputes regarding CTC payments, but Section 22.2 defers to TEP's "applicable tariffs" (Tariff RR), which states that "disputed charges shall be handled according to ACC procedures." We interpret that to mean that A.C.C. rule R14-2-212.B applies whether it is a consolidated bill dispute by an ESP or a customer dispute.

We will take up the substance of our dispute and discussion of other damages directly with Mr. Glaser or his designee.

Sincerely,

Vicki Sandler

Vicki Sandler
President

cc: Mr. Steve Glaser
Mr. Leland Snook

APS energy SERVICES

P.O. Box 53901, MS 8103
Phoenix, AZ 85072-3901

Payment Due Date	**5/15/01**
Invoice Number	TEP - 1
Date Printed	4/27/01
Account #TEP-UDC-1	

TUCSON ELECTRIC POWER COMPANY
MS. JUDY TAYLOR
P.O. BOX 711, Mail Stop SC126
TUCSON, AZ 85702

For question regarding your bill, please call 602-744-5000

Invoice

Event	Price	Total
Adjustment - underpayment of Market Generation Credit on APSES Direct Access Accounts 1/1/2001 - 4/27/2001	$146,285.82	$146,285.82
(Detail attached)		
Interest (1 month @ 18% annual rate)		$2,194.29
Account Total		**$148,480.11**

Total Due **$148,480.11**

Please return lower portion with your payment

Please include your account number on your check

APS energy SERVICES

Invoice Number	TEP - 1
Payment Due Date	5/15/01

Account Name: Tucson Electric Power Company

Make Check Payable to:

APS Energy Services
P.O. Box 53901, MS 8103
Phoenix, AZ 85072-3901

Total Amount Due: **$148,480.11**

Amount Enclosed: [ ]

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition ("AECC"). AECC is a coalition of Arizona electricity customers in favor of electric competition. AECC was an active participant in the public process that led to the development of the Commission's Electric Competition Rules and played a prominent role in negotiating comprehensive settlement agreements with Arizona Public Service Company ("APS") and Tucson Electric Power Company ("TEP") that resolved the issues of stranded cost, implementation of direct access service, and standard offer rate reductions.

Q. Were you personally involved in the negotiations that resulted in the APS and TEP settlement agreements?

A. Yes, I was closely involved in both series of negotiations on behalf of AECC.

EXHIBIT
AECC-2
admitted

1 **Q. Have you previously testified before this Commission?**

2 A. Yes. I have testified in a number of proceedings, including the generic
3 proceeding on retail electric competition (1998)[1] and the hearings on the APS and
4 TEP settlement agreements (1999).[2] I also filed testimony in the APS variance
5 portion of this consolidated docket.

6 **Q. Please describe your qualifications.**

7 A. My academic background is in economics, and I have completed all
8 course work and examinations toward the Ph.D. in Economics at the University of
9 Utah, and have served on the adjunct faculties of both the University of Utah and
10 Westminster College, teaching both undergraduate and graduate courses in
11 economics. I joined Energy Strategies in 1995, where I assist private and public
12 sector clients in the areas of energy-related economic and policy analysis,
13 including evaluation of electric and gas utility rate matters. In addition to my prior
14 testimony before the Arizona Corporation Commission, I have testified numerous
15 times on the subjects of electric utility cost-of-service, rate design, and industry
16 restructuring before state utility regulators in Utah, Nevada, Oregon, Washington,
17 Colorado, Wyoming, Georgia, and New York.

18 Prior to joining Energy Strategies, I held policy positions in state and local
19 government. From 1983 to 1990, I was economist, then assistant director, for the
20 Utah Energy Office, where I testified regularly before the Utah Public Service
21 Commission on utility policy matters. From 1991 to 1994, I was chief of staff to
22 the chairman of the Salt Lake County Commission, one of the larger municipal

[1] Docket No. RE-00000C-94-0165.

governments in the western U.S., where I was responsible for development and implementation of a broad spectrum of public policy.

A more detailed description of my qualifications is contained in Exhibit KCH-1, attached to this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. Through my testimony, AECC reaffirms its support for the Settlement Agreements it has entered into with both APS and TEP. My testimony then addresses the "Track A" issue of market power in the context of those settlement agreements.

<u>AECC support for settlement agreements</u>

Q. What is AECC's position regarding the APS and TEP settlement agreements?

A. AECC continues to strongly support these agreements. The APS and TEP settlement agreements are compromises developed within the framework of the Commission's Electric Competition Rules. AECC has always viewed the benefits of these agreements from a long-term perspective: the establishment of direct access rights for all customers while permanently resolving the difficult issue of stranded cost within a framework of retail price stability. Overall, these agreements have been successful and remain the proper framework for proceeding forward. While the lack of development of direct access service has obviously been disappointing, the causes of this are largely external to the agreements, not the least of which was the extreme wholesale price surges of 2000-01. It is a

[2] Docket Nos. RE-00000C-94-0165, E-01345A-98-0473, E-01933A-97-0773, E-01345A-98-0471, and E-01933A-97-0772.

credit to the agreements that, during that period of very high wholesale prices, Arizona retail customers, almost alone in the western U.S., were afforded stable, even declining, rates. The APS agreement will continue to provide rate stability through mid-2004, and the TEP agreement will provide it through the end of 2008.

AECC also recognizes that the major issue at hand is not how well the agreements have worked in the past, but how well the agreements and the Electric Competition Rules will work in the future. In my opinion, the answer to that question turns on the issue of how potential market power is addressed in the context of the settlement agreements and the Rules. My testimony will show that market power issues *can* be properly addressed in those contexts. Accordingly, market power issues will be the primary focus of my remaining testimony.

Market power issues

Q. What conclusions do you draw concerning market power issues in Arizona?

A. On a going-forward basis, one of the chief concerns that has arisen in Arizona – appropriately I believe – is whether the state's restructuring program is capable of ensuring that retail customers will not be victims of market power abuse after the expiration of the standard offer price caps. AECC has always been mindful of the potential for market power in the transition to a competitive market, and believes that the Commission, staff, and stakeholders should be vigilant in ensuring that any market power problems be anticipated and addressed. In the context of the settlement agreements, the potential for market power is addressed in two ways: (1) Market power in load pockets is addressed initially by

adhering to the "must-run generation" protocol of the Arizona Independent Scheduling Administrator (AISA), and ultimately, by developing and adhering to an appropriate load pocket treatment overseen by the Regional Transmission Organization (RTO) that covers Arizona, and (2) To the extent that market power were to become a more generalized problem in Arizona, parties could seek relief at FERC, which has jurisdiction over wholesale sales from APS and TEP generation, as well as over the APS and TEP transmission systems. While FERC's past record in addressing market power issues has been controversial and the target of significant criticism, market power is now clearly a "front-burner" issue at FERC, and is receiving, and will most surely continue to receive, a great deal more scrutiny. In this light, I recommend that in conjunction with the divestiture of generation pursuant to the Electric Competition Rules and the settlement agreements, the Commission should seek new, more rigorous market power tests to be performed with respect to the APS territory and TEP territory sub-markets. The Commission should advocate to FERC that any market-based rate authorization for affected utilities' generation affiliates should be limited to time periods in which the affected utilities and their affiliates pass this updated market power test.

Finally, I conclude that any RTO that serves Arizona must adopt market monitoring procedures that would ensure that potential market power into Arizona sub-markets is monitored and mitigated. I also recommend that the Commission actively participate in the development of these procedures.

1 **Market power in load pockets**

2 **Q. By way of background, what is "market power"?**

3 A. Market power refers to the ability of a market participant to exercise
4 influence over price. In a perfectly competitive market, price is set by the
5 interaction of supply and demand of numerous market participants, none of which
6 can influence price through their individual actions. When an individual
7 participant can, through its actions, influence the price of a product in the
8 marketplace, some degree of market power exists. From a public policy
9 standpoint, the concern over market power involves a supplier's ability to increase
10 prices over competitive levels that is profitable or sustainable.

11 Market power can be categorized as "vertical," in which a market
12 participant exercises control over price by virtue of its dominance in one or more
13 stages in the production process, or "horizontal," in which a market participant
14 exercises control over price through its dominance in the final market for the
15 product.

16 Both types of market power are relevant to the electric power industry.
17 Vertical market power can exist when a company controlling the monopoly wires
18 business uses that control to disadvantage generators who compete with it (or its
19 affiliate) in the generation business. Horizontal market power can exist when a
20 single company controls sufficient market share in the generation market to allow
21 it to set or significantly influence the market price in a given time period.

22 **Q. Also by way of background, what is a "load pocket"?**

A. A load pocket is a geographic region whose full power needs cannot be met by imports from the larger power grid during certain time periods, and which instead must rely on generation resources that are located nearby. It is this reliance on local generation which gives rise to the "load pocket market power problem," since in many cases the local generation upon which the customers in the load pocket rely will possess significant market power (during the period of such reliance).

Q. Are there generally-recognized load pockets in Arizona?

A. Yes. It is generally recognized that Phoenix, Tucson, and Yuma are load pockets, at least during certain hours of the year.

Q. How do the settlement agreements address market power in load pockets?

A. For the period prior to an RTO being put in place, both the APS and TEP settlement agreements commit the respective utilities to adhere to the FERC-approved protocols of the AISA.[3] Among these protocols is the "Must-Run Generation" Protocol, which addresses market power in load pockets.[4] The TEP settlement agreement also includes a provision that specifically requires the billing of variable must-run generation costs to be consistent with the AISA protocols.[5] Utility compliance with the AISA Must-Run Generation Protocol is consistent with the Electric Competition Rules, which directs the AISA to implement and oversee must-run generation protocols.[6]

Q. Has the AISA Must-Run Generation Protocol been approved by FERC?

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[3] APS Settlement Agreement, par. 7.6; TEP Settlement Agreement, par. 9.1.
[4] AISA Protocols Manual, Section VIII, which is included in this testimony as Exhibit KCH-2.
[5] TEP Settlement Agreement, par. 4.2.
[6] R14-1609(D)(2).

A. Yes. It was approved as part of the AISA tariff effective November 2000.[7]

Q. What is the general approach to addressing load pocket market power in the AISA Must-Run Generation Protocol?

A. The AISA Must-Run Generation Protocol is designed to mitigate market power during load pocket situations while allowing market participants the flexibility to make resource decisions. During load pocket conditions, generation owners inside the load pocket are required to offer to sell to scheduling coordinators, on a cost-of-service basis, sufficient generation beyond the amount of the transmission import constraint to serve load within the load pocket. This means, for example, that even after a divestiture, the Pinnacle West generation company ("genco") is required to offer power at cost-based rates to the APS standard offer provider to serve load in the Phoenix load pocket during load pocket conditions. The Pinnacle West genco would face an identical obligation to offer power at cost-based rates to competitive scheduling coordinators.

These policies are currently in place in Arizona and have been approved by FERC with ACC support.

Q. How is market power within load pockets to be mitigated after the AISA is replaced by an RTO?

A. Mitigation of market power within load pocket should be addressed by the RTO tariff in a manner that protects retail customers while providing transmission owners and generators the necessary long-term incentives to alleviate the load pocket problem. This issue was the subject of considerable discussion in the

[7] 93 FERC ¶ 61,231.

Desert STAR process, which led to the development of a protocol that is similar to that in place at the AISA. The RTO protocol differs in that it allows the local generation owner to sell at market prices (established outside the load pocket) during load pocket conditions. It also attempts to establish a framework for creating proper incentives for generation to be constructed inside the load pocket. The Desert STAR-developed protocol was later incorporated into the WestConnect RTO filing at FERC, although it has not yet been approved, and may be subject to modification.[8]

Q. Do you believe the approaches to mitigating load pocket market power contained in the AISA Must-Run Generation Protocol and the WestConnect filing are reasonable and in the public interest?

A. Yes. I believe both variations are well thought-out, balanced approaches to a difficult problem that were developed with the input of many stakeholder groups. I think it is important for the Commission and staff to recognize that due to the work that has gone into developing these must-run generation protocols, Arizona has in place a good foundation for addressing market power in load pockets.

<u>Generalized market power</u>

Q. Please describe the issue of more "generalized" market power.

A. The problem of more generalized market power occurs if a market participant uses (or is able to use) control of the transmission system to thwart

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[8] FERC Docket Nos. RT02-1-000 and EL02-9-000, "Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico, Tucson Electric Power Company, WestConnect RTO,

1 competition in the wholesale generation and/or retail electric markets, or controls
2 sufficient generation that it can act as a price setter in the wholesale generation
3 (and ultimately the retail electric) market.

4 Vertical market power (i.e., transmission system control hindering
5 competition in generation and/or retail markets) has been the focus of an intense
6 national debate over the past number of years, which has centered around the
7 implementation of FERC Orders 888, 889, and 2000. Indeed, one of the major
8 reasons for the extensive effort being put into development of RTOs in the United
9 States is the express purpose of mitigating vertical market power. AECC has
10 participated in this debate and implementation through its involvement is both the
11 AISA and Desert STAR stakeholder process, as well as its intervention at FERC
12 in the WestConnect docket. I will not recount this extensive effort here; however,
13 I am very confident in testifying that the issue of vertical market power is getting
14 an extensive vetting at FERC.

15 **Q. What about the issue of a more generalized horizontal market power?**

16 A. In my view, in comparison to load pocket market power and vertical
17 market power, this market power issue has had the least attention in Arizona
18 heretofore. This is not surprising, as Arizona's vertical market power debate has
19 been an extension of a larger national discussion, and the load pocket issue was a
20 more obvious and immediate matter of attention in the context of developing
21 retail access procedures.

LLC," Order No. 2000 Compliance Filing and Declaratory Order Petition ("WestConnect Filing"), Appendix D.

However, with generation divestiture on the horizon and a recent history of market power problems in the western U.S., the potential for a generalized horizontal market problem is now receiving needed attention.

Q. How would a more generalized market power problem be dealt with in the context of the settlement agreements?

A. Under the settlement agreements, the forum for addressing such a problem is FERC. In the APS Settlement Agreement, this is explicitly recognized in the final paragraph of the section addressing corporate structure, which states that: "The Parties reserve their rights under Sections 205 and 206 of the Federal Power Act with respect to the rates of any APS affiliate formed under the provisions of this Article IV."[9] This provision was included in the agreement to make clear that in agreeing to a corporate restructuring (as required by the Competition Rules), AECC was not waiving its rights to appeal to FERC for relief from potential market power problems.

Q. How confident are you that this right of appeal to FERC is adequate to protect Arizona ratepayers from market power abuse?

A. I am reasonably confident that, in today's environment, with the benefit of lessons learned from recent experiences in the west, horizontal market power problems will receive appropriate attention at FERC. Indeed this is already occurring. In particular I note that FERC has moved toward more rigorous tests of market power potential, namely the Supply Margin Assessment (SMA) test, which indicates the presence of market power if a single seller controls an amount

[9] APS Settlement Agreement, paragraph 4.6.

of generation that exceeds the market's supply margin (generation in excess of load) during peak demand.[10]

Q. Do you believe the SMA method should be applied to APS and its affiliates?

A. I believe a similar, but more comprehensive, test developed by the California ISO Department of Market Analysis should be used. This test is called the Residual Supply Index (RSI) screen, which calculates, for each hour of the year, the ratio of the residual supply (total supply minus the capacity of the supplier in question) to the system demand (load plus reserve). When the RSI is significantly above 100 percent, there is sufficient supply in the market to support competitive prices even if the supplier in question withholds all of its capacity.[11] However, if the RSI is below 100 percent or (not significantly above 100 percent), then potential market power is indicated for the supplier in question, and mitigation measures are in order.

I note that APS and its affiliates already have market-based rate authorization from FERC on the basis of market power tests performed using an alternative methodology applied to the western U.S. marketplace. I believe that upon divestiture of generation pursuant to the Electric Competition Rules and the settlement agreements, the market power test should be re-performed using the RSI test applied to the APS territory sub-market. Arizona interests, including the Commission, should advocate to FERC that continuation of market-based rate authorization should be limited to time periods in which the Pinnacle West

[10] 97 FERC ¶ 61,219.

[11] "Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, Docket No. EL01-18-000, and Electricity Market Design and Structure, Docket No. RM01-12-000," FERC. "California

1 companies pass this updated market power test. The same test should also be
2 applied to TEP with respect to the TEP territory sub-market.

3 **Q. Why should the market power test be performed with respect to the APS-**
4 **territory sub-market?**

5 A. Because that is the relevant market for assessing whether horizontal
6 market power is likely to be present after divestiture. I grant that Pinnacle West is
7 a small fish in the big pond of the western grid, but the presence of transmission
8 constraints and other operational concerns make it necessary to target this market
9 power test to the APS territory sub-market. Indeed, it was APS itself, in
10 articulating its defense of its proposed PPA in the variance portion of this docket,
11 which most stridently raised the specter of potential market power in the APS
12 territory sub-market.

13 **Q. How has APS raised the specter of potential market power in the APS**
14 **territory sub-market?**

15 A. In the variance portion of this docket, APS made the argument that
16 requiring it to procure from competitive bid 50 percent of the resources needed
17 for standard offer service would likely result in unnecessarily high prices to
18 standard offer customers. In making its case against a mandatory 50 percent bid
19 requirement, APS asserted that new competitive generation was being constructed
20 in locations that were not fully conducive to delivery to APS's load, and that
21 higher prices and diminished reliability would result from bidding out generation
22 at the required levels.

Independent System Operator Corporation Department of Market Analysis Comments Regarding [FERC]'s Proposed Market-Based Rate Standard and Mitigation Mechanism," April 24, 2002.

1 **Q. What has this assertion got to do with the potential for market power in the**
2 **APS territory sub-market?**
3 A. *Implicit* in APS' variance argument is the proposition that absent a PPA,
4 an "unshackled" Pinnacle West would possess market power sufficient to drive
5 generation prices well above costs in the APS territory sub-market. Although the
6 PPA remedy proposed by APS has met with substantial opposition, the implicit
7 market power proposition supporting that proposal should be taken seriously. My
8 recommendation that continued market-based rate authorization for the Pinnacle
9 West companies should be contingent upon the passing the RSI market power test
10 applied to the APS territory sub-market speaks to this issue.
11 **Q. What remedies to horizontal market power are available?**
12 A. Generally, the remedies for horizontal market power are price regulation
13 combined with a "must-offer" requirement or divestiture of generation to other
14 sellers.
15 **Q. In the event that Pinnacle West was found to have market power in the APS**
16 **sub-market during certain hours of the year, what mitigation measure would**
17 **you recommend?**
18 A. If the market power was load pocket related, then the existing AISA must-
19 run generation protocol should be used. If the market power was more generally
20 applicable to the APS territory, then some type of capped pricing – either tied to
21 cost-of-service or an external market index – combined with a "must-offer"
22 obligation should be required for the hours in which market power was indicated.
23 An approach similar to the AISA must-run protocol or the local generation

resource ancillary service filed by WestConnect at FERC could be modified to accomplish this.

Q. Would this approach unfairly subject Pinnacle West Companies to "lower-of-cost-or- market" pricing?

A. No. First of all, market power mitigation measures should only be employed for hours in which they are needed. Secondly, market power mitigation measures can be designed to compensate sellers using market prices established in nearby markets that are not subject to market power problems.

Q. Are there any other actions that should be taken to guard against potential market power problems?

A. Because power markets are dynamic, it is important that potential market power be subject to continuous scrutiny by an entity with region-specific expertise. FERC has recognized this need by requiring that RTOs perform a market monitoring function. In the case of Arizona, I believe this market monitoring function should include oversight of the potential market power situations in the APS territory and TEP territory sub-markets after divestiture of the affected utilities' generation pursuant to the Electric Competition Rules.

The WestConnect filing includes an appendix devoted to market monitoring, which calls for the creation of a Market Monitoring and Tariff Compliance Unit, but much of the detail of how this unit is to work has yet to be developed.[12] I recommend that the Commission become closely involved in the development of the market monitoring procedures of WestConnect (or alternative

[12] WestConnect Filing, Appendix H.

RTO with responsibility for Arizona) to ensure that potential market power into Arizona sub-markets is monitored and mitigated.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," Public Utilities Commission of Colorado, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," Arizona Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002.

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," Georgia Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of Nevada, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," Washington Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," Georgia Public Service Commission, Docket No. 1400-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," Utah Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Revised Tariff Schedules for Electric Service in Oregon, Advice 00-14," Public Utility Commission of Oregon, Docket No. UE-115.

Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," Arizona Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," Utah Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of Ohio, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of Ohio, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of Ohio, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," Salt River Project Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," Arizona Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," Utah Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," Arizona Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," Arizona Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Arizona Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," Arizona Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," Salt River Project Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," Salt River Project Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company

Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," New York Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," Utah Public Service Commission, Docket No. 96-2018-01. Direct testimony submitted July 8, 1996.

"Questar Pipeline Company," Federal Energy Regulatory Commission, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," Arizona Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," Wyoming Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," Utah Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," Utah Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," Utah Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," Utah Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," Utah Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," Utah Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," Federal Energy Regulatory Commission, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," Utah Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," Utah Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," Utah Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," Utah Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs); cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Consultant to business customers, "In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Preparation of comments and participation in staff workshops. Rule on retail electric competition adopted December 23, 1996.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

Exhibit KCH-2

AISA Must-Run Generation Protocol

VIII. Must-Run Generation Protocol

1. Purpose:

The purpose of this Protocol is to provide a framework and process governing the access to energy from Must-Run Generation to support retail transactions in a competitive market. During certain hours, load within a Load Zone may exceed the Import Limit on the Interconnected Transmission System. For such hours, each SC's ARNT will be insufficient to serve 100 percent of the SC's share of Retail Network Load in the Load Zone through imports alone. Such conditions will require that Local Generation be made available to SCs. For each SC, the difference between its share of Retail Network Load in the Load Zone and its ARNT will be specified in advance, and will be the SC's Local Generation Requirement. Third Party Suppliers that have facilities with Must-Offer Generation obligations that commit to run and commit to schedule exports from the Load Zone by the 15th day of the month ahead will decrease the Local Generation Requirement on a MW for MW basis. The specification of the SC's share of the Local Generation Requirement will occur concurrently with the steps taken in the administration of the ARNT Protocol.

Implementation of the Must-Run Generation Protocol is to occur in two phases. In Phase I, which commences with the effective date of this Protocols Manual, the Temporary Must-Run Generation Procedures set forth in Section 6 will be implemented. In Phase II, which commences when competitive direct retail access load in Arizona reaches 300MW and the Board has approved a business plan covering all aspects of Az ISA activities (including all Phase II activities), the Must-Run Generation Procedures set forth in Sections 1-5 of this Protocol will be implemented.

2. Parties

The Must-Run Generation Protocol applies to the following entities:

2.1 CAOs

2.2 SCs

2.3 TPs

2.4 Third Party Suppliers

2.5 Az ISA

3. Local Generation Management Options for Must-Run Generation Requirements

Each SC shall manage its obligation to provide its share of the Local Generation Requirement by using one or more of the following means:

3.1 Scheduling Discretionary Local Generation;

3.2 Purchasing Must-Offer Generation;

3.3 Acquiring ARNT into the Import-Limited Zone from another SC;[3] or

3.4 Implementing dispatchable direct retail load-tripping within the Load Zone (which reduces Retail Network Load within the Load Zone, and thus reduces the SC's share of Local Generation Requirement).

4. Must-Run Generation Framework

4.1 The Must Run Generation Protocol is applicable to the following Import-Limited Load Zones:

- APS Phoenix
- Tucson
- Yuma

4.2 For each Import-Limited Load Zone, the TP will determine the total Local Generation Requirement for each hour, which will be equal to the forecasted Retail Network Load within the Import-Limited Load Zone minus the Import Limit. Local Generation providers that have facilities with Must-Offer Generation obligations that commit to run and commit to schedule exports from the Load Zone by the 15th day of the month ahead will decrease the total Local Generation Requirement on a MW for MW basis.[4]

4.3 Each SC scheduling into an Import-Limited Load Zone will be assigned a share of the total Local Generation Requirement for each hour. The Az ISA will calculate each SC's share of Local Generation Requirement for each hour of the

[3] The SC providing the additional ARNT may be causing its own share of the Local Generation Requirement to increase, all things being equal.

[4] Third Party Suppliers that have Local Generation facilities with *no* Must-Offer Generation obligations that commit to run and commit to schedule outside the Load Zone may make it possible for imports into the Load Zone to be increased; however, unless such Local Generation facilities are committed to meet Local Generation Requirements in the event that the export is reduced, any increase in transmission imports could only be made if such transmission were recallable.

month and each SC's ARNT for each transmission path for each day of the month. In Phase II, the Az ISA will communicate the results of this allocation to all SCs by the 15th day of the month prior to the Operating Month. This function will be performed by the TPs until the Az ISA has the capability but, in no event, later than such time as the ARNT trading mechanism is implemented.

4.4 Each SC's share of the total Local Generation Requirement will be equal to that SC's scheduled Retail Network Load within the Import-Limited Load Zone minus the SC's ARNT into that same zone.

4.5 Each SC must meet its share of the Local Generation Requirement by one or more of the means identified in Section 3 of this Protocol.

4.6 For each Import-Limited Load Zone, the provider of Must-Run Generation service (e.g., the TP) must provide the amount of Must-Offer Generation scheduled by SCs, up to the amount of the total Local Generation Requirement. Must Offer Energy is provided at regulated prices as described in Sections 4.8 and 4.9 of this Protocol.

4.7 Each SC will be given the opportunity to purchase Must-Offer Generation up to the amount of the SC's share of the Local Generation Requirement.

4.8 Recovery of Must-Run Generation Fixed Costs occurs as part of the TP's OATT. Must-Run Generation Fixed Costs are the Fixed Costs associated with specific Must-Run Generation units. Must-Run Generation Fixed Costs will be limited to the percentage of each Must-Run Generation unit's annual usage[5] that is attributable to providing Must-Run Generation service.

4.9 Recovery of Must-Run Generation Variable Costs occurs via SC purchases of Must-Offer Generation. These purchases will take place using a regulated pricing mechanism, as set forth in the TP's OATT, that reflects the actual Variable Cost of Must-Run Generation within each Load Zone, for each hour, as it is dispatched in the most economic sequence permitted by system conditions.

5. Must-Run Generation Scheduling Sequence

5.1 Month Ahead of Operating Month

Pursuant to Section 3.2.3 of the ARNT Protocol, the monthly auctions of ARNT and share of Local Generation Requirement for each SC shall be completed by the 17th day of the month ahead of the Operating Month. Local Generation providers that have facilities with Must-Offer Generation obligations that commit to run and commit to schedule exports from the Load Zone by the 15th day of the month ahead of the Operating Month will decrease the Local Generation Requirement on a MW for MW basis. When such situations occur, ARNT into

[5] In certain circumstances, a generation facility that is needed for Must-Run Generation purposes on a first-contingency basis may have a total annual usage of zero. When such a generation facility is used, the owner of the generation facility will not be precluded from recovering appropriate Must-Run Generation Fixed Costs.

the Load Zone is increased by the amount of the reduction in the total Local Generation Requirement and is included in the auction of ARNT to SCs.[6] Concurrently, the Must-Offer Generation obligation of the Local Generation provider is reduced MW for MW. Should a Local Generation provider's export of energy be reduced during a must run situation for any reason, the Must-Offer Generation obligation will be restored in the amount of the export reduction.

Generators within Load Zones may be scheduled to serve Load outside the Load Zone without committing by the 15th day of the month ahead of the Operating Month. However, while this generation may result in increased ATC into the Load Zone, the Must-Offer Generation obligation will not change.

5.2 18th Day of the Month Prior To Operating Month Through Two Days Ahead of Operating Day

As ARNT is traded among SCs, each SC's share of the Local Generation Requirement will change to reflect the SC's amended ARNT. These changes shall be reported by the SCs to the Az ISA, tracked by the Az ISA and communicated by the Az ISA to TPs, as set forth in Section 5.3.

5.3 Two Days Ahead of Operating Day

By 1600 hours two days ahead of Operating Day, the Az ISA will submit the final results of the trades and exchanges of ARNT and each SC's share of Local Generation Requirements to the TP. The TP shall update its OASIS accordingly.

5.4 Day Ahead of Operating Day

Each SC will submit its Balanced Schedule pursuant to Section 6.3 of the Scheduling Protocol, which must meet or exceed its share of the Local Generation Requirement and must specify its intended purchase of Must-Offer Generation. Must-Offer Generation made available to an SC is capped at the SC's share of the Local Generation Requirement. An SC may schedule Discretionary Local Generation and/or reduce its share of Retail Network Load within the Load Zone through dispatchable direct retail Load tripping.

5.5 18th Day of the Month Prior To Operating Month Through Scheduling Hour

5.5.1 Changes in System Configurations

If contingencies or changes in system configurations result in a reduction in an SC's ARNT into an Import Limited Load Zone, the SC's share of the Local Generation Requirement shall be recalculated using the formula specified in Section 4.4.

[6] ARNT can be made available up to the lesser of: (i) total ARNT; or (ii) the Import Limit, considering exports.

5.5.2 Increased Exports by Must-Offer Generation Providers after ARNT is Allocated

If Local Generation providers that have facilities with Must-Offer Generation obligations schedule exports from the Load Zone after ARNT is allocated, such scheduling shall not decrease the Local Generation provider's Must-Offer Generation obligation even if it results in an increase in ATC into the Load Zone.

6. Temporary Must-Run Generation Procedures

During Phase I, temporary changes must be made to the Must-Run Generation Protocol to correspond to the temporary ARNT allocation procedures that will be in effect. The temporary Must-Run Generation procedures differ from the standard procedures in the following ways:

6.1 There is no trading of ARNT among SCs.

6.2 SCs' ARNT and shares of the Local Generation Requirement are specified and communicated to the SCs by the TPs ahead of the Operating Day. Local Generation providers that have facilities with Must-Offer Generation obligations that commit to run and commit to schedule outside the Load Zone by seven (7) days ahead of the Operating Day will decrease the total Local Generation Requirement. If there are changes in system conditions, the Local Generation Requirement may be modified subject to the provisions of Section 5.5 of this Protocol.

6.3 Each SC's hourly share of the Local Generation Requirement will be determined as follows: For hours for which a non-zero Local Generation Requirement is anticipated, the TP will divide each SC's previous day total Retail Network Load Schedule for the Load Zone for each hour by the total Retail Network Load in the Load Zone for that hour. The resulting percentage will be used to determine the SC's share of the Local Generation Requirement for the corresponding day and hour of the subsequent week.

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition (AECC).

Q. Are you the same Kevin C. Higgins who has filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to a proposal in the direct testimony of James S. Pignatelli of Tucson Electric Power (TEP) that would repudiate a key aspect of TEP's Commission-approved Settlement Agreement with AECC, the Residential Utility Consumer Office, and Arizona Community Action Association.[1]

Q. Specifically what proposal by Mr. Pignatelli would repudiate a portion of TEP's Settlement Agreement?

EXHIBIT
AECC-3
admitted

A. On page 14 of his direct testimony, Mr. Pignatelli proposes that all residential customers and commercial and industrial customers with loads under 3 MW be excluded from electric competition.

Q. How is that a violation of the TEP Settlement Agreement?

A. Paragraph 1.2 of the TEP Settlement ensures direct access rights for *all* customers.[2] Mr. Pignatelli's proposal would abrogate that right for the vast majority of TEP's customers while offering them absolutely nothing in exchange. It is a blatant attempt by a signatory to an agreement to advance its own pre-settlement objectives in contravention of the commitments it made when it struck its deal and received the benefits of its bargain. It is a one-sided, bad faith proposition that is not even within the scope of the Track A issues identified by the Commission. Mr. Pignatelli's proposal should be rejected.

Q. How does Mr. Pignatelli's proposal advance TEP's pre-settlement objectives?

A. TEP had long opposed extending direct access rights to smaller customers in the first place.[3] Now, after committing in its settlement agreement to extending these rights to all customers, TEP is using the generic docket as a pretext to resuscitate its pre-settlement litigation position. Eliminating direct access rights

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[1] Arizona Corporation Commission Decision No. 62103, November 30, 1999.

[2] Paragraph 1.2 states in part: "Unless subject to judicial or regulatory restraint, all TEP customers will be eligible to receive Competitive Retail Access on January 1, 2001." For TEP to be the active agent in seeking regulatory restraint of this provision is a violation of paragraph 14.2 of the Settlement Agreement which provides that: "Neither the Parties nor the Commission shall take or propose any action which would be inconsistent with the provisions of this Settlement Agreement."

[3] See for example RE-00000C-94-0165, "TEP's Exceptions to Proposed Order Adopting Amendments to the Electric Competition Rules," February 17, 1999, p. 2: "Only customers with 1 MW minimum demand should be eligible for direct access."

for the majority of its customers would be a major step toward fulfilling TEP's apparent aspiration to eradicate customer choice in its service territory.

Q. Wouldn't eliminating direct access for the majority of TEP's customers provide them with the benefit of stable rates through 2008?

A. No. TEP customers *already have* the assurance of stable rates through the end of 2008 by virtue of the settlement agreement – *and* they all have direct access rights as well. Customers would gain nothing from adoption of Mr. Pignatelli's proposal, while losing an option that might have significant value to them in the future.

Q. Are there provisions of the TEP Settlement Agreement that AECC would change if it could effect such changes unilaterally?

A. Of course. As in any settlement, a compromise was reached, and AECC accepted a final result that was short of what we would have sought in litigation. If AECC were to emulate TEP's strategy of lobbying for after-the-fact changes to the deal, the first thing AECC would seek to have changed is the size of the "Adders" used in the determination of TEP's shopping credit. The Adder is intended to capture the difference between a 100-percent-load-factor market price and actual customer load characteristics, plus an additional amount for costs not readily quantifiable until a more mature Arizona market has developed.[4] The size of the Adder is one of the most important drivers in the economics of direct access in TEP's service territory: the larger the Adder, the larger the shopping credit for direct access service. The lack of direct access activity in TEP's territory is an indication that the Adders are too small, although the TEP witnesses

do not bother to mention this in their assessment of the retail market. To the extent that TEP is concerned that there are insufficient shopping opportunities for residential customers and commercial and industrial customers under 3 MW, TEP should be advocating for larger Adders to rectify this. Similarly, TEP could propose to lower its stranded cost charges for these customers.

Q. Is there an opportunity in the TEP Settlement Agreement to revisit the size of the Adders?

A. Yes. The settlement agreement allows this issue to be re-opened after June 1, 2004, at which time the Commission will have the opportunity to reconsider the Adders in the settlement agreement and reset them, if necessary.[5] In my opinion, there will be a strong case for increasing the Adders at that time, which will have the effect of improving the economics of retail shopping. I view Mr. Pignatelli's proposal to eliminate direct access for the majority of TEP's customers as an opportunistic, preemptive strike against having the Adders adjusted upward in 2004.

Q. Please summarize the recommendations in your rebuttal testimony.

A. The Commission should reject Mr. Pignatelli's proposal to exclude all residential customers and commercial and industrial customers with loads under 3 MW from electric competition. His proposal is a blatant violation of TEP's Settlement Agreement and would abrogate direct access rights for the vast majority of TEP's customers while offering them absolutely nothing in exchange.

Q. Does this conclude your rebuttal testimony?

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[4] TEP Settlement Agreement, par. 2.1(e) and (f).
[5] TEP Settlement Agreement, par. 2.1(f).

1 A. Yes, it does.

Staff

1 – 17

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

REBUTTAL TESTIMONY

OF

PAUL R. PETERSON

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSIONS

JUNE 11, 2002

EXHIBIT
S-5
admitted

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1 **I. QUALIFICATIONS**

2 **Q. Please state your name, position and business address.**

3 A. My name is Paul R. Peterson. I am a Senior Associate with Synapse Energy
4 Economics, 22 Pearl Street, Cambridge, MA 02139.

5 **Q. On whose behalf are you testifying in this case?**

6 A. I am testifying on behalf of the Utilities Division of the Arizona Corporation
7 Commission ("Staff").

8 **Q. Have you testified previously in this proceeding?**

9 A. Yes. I filed Direct testimony on behalf of the Staff on May 29, 2002. That
10 testimony contains my qualifications and resume.

11 **II. SUMMARY**

12 **Q. What is the purpose of your testimony?**

13 A. I have been asked by the ACC Staff to respond to portions of the Direct testimony
14 of Arizonans for Electric Choice and Competition ("AECC") witness Higgins and
15 Arizona Public Service Company ("APS") witnesses Davis and Hieronymus.

16 **Q. Please summarize your responses to the testimony of these witnesses.**

17 A. Mr. Higgins places a great deal of reliance on the FERC's ability to develop and
18 implement appropriate wholesale market structures. Based on the FERC's poor
19 performance to date, I do not share Mr. Higgins optimism or confidence. Mr.
20 Davis appears to state that the decision to require a transfer of generation assets
21 was made over three years ago and cannot and should not be re-examined in light
22 of subsequent events. I maintain that the Commission has a responsibility to
23 make the best decision it can <u>today</u>, based on current information, to protect the
24 interests of Arizonans. I have several responses to Mr. Hieronymus' testimony
25 regarding his market power analyses and the performance of bid-based markets.

III. RESPONSES TO DIRECT TESTIMONY OF OTHER WITNESSES

Q. Please describe your concerns with Mr. Higgins testimony on behalf of AECC.

A. On page 5, lines 13-15, and on page 12, lines 16-19, Mr. Higgins recommends that the Commission require rigorous market power tests with respect to sub-markets within APS and TEP service territories after divestiture of generation occurs. While I agree that these rigorous tests should be performed, they should be done prior to divestiture to allow the Commission to assess the potential for market power abuses before allowing or permitting the transfer of generation assets. Moreover, I do not share Mr. Higgins confidence on page 11, lines 17-19, that horizontal market power problems will be resolved by the FERC. FERC has not demonstrated an ability to effectively address market power problems in existing wholesale markets.

Q. Why won't the new FERC Markets Oversight Office be sufficient to identify market problems and recommend solutions?

A. It might be effective, but it is untested. To date, it has been the ISOs, through their market monitoring units, who have identified market power problems and anti-competitive behavior by participants and made recommendations to the FERC to curb abuses. I concur with Mr. Higgins conclusion, page 5, lines 19-22, that Arizona needs an RTO to adopt effective market monitoring and mitigation procedures and that the Commission should participate in the development of those procedures.

Q. Please describe your concerns with Mr. Davis' testimony.

A. On pages 3-9, Mr. Davis makes the argument that decisions formulated in 1998 and 1999 regarding the divestiture of generation assets should be strictly adhered to without reconsideration in light of subsequent events. I disagree; sound public policy decision-making should evaluate current decisions in light of all the information that is available. Certainly this Commission should consider the problems that have occurred since 1999 in both wholesale and retail electric

markets as many states and the FERC have attempted to implement competitive practices. While California has drawn most of the media attention for its wholesale and retail market failures, other bid-based wholesale markets have experienced significant problems[1] and retail competition has significantly lagged behind the expectations of 1999.[2] Even accepting Mr. Davis's assertion that APS has commenced the process of divestiture in reliance on agreements made more than three years ago, the Commission should not be bound to continue that process if the evidence in this proceeding persuades it that such a course could be harmful to Arizona consumers.

Q. Please describe your concerns with Mr. Hieronymus' testimony on behalf of APS.

A. I have two principal concerns. First, Mr. Hieronymus regards the California debacle as a singular event that is unique to that state. Second, Mr. Hieronymus relies on traditional market power definitions and analyses in evaluating the potential for problems in wholesale electric markets, thereby ignoring the special volatility issues associated with the production and delivery of electricity over an integrated bulk power system.

Q. Why are the problems that California experienced not limited to that state's particular market rules and history?

A. While I agree that California's market structure and failure to build new supply resources contributed to the severity of its problems, all bid-based wholesale markets have experienced problems with market design flaws and short-term imbalances between demand and supply that have been exploited by market participants to raise prices above competitive levels. The FERC has been just as slow to address problems in the Northeast wholesale markets as it was in California. According to economic theory, properly structured competitive markets are largely self-regulating. People who believe "that the competitive

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[1] See, Direct testimony of Paul Peterson in this proceeding.

[2] See, Direct testimony of Neil Talbot in this proceeding.

1 wholesale and retail energy markets are superior to regulated monopoly"[3] are
2 often reluctant to acknowledge that, absent proper structures or effective
3 mitigation procedures, the transition from monopoly to competitive markets can
4 produce extremely uneconomic results during the early years of implementation.
5 This is especially true for wholesale electricity markets.

6 **Q. Why are electricity markets particularly vulnerable to uneconomic results?**

7 A. Maintaining excess capacity is expensive. The operators of power systems
8 maintain a quantity of excess capacity (reserves) based on historical averages of
9 load, which is very weather dependent, and long-term estimates of generation unit
10 availability and transmission system failures. When any of these factors deviate
11 from the norm, load can exceed available supply and create a capacity deficiency
12 event. In New England, the ISO plans for up to thirty capacity deficiency events
13 each year, most of which will only last for a few hours. During such times, all
14 available generation resources are needed. Prior to restructuring, reliability was
15 maintained "at any cost", which meant that even generators with high operating
16 costs were required to run. In the new world of bid-based wholesale markets,
17 reliability is maintained "at any bid", which means that every owner of a
18 generation unit has market power. If bids are unconstrained, there is no limit to
19 the "cost" of keeping the lights on. FERC explicitly recognized this issue when it
20 imposed bid caps in the New York and New England wholesale markets.

21 **Q. Can you give examples of these phenomena?**

22 A. There are two examples in New England that I am very familiar with. The first
23 occurred in May 2000 during an unusual heat wave for that time of the year. A
24 bid of $6,000/MWH set the clearing price for about four hours. Electricity costs
25 were estimated to have increased by $90 million dollars in the spot market over
26 that short time period; costs for future bilateral arrangements were also likely to
27 have increased as a result of this price spike. The ISO determined that the bid

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[3] Hieronymus Direct testimony at 4, lines14-15.

was consistent with the market rules in effect at the time.[4] The second example occurred over three days in July 2001. A combination of hot weather and unit outages caused the hourly clearing price to jump from $40 –200 /MWH to $1,000/MWH (the existing bid cap) over a fifteen minute period and to remain there for a total of thirteen hours. The ISO estimated that $80 million dollars in higher spot market costs were incurred over those thirteen hours. Several investigations have determined that there were no traditional market power abuses.[5]

Q. What do you conclude about the volatility of these markets and the potential for market power abuse?

A. First, I am not aware of any competitive markets where prices rise by over 2000 percent in a matter of minutes on a regular basis. Whether or not these two examples are an exercise of "market power", based on economic theory or FERC's tests, seems a question of semantics; they are certainly not examples of competitive and efficient markets. Second, it demonstrates that participants in bid-based electric markets can reap windfall profits even if they do not withhold capacity or sustain the high prices, as required by Mr. Hieronymus's definition of market power on pp.23-24 of his testimony. Third, while these are two egregious examples of market design flaws or market abuses, there are probably many other examples of smaller scale abuses by market participants who have discovered ways to game the system through manipulation or circumvention of the rules. I think there is some truth to the assertion that has surfaced in the response to the ENRON memos that "everyone is doing it".

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4 See, ISO New England documents "Events of May 8-9, 2000", 6/1/2000, and "Supplemental Report on May 8", 7/28/200.

5 See, ISO New England document "Summer 2001 Report", 9/14/01, and "Competitive Assessment of the New England Market" by David Patton, IMA, May 2002.

IV. RECOMMENDATIONS

Q. What are your recommendations to the Commission?

A. I agree with the testimony in this proceeding from Staff and other witnesses that well-structured and properly functioning wholesale markets are a pre-condition for effective retail competition that can provide benefits to consumers. As I noted in my Direct testimony, FERC prefers to rely on structural solutions, such as RTOs, open access to transmission, adequate supply, and demand response to curb market power abuses.[6] Where these structural elements are not present, and the testimony in this proceeding has shown that they are currently lacking in the Western wholesale markets, FERC states that effective market rules, market monitoring, and market mitigation must be developed and implemented. Mr. Hieronymus agrees that these structures and rules "have taken on a new urgency . . . [and are] seen as the 'front line' of defense against both the exercises of market power and gaming of inadequate and inefficient market rules".[7] My recommendation to the Commission is to make sure that either the structural elements or appropriate rules are in place at the wholesale level before making any irrevocable decisions regarding the transfer of utility generation assets. I further recommend that the Commission require market power analyses based on tests that account for the unique attributes of wholesale and retail electric systems.

Q. Does this complete your Rebuttal testimony?

A. Yes.

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[6] Peterson Direct testimony at 9-10.

[7] Hieronymus Direct testimony at 22, lines 15-18.

EXHIBIT
5-6
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

NEIL H. TALBOT

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF UTILITIES DIVISION

MAY 29, 2002

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DIRECT TESTIMONY OF NEIL H. TALBOT

I. Introduction and Purpose of Testimony

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Neil H. Talbot and my business address is 22 Pearl Street, Cambridge, Massachusetts 02139.

Q. WHAT IS YOUR EMPLOYMENT?

A. I am an economic and financial consultant with Synapse Energy Economics, Inc.

Q. WHAT IS YOUR AREA OF EXPERTISE?

A. My area of expertise is electric utility economics.

Q. WHAT ARE YOUR ACADEMIC QUALIFICATIONS?

A. I obtained degrees in economics and finance from Cambridge University, England, and Boston College respectively.

Q. PLEASE OUTLINE YOUR EMPLOYMENT HISTORY.

A. Since 1968, I have been employed as an economic consultant, and during most of this period I have focused on the U.S. electric utility industry and, to a lesser extent, other public utility and energy industries. I have been associated with several consulting firms during this period -- first the Economist Intelligence Unit, London, then Arthur D. Little, Inc. of Cambridge, Mass., and later Tellus Institute of Boston and LaCapra

Associates of Boston. Currently, I am employed as a consultant to Synapse Energy Economics, Inc., of Cambridge, Mass.

Q. PLEASE DESCRIBE YOUR CONSULTING WORK.

A. Since 1973, when I was retained by Potomac Electric Power Company of Washington, D.C. to do a long-term load forecast, I have spent most of my time working on the U.S. electricity industry. Since the early 1990s, most of my work has focused on industry restructuring. My professional biography is attached as Exhibit NHT-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THESE PROCEEDINGS?

A. I am a member of the Synapse Energy Economics team that has been retained by the Utilities Division ("Staff") of the Arizona Corporation Commission to investigate electricity restructuring issues in Arizona.

Q. WHAT IS THE PURPOSE OF YOUR CURRENT TESTIMONY?

A. This testimony, together with that of other members of the Staff team, addresses the "Threshold Issues" which were identified in Staff's April 23, 2002 response to the Arizona Public Service Company (APS) Motion for Determination of Threshold Issues, and certain related issues identified by Chairman Mundell. These issues include "the transfer of assets and associated market power issues, as well as the issues of the Code of

Conduct, the Affiliated Interest Rules, and the jurisdictional issues raised by Chairman Mundell..."

Q. WHICH OF THESE ISSUES WILL YOU ADDRESS?

A. First, I will address the presence of market power in Arizona electricity markets, and the implications thereof. On this subject, I will rely in part on data on Arizona electricity markets provided by Staff witness Jerry Smith. Staff witness David Schlissel also addresses market power in Arizona electricity markets, and Staff witness Paul Peterson will address the changing market rules being developed by Independent System Operators, the development of Regional Transmission Organizations, and certain Federal Energy Regulatory Commission policies and practices related to market power.

Second, I will deal with certain jurisdictional issues raised by Chairman Mundell.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is in five sections. After the present section, it has the following sections:

II. Summary and Recommendations.

III. Market Power in Western and Local Electricity Markets.

IV. Certain Jurisdictional Issues.

V. Concluding Remarks.

II. Summary and Recommendations

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON MARKET POWER.

A. I describe problems of market power in both regional and local electricity markets. I recommend that there should be a rebuttable presumption that incumbent utilities and their affiliate generators will have both horizontal and vertical market power when they restructure. I argue that utility systems have traditionally been designed to supply generation on a vertically-integrated basis, and that initially their transmission systems are unlikely to be able to support a robust competitive market, one which must rely on more trading of electricity between service territories. I outline continuing inadequacies in the structure of the Western regional market, but I emphasize the fact that even if there is a *relatively* competitive regional market, the local Arizona market is broken into load pockets that give incumbent generators significant market power. Horizontal market power is a general concern, and in cases of transfer of generation to affiliates, vertical market power is also a concern. As a threshold requirement for restructuring, a utility should be required to demonstrate that it or its generation affiliate or other generator(s) to which it proposes to divest generation assets will be unable to exercise market power. If the utility acknowledge that there will be market power concerns, it should propose

appropriate mitigation measures, including enhancements of its transmission system and minimum roles for IPP generation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON JURISDICTIONAL ISSUES.

A. I start from the basis that the Commission retains the authority to ensure that generation rates, as well as transmission and distribution rates, are just and reasonable. The Utility Distribution Company (UDC) has an obligation to provide transmission and distribution service, and generation service for its Standard Offer Service customers, at just and reasonable rates. It follows that a UDC should retain its control over the acquisition of electricity for Standard Offer Service customers and should not delegate that control to an affiliate.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO TRANSFER OF GENERATION ASSETS?

A. I have already noted that transfer of generation assets to an affiliate generator in current circumstances would give rise to horizontal and vertical market power concerns. Enhancements are needed to transmission systems in Arizona, and regional power market institutions such as an RTO are not yet ready to adequately monitor the regional, let alone the local, market

III. Market Power in Western and Local Electricity Markets

Q. PLEASE DEFINE MARKET POWER.

A. Market power is the ability of a single seller or group of sellers of a product or service to influence its price.

The Harm Caused by the Exercise of Market Power

Q. PLEASE DESCRIBE THE HARM THAT CAN BE CAUSED BY MARKET POWER.

A. Suppliers with market power have the ability to raise prices above the levels that would prevail in a competitive market. Such price increases may prevail over periods of time, or they may be relatively short-term price spikes. Pervasive price increases may reflect the inefficiency of suppliers with higher cost structures than would prevail under competitive conditions. They may also simply represent higher profits for suppliers. In either case, consumers end up paying more for the service. In the California electricity crisis, we can see a dramatic instance of this harmful effect on consumers, an effect which was in the tens of billions of dollars.

Q. IF SELLERS RAISE PRICES, WON'T NEW COMPETITORS SOON BE DRAWN INTO THE ELECTRICITY MARKET?

1 A. No. Firstly, there are effective barriers to entry in electricity markets, at
2 least in the short term. It takes at least two years for new competitors to
3 construct new generation facilities, and it can take much longer to plan, get
4 permits for, and construct new transmission facilities. Other barriers to
5 entry may include bureaucratic obstacles to plant approval, and the
6 difficulty of finding sites with fuel supply and transmission access.
7 Furthermore, as we now know from the California experience, profits from
8 the short-term manipulation of the market can be so large that sellers may
9 not care about competitive entry in the long term. Meanwhile, consumers
10 suffer.
11 Q. DID THE CALIFORNIA CRISIS REVEAL OTHER POTENTIAL
12 HARMFUL EFFECTS OF MARKET POWER?
13 A Yes. The exercise of market power in California appears to have
14 exacerbated an underlying problem of shortages of supply, resulting in
15 market disruptions and impairing reliability of supply. In otherwords, it
16 seems likely that the games played by suppliers resulted in blackouts and
17 brownouts.
18 Q. CAN MARKET POWER HAVE OTHER HARMFUL EFFECTS?
19 A. Yes. Sellers with protected positions in a market are less likely to be
20 innovative and responsive with respect to service quality and variety of
21 services. The result is that customers are likely to suffer from reduced

service quality and variety, as well as higher prices. One of the arguments in favor of competition in the generation market is that it is likelyto lead to the emergence of suppliers that are not only more efficient, but are more responsive to customer requirements in other ways. These developments are less likely to occur in a market in which there is a significant amount of market power.

Types of Market Power

Q. WHAT DIFFERENT TYPES OF MARKET POWER ARE THERE?

A. Broadly, there are two types: horizontal market power and vertical market power. Horizontal market power exists when one or more sellers can directly influence the price of the product or service they are selling. Vertical market power exists when one or more sellers can *indirectly* control the market for a product or service they are selling by influencing the price or availability of a complementary product or service at a different stage of production. For example, a seller of electricity can influence its price in an area if it can restrict access to, or the price of, transmission facilities that competitors need to deliver electricity into that area.

Q. IN THE PRESENT PROCEEDING, WHICH MARKET POWER ISSUES WOULD YOU SUGGEST THE COMMISSION SHOULD ADDRESS?

A. I would suggest that the Commission focus on the *wholesale* market for electricity (the bulk power market). I do not believe the competitiveness of retail access as such is a threshold issue -- it will remain under the primary jurisdiction of the Commission, and can be fostered over the next several years. Regarding the wholesale market, I would distinguish between two kinds of issues -- *regional* and *local*. I would suggest that the Commission should recognize that regional problems are largely beyond its control. They are primarily the province of the Federal Energy Regulatory Commission (FERC). The California authorities also affect the regional market, because that state represents such a large share of the Western market, and its market structure is currently being changed.

Problems in the Regional Market

Q. WHAT KINDS OF REGIONAL PROBLEMS DO YOU HAVE IN MIND?

A. I refer to the degree of competitiveness of Western and Southwestern electricity markets, or, putting it the other way round, their degree of vulnerability to price increases caused by market manipulation and/or tightness of power supplies.

Q. CAN SOME INTERCONNECTED ELECTRICITY MARKETS BE MORE COMPETITIVE THAN OTHERS?

1 A. Yes. For example, for purposes of exports to California, the regional market
2 faced by Arizona generators, e.g., those in the Palo Verde area, is *relatively*
3 competitive, more so than the Arizona market itself. There are many sellers
4 on the Western electricity grid with access to the California market. They
5 can be expected to vie with each other to keep prices competitive, at least
6 during periods when the system is not suffering from supply shortages or
7 transmission congestion.
8 Q. DO YOU BELIEVE THE REGIONAL MARKET IS NOW FULLY
9 COMPETITIVE AND LIKELY TO BE STABLE?
10 A. No, unfortunately it is clear that the regional market is not yet fully
11 competitive. The California crisis showed that the regional market is prone
12 to shortages, and, more fundamentally, that it lacks the necessary
13 institutional and market structures to prevent shortages and deal with
14 market manipulation.
15 Q. ARE THERE CURRENT DEVELOPMENTS THAT COULD
16 JEOPARDIZE THE DEVELOPMENT OF THE REGIONAL MARKET?
17 A. Yes. In the wake of the Enron disaster, there have been subsequent
18 discoveries of accounting irregularities in other firms producing and
19 marketing electricity. There is also direct evidence that Enron manipulated
20 the California market, and the suggestion that other companies might have
21 used similar practices. The stock market has responded by slashing the

stock prices of the companies involved, and industry sources of capital in credit markets are drying up. These developments are coming at a bad time. Already, the Western independent power producer (IPP) industry was entering what threatens to be a "bust" phase of a boom-and-bust cycle. In 2000 and 2001, high electricity market prices in the West were bad for consumers but good for producers, and there was a construction boom. By the end of 2001, prices were falling and construction plans were being shelved. Now, investors' aversion to risk in the power industry could result in regional shortfalls of capacity if the economy and electricity demand resume their growth during the next few years. The New York Times, in a May 16, 2002 article titled *Power Giants Have Trouble Raising Cash for Plants*, quoted industry experts as having this concern. There is a related concern that transmission construction might also fall short of requirements.

Q. HOW SHOULD THE COMMISSION ADDRESS REGIONAL ISSUES THAT FALL WITHIN FERC'S PURVIEW?

A. I believe that the Commission's primary concern with respect to these regional markets should be to ensure, before it places greater reliance on them, that structures are in place to provide protection for ratepayers and to create and sustain workable competition. Again, putting it the other way round, the Commission should assure itself that there is unlikely to be a recurrence of the market crises of the past two years. Although the

1 Commission has little control over regional markets, it can monitor them to
2 determine if and when an appropriate market structure is in place under the
3 jurisdiction of FERC.
4 Q. WHAT DO YOU MEAN BY AN APPROPRIATE MARKET
5 STRUCTURE?
6 A. Usually, an appropriate market structure would be one that includes an
7 effective Regional Transmission Organization (RTO) under the aegis of
8 FERC with the means to actively monitor wholesale regional markets, and
9 identify and deal with market power abuses. The RTO should be able to set
10 transmission rates and require or influence the construction of new
11 transmission capacity to encourage trading. Not least, the RTO should be
12 able, together with Western states, to ensure that policies are in place to
13 avoid a boom-and-bust cycle in the regional electricity market. In the
14 absence of an RTO, a utility seeking to transfer assets should provide a plan
15 as to how these functions will be addressed before the transfer occurs.
16 Q. ARE APPROPRIATE REGIONAL STRUCTURES IN PLACE TODAY?
17 A. No. Firstly, FERC is still trying to get to grips with market design issues, as
18 evidenced by the fact that it has issued a Market Design NOPR. Staff
19 witness Paul Peterson will deal with this issue in his testimony. I may add
20 that California, which as noted above is large enough to affect the whole

regional market, is proposing new market rules. What we are seeing in the regional energy market is a work in progress.

Q. MEANWHILE, WHAT ROLE SHOULD THE COMMISSION PLAY WITH RESPECT TO REGIONAL MARKETS?

A. With respect to regional markets, I would suggest that the Commission work within the framework of FERC and perhaps other regional entities to create local conditions that support FERC policies, e.g. permitting and encouraging the construction of generation and transmission capacity in Arizona as part of regional electricity system expansion. And the Commission should make its own finding about if and when the regional wholesale market is sufficiently competitive to make it prudent for Arizona to place greater reliance on it.

Q. DOES THE CHAIRMAN'S LETTER OF MAY 14, 2002, REGARDING POTENTIAL MARKET MANIPULATION IN THE WEST AND RELIABILITY OF ELECTRIC SERVICE IN ARIZONA ADDRESS THIS ISSUE?

A. Yes. I note that the Chairman is requesting that "the ACC staff actively monitor FERC's investigation of potential energy market manipulation in the West and make timely summary findings in the ACC generic electric restructuring docket as to the status of FERC's investigation." I would suggest that the Staff's monitoring effort should be oriented toward the

future, with a view to determining if and when the regional market is likely to be structured in a manner that avoids electricity shortages and market manipulation going forward.

Market Power in the Arizona Electricity Market

Q. IF THE REGIONAL MARKET IS QUITE COMPETITIVE DESPITE HAVING SIGNIFICANT REMAINING PROBLEMS, IS THE ARIZONA MARKET IN THE SAME SITUATION?

A. No, the Arizona market is significantly *less* competitive than the regional market. Firstly, it is vulnerable to recurrences of regional problems that could result in regional shortages or price spikes. More importantly, however, the Arizona market is limited by transmission constraints that protect local generators against outside competitors. It is therefore less competitive, at least during some seasons and times of day.

Q. PLEASE DISCUSS LOCAL MARKET POWER ISSUES THAT SHOULD BE OF CONCERN TO THE COMMISSION.

A. There are two sets of local issues that are critical in restructuring. One is the adequacy or inadequacy of local transmission and generation capacity to diminish *horizontal* market power in the Arizona market. The other is the problem of *vertical* market power resulting from the ownership of transmission and generation facilities by affiliates of the Utility Distribution

1 Companies (UDCs). The Commission has considerable authority over these
2 two sets of issues.
3 Q. WHAT ARE YOUR CONCERNS REGARDING THE ADEQUACY OR
4 INADEQUACY OF LOCAL TRANSMISSION AND GENERATION
5 CAPACITY?
6 A. Data developed by Staff witness Jerry Smith shows clearly that most of
7 Arizona's electricity consumption is in "load pockets" which have limited
8 capability to import electricity and therefore depend on generation *within*
9 the area to meet loads during at least some periods of time. Mr. Smith
10 identifies the Valley area, Tucson and Yuma as load pockets. Tucson
11 Electric Power has stated that it "is constrained relative to imports into the
12 Tucson area...All of TEP's retail load is within the import limited service
13 territory of TEP."
14 Q. WHAT IS THE SIGNIFICANCE OF THIS DATA REGARDING LOAD
15 POCKETS?
16 A. This data makes it clear that there is pervasive market power in Arizona.
17 The existence of load pockets means that some generating units within the
18 load pocket must run during at least certain periods of time. The owners of
19 those units, who are mostly the incumbent utilities, can increase prices in
20 these circumstances. Transmission barriers limit the ability of generators
21 from outside the load pocket to compete for customers within the load

pocket. Moreover, the California electricity crisis showed clearly that when supplies are tight sellers can manipulate prices.

Q. IS THIS A TEMPORARY OR PERMANENT PROBLEM?

A. Staff witness Smith has pointed out that there is a substantial transmission and generation construction program in Arizona that may alleviate the load pocket problem during the next few years. At some point during that period, I would hope that the Commission can satisfy itself that, with relatively minor exceptions, the wholesale electricity market is ready for competition, provided FERC and other states have done their bit at the regional level.

Q. DOES MR. SCHLISSEL ALSO ADDRESS THE PROBLEM OF MARKET POWER?

A. Yes. Mr. Schlissel provides a more detailed analysis of market power in local wholesale electricity markets.

Q. YOU REFERRED ALSO TO *VERTICAL* MARKET POWER AT THE LOCAL LEVEL. PLEASE DISCUSS THIS PROBLEM.

A. Some of Arizona's UDCs, including APS and TEP, own both transmission and generation. This creates the potential for exercise of *vertical* market power. APS is proposing to transfer generation to an affiliate, PWEC. The Commission should be satisfied that APS is building adequate transmission capacity and making it available to competitors on equal terms, and is not restricting access in a manner that favors PWEC generation. This leads to

the issue of a code of conduct between affiliates, which Staff witness Barbara Keene will discuss.

Rebuttable Presumption of Market Power

Q. FROM A REGULATORY STANDPOINT, HOW SHOULD THE ACC APPROACH THE LOCAL MARKET POWER PROBLEM IN ARIZONA?

A. I would suggest that there should be a *rebuttable presumption* of market power. This is the approach adopted in Minimum Filing Requirements that I helped write for the Arkansas Public Service Commission. As one of the participants in the Arkansas proceedings said to me, "The last thing we want to do is go from a situation of regulated monopoly to a situation of *unregulated* monopoly." Attachment A to that commission's Order No. 11, dated June 27, 2000, in Docket No. 00-048-R, Section 4, titled Burden of Proof, reads as follows:

> Given that each electric utility has hitherto been a regulated monopoly supplier of retail electricity services in its service territory, there shall be a rebuttable presumption that each utility and its (marketing) affiliate will be in a position to exercise market power when the Arkansas retail electric market is deregulated and retail open access is introduced.

Q. PLEASE EXPLAIN THIS PROVISION AS IT RELATES TO *HORIZONTAL* MARKET POWER.

A. The transmission systems of most traditional electric utilities, including Arizona's electric utilities, were not designed to be able to bring in large amounts of power from other areas. Apart from situations in which utilities relied upon supplies from remote power plants in which they had ownership shares, transmission links were mostly built to enhance reliability and allow for limited exchanges of economy energy between utilities. They were not built to allow for extensive trading and purchases from independent power producers in a regional market framework.

Q. SHOULD THE REBUTTABLE PRESUMPTION OF MARKET POWER ALSO APPLY TO *VERTICAL* MARKET POWER?

A. Yes. The manner in which vertically-integrated utilities were planned and operated gives rise to a likelihood of vertical market power. This is well expressed in a July 17, 1998 order of the New York Public Service Commission, *Order Adopting a statement of policy regarding vertical market power in a restructured electric industry* in Case No. 96-E-0900, et al.). The statement reads in part:

> In creating a competitive electric market, the Commission has viewed divestiture as a key means of achieving an environment where the incentives to abuse market power are minimized…

1 Vertical market power occurs when an entity that has market power
2 in one stage of the production process leverages that power to gain
3 advantage in a different stage of the production process. A
4 transmission and distribution company (T&D company) with an
5 affiliate owning generation may, in certain circumstances, be able to
6 adversely influence prices in that generator's market to the
7 advantage of the combined operation. Two examples are given
8 below.
9 -- The affiliate's generator is located in the same market as the T&D
10 company. The T&D company has an incentive to make entry by
11 generators into its own territory difficult, and therefore, expensive
12 for a new entrant by either delaying or imposing unrealistic
13 interconnection requirements, and thereby raising prices in the
14 region…
15 -- The affiliate's generator is on the high cost side of a transmission
16 constraint and the T&D company has the ability to influence the
17 transmission constraint. The T&D company has the incentive to
18 retain the constraint to keep the market price high on the high cost
19 side of the constraint…
20 To guard against undesirable incentives, a rebuttal (sic) presumption
21 will exist for the purposes of the Commission's…review of the

1 transfer of generation assets, that ownership of generation by a T&D
2 company affiliate would unacceptably exacerbate the potential for
3 vertical market power...
4 Q. INCIDENTALLY, DOES APS SHARE THE VIEW THAT UTILITY
5 SYSTEMS WERE TRADITIONALLY PLANNED IN A MANNER
6 THAT IS NOT CONDUCIVE TO THOROUGHGOING COMPETITION?
7 A. Yes, I believe it does. Mr. Jack Davis stated as much in his Rebuttal
8 Testimony in Docket No. E-01345A-01-0822, filed on April 22, 2002, on
9 page 5. He said that it would be "misplaced and premature" to put trust in
10 the wholesale markets "prior to the implementation of the very structural
11 reforms and infrastructure upgrades cited by Staff as essential to the
12 efficient working of that same market." Likewise, APS witness Mr. John
13 Landon, in his Rebuttal Testimony in the same docket, filed on April 22,
14 2002, at page 19, emphasizes the current shortfall of transmission capacity:
15 (T)he amount of transmission resources necessary to support fully
16 competitive wholesale markets will necessarily be significantly
17 greater than those needed for a regulated utility service from a
18 vertically integrated system. Thus, it is hardly surprising that
19 transmission in Arizona is not sufficiently robust to allow an
20 immediate shift to fully competitive wholesale markets."

And APS witness Cary Deise, in his Rebuttal Testimony of April 22, 2002 in the same docket, at page 3, criticizing what he calls "errors" made by certain intervenor witnesses relating to APS' transmission system and its capabilities, says the following:

> The system simply was not designed, nor should it have been designed, with large amounts of surplus capacity to accommodate unplanned generation additions (competitive or otherwise) within a relatively concentrated area, let alone allow unconstrained access to all of APS' loads or to loads in other regions or states.

Q. THESE STATEMENTS MADE BY APS WITNESSES ARE INTENDED TO SHOW THAT IT IS UNWISE FOR APS TO SWITCH IMMEDIATELY TO COMPETITIVE BIDDING. IS IT APPROPRIATE TO RELY ON THESE STATEMENTS AS SUPPORT FOR THE VIEW THAT THE ARIZONA POWER MARKET IS VULNERABLE TO THE EXERCISE OF MARKET POWER BY INCUMBENT UTILITIES?

A. Yes. This is the other side of the same coin. The basis of APS's proposals for a variance and PPA is that the wholesale power market is too thin and too volatile.

Q. CAN A CODE OF CONDUCT PREVENT THE EXERCISE OF VERTICAL MARKET POWER?

A. While it is better to have a market structure in which participants' incentives are aligned with the public interest – as is supposed to be the case in a workably competitive market -- an effective code of conduct or affiliate interest rules can militate against this anti-competitive coordination of transmission and generation. Codes of conduct are discussed in the testimony of Staff witness Barbara Keene.

Q. WILL THE LARGE AMOUNTS OF GENERATION OWNED OR CONTROLLED BY PWCC OR OTHER UTILITY-AFFILIATED GENERATORS PRESENT A MARKET POWER PROBLEM?

A. Construction of new IPP generation and increases of transmission capacity will tend to reduce the market power of incumbent generators. On the other hand, I note that PWEC is undertaking a billion-dollar generation construction program, which will, other things being equal, tend to increase its market power. Whether on balance a significant market power problem will still exist remains to be seen. Probably the most significant mitigating factors in both the local and regional markets will be the adequacy of generation capacity and a coordinated expansion of the transmission grid.

Quantitative Tests for Market Power

Q. ARE THERE QUANTITATIVE TESTS THAT CAN BE USED TO TEST FOR HORIZONTAL MARKET POWER?

A. Yes. It is important to note, however, that these tests are not definitive -- they provide at best an indication of market power. Moreover, these tests can fail to capture the specific structure of the electric generation industry, dependent as it is on a local and regional combination of power plants and transmission lines, the need to instantaneously satisfy fluctuating demands for electricity, and the institutional structure of the markets for energy and ancillary products. The specifics of the industry have led to exercises of market power when they were not expected, as in California during 2000 and 2001. And this experience has led to changes in the tests that are applied.

Q. HOW HAVE THESE ADMITTEDLY IMPERFECT TESTS FOR MARKET POWER EVOLVED IN RECENT YEARS?

A. Up until recently, the FERC was relying on rules of thumb and traditional market power tests derived from the *Horizontal Merger Guidelines* of the U.S. Department of Justice and Federal Trade Commission. These relied primarily on structural analysis of suppliers' market shares, using quantitative measures like the HHI index to measure market *concentration*.

Q. PLEASE DESCRIBE THE HHI INDEX.

A. The Herfindahl-Hirschman Index or HHI is computed as the sum of the squares of the percentage market shares of suppliers of a relevant market. The higher the index, the greater the degree of concentration and the

potential for market power. For example, if there were five suppliers -- including some large ones -- with market shares of 50%, 30%, 10%, 5% and 5% respectively:

$$HHI = 50^2 + 30^2 + 10^2 + 5^2 + 5^2 = 2500 + 900 + 100 + 25 + 25 = 3{,}550$$

An index of 3,550 shows a high degree of concentration. If the market had five *equally-sized competitors*, each with a market share of 20%, the index would be lower:

$$HHI = 20^2 \text{ X } 5 = 400 \text{ X } 5 = 2{,}000$$

And if the market had *ten* equally-sized competitors, each with a market share of 10%, the index would be even lower:

$$HHI = 10^2 \text{ X } 10 = 100 \text{ X } \overset{10}{\cancel{5}} = 1{,}000$$

What these three examples show is that it is not only the *number* of companies that reduces the HHI, it is also the absence of one or more companies with *large shares* of the market. The Texas restructuring legislation contains an upper limit of 20% market share for any one supplier, and the Arkansas Minimum Filing Requirements use as a threshold test a market share of 25% for a utility and its marketing affiliates.

Q. WHAT ARE THE CRITICAL LEVELS OF THE HHI?

A. The U.S. Department of Justice and Federal Trade Commission "broadly characterize" markets as unconcentrated if the HHI is below 1,000, moderately concentrated if the HHI is between 1,000 and 1,800, and highly

concentrated if the HHI is above 1,800. Note that the first two examples given above, in which there were five competitors, would be "broadly characterized" as highly concentrated, including the second example in which the five competitors were equally sized. The third example, however, with ten equally sized competitors, would be on the borderline between moderately concentrated and unconcentrated. The screen in the Arkansas Minimum Filing Requirements provides that a utility shall file a strategic behavior analysis (see below) if it controls at least 25% of a market *and* the market's HHI exceeds 1,000. It is difficult to apply the HHI index to electricity markets, because there are often disputes over the geographical extent of the market which involve making judgements about the availability and price of transmission. Moreover, since the HHI does not account for the overall tightness of the market, it is not an ideal measure.

Q. HAS FERC'S APPROACH CHANGED TO TAKE THIS ISSUE INTO ACCCOUNT?

A. Yes. FERC has introduced a new structural test, which it calls the "pivotal supplier" or Supply Margin Assessment (SMA) test. This test takes into account not only the sizes of suppliers, but the tightness of the market in terms of reserve margin, something that appears to have been a major factor in the manipulation of markets in California during the past two years. The

pivotal supplier test is described and applied to Arizona in the testimony of Staff witness David Schlissel.

Q. WHAT OTHER TESTS HAVE BEEN APPLIED?

A. Another major step in regulatory thinking on the subject of market power has involved recognition of the games that suppliers can play, particularly if they own several generation plants. These games are called "strategic behavior" and include strategic bidding or pricing of generation and strategic withholding of generation from the market. Even though a market appears to have a relatively low level of concentration according to the HHI, computer modeling of the system under alternative assumptions regarding pricing and withholding can reveal opportunities for market manipulation by large sellers.

Q. IS THE EXERCISE OF MARKET POWER NOW ENTIRELY PREDICTABLE AND AVOIDABLE?

A. No, I believe it would be optimistic to believe that FERC is now completely on top of the problem. Putting it differently, it does not seem that market power will disappear when some new market structure is designed and implemented. Anjali Sheffrin, the director of market analysis at the California ISO, says that energy markets remain vulnerable to manipulation. Marketers "will keep testing us any way they can, in big ways and

small...Unless we are more diligent, we could have the same kind ofcrisis all over again." (New York Times, May 12, 2002, first business page.)

Q. WHAT IS THE SOLUTION TO THIS RECURRING PROBLEM?

A. There will no doubt be many market design fixes to problems as they emerge. The overarching solution, however, is institutional. It is essential to have an RTO with market monitoring responsibility, adequate capability to exercise that responsibility, and the authority to apply sanctions and penalties. In the New York Times article referred to above, an energy trader is quoted as saying, "Energy trading is a football game; it ain't bridge...If you want a nice game because electricity is an important public good, then set up a nice game." Pursuing this sports metaphor, when we reject a "nice" regulated utility game for electricity in favor of the rough and tumble of competition, we must recognize that electricity markets need market monitors as much as football games need referees.

IV. Certain Jurisdictional Issues

Q. CHAIRMAN MUNDELL HAS INCLUDED JURISDICTIONAL CONCERNS IN THE LIST OF THRESHOLD ISSUES. PLEASE COMMENT ON THE ISSUE OF JURISDICTION.

A. If an Arizona UDC transfers generation assets to an affiliate generator or divests them to a non-affiliated generator, the presumption is that the

1 Commission will effectively lose jurisdiction over those assets. This is
2 because the Commission does not have jurisdiction over wholesale sales.
3 FERC would acquire jurisdiction over the buyback of power by the UDC
4 from the affiliated or non-affiliated generator.
5 Q. DOES THE LOSS OF JURISDICTION BY THE ACC INVOLVE A RISK
6 TO UDC RATEPAYERS?
7 A. Yes. The Commission would lose the ability to set generation rates in the
8 traditional manner, on the basis of cost of generation including fair rate of
9 return. If the local electricity markets are not yet workably competitive, the
10 buyback of power or the purchase of power from other generators might be
11 at prices in excess of cost.
12 Q. HOW HAVE OTHER COMMISSIONS DEALT WITH THIS RISK?
13 A. Nevada and New Mexico have delayed the transfer of generation assets
14 until such time that the state authorities are satisfied that the local and
15 regional generation markets are workably competitive and effectively
16 regulated by FERC and a regional RTO. Virginia is requiring that
17 generation assets be transferred to a different division of the same corporate
18 entity as the UDC. Montana has apparently been able to argue that the
19 transfer of generation assets carried with it an obligation to sell power back
20 to the utility at cost, but this appears to be a special case.

Q. ARE THERE OTHER WAYS IN WHICH THIS RISK CAN BE AVOIDED?

A. Perhaps the jurisdiction problem can be satisfactorily overcome if the transfer of assets is coupled with a reasonable buyback agreement or Purchased Power Agreement (PPA), effective until the Commission makes a determination that the local and regional markets are workably competitive and effectively regulated by FERC and a regional RTO. APS may argue that it has already proposed a reasonable PPA; however, Staff believes that APS's proposal is not appropriate.

Q. EVEN IF THE POWER MARKETS ARE EFFECTIVELY COMPETITIVE AND WELL-REGULATED, IS THERE A DANGER THAT AN AFFILIATE GENERATOR COULD BE FAVORED BY A UDC?

A. Yes. Staff witness Barbara Keene has proposed a code of conduct to help mitigate this problem. The Commission could and should require that a UDC does not favor an affiliate. Competitive bidding rules, and/or rules regarding the selection of suppliers under bilateral contracts, can cover this situation, either as part of or in addition to a code of conduct. Regulations of this kind would seem to remain within the Commission's jurisdiction.

Q. THE UDC RETAINS THE OBLIGATION TO PROVIDE SERVICE, INCLUDING STANDARD OFFER SERVICE. DOESN'T THIS IMPOSE

ON THE UDC THE DUTY TO ACQUIRE POWER IN A WAY THAT WILL ENSURE THAT RATEPAYERS WILL HAVE JUST AND REASONABLE RATES?

A. Yes. Staff witness Matthew Rowell will address this issue.

Q. DOES THIS ISSUE HAVE JURISDICTIONAL RAMIFICATIONS?

A. Yes. It suggests that the Commission retains, or should retain, jurisdiction over the prudence of UDC's acquisition of power to serve standard offer customers. The Commission should be able to satisfy itself that generation rates for standard offer service are just and reasonable.

Q. HOW CAN THE COMMISSION DO THIS IN THE CASE OF POWER ACQUIRED UNDER FERC-REGULATED CONTRACTS OR FROM FERC-REGULATED MARKETS?

A. Firstly, it seems that the Commission should ensure that acquisition *is by the UDC itself* and is not delegated to an affiliate. The Commission can then determine that purchase power agreements are reasonable from a ratepayer standpoint. (I believe the Pike County case gives some authority to state commissions in circumstances of this kind.) Secondly, the Commission should establish competitive acquisition procedures for the UDC, as I suggested earlier.

VII. Concluding Remarks

Q. WHAT DO THESE VARIOUS PRINCIPLES MEAN FOR ARIZONA?

A. I am concerned about the transfer of utility assets to a utility affiliate. I believe that the transfer would result in a loss of Commission jurisdiction over utility generation assets. I believe that the Commission should ensure that the market is ready to support competition before taking such an irrevocable step. The Commission can do this by requiring the utilities' to file market power studies before transferring generation assets. To do otherwise risks premature restructuring.

Q. WHAT IS YOUR PRIMARY CONCERN ABOUT PREMATURE RESTRUCTURING?

A. In a nutshell, my concern is market power. This is turning out to be a far more pervasive problem around the country than it was expected to be.

Q. IN ITS REBUTTAL TESTIMONY IN DOCKET NO. E-01345A-01-0822, FILED ON APRIL 22, 2002, APS ARGUED THAT ITS FINANCIAL ARRANGEMENTS DEPEND ON THE TRANSFER OF ASSETS TO PWEC, AND THAT IT WOULD BE UNFAIR FOR THE COMMISSION TO HAVE A CHANGE OF HEART AT THIS TIME. DO YOU AGREE?

A. The Company's argument misses the underlying point. What is involved here is not a change of heart but a change of circumstances. It is quite

reasonable for the Commission to review certain threshold issues and, if necessary, change one or more elements of its restructuring plan, which assumed the existence of a competitive wholesale market.

Q. APS CLAIMS THAT THE TRANSITION TO COMPETITIVE MARKETS HAS BEEN UNDER WAY FOR YEARS AND IS PROCEEDING SUCCESSFULLY. DO YOU AGREE?

A. No. The difficult parts of the transition have not yet taken place. While Arizona's retail markets have in theory been opened to competition, there are as yet no retail competitors in place, and retail markets remain the domain of regulated, vertically-integrated utilities. Tough issues, such as the breakup of large generators to prevent market power, have not been addressed. And the regional RTO arrangements are not in place. In fact, the reason why the situation is stable is that, as far as retail customers are concerned, nothing has changed.

Q. IN ITS MOTION FOR DETERMINATION OF THRESHOLD ISSUE, APS SAID THAT "THE THRESHOLD POLICY CHOICE IS STRAIGHTFORWARD – DO WE CONTINUE TOWARDS RETAIL ELECTRIC COMPETITION OR DOES THE COMMISSION REVERSE COURSE AND RETURN TO TRADITIONAL COST-OF-SERVICE MONOPOLY REGULATION." DO YOU AGREE WITH THE WAY IN WHICH APS HAS FRAMED THE THRESHOLD ISSUE?

A. No. In presenting the issue as an either/or one, APS has not mentioned the more important issue that it behooves the Commission to address in light of the slow development of the competitive market in Arizona and the region. Staff is not proposing at this point that the Commission should reverse course. Staff is instead suggesting that the Commission ensure that the appropriate steps are taken at the appropriate times. To allow asset transfer to occur before a workably competitive market is in place may actually impede the development of viable competition. For these reasons, it is appropriate for the Commission to examine the reasonableness of asset transfer in light of the potential for market power and other potential market manipulation.

Q. DOES THAT COMPLETE YOUR TESTIMONY?

A. Yes, thank you.

EXHIBIT NHT-1

NEIL H. TALBOT

Economic & Financial Consultant

Education

M.S.F.	Finance, Boston College, 1992
M.A.	Economics, Cambridge University, England, 1968

Employment History

1995 -	Economic and financial consultant to Synapse Energy Economics
1980-1994	Tellus Institute, Boston, Mass. Member of Energy Group responsible for utility economic, financial and regulatory analyses.
1973-1979	Arthur D. Little, Inc., Cambridge, Mass. Member of Managerial Economics Section responsible for public utility economic and planning studies and energy economics.
1968-1973	The Economist Intelligence Unit Ltd., London, England. Project leader of Caribbean economic development studies; research and consulting on industrial and utility economics.

Summary of Relevant Experience

Neil Talbot is an economic and financial consultant to Synapse Energy Economics, Inc. He has masters degrees in economics and finance from Cambridge University and Boston College respectively. He has had 32 years' experience as a consultant focusing primarily on utility company economic, financial and regulatory issues with the Economist Intelligence Unit of London, Arthur D. Little, Inc. of Cambridge, Mass., Tellus Institute of Boston, Mass., and Synapse Energy Economics, Inc. He has prepared a wide range of studies and testimony on utility planning, rate of return, mergers and acquisitions, incentive rates, financial modeling of utilities under alternative rate scenarios, valuation of utility assets and evaluation of utility projects and contracts.

In recent years, Mr. Talbot has focused on the new issues facing the electric utility industry. He is currently a member of the Synapse Energy Economics team retained by the Utah Committee of Consumer Services to review the proposed reorganization of PacifiCorp. He has been a consultant to the Arkansas Public Service Commission on the restructuring of the electric utility industry; his most recent assignments have been to advise on the rate-making treatment of the proposed merger (now cancelled) between Entergy (parent of Arkansas Power & Light Co.) and FPL Corp., and to draft a market power rule

and filing guidelines which were recently submitted to the commission. Articles written by Talbot include *The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation* (The Electricity Journal, January/February 1999) and *A Stranded Cost Recovery Alternative* (Electricity Journal, May 1998).

Mr. Talbot was retained in 1999 by the Utah Committee of Consumer Services to review the financial aspects of the proposed acquisition of PacifiCorp by ScottishPower, and by the Maine Office of Public Advocate to review the proposed acquisition of CMP Group by Energy East. On behalf of the Attorney General of Washington State, he testified in 1996 on the financial impacts of the proposed merger of Puget Sound Power & Light Company and Washington Energy Company. His focus was on financial impacts of the merger and he developed and applied a corporate financial model to the utilities.

Mr. Talbot has testified frequently on cost of capital for regulated utilities. In 1995, he presented testimony on behalf of the Illinois Citizens Utility Board (CUB) on the cost of capital of Northern Illinois Gas Company. His testimony also opposed the company's proposed incentive regulation plan, which the company withdrew during the proceedings. Also for CUB, he testified on the cost of service and cost allocations of Commonwealth Edison Company.

In 2000, Mr. Talbot assembled a Synapse Energy Economics team for the Vermont Department of Taxes to prepare valuations of the Hydroelectric Generating Facilities on the Connecticut and Deerfield Rivers. In the 1990s, Talbot appraised various hydroelectric power plants for towns in Vermont. He evaluated purchased power contracts of Public Service Company of New Hampshire and Bangor Hydro Electric in 1994 and 1995 respectively.

In other rate work, Mr. Talbot has reviewed the incentive regulation plan (Alternative Rate Plan) for Central Maine Power Company and the Alternative Marketing Plan of Bangor Hydro, in testimony before the Maine Public Utilities Commission. He is the author of an AARP position paper entitled *Evaluating Price Cap Proposals in the Electric Utility Industry*. In 1998 he completed a *Sunset Review of the Energy Center of Wisconsin*.

Selected Testimony

Agency	Case or Docket No.	Date	Topic
Maine Public Commission	99-411	Sept. 1999	Acquisition of Central Maine Power Utilities by Energy East
Utah Public Commission	98-2035-004	June 1999	Acquisition of PacifiCorp (UP&L) Service by Scottish Power
Arkansas Public Commission	97-451-U	May 1998	Testified as Staff Expert in Electric Service Industry Restructuring Proceeding
Arkansas Public Commission	96-360-U	July 1997	Changes in Retail Rates and Transition to Service Competition Plan
Washington U.T.C.	UE-960195	Sept. 1996	Proposed Merger of Puget Sound P&L and Washington Natural Gas Co.
Maine Public Utilities Commission	96-187	Aug. 1996	Proposed Interim Competitive Transition Charge Tariff of Central Maine Power Co.
Illinois Commerce Commission	95-219	Nov. 1995	Incentive Regulation and Rate of Return for Northern Illinois Gas Company
Maine Public Utilities Commission	95-901	April 1995	Evaluation of Purchased Power Contract Buyout Proposals of Bangor Hydro
California Public Utilities Commission	A.93-12-029	Sept. 1994	Performance Based Ratemaking for Southern California Edison Company
N. Hampshire Public Utilities Commission	93-179	June 1994	Eval. of proposed buyouts by Public Service Company of New Hampshire of long-term purchased power contracts
Illinois Commerce Commission	94-0065	June 1994	Division among customer classes of an increase (or decrease) in revenue requirements for Commonwealth Edison Company, focusing on cost-of-service studies, both marginal and embedded
Kansas Corporation Commission	176,716U	Oct. 1991	Fair rate of return for KPL's Kansas gas operations
Kansas Corporation Commission	172,745-U 174,155-U	Jan. 1991	Proposed merger of Kansas Gas & Electric Company and Kansas Power & Light Company

New Hampshire Public Utilities Commission	DF 89-085	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation
New Hampshire Public Util. Com.	DR-89-244	March 1990	Rate impact of Northeast Utilities take-over of Publ. Serv. Co. of N.H.
Pennsylvania Public Utility Commission	R-891364	Oct. 1989	Fair rate of return and financial impact of rate recommendations on Philadelphia Electric Company
West Virginia P. S. Com.	Case No. 89-173-E-GI	Aug. 1989	Annual fuel review of Appalachian Power Company
Connecticut D. P. U. C.	89-02-16	June 1989	Fair Rate of Return and Rate Design for Connecticut Water Company
New York Public Service Commission	29484 and 88-E-084	July 1988	10-Year Rate Plan of Long Island Lighting Company
Public Service Commission of Utah	87-035-27	Apr. 1988	Effects of the Proposed Merger on UP&L's Energy Balancing Account and on Its Financial Sit. and Cost of Capital
New Mexico Public Service Commission	1811	Jan. 1988	Fair Price for Coal Resources
Public Service Com. of Indiana	38045	Nov. 1986	Evaluation of a power plant for Northern Indiana Public Service Company
Public Service Commission of Maryland	8522	July 1986	Management Audit of Potomac Electric Power Company's Fuel Procurement Practices
West Virginia Public Service Commission	86-081-E-GI 86-082-E-GI	May 1986	Economic Analysis of Pumped Storage Facility
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224	June 1985	The Financial Impact of Alternative Rate Treatments of Wolf Creek on Kansas City Power & Light Company
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U	April 1985	Concerning Wolf Creek Fuel Procurement and Nuclear and Other Fuel Costs
State of Connecticut D. P. U. C.	84-02-09	June 1984	Fair Rate of Return for Connecticut Natural Gas Company
Public Service Commission of Utah	80-035-17	Jan. 1981	Long-range Forecast: Electric Energy Requirements and Peak Demand

Ohio Power Siting Commission	July 1978	CAPCO Power Pool Load Forecast
Idaho Public Utilities Commission	March 1976	Evaluation of Pioneer Power Plant

Consulting, Research & Papers

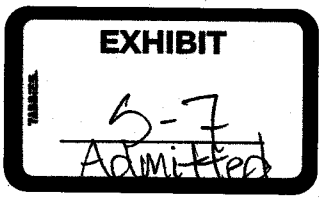
Ongoing	Member of Synapse Energy Economics team evaluating PacifiCorp reorganization proposals
1996-2001	Consultant to the Arkansas Public Service Commission on electric utility industry restructuring and competitive retail access.
1996-2000	Consultant to New Jersey Division of Ratepayer Advocate on electric utility industry restructuring and competition, working regularly in client's office as staff consultant drafting position papers
January 1999	*The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation*, Electricity Journal, Vol.12, No. 1
May, 1998	*A Stranded Cost Recovery Alternative*, Electricity Journal, Vol.11, No. 4
October, 1996	*A Consumer's Skeptical Perspective on Multi-Year Price Cap Plans*, Presentation to Washington, D.C. Conference on *Performance-Based Ratemaking for Electric & Gas Utilities* (Int. Bus. Communications)
August, 1996	*Evaluating Price Cap Proposals in the Electric Utility Industry*, published by American Association of Retired Persons.
July, 1996	*Appraisal of New England Power Company's Moore Station*, a report for Town of Waterford, Vermont
February, 1996	Consultant of Pennsylania Office of Consumer Advocate on Multi-Year Rate Plan of Pennsylvania Power Company
1995	Consultant to City of Wynnewood, Oklahoma, on Long-Term Power Contract with Oklahoma Municipal Power Assoc.
December, 1995	Support for Great Bay Power Corp. with Regard to Cost of Equity Capital in its Cost-of-Service Filing with F. E. R. C.
February 1995	Comments on Retail Competition in the Electric Power Industry Filed with New Hampshire PUC on Behalf of the Office of the Consumer Advocate
December 1994	Assistance on public utility holding company and diversification proposal of Pennsylvania Power & Light Company
November	Preparation of Comments on Electricity Competition filed with the

1994	Pennsylvania PUC by the Office of Consumer Advocate
1992-1993	Co-ordinator of Energy and Environmental Alternatives Planning Assistance Program - Africa. For Stockholm Environment Institute.
1993:	*Zambia: Resuming the Energy Transition.* A report to: Zambia Department of Energy. Co-author. For Stockholm Environment Institute, funded by Swedish International Development Agency.
1994:	*Zimbabwe: Energy End-Uses and End-Use Efficiency.* A report to: Zimbabwe Department of Energy. For Stockholm Environment Institute and Swedish International Development Agency. Co-author.
Oct. 1993	*Financial Economics and Renewable Energy,* presented at: NARUC-DOE National Conference on Renewable Energy, Savannah, Georgia, Oct. 3-6.
July 1992	*Integrated Energy - Environment Planning: Experiences from the United States and Africa,* paper presented with Michael Lazarus, at South African Energy Policy Research and Training Project Workshop, Cape Town.
December 1991	Appraisal of Harriman Hydroelectric Plant of New England Power Co. A report to Town of Whitingham, Vermont. Principal author. 89-047.
Jan.-June 1991	U.S. Agency for Int. Development. Senior Econ. for energy price reform studies for Romania. Provided advice to government regarding energy price reform, energy planning and environmental impacts.
July 1977	*Management Effectiveness and Operating Efficiency of Kansas Gas and Electric Company,* a report to the Kansas Corporation Commission. Co-author.
Feb. 1976	*Idaho Power Company's Need for Additional Generating Capacity,* a report to Idaho Public Utilities Commission. Principal investigator.
Apr. 1974	*Inflation and Economic Growth in the U.S. Virgin Islands,* a report to the Legislature of the U.S. Virgin Islands. Principal investigator.
Jan. 1974	*A Study of International Inflationary Trends, with Special Emphasis on Algeria,* a report to the Algerian Government. Co-author.
Sept. 1973	*Long Term Load Forecast,* a report to Potomac Electric Power Co. Author.
Oct. 1976	Speech on *Load Forecasting for Electric Utilities* published in Proceedings of Need for Power Conference, Columbus, Ohio.

Professional Societies

Member, American Economic Association
Member, Financial Management Association
Member, National Association of Business Economists

BEFORE THE ARIZONA CORPORATION COMMISSION



WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

REBUTTAL TESTIMONY

OF

NEIL H. TALBOT

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 11, 2002

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I. Introduction and Purpose of Testimony

Q. Please state your name and business address.

A. My name is Neil H. Talbot and my business address is Synapse Energy Economics, 22 Pearl Street, Cambridge, Massachusetts 02139.

Q. Are you the same Neil H. Talbot who filed direct testimony in this proceeding on May 29, 2002?

A. Yes.

Q. On whose behalf are you testifying in these proceedings?

A. I am a member of the Synapse Energy Economics team that has been retained by the Utilities Division ("Staff") of the Arizona Corporation Commission to investigate electricity restructuring issues in Arizona.

Q. What is the purpose of your current testimony?

A. This testimony, together with that of other members of the Staff team, is rebuttal of the direct testimony of other parties in this matter concerning the "Threshold Issues" or "Track A" issues -- "the transfer of assets and associated market power issues, as well as the issues of the Code of Conduct, the Affiliated Interest Rules, and the jurisdictional issues raised by Chairman Mundell..."

Q. Whose testimony will you address?

A. I will briefly address parts of the testimony of Panda Gila witness Craig Roach, AECC witness Kevin Higgins, Reliant Resources witness Curtis Kebler, RUCO witness Richard Rosen, TEP witnesses James Pignatelli, Steven Glaser and Michael DeConcini, and APS witnesses Jack Davis and William Hieronymus.

Q. How is your testimony structured?

A. I devote a section to each witness. However, in order to present my conclusions more conveniently, I organize my summary according to subjects, such as market power, rather than according to witnesses.

II. Summary and Conclusions

Q. Please summarize your rebuttal testimony on the issue of transfer of generation assets.

A. My testimony supports the recommendations of Staff witness Matthew Rowell, and particularly his recommendation that "Prior to the transfer of any generation assets, the utilities should be required to file a market power study and market power mitigation plan for Commission approval." (Mr. Rowell's Direct Testimony, page 10, lines 3-5) Thus, I take issue with both the more restrictive proposals of witnesses like Dr. Roach on behalf of Panda Gila, and the less restrictive proposals of witnesses like Dr. Hieronymus on behalf of APS.

Q. Please summarize your rebuttal testimony on market power issues.

A. I argue that there should be a rebuttable presumption that the generation affiliate or other company to which a UDC transfers or divests its generation assets will have market power. Furthermore, I rely on the findings of Staff witnesses Schlissel, Peterson, and Rowell that in fact wholesale electricity markets in Arizona and the Southwest are not yet workably competitive. Accordingly, I take issue with the views of witnesses like Dr. Hieronymus who suggest, at least in some parts of their testimony, that market power problems are being resolved. Nor do I agree with Mr. Higgins that the whole matter is best left in the hands of FERC. On the other hand, I do not share Dr. Rosen's extreme skepticism about FERC and the wholesale markets.

Q. Please summarize your rebuttal testimony on jurisdictional issues.

A. I am in agreement with Mr. Pignatelli's assessment that, after transfer or divestiture of UDC assets, FERC would have exclusive jurisdiction over the rates charged for wholesale sales of energy from those assets, but that, as he says, "the Commission would have jurisdiction over the inclusion of those sales in rates in accordance with Arizona law."

Q. Do you address the issue of codes of conduct and affiliate rules?

A. No. That subject is covered by Staff witness Barbara Keene.

III. Panda Gila River Witness Craig Roach

Q. Do you agree with Dr. Roach's conclusions that "APS has generation and transmission market power," and that "if APS is allowed to unconditionally transfer its generation facilities to an affiliate, it will also be transferring its market power to that affiliate..."?

A. Yes. Dr. Roach's diagnosis of APS market power is similar to that of Staff. Mr. David Schlissel will address the detailed calculations that Dr. Roach has used to support his conclusions regarding APS horizontal market power.

Q. Has Dr. Roach addressed the market of any other utility distribution company in Arizona?

A. No. Staff believes, however, that the TEP system has similar transmission constraints to those of the APS system. As I argued in my Direct Testimony, it would be prudent to have a rebuttable presumption that a utility or its generation affiliate will have market power unless and until appropriate mitigation measures are implemented.

Q. Do you agree, then, with Dr. Roach's recommendation that, "because the Commission will have less authority after the transfer to prevent harm to consumers from the exercise of market power by that affiliate, it *must* ensure that, prior to such transfer, APS' market power will be mitigated"? (emphasis added)

A. Yes. Staff certainly believes it would be good public policy to mitigate market power *before* transfer. As Staff witness Matthew Rowell said in his Direct Testimony, on page 10, lines 3 to 4, "Prior to the transfer of any generation assets, the utilities should be required to file a market power study and market power mitigation plan for Commission approval." Generally, it is important to make the

conditions of transfer, i.e. the implications of transfer for Standard Offer service, very clear and legally binding on a Utility Distribution Company (UDC) *before* transfer is permitted. Each UDC has an obligation to provide Standard Offer service to its retail customers at just and reasonable rates. If a UDC decides to transfer its assets (including must-run units if the Commission determines that to be appropriate) into an imperfectly competitive wholesale power market, it should be allowed to do so, provided the UDC is prepared to take the risk of not recovering the purchased power costs that exceed the UDC's traditional cost-based rates.

Q. Do you agree with Dr. Roach's recommendation, on the bottom of page 4 and top of page 5 of his testimony, that APS should only be allowed to transfer its generation assets if it competitively procures 100% of the power it needs for Standard Offer customers?

A. No. I think this requirement is too restrictive. Rather, as Staff witness Matthew Rowell proposed on page 10 of his Direct Testimony, a UDC should have the discretion to transfer generating units under appropriate conditions. The conditions are critical during the "transition period." This period is defined as "the period from now until the Commission determines that the wholesale market for power delivered to the UDCs' service territories is workably competitive." (Mr. Rowell's Direct Testimony, page 5, lines 18-20)

Q. Starting on page 16 of his testimony, Dr. Roach describes "four specific mitigation measures" to prevent the exercise of market power by a UDC affiliate. Please comment.

A. I believe Dr. Roach's specific proposals are less important than the underlying premise of his proposals, namely that a workably competitive electricity market can be established in Arizona, under certain conditions. I agree with him, and I also agree with him that the conditions are not yet in place.

IV. AECC Witness Kevin Higgins

Q. What is your overall assessment of Mr. Higgins' testimony?

A I have a major area of agreement with Mr. Higgins, and a major area of disagreement. Let me first describe the area of agreement. Like Dr. Roach and myself, Mr. Higgins agrees that market power is a key issue. As he puts it, the answer to the question "how well the agreements and Electric Competition Rules will work in the future...turns on the issue of how potential market power is addressed." (Testimony, page 4, lines 6-10)

Q. What is the area of disagreement?

A. Mr. Higgins appears to take the view that market power issues will be adequately taken care of under existing arrangements, mostly under the aegis of FERC, and without significant initiatives by this Commission. For example, he says that, "(t)o the extent that market power were to become a more generalized problem in Arizona, parties could seek relief at FERC..." (Testimony, page 5, lines 4-7) I believe he is over-confident about the readiness of FERC to address serious market power concerns. This Commission needs to take steps to ensure that Arizona markets are competitive, and to make conditions regarding competitiveness, and/or other protections of retail customers, pre-conditions of asset transfer.

Q. Why do you believe that FERC is not, or not yet, the answer to all wholesale market power problems?

A. During the unfolding California crisis, it seemed at first as if FERC was part of the problem, not part of the solution. As Mr. Higgins acknowledges, "FERC's past record in addressing market power issues has been controversial and the target of significant criticism..." But he believes that FERC has now been galvanized into action. By contrast, Staff witness Paul Peterson describes the outstanding issues that still need to be addressed by FERC, and shows that it is likely to take some time before great reliance can be placed on FERC's control over the regional power market. Meanwhile, there is a regulatory gap: it is not that

FERC lacks jurisdiction, rather that the institutions -- primarily RTOs -- by which it plans to implement its programs and policies, such as market monitoring, are not yet in place. Mr. Higgins says that "the Commission should seek new, more rigorous market power tests to be performed with respect to the APS territory and TEP territory sub-markets..." (Testimony, page 5, lines 13-15) Apparently, the Commission should propose these tests to FERC, and it is FERC that should adjudicate these tests and determine what mitigation may be needed, but it is not clear how long it would take to accomplish this effort, or whether it would be effective.

Q. Regarding market power in load pockets, Mr. Higgins argues that the Arizona Independent Scheduling Administrator (AISA) can take care of this problem until a regional RTO takes over. Do you agree?

A. Staff witness Jerry Smith addresses this issue. His view is that the AISA may not be able to effectively address these problems.

V. Reliant Resources Witness Curtis Kebler

Q. Please comment on Mr. Kebler's testimony.

A. I would like to refer to four points made by Mr. Kebler. First, he clearly states that UDC generation asset transfer will create a market power problem. As he puts it:

> The transfer of APS' generation assets...results in the concentration of available generation capacity within a single entity. In addition, existing transmission constraints limit the amount of external generation that can be imported into the Phoenix load center area. Absent structural remedies, these circumstances do not provide the conditions necessary for multiple suppliers to compete effectively in the provision of generation services on behalf of Standard Offer customers. (Testimony, at page 2, lines 14-20)

Q. Please comment on Mr. Kebler's proposed solution.

A. While Mr. Kebler provides a reasonable diagnosis of the horizontal market power problem in the wholesale electricity market in Arizona, he places excessive reliance on one cure, a capacity auction, something that is a feature of

restructuring in Texas. All I want to say about this at the present time is that it appears to be a Track B issue.

Q. You referred to four points made by Mr. Kebler. The first is that he highlights the importance of the market power problem. What is the second?

A. Mr. Kebler raises the possibility of "going forward with the asset transfer, but with something less than 100% of capacity initially." (Testimony, page 8, line 21 to page 9, line 1) I believe this is not inconsistent with Staff recommendations.

Q. What is Mr. Kebler's third point?

A. Like Dr. Roach, he emphasizes the importance of making transmission available on equal terms to competitive suppliers. In his specific proposal for a capacity auction, Mr. Kebler points out that the capacity that is auctioned must be designated as Network Resources on behalf of native load customers. Staff witness Jerry Smith will address this issue.

Q. What is Mr. Kebler's final point?

A. Mr. Kebler states correctly that "Track A and Track B issues are necessarily inter-related." (Testimony, page 4, lines 5-7) This linkage is the reason why Staff is proposing that it may be necessary to make UDC generation asset transfer (a Track A issue), if permitted, conditional on not only the resolution of the market power problem (a Track A issue), but also on the resolution of certain issues, such as appropriate procurement, or creation of associated mitigation measures (Track B issues).

VI. RUCO Witness Richard Rosen

Q. Please discuss Dr. Rosen's views regarding market power.

A. Dr. Rosen has developed very strong arguments about the serious nature of the market power problem in wholesale electricity markets. He explains how market power can be exercised in many ways. His analysis is important for the Commission and consumers.

Q. Does Dr. Rosen believe that the Commission can rely upon FERC regulation to ensure that wholesale electricity markets are competitive?

A. No. Dr. Rosen is highly skeptical about FERC's approach to market power monitoring and mitigation. Looking back over the past two years, there is considerable evidence to support his skepticism. Looking forward, it remains to be seen whether Dr. Rosen's skepticism, or the optimistic views of AECC's witness Kevin Higgins, or something in between, turn out to be most accurate.

Q. Has Dr. Rosen analyzed the market power situation in Arizona specifically?

A. Yes. While his analysis of Arizona electricity markets is not supported by the kind of data that Staff witnesses Jerry Smith and David Schlissel, and Panda witness Craig Roach, have developed, he makes a persuasive case that the Commission should not take the problem of market power in Arizona lightly.

VII. TEP Witnesses Pignatelli, Glaser and DeConcini

James A. Pignatelli

Q. Mr. Pignatelli expresses considerable skepticism about retail electric competition. Please comment.

A. I acknowledge that in this proceeding there is a wide range of reasonable views on this subject, and Mr. Pignatelli's views are certainly understandable. Thus far, the results of restructuring have been disappointing, and the risks are more evident than the benefits. However, the Commission embarked on the restructuring process several years ago, and, in my view, it should not change course without good reason. The survey of restructuring that I undertook recently for Staff, and which was contained in the Staff Report, showed that any given state's view of restructuring depends more than anything else on the condition of the *wholesale* electricity market. Where the wholesale market has functioned relatively smoothly, as in the Northeast, restructuring is generally continuing and the principal objective is to make energy markets more competitive. Where the wholesale market has been unstable, as in California and the other Western states

affected by the California crisis, restructuring has in some cases been abandoned or delayed.

Q. Mr. Pignatelli describes the lack of effective competition in the *retail* electric market in Arizona to date. Please comment.

A. My focus here is more on the threshold issue of competition in the *wholesale* market. Despite his skepticism about retail competition, Mr. Pignatelli is much more optimistic about the wholesale market, which I think is what the Commission is primarily concerned about as a Track A issue. He says in his Direct Testimony, at page 10, lines 2-7:

> I believe that with the proper procedures and safeguards in place, competition among electric generators for *wholesale* sales of electricity can be viable within a short period of time. I believe that in order for there to be competition among electric generators for retail sales of electricity there first must be an established and functioning wholesale market.

Mr. Pignatelli also makes the important point that "one of the most critical components that will influence retail electric competition is generation price *volatility* in wholesale markets." (page 12, lines 11-14, emphasis added) He continues:

> Before a robust competitive retail market can exist in Arizona the art of balancing regional supply and demand without a regulatory mandate and delivery infrastructure issues must be addressed. For its part, the Commission can encourage the development of (a) additional generating resources and/or load management, which will be required to maintain a regional supply and demand balance; and (b) additional transmission infrastructure and new gas pipeline or railroad infrastructure that will be necessary to ensure adequate delivery capability to customers and fuel supply to generators.

Following this line of argument, I think the Commission should focus first on the conditions necessary to create a viable wholesale electricity market. Mr. Pignatelli has listed components of such a wholesale market. (Direct Testimony, page 10, lines 17-24)

Q. On page 11 of his testimony, Mr. Pignatelli addresses the question of jurisdiction. Please comment.

A. Mr. Pignatelli's understanding of the issue of jurisdiction over sales from divested or transferred generation assets to a UDC appears to be the same as mine. Namely, that FERC would have exclusive jurisdiction over the rates charged for wholesale sales of energy from those assets, but that, as Mr. Pignatelli says, "the Commission would have jurisdiction over the inclusion of those sales in rates in accordance with Arizona law."

Q. Finally, turning to page 17, lines 17 et seq., of Mr. Pignatelli's testimony, please comment on his first recommendation regarding Track A issues.

A. Mr. Pignatelli recommends that, "The Commission should issue findings of fact that detail the purported benefits of electric competition both on a retail and wholesale basis." If his intention is to get a specific quantitative assessment or cost-benefit analysis of competition, I think this is too much to expect of the Commission. In my opinion, it is not yet possible to quantify the benefits of retail competition. On the other hand, a mere listing of the benefits of retail competition is a somewhat empty exercise.

Steven J. Glaser

Q. Mr. Glaser argues that it will be difficult for TEP to comply with the deadline of December 31, 2002 for transferring ownership of its generation assets. Do you agree?

A. Yes. I think it is appropriate for TEP to be given a variance from this deadline until the Commission has completed its review of the Electric Competition Rules.

Michael J. DeConcini

Q. Mr. Deconcini says at page 8, lines 13-14 of his testimony, that "the current power market is competitive at a wholesale level and that a competitive generation market can and will provide adequate generation resources." Do you agree?

A. No, the Arizona and regional wholesale markets are not yet workably competitive and smoothly functioning. One has to look no further than the testimony of Mr. Pignatelli to see what is still needed to make the wholesale market workably competitive, and, as he emphasizes, to avoid price volatility by balancing regional supply and demand. (See Mr. Pignatelli's testimony at pages 10 and 12, to which I referred earlier.) Further, Mr. DeConcini himself, when he lists key steps that "need to be taken in order to provide the opportunity for significant retail competition," includes wholesale market steps such as relieving transmission constraints, implementing standard wholesale market rules, and instituting effective wholesale market monitoring.

VIII. APS Witnesses Davis and Hieronymus

Jack E. Davis

Q. In his Direct Testimony, Mr. Davis points out that the electric competition rules and APS settlement agreement provided for divestiture of APS generation. Do you agree with his contention, on page 2, lines 23 to 24, that "the reasons prompting these various actions by the Commission and/or Staff are as valid today as they were in 1998 and 1999"?

A. No. While it is generally agreed that divestiture of generation assets is an important part of restructuring, and is favorable to competition in appropriate circumstances, it is clearly understood that this is only the case if competitive conditions exist in electricity markets. Otherwise, there is the danger that regulated monopolies would be replaced by unregulated monopolies, which would be the worst of both worlds.

William H. Hieronymus

Q. Please turn to page 2, lines 13 to 15, of Dr. Hieronymus' testimony. He says that "the separation of APS's generation is in the public interest because the public interest is best served by the creation of a liquid and vibrant competitive wholesale market." Please comment.

A. Dr. Hieronymus' statement confuses two separate issues -- separation and competition. Yes, along with other necessary features, separation can be part of a competitive wholesale market. However, absent those features, it could give an affiliate generator an opportunity to exercise considerable market power. To the extent there is market power in the restructured industry, the benefits of competition will not be realized. However, if and when the right conditions are in place, I agree with Dr. Hieronymus's view that "a competitive wholesale market is an essential underpinning of retail competition and, with it, the product and pricing innovations that retail competition can produce." (Direct Testimony, page 3, lines 8-10)

Q. Do you agree with the remarks Dr. Hieronymus makes about market restructuring in other states on page 4 of his testimony?

A. No, I believe his assessment of restructuring is too rosy and optimistic. While acknowledging that "recent events in areas near Arizona have tarnished the image of market restructuring, he makes two statements in the first full paragraph of page 4 that I do not agree with. First, he states that "allegations of misbehavior notwithstanding, the specific events of 2000-2001 in the WSCC arose from a very unsual combination of events that are unlikely to recur simultaneously.." While the extreme price volatility of the past two years may be unlikely to recur, there are still at least two causes of concern in Western markets. One is the lack of an established market structure, monitored by an effective RTO. The other is the continuing concern that, after the current period of adequate supply, a period of power shortages might ensue.

Q. What is the other statement of Dr. Hieronymus's that you disagree with?

A. Dr. Hieronymus says that "many other policy decision makers have not been fazed by the California experience. The movement away from the regulated monopoly model to the competitive market model has only marginally slackened its pace." This view does not quite achieve the right balance. The survey of other states that I conducted for the Staff, and is contained in the Staff Report, showed that regulators in the West have indeed been "fazed" by the California experience. In fact, New Mexico, Montana, Nevada, and California itself, have reversed, put on hold, or significantly delayed, restructuring. This experience is of immediate relevance to Arizona. Dr. Hieronymus himself notes that, "The states with approved retail access include one, California, where access has been suspended, and seven where it has been delayed since the events of 2000-2001." (Direct Testimony, page 7, line 20 to page 8, line 2) As I said earlier in my testimony, the best indicator of regulatory views about retail restructuring is the stability of the wholesale market. The top priority for Western states, where restructuring is effectively on hold, is surely to first achieve a stable, workably competitive, wholesale electricity market.

Q. Beginning at the bottom of page 4 of his testimony, and in later sections, Dr. Hieronymus takes a fairly sanguine view about APS' ability to exercise market power. Do you agree that the Commission should not be too concerned about the problem?

A. No. As I said in my Direct Testimony in this matter, I think the better approach is for the Commission to make a rebuttable presumption that a regulated utility, when its generation is deregulated, will have market power in its local market. The prudence of this approach is supported by the analyses of Staff witness Jerry Smith and David Schlissel, and by that of Dr. Craig Roach. Those analyses refer to horizontal market power.

Q. Do you have any comments on the problem of vertical market power?

A. Yes. I note that Dr. Hieronymus states that, while he has focused on horizontal market power, "vertical market power has far greater potential to destroy competitive markets." (Testimony, page 26, lines 16-18) He believes that the Commission, and "FERC in its orders and its RTO policy" have already focused "strongly" on this issue. On page 22, lines 14-18 of his Direct Testimony, Dr. Hieronymus says that "RTO formation has taken on a new urgency since RTO market power monitoring and mitigation is seen as the principal 'front line' defence against both the exercise of market power and gaming of inadequate or inefficient market rules." As Staff witness Paul Peterson explains, it will take some time before the Commission can have full confidence in the RTO arrangements in the Southwest. Meanwhile, the Commission will have to be vigilant to ensure that the affiliate relationship between a UDC and its transmission and generation affiliates does not give rise to the exercise of vertical market power.

Q. What kinds of abuses do you have in mind?

A. If a UDC buys back power from its generation affiliate, there is obviously significant potential for favoring the affiliate over competitors. Secondly, as APS witnesses have pointed out, the transmission system of a vertically-integrated utility is not designed to support large amounts of competitive sales and purchases of electricity. It will be important for the UDC or its transmission affiliate to be required to adequately build out the transmission system for a competitive market, even though that construction program could be costly and could undermine the market advantage of the affiliate generator.

IX. Concluding Remarks

Q. Do you have any concluding remarks?

A. Yes. While Staff is not recommending that generation asset transfer be denied, I believe that, if transfer is permitted, it should be subject to appropriate conditions, as set out on page 5 of Staff witness Matthew Rowell's testimony, including the filing of a market power study and market power mitigation plan. The Commission should ensure that generation rates for Standard Offer customers are just and reasonable. Given the current state of Western wholesale markets, I don't believe that during this transition period wholesale markets can be counted on as a reliable yardstick for just and reasonable rates.

Q. **Does this complete your testimony?**

A. Yes.

EXHIBIT
S-8
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

DAVID A. SCHLISSEL

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF UTILITIES DIVISION

MAY 29, 2002

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I. QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Staff of the Arizona Corporation Commission. ("Staff")

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in economic and policy analysis of the electric industry, particularly issues of restructuring, market power, consumer protection, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, need for new transmission and generation capacity, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Arkansas Public Service Commission Staff, the Vermont Department of Public Service, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

II. CONCLUSION AND RECOMMENDATION

Q. What is the purpose of your testimony.

A. I have been asked by the ACC Staff to examine whether the transfer and separation of generating assets by the Arizona Public Service Company ("APS") and/or the Tucson Electric Power Company ("TEP") will create market power issues. This testimony presents the results of my investigation of this issue.

Q. Please summarize your conclusion concerning the transfer and separation of APS' generating assets.

A. As a result of the transfer and separation of its generating assets, APS and its affiliates would be able to exercise market power, most significantly in the transmission constrained areas in the Phoenix Valley and Yuma.

Q. Please summarize your conclusion concerning the transfer and separation of TEP's generating assets.

A. As a result of the transfer and separation of its generating assets, TEP and its affiliates would be able to exercise market power in the Tucson load constrained area which contains all of the Company's retail loads.

Q. What is your recommendation?

A. APS and TEP should be required to present detailed analyses of the potential for the exercise of market power before the Commission grants approval for the transfer and separation of their generating assets to affiliates.

III. ARIZONA PUBLIC SERVICE COMPANY

Q. Has APS indicated that it believes that there would be a competitive wholesale market if its generating assets are transferred to its affiliate Pinnacle West Energy Corporation ("PWEC") in the near future?

A. No. In fact, in its testimony in Docket No. E-01345A-01-0822, APS repeatedly emphasized that there will not be sufficient competitive generating facilities to supply even 50 percent of its standard offer loads in 2003 or in any year in the near future.[1] The Company also has said that existing transmission constraints will prevent those new merchant plants currently under construction from supplying significant quantities of power to its standard offer customers.

> Another fact is that it is not presently possible to obtain 50%, let alone 100%, of APS' requirements from the Palo Verde hub to the Company's' primary and secondary load centers, and yet it is precisely in the Palo Verde area that most of the Merchant Intervenors have elected to build their plants or to interconnect with the Arizona grid. Others, although located far from Palo Verde, are also positioned far from the APS transmission system, with no practical way to reach APS.[2]

In fact, APS has argued that while it may be "theoretically possible" that 700 MW of load in its non-transmission constrained areas could be competitively bid, it has serious reservations about the feasibility of such an approach.[3]

Even if it were possible to competitively bid this 700 MW of load in non-transmission constrained areas, the Company's remaining standard offer loads, including the customers in the Phoenix Valley and Yuma load pockets, would be at risk for higher rates should APS effectively exercise its market power to raise wholesale power costs.

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1 Direct Testimony of William H. Hieronymus on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, at page 24, lines 11-13.

2 Direct Testimony of Jack E. Davis on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 6, lines 5 to 11.

3 Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 18, line 4, to page 19, line 14.

Q. Has APS implied that it might seek to profit from the limited competition for serving its standard offer loads?

A. Yes. APS witness Hieronymus in Docket No. E-01345A-01-0822 has testified that:

> Moreover, the aggregate capacity available from these [merchant generating facilities], even assuming they could deliver to APS loads, is less than half of the PWEC load that would be put out to bid. Of course, PWEC or PWCC could bid, but would do so with the knowledge that it faced limited competition and that some of its capacity likely would be needed.[4]

This suggests that APS might seek to take advantage of its market power.

Q. Please explain how you have evaluated whether the transfer and separation of APS' generating assets will create market power concerns?

A. As I will explain later in this testimony, a detailed system simulation analysis needs to be performed to determine the extent to which APS will be able to exercise market power in its service territory when its generating assets are transferred to PWEC. This system simulation analysis would reflect existing transmission constraints and planned transmission and generation upgrades.

However, I have not had the opportunity to perform such an analysis due to the limited time provided for the preparation of this testimony. Therefore, I have performed a screening analysis using the new Supply Margin Assessment ("SMA") test that FERC has said should be used pending completion of a generic rulemaking proceeding.[5]

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4 Ibid., at page 3, line 20, to page 4, line 2.

5 FERC Order in Dockets Nos. ER96-2495-015, ER97-4143-003, ER97-1238-010, ER98-2075-009, ER98-542-005, ER91-569-009 and ER97-4166-008, issued November 20, 2001, at page 7.

Q. Has FERC explained why it believes that this SMA screen is an appropriate test for examining whether an applicant can exercise generation market power?

A. Yes. FERC explained that because of structural changes and corporate realignments that have occurred and continue to occur in the electric industry, earlier analyses no longer adequately protect customers against generation market power in all circumstances.[6]

According to FERC, as a method for assessing whether an applicant has generation market power, the SMA screen builds on and improves the earlier methodology in two ways:

> First, in determining the geographic market, the SMA considers transmission constraints. Thus, the SMA can more accurately determine what supply can reach buyers to compete with the applicant.
>
> Second, in determining the size that triggers generation market power concerns, the SMA establishes a threshold based on whether an applicant is pivotal in the market, i.e., whether at least some of the applicant's capacity must be used to meet the market's peak demand. When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity. An applicant will be pivotal if its capacity exceeds the market's surplus of capacity above peak demand -- that is, the market's supply margin. Thus, an applicant will fail the SMA screen if the amount of its capacity exceeds the market's supply margin. By contrast, under the hub-and-spoke method, an applicant would pass the screen if its market share were less than 20 percent, even if its capacity were pivotal. The SMA's supply margin threshold is a better screen for market power because, unlike the 20 percent market share screen, it is sensitive to the relative scarcity of electricity supply available from suppliers other than the applicant in the applicable market. Effectively, the supply margin threshold identifies whether the applicant is a must-run supplier needed to meet peak load in the control area. Thus, the supply margin is sensitive to the potential for the applicant to successfully withhold supplies in the market in order to raise prices.[7]

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6 Ibid.

7 Ibid., at pages 7 to 8.

In other words, FERC has found that an applicant is "pivotal" and has the ability to exercise market power within its control area market because its generation is needed to meet the market's peak demand.

Q. Has APS acknowledged that its generation is needed to meet the peak demand of its customers in the Phoenix Valley transmission constrained area (i.e., load pocket)?

A. Yes. APS rebuttal witness Deise in Docket No. E-01345A-01-0822 presented an APS Valley Import Analysis that showed that the Company would need 427 MW of its in-Valley capacity to meet projected peak loads in 2003.[8] The amount of in-Valley capacity needed to meet projected peak demands in subsequent years would increase to 1,034 MW by 2007 but would decrease in 2008 following the completion of planned transmission system upgrades.

Year	APS Valley Load	APS Transmission Import Capability	APS In-Valley Generation Requirement
2003	4112	3685	427
2004	4256	3685	571
2005	4405	3685	720
2006	4559	3685	874
2007	4719	3685	1034
2008	4884	4685	199
2009	5055	4685	370
2010	5232	4685	547

Obviously, APS dependence on in-Valley generation units to meet projected peak demands will continue to increase after 2007 if the proposed transmission system upgrades are not completed as currently planned.

Consequently, under FERC's SMA screen test, APS would have the ability to exercise market power within its Phoenix Valley service area because its generation would be needed to meet the area's peak demand.

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8 Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, Schedule CD-3R.

Q. Does APS need to operate its in-Valley generating facilities for a significant number of hours each year to serve customer demands?

A. Yes. For example, APS has indicated that it had to operate some amount of "must-run" in-Valley generation for 956 hours in the year 2000.[9]

Q. Would APS similarly have the ability to exercise market power in its Yuma load pocket?

A. Yes. The ACC Staff has found that APS' transmission import capability into the existing Yuma load pocket will be inadequate to meet projected peak demands at least until 2004 when a new transmission line is scheduled for completion.[10] Until that time, at least, APS will rely on generation inside its Yuma load pocket to meet some of its projected peak demands.

Q. Is it only the need to rely on generating facilities inside these load pockets that creates the potential for market power?

A. No. The potential for APS to exercise market power also is enhanced by the fact that, for the foreseeable future at least, some APS or affiliate-owned generating facilities located outside the Phoenix Valley will continue to be needed to serve both peak and non-peak customer demands within that load pocket. This is due to the limited amount of merchant capacity that will be capable of being imported into the Phoenix Valley.[11] APS' control over the existing transmission system also creates vertical market power concerns about its possible use of that control to advantage its own affiliates while disadvantaging competitors.

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9 Revised Biennial Transmission Assessment, 2000-2009, Revised July 2001, Appendix D, at page 16.

10 Revised Biennial Transmission Assessment, 2000-2009, Revised July 2001, Appendix D, at pages 32 and 33.

11 See the Direct Testimony of Jack E. Davis on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 6, lines 5 to 11 and the Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 18, line 4, to page 19, line 14.

Q. Has APS acknowledged that the existence of the Phoenix Valley and Yuma load pockets creates market power concerns?

A. Yes. APS witness Hieronymus testified in Docket Nos. E-01345A-98-0473, E-01345A-97-0773, and RE-00000C-94-0165 that the existence of the Phoenix Valley, Yuma and Douglas load pockets creates market power concerns:

> A load pocket is a geographic area in which the peak load exceeds the capability of the transmission system to allow power imported from outside the pocket to fully and reliably serve load. Usually, this limit is the thermal limit of the transmission lines entering the pocket. Since imports cannot fully meet load, it is necessary that some part of the load must be met by running generation located within the pocket. Other concerns, such as system stability and voltage problems, may also dictate that generation within the pocket must be run.
>
> * * * *
>
> [load pockets create market power concerns] because only generation within the load pocket can meet the load that exceeds the import limit. If there is only one, or very few owners of generation in the pocket, and the prices that they charge are not regulated, the owner(s) may be able to charge excessive prices. This will be true even if the market in the area surrounding the pocket is competitive.[12]

This is precisely what the situation in the Phoenix Valley will be if APS is allowed to transfer its generating assets to its PWEC affiliate.

Q. Did APS admit that its unregulated affiliate, then called Genco, but now named PWEC, could exercise market power in the pricing of the output of its in-pocket generating units?

A. Yes. Mr. Hieronymus acknowledged that APS theoretically could charge above competitive prices when its units within the Phoenix Valley, Yuma, and Douglas load pockets must run:

> In the case of the Yucca and Douglas CTs it would be able to charge above competitive prices during those hours when the units are must

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[12] Rebuttal Testimony of William H. Hieronymus on Behalf of Arizona Public Service Company, Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165, at page 5, lines 5 to 17.

run in the absence of regulation. In the case of the valley units, APS competes with SRP, and SRP has sufficient generation in the valley that APS generation is not required. However, with only two sellers to meet the roughly 1,000 MW of peak load that cannot be met with imports, there may be a concern that the prices charged for in-valley generation will not be competitive.[13]

Q. Did Mr. Hieronymus believe that APS actually would be able to exercise market power in the pricing of the generation within the existing load pockets?

A. No. He testified that FERC would act to protect consumers where the existence of load pockets creates the ability to exercise market power.[14]

Q. Do you agree that the Commission can rely on FERC to protect Arizona consumers against the possibility that APS will exercise market in the Phoenix Valley, Yuma, and Douglas load pockets?

A. No. Given FERC's failure to act in an effective and timely manner to protect purchasers of wholesale energy in California from widespread market power abuses, I don't believe that the ACC should rely on FERC to protect Arizona consumers.

Q. Has APS estimated how much of its load could be competitively bid in the near future given the current transmission system and planned generation and transmission additions?

A. Yes. As I noted earlier, APS rebuttal witness Deise testified in Docket No. E-01345A-01-0822 that it might be "theoretically possible" to competitively bid up to 700 MW of APS' unconstrained loads in its Northern Arizona, Southern Arizona and Eastern Mining areas; but he had serious reservations about the feasibility of such an approach.[15]

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[13] Ibid., at page 7, lines 1 to 8.

[14] Ibid., at page 8, lines 12 to 18.

[15] At page 18, line 19, to page 19, line 14.

However, Mr. Deise emphasized that it was not possible "without making a number of critical explicit or implicit assumptions" to tell the Commission how much power can be competitively bid in the Company's service area given existing transmission constraints and the design of APS' transmission system:

> For example how are the Dedicated Units being used, how specifically will the bid be structured, where will the required delivery points be located, and for what capacities at each delivery point? The bid amount also cannot be determined without knowing the exact location and operational characteristics of all the generation resources that would operate on APS' system following the competitive bid.[16]

Mr. Deise further explained that without such a detailed analysis it was not possible to determine how much of the new merchant capacity being built outside of the Phoenix Valley could be competitively bid into APS' service territory:

> I certainly agree that significant amount of new generating capacity is being constructed in Arizona and is currently planned for future construction in Arizona. I would also agree that this new capacity should allow Arizona to contribute to the supply needs of the Western Interconnection.
>
> However, much of this new capacity is relatively concentrated around the Palo Verde hub - something that is certainly not surprising given the amount of trading there and the fact the direct interconnection by generators to the "common bus" at Palo Verde reduces transmission costs to the generators. Because APS' system cannot physically take delivery of all its power requirements from one location like Palo Verde, I do not believe that the analysis of whether there is an adequate "competitive supply margin" for delivery to APS' transmission system can be performed by simply adding up all the new and planned capacity in the state and comparing it with load requirements. For APS, power would have to be delivered at all the injection points that I discussed in Part IV of my testimony, which requires a more involved analysis than the additive process that [ACC Staff witness Jerry] Smith appears to have performed in his testimony on this issue. Thus, while I agree that there is a significant amount of new generating capacity being added in Arizona and to the Western Interconnection generally, I don't believe that new capacity can simply

[16] Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, at page 23, lines 4 to 12.

> be summed to determine whether there is an adequate "competitive supply margin" for APS's system ....[17]

Q. Should the Commission only be concerned about APS' ability to exercise market power during peak demand hours or should it be concerned about non-peak hours as well?

A. The Commission should be concerned about market power both in peak demand hours and in non-peak hours. Events in California have shown that generation owners have been able to raise prices by exercising market power even in off-peak hours. For example, a report by the California Independent System Operator's Department of Market Analysis issued in May of 2001 has concluded that 30 percent of wholesale energy costs during calendar year 2000 could be attributed to the exercise of market power (i.e., that wholesale energy costs were about 30 percent higher than they would have been in the absence of market power).[18] The California Independent System Operator ("CAL ISO") also found that wholesale energy prices exceeded the competitive benchmark **in all hours, under a variety of system conditions**:

> The results illustrate that market power abuse is not limited to hours when a deficiency in operating reserves requires the ISO to declare a System Emergency, much less hours in which a Stage 3 emergency has been declared. The data demonstrate that over the most recent 12-month period (including the first two months of 2001) the gap between actual wholesale prices and the proper competitive level (which takes into account spikes in natural gas prices) *continues to grow*. (emphasis in original)[19]

In fact, the CAL ISO has concluded that less than 2% of the hourly bidding profiles by the five large in-state generation owners during the period May through November 2000 displayed no clear pattern of withholding or market

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17 Ibid., at page 24, line 7, to page 25, line 3.

18 *Comments of the California Independent System Operator Corporation on FERC Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market,* dated March 22, 2001, at page 8. These comments are available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

19 Ibid.

power.[20] The other 98% of the hourly bidding profiles displayed various patterns leading to inflated market prices. CAL ISO subsequently stated that it was unable to identify any hours during the period May 2000 through November 2000 in which one of the generation owners, Williams Energy Marketing & Trading Company, "did not engage in physical or economic withholding."[21]

According to CAL ISO, during the ten month period, May 2000 to February 2001, the degree of market power observed in California wholesale markets had represented additional total costs of $6.8 billion.[22] Only about $600 million of these additional costs were incurred during hours of potential resource scarcity, so that, "even excluding these hours, wholesale energy costs had been driven up over $6.2 billion since May 2000, by the exercise of market power."[23]

Q. What analyses should the Commission require APS to perform before it allows the transfer of generating assets to affiliated companies?

A. A proper analysis of the market power implications of the proposed transfer of generating assets would require an electric system simulation model to look at the hourly behavior of the market under a wide variety of physical conditions, contractual situations and bidding behaviors. Such a realistic analysis should reflect the transmission system constraints discussed in Docket No. E-01345A-01-0822 by Staff witness Smith and ACC witnesses. It also would examine the potential for the exercise of market power during both peak and non-peak hours in both peak and non-peak seasons.

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20 *Empirical Evidence of Strategic Bidding in California ISO Real-time Market*, Anjali Sheffrin, Director, Department of Market Analysis, CAL ISO, March 21, 2001, at page 8. This report available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

21 *Motion to Intervene and Protest of the California Independent System Operator Corporation*, April 2, 2001, in FERC Docket No. ER99-1722-004, at page 10. A copy of this Motion is available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

22 *Comments of the California Independent System Operator Corporation on FERC Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market,* dated March 22, 2001, Attachment B, at page 10. These comments are available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

23 Ibid.

IV. TUCSON ELECTRIC POWER COMPANY

Q. Would a transfer and separation of Tucson Electric Power Company's ("TEP") generating assets create a similar potential for the exercise of market power?

A. Yes. All of TEP's retail load is located within its Tucson transmission limited service territory.[24] TEP projects that this load will grow from 1,889 MW in 2003 to 2,214 MW in 2010. There will be a limit on the transmission system's import capability of 1,535 MW after the second Saguaro to Tortolito 500 kV tie and transformer are installed. Thus, TEP will need to operate large amounts of generating capacity inside the load pocket in order to meet projected peak demands.[25]

Year	Load Area Peak Demand	Local Area Transmission Import Limit	TEP Local Area Generation Requirement
2003	1889	1535	354
2004	2001	1535	466
2005	2025	1535	490
2006	2082	1535	547
2007	2099	1535	564
2008	2137	1535	602
2009	2175	1535	640
2010	2214	1535	679

Applying the FERC SMA screen shows that TEP would have the ability to exercise market power within the Tucson load pocket because its generation would be needed to meet the market's peak demand.

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24 TEP April 25, 2002 response to Staff Data Request No. RTW 1-4 in Docket No. E-01933A-02-0069.

25 The information presented in this table was taken from the loads and resources table provided in TEP's April 25, 2002 response to Staff Data Request No. RTW 1-1 in Docket No. E-01933A-02-0069.

Q. What analyses should the Commission require TEP to perform before it allows the transfer of generating assets to an affiliated company?

A. As I discussed previously with regard to APS, the Commission should require that TEP present a detailed analysis of the market power implications of the proposed transfer and separation of generating assets. This analysis should use an electric system simulation model to look at the hourly behavior of the market under a wide variety of physical conditions, contractual situations and bidding behaviors.

Q. Does this complete your testimony?

A. Yes.

EXHIBIT DAS-1

David A Schlissel

Senior Consultant
Synapse Energy Economics
22 Crescent Street, Cambridge, MA 02138
(617) 661-3248 • fax: 661-0599

SUMMARY

I have worked for twenty-seven years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric Industry Restructuring and Deregulation - Investigated whether generators have been intentionally withholding capacity in order to manipulate prices in the new spot wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and auctions of power purchase agreements. Analyzed stranded utility costs in Massachusetts and Connecticut. Examined the reasonableness of utility standard offer rates and transition charges.

System Operations and Reliability Analysis - Investigated the causes of distribution system outages and inadequate service reliability. Evaluated the impact of a proposed merger on the reliability of the electric service provided to the ratepayers of the merging companies. Assessed whether new transmission and generation additions were needed to ensure adequate levels of system reliability. Scrutinized utility system reliability expenditures. Reviewed natural gas and telephone utility repair and replacement programs and policies.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Reviewed power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors. Evaluated the reasonableness of contract provisions and terms in proposed power supply agreements.

Nuclear Power - Examined the impact of industry restructuring and nuclear power plant life extensions on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates. Assessed the potential impact of electric industry deregulation on nuclear power plant safety. Reviewed nuclear waste storage and disposal costs. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than seventy proceedings before regulatory boards and commissions in twenty one states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

EXHIBIT
S-9
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

REBUTTAL TESTIMONY

OF

DAVID A. SCHLISSEL

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 11, 2002

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II. FLAWS IN THE TESTIMONY OF APS WITNESS HIERONYMUS 1

III. THE TESTIMONY OF PANDA GILA RIVER WITNESS ROACH 5

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you filing this Rebuttal Testimony?

A. I am submitting this Rebuttal Testimony on behalf of the Utilities Division of the Arizona Corporation Commission. ("Staff")

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed Direct Testimony in this proceeding on May 29, 2002.

Q. What is the purpose of this Rebuttal Testimony?

A. The purpose of this Rebuttal Testimony is to address several points made in the testimony filed by APS witness William Hieronymus and Panda Gila River witness Craig Roach.

II. FLAWS IN THE TESTIMONY OF APS WITNESS HIERONYMUS

Q. Do you think that Mr. Hieronymus appropriately applies FERC's new SMA test to APS?

A. No. Mr. Hieronymus correctly cites the specific FERC language that describes the SMA test.[1] However, his application of that test to the APS control area does not present a meaningful result because it fails to reflect the transmission system constraints that severely limit the amount of capacity that can be imported into the Phoenix Valley and Yuma load pockets.

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[1] Testimony of William H. Hieronymus, at page 32, line 12, to page 33, line 21.

1 **Q. How then should Mr. Hieronymus have structured his analysis?**

2 A. Instead of looking at the APS control area as a single market, Mr. Hieronymus
3 first should have applied the SMA to APS's Phoenix Valley and Yuma
4 transmission constrained service areas and then to the non-transmission
5 constrained area that APS serves outside of these load pockets.

6 **Q. What would have been the results of such an analysis?**

7 A. As I explained in my Direct Testimony, the SMA test reveals that APS and its
8 affiliates will be able to exercise market power in the Phoenix Valley and Yuma
9 load pockets until more merchant generation is built within those load pockets
10 and/or additional transmission import capacity is added.[2]

11 The absence of significant transmission constraints outside of the Phoenix Valley
12 and Yuma load pockets could mean that APS would be less able to exercise
13 market power in the relatively non-transmission constraints portions of its control
14 area. However, as I noted in my Direct Testimony, APS rebuttal witness Deise in
15 Docket No. E-01345A-01-0822 testified that only up to about 700 MW of APS'
16 unconstrained loads in its Northern Arizona, Southern Arizona and Eastern
17 Mining areas could be competitively bid.[3] This suggests that APS might even be
18 able to exercise market power in these non-transmission constrained areas.

19 **Q. Do you think that the Commission should give any weight to Mr.**
20 **Hieronymus's conclusion that APS would not be abl e to exercise market**
21 **power in the larger western markets?**[4]

22 A. No. Even though APS may not be able to exercise market power in the larger
23 western markets, it will be able to exercise market power in the Phoenix Valley

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2 Direct Testimony of David A. Schlissel, at page 3, line 1, to page 9, line 18.

3 Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, at page 18, line 19, to page 19, line 14.

4 Testimony of William H. Hieronymus, at page 30, lines 18-20.

and Yuma load pockets which together represent more than 2/3 of its retail load in Arizona.

Q. Do there appear to be any contradictions in Mr. Hieronymus's testimony?

A. Yes. At page 30, lines 5 and 6, Mr. Hieronymus stated that "California is, and is likely to remain, capacity short and shorter still in terms of economic energy." However, he then assumed in his SMA analysis, that there would be some 15,483 MW of capacity available during the summer of 2003 for export from California into APS's control area.[5]

Q. Do you agree with the claim by APS witness Hieronymus that "the most obvious means of dealing with potential market power is to require that the supplier dedicate a portion of its capacity to a long -term contract?"

A. No. A long-term contract can "lock-in" purchasers to paying higher than competitive prices over long periods of time. For example, the California Department of Water Resources ("DWR") rushed into short-term and long-term power supply contracts during that State's energy crisis in 2001. This was a time when, it is now almost universally accepted, power suppliers were exercising both physical and economic market power to force up the prices that were being paid for power consumed in the State. These contracts are a widely recognized disaster that have committed the State of California to pay extremely high prices for power, in some instances for a very long time.

In fact, the California State Auditor, the California Public Utilities Commission ("PUC") and the Attorney General, among others, are currently challenging these flawed and significantly overpriced short-term and long-term contracts. For example, the California PUC recently filed a complaint at FERC against specified sellers of long-term power contracts to the California DWR.

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[5] Testimony of William H. Hieronymus, Exhibit No. WHH-3.

In this complaint, the CPUC addressed 32 contracts between the DWR and 22 sellers. The California PUC's preliminary calculations indicated that collectively the challenged contracts are priced at levels exceeding just and reasonable prices by approximately $21 billion.[6] The PUC further noted that the DWR was forced to procure enormous amounts of power in order to keep the lights on in California "under conditions of extreme market power."[7]

> In the months in which DWR negotiated the bulk of the contracts (February – April 2001), spot market prices averaged over $300/MWh every hour of every day-ten times higher than prior year prices. Suppliers took advantage of their market power and charged unreasonable prices, for unreasonably lengthy periods, and under unreasonable non-price terms and conditions. DWR was forced to accept these terms or let the state go black.

A December 2001 Report by the California State Auditor similarly has noted that the decision to enter into about 40 agreements with a value of $35.9 billion in just 30 days may have affected the composition and details of the contracts signed by the DWR:

> The speed in which the department entered into contracts in response to the crisis precluded the planning necessary for a power-purchasing program of this size. As a result, it assembled a portfolio of power contracts that presents significant risks that will need careful management to avoid increased costs to consumers.[8]

The State Auditor's report further noted that the majority of the contracts entered into by the California DWR were not written to ensure a reliable source of power, but instead conveyed **lucrative financial terms** upon the suppliers to ensure that energy is delivered.[9] In addition, the terms of the contracts contain provisions

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6 California Public Utilities Commission Press Release, dated February 24, 2002.

7 Ibid.

8 *California Energy Markets, Pressures Have Eased, but Cost Risks Remain,* at page 1.

9 *California Energy Markets, Pressures Have Eased, but Cost Risks Remain,* at page 2.

that can increase the cost of power; thus they need careful management to avoid additional costs to consumers.[10]

III. THE TESTIMONY OF PANDA GILA RIVER WITNESS ROACH

Q. Do you agree with the conclusions of Panda Gila River witness Craig Roach/

A. Yes. I agree with Dr. Roach's conclusions that (a) APS has generation and transmission market power; (b) if APS is allowed to unconditionally transfer its generation facilities to an Affiliate, it will also be transferring its market power to that Affiliate; and (c) because the Commission will have less authority after the transfer to prevent harm to consumers from the exercise of market power by that Affiliate, it must ensure that, prior to such transfer, APS' market power will be mitigated.[11]

Q. Is your application of the SMA test to the Phoenix Valley load pocket consistent with Dr. Roach's application of the same test to what he terms the APS Valley Market?

A. Yes. The Table on page 6 of my Direct Testimony and Dr. Roach's Table Three present similar information, albeit in slightly different formats. Table DAS-R1 below presents my SMA analysis in the same format as was used by Dr. Roach and APS witness Hieronymus:

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[10] *California Energy Markets, Pressures Have Eased, but Cost Risks Remain,* at page 2.

[11] Direct Testimony of Craig R. Roach on behalf of Panda Gila River, L.P., at page 3, line 21, to page 4, line 3.

Table DAS-R1
Phoenix Valley SMA Test

	2003	2004	2005	2006	2007	2008	2009	2010
In-Area Capacity	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275
Import Capacity	3,685	3,685	3,685	3,685	3,685	4,685	4,685	4,685
Total Supply	4,960	4,960	4,960	4,960	4,960	5,960	5,960	5,960
Projected Peak Load	4,112	4,256	4,405	4,559	4,719	4,884	5,055	5,232
Supply Margin	848	704	555	401	241	1,076	905	728
Can Peak Load be met without APS Capacity	No	No	No	No	No	No	No	No
Pass/Fail SMA	Fail	Fail	Fail	Fail	Fail	Fail	Fail	Fail

Consequently, I concur with Dr. Roach's conclusion that APS has generation market power in the APS Valley Market.[12]

I also agree with Dr. Roach's observation that APS would fail the SMA test by even larger margins if its share of the transmission import capacity into the Phoenix Valley were considered.

Q. Does this complete your rebuttal testimony?

A. Yes.

[12] Direct Testimony of Craig R. Roach on behalf of Panda Gila River, L.P., at page 14, lines 16 and 17.

EXHIBIT
S-10
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDIPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

ERINN ANDREASEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

MAY 29, 2002

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Erinn Andreasen. My business address is 1200 West Washington St., Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst.

Q. Please describe your educational background and recent work experience.

A. In 1999, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Agribusiness with a specialization in international business. Since, I have completed 21 hours in the MBA program at the University of Phoenix and am scheduled to complete my Masters degree in 2003. I have worked at the Commission for two years as an Economist and a Public Utilities Analyst. My current duties include the review and evaluation of applications for electric Certificates of Convenience and Necessity ("CC&N"), electric utility special contracts, demand-side management programs, and utility tariff filings. I have testified in several electric CC&N proceedings.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-00000A-02-0051?

A. Yes.

Q. What is the purpose of your testimony?

A. I will explain the purpose and concept of an Electric Competition Advisory Group ("Advisory Group") and present a recommendation to create the proposed Advisory Group.

ELECTRIC COMPETITION ADVISORY GROUP

Q. Is there currently a formal means for communications and information sharing among stakeholders and Commission Staff in the electric industry regarding topics such as wholesale and retail market transactions, market structures, and impediments to competition?

A. No. Through its ordinary duties, Commission Staff ("Staff") communicates with industry participants and monitors the industry in an informal manner. However, a more formal approach toward facilitating communication and information sharing has not been established.

Q. What do you recommend as a means to facilitate the sharing of this type of information among stakeholders, market participants, and Staff in the electric industry?

A. I recommend that an Advisory Group be formed.

Q. What is the purpose of the Advisory Group?

A. The Advisory Group would observe market activities and provide a forum for Staff, stakeholders, and market participants to share information and discuss issues regarding wholesale and retail market transactions, market structures, impediments to competition, and other matters. The Advisory Group may also be asked by Staff to provide input

regarding the market power study and market power mitigation plan that is described in the direct testimony of Matt Rowell.

Q. How will an Advisory Group be beneficial?

A. The Advisory Group is needed to facilitate the sharing of information so that Staff can make reports and policy recommendations to the Commission based on recent knowledge of market activities from stakeholders and market participants.

Q. When would Staff provide reports and policy recommendations to the Commission?

A. Staff would report to the Commission on the issues discussed among the Advisory Group participants and make policy recommendations on a periodic basis.

Q. Who do you anticipate participating in the Advisory Group?

A. The group would consist of Staff, stakeholders, and market participants including: independent power producers, transmission users, Electric Service Providers, utilities, consumer advocates, and various associations.

Q. Is participation in the Advisory Group mandatory?

A. No. Participation is voluntary. However, Staff strongly encourages participation.

Q. Who will chair the Advisory Group?

A. The Director of the Utilities Division or the Director's designee.

Q. Will the Advisory Group provide a formal market monitoring function requiring market studies or analyses provided by its stakeholders, market participants, or Staff?

A. No. The Advisory Group would not have an enforcement function and would not be requiring or performing in-depth market monitoring studies or analysis. Staff would rely on the information presented by the stakeholders and market participants to become aware of both retail and wholesale market concerns.

Q. The Federal Energy Regulatory Commission ("FERC") is making efforts to address market monitoring in the wholesale market. Is there a role for states to participate in creating market monitoring performance measures?

A. In its Staff Working Paper on Standard Market Design, FERC Staff has indicated that the states would have a role in developing performance measures for market monitoring of activities performed by Regional Transmission Organizations.[1]

Q. Would the Advisory Group provide comments to Staff on market monitoring issues?

A. Staff could request that the Advisory Group provide feedback on these types of issues as well as other issues that Staff or the Commission finds to be relevant.

Q. If the Commission does not have jurisdiction over the wholesale market, why is Staff concerned with wholesale transactions and market structures?

A. Staff is concerned with transactions and structures in the wholesale market as they may ultimately have an effect on events in the retail market. Staff is also interested in the wholesale market to the extent that the Commission would deem it necessary to intervene in proceedings at FERC.

[1] FERC Working Paper on Standardized Transmission Service and Wholesale Market Design, p. 24.

STAFF RECOMMENDATION

Q. What do you recommend in regard to the formation of the Advisory Group?

A. I recommend that the Commission form an Electric Competition Advisory Group for purposes of facilitating communication and the sharing of information among Staff, stakeholders, and market participants about wholesale and retail market transactions, market structures, and impediments to competition.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT

5-11
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

MAY 29, 2002

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington St., Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in the Appendix.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-00000A-02-0051?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony is concerned with affiliate relationships. I will present recommendations regarding the need for a new code of conduct between affiliates.

PROBLEMS WITH AFFILIATE RELATIONSHIPS

Q. What are affiliate relationships?

A. Affiliate relationships are interactions between a public utility and any other entity directly or indirectly controlling or controlled by, or under direct or indirect common control with, the public utility. Control means the power to direct the management policies of an entity.

Q. What are some of the problems associated with affiliate relationships?

A. Some of the problems include the potential for self-dealing, preferential treatment to affiliates, and cross-subsidization.

Q. Please explain what is meant by the term *self-dealing*.

A. Self-dealing involves a utility procuring capacity, power, or other energy services from an affiliate. The use of utility-owned capacity to deliver power is also a form of self-dealing. Although self-dealing can have advantages when there are economies of scope or when an affiliate is the lowest-cost supplier, self-dealing also provides the utility opportunities and incentives to engage in inefficient or abusive behavior harmful to ratepayers. One form of abusive self-dealing is transfer pricing. Transfer pricing occurs if an affiliate is able to charge the utility above-market prices for goods and services knowing that the increased prices will be passed through to ratepayers.

Q. Please explain what is meant by *preferential treatment to affiliates*.

A. Preferential treatment occurs when the utility's affiliates or customers of its affiliates receive different treatment by the utility than the treatment the utility provides to other, unaffiliated companies or their customers.

Q. Please explain what is meant by *cross-subsidization*.

A. Cross-subsidization occurs when costs associated with providing a service are recovered through prices charged for another service. Cross-subsidization also includes the transfer of tangible or intangible assets from the utility to affiliates. Consumers pay higher rates to cover the costs of the unregulated companies. One form of cross-subsidization is a disproportionate allocation of common or joint costs to the utility (cost shifting). Another form of cross-subsidization is utility payments to an affiliate that are higher than market level. In addition, when unregulated affiliates are subsidized by regulated companies, they can undercut market prices (predatory pricing). This cross-subsidization retards

market competition and deters new market entrants. While cross-subsidies may initially allow unregulated affiliates to offer lower prices, prices will eventually rise once existing competitors have been driven out and potential new entrants discouraged from entering the market.

Q. What are *Codes of Conduct*?

A. Codes of Conduct are safeguards governing the behavior and structure of utility relationships with affiliates. The purposes of Codes of Conduct include: creating barriers to self-dealing, preventing preferential treatment to affiliates, ensuring that utility ratepayers do not subsidize unregulated utility affiliates, and mitigating market power.

INADEQUACIES OF EXISTING RULES OF CONDUCT TO PREVENT PROBLEMS

Q. What rules of conduct currently exist that deal with affiliate relationships?

A. The Commission has Public Utility Holding Companies and Affiliated Interests rules (A.A.C. R14-2-801 through -806) and a Code of Conduct section (A.A.C. R14-2-1616) within the Retail Electric Competition rules. The Federal Energy Regulatory Commission (FERC) also has rules of conduct.

Q. Please describe the Commission's Public Utility Holding Companies and Affiliated Interests rules.

A. The Public Utility Holding Companies and Affiliated Interests rules apply to all Class A investor-owned utilities under the Commission's jurisdiction. Features of the rules include the following:

- A utility or affiliate has to provide notice of intent to organize or reorganize a public utility holding company.
- A utility cannot transact business with an affiliate unless the affiliate provides the Commission access to its books and records.

- A utility needs prior Commission approval before obtaining a financial interest in an affiliate, lending $100,000 or more for a period of at least 12 months to an affiliate, using utility funds to form a subsidiary, or divesting itself of a subsidiary.
- Annually, utilities and holding companies must file descriptions of diversification activities and plans.

Q. Please describe the Commission's Code of Conduct section within the Retail Electric Competition rules.

A. The Code of Conduct rule applies to any Affected Utility which plans to offer Noncompetitive Services and which plans to offer Competitive Services through its competitive electric affiliate or electric service provider (ESP). The Code of Conduct only applies to the relationship between the Affected Utility and its ESP affiliate. The Code of Conduct addresses the following subjects:

- cross subsidization between utilities and competitive affiliates
- access to confidential information by competitive affiliate
- joint employment by utility and competitive affiliate
- use of utility's name or logo by competitive affiliate
- preferential treatment toward competitive affiliate
- joint advertising, joint marketing, and joint sales by utility and competitive affiliate
- transactions between utilities and competitive affiliates
- representation to customers of better service as result of affiliation
- complaint procedures

Q. Please describe FERC's rules of conduct.

A. FERC has two kinds of rules of conduct. One is standards of conduct for transmission providers (18CFR37.4). The standards require that a transmission provider's

transmission function operate independently from its marketing and sales functions and that a transmission provider must treat all transmission customers on a nondiscriminatory basis. FERC has issued a Notice of Proposed Rulemaking to have new standards of conduct that would apply uniformly to both natural gas pipelines and transmitting public utilities.

FERC also requires a code of conduct for a utility to transact business with affiliates at market-based rates. This code places restrictions on the sales of non-power goods and services between the utility and its marketing affiliates. It may also include requirements to separate marketing affiliate employees from utility employees and restrictions on the sharing of information.

Q. Do the currently existing rules of conduct effectively deal with the problems associated with affiliate relationships that you described above?

A. The Public Utility Holding Companies and Affiliated Interests rules do not address wholesale power transactions between affiliated entities. The Code of Conduct section within the Retail Electric Competition rules is designed to prevent anti-competitive activities by a utility and its competitive electric affiliate (Electric Service Provider). It does not cover activities between a utility and any other affiliate. The FERC standards of conduct for transmission providers do not address types of market power abuse, such as cross-subsidization and transfers of information. The FERC code of conduct for a utility to transact business with affiliates at market-based rates places restrictions on non-power sales but does not address power sales.

OTHER STATES' EXPERIENCES

Q. How have other states dealt with the problems of affiliate relationships?

A. One example is Kentucky. Kentucky has a statute (KRS Chapter 278) relating to utilities and affiliates of utilities. The statute prohibits regulated utilities from using utility

revenues to fund unregulated affiliates, requires separate recordkeeping, specifies cost allocation procedures, provides requirements regarding affiliate transaction pricing, governs sharing of information and resources, requires all dealings between a utility and a nonregulated affiliate to be at arm's length, prohibits undue preferential treatment to affiliates, prohibits a utility from entering into financing arrangements for nonregulated activities through an affiliate that would permit a creditor upon default to have recourse to the utility's assets, and contains other requirements.

Q. Are there other examples?

A. Yes. Maryland has standards of conduct for all gas and electric utilities and their core and non-core affiliates (Order No. 76292). The standards are intended to 1) prevent cross-subsidization of affiliates, 2) prevent affiliates from gaining any improper advantage in their competitive markets because of their affiliation to the regulated utility, 3) minimize the sharing of confidential information, 4) protect the privacy of consumers, and 5) prohibit discrimination in the provision of regulated services. There is a separate code of conduct for utilities and their affiliated electric generation companies (GENCOs). The GENCO code of conduct is intended to foster competitive electric generation markets, minimize market power, and help eliminate any inherent advantages that a GENCO might possess.

Massachusetts has standards of conduct for distribution companies and their affiliates (220 CMR 12.00). Provisions in the standards include restrictions on the release of proprietary customer information by a distribution company to an affiliate and requirements regarding the pricing of transactions between distribution companies and affiliates.

Q. Why have these states established standards of conduct between affiliates?

A. These states have established standards of conduct between affiliates because they are trying to prevent conduct on behalf of the utility and its affiliates that would interfere with public policies that those states are trying to foster. Similarly, in this case, Staff recommends that the Commission require adoption of codes of conduct to further Arizona public policy.

STAFF RECOMMENDATIONS

Q. What does Staff recommend as a solution to the problems associated with affiliate relationships in Arizona?

A. Staff recommends the following:

1) Any investor-owned utility that wants to purchase power from an affiliate within 12 months of a Commission Decision in this docket must file a code of conduct for Commission approval within 90 days of a Commission Decision in this docket.

2) Any investor-owned utility that has already purchased power from an affiliate must file a code of conduct for Commission approval within 90 days of a Commission Decision in this docket.

3) Any investor-owned utility that has not made a filing in response to nos. 1 or 2 above but in the future plans to purchase power from an affiliate must obtain Commission approval of a code of conduct before executing any affiliate transactions.

4) Prior to a transfer of generation assets to an affiliate, an investor-owned utility must file a code of conduct for Commission approval unless such code of conduct has already been filed in response to recommendations nos. 1, 2, or 3 above.

Q. What entities should be covered by the proposed code of conduct?

A. The code of conduct should cover an investor-owned electric utility regulated by the Commission and all affiliates from which the utility may purchase power or which are in energy-related fields.

Q. What items should be included in the proposed code of conduct?

A. The code of conduct should address, at a minimum, arm's-length transactions; access to confidential information; cross-subsidization; preferential treatment to affiliates; joint employment and employee transfer issues; sharing of office space, equipment, and services; proprietary customer information; financing arrangements with affiliates; and conflict of interest.

Q. Do you have specific recommendations in regard to addressing arm's-length transactions in the code of conduct?

A. Yes. Arm's-length transactions are defined as transactions negotiated by unrelated parties, each acting in his or her own self-interest. Therefore, Staff recommends that the same representative should not appear on both sides of a transaction. Second, for ratemaking purposes, sales or transfers from an affiliate to the utility should be priced at the lower of cost or market. Third, for ratemaking purposes, sales or transfers from the utility to an affiliate should be priced at the higher of cost or market.

Q. Does this conclude your testimony?

A. Yes.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987

"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

EXHIBIT
5-12
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

CORRECTIONS

TO

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

JUNE 14, 2002

Q. What entities should be covered by the proposed code of conduct?

A. The code of conduct should cover an investor-owned electric utility regulated by the Commission and all affiliates from which the utility may purchase power or which are in energy-related fields.

Q. What items should be included in the proposed code of conduct?

A. The code of conduct should address, at a minimum, arm's-length transactions; access to confidential information; cross-subsidization; preferential treatment to affiliates; joint employment and employee transfer issues; sharing of office space, equipment, and services; proprietary customer information; financing arrangements with affiliates; and conflict of interest.

Q. Do you have specific recommendations in regard to addressing arm's-length transactions in the code of conduct?

A. Yes. Arm's-length transactions are defined as transactions negotiated by unrelated parties, each acting in his or her own self-interest. Therefore, Staff recommends that the same representative should not appear on both sides of a transaction. ~~Second, for ratemaking purposes, sales or transfers from an affiliate to the utility should be priced at the lower of cost or market. Third, for ratemaking purposes, sales or transfers from the utility to an affiliate should be priced at the higher of cost or market.~~

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
S-13
admitted

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-013450A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY"S APPLICATION FOR A VARRIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELCTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILIES ENGINEER

UTILITIES DIVISION

May 29, 2002

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INTRODUCTION

Q. Please state your name and business address.

A. Jerry D. Smith, 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer for the Utilities Division.

Q. Please summarize your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Please describe pertinent work experience.

A. I joined the Commission Staff in February 1999, following a lengthy career with the Salt River Project ("SRP"), one of the state's largest electric utilities. During my SRP career I:

1. analyzed and planned transmission and distribution system improvements;
2. managed design services required for retail customer projects; and
3. served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities.

While employed by SRP, I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation,

modification and administration of new contribution in aid of construction charges and tariffs.

My responsibilities with the Commission have included involvement in Arizona's regulatory rulemaking and rate processes regarding retail electric competition. I have actively participated in the organizational development of an Arizona Independent Scheduling Administrator ("AzISA") and a Regional Transmission Organization ("RTO") called Desert STAR. Desert STAR has since been replaced by a different RTO organizational form and filed with FERC as Westconnect. I was also responsible for the Commission's investigation of distributed generation and interconnections for potential rulemaking consideration.

My experience with the Commission includes providing analysis and testimony regarding quality of service issues, utility planning and siting requirements, system adequacy assessments and cost of service studies. I have also been the Commission's primary staff witness for recent power plant and transmission line siting cases.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission regarding numerous matters. I have given testimony regarding rate cases, quality of service cases, power plant and transmission line siting cases and I have filed direct testimony regarding the Arizona Public Service Company ("APS") request for variance to ACC Rule 14-2-1606.B in Docket No. E-01345A-01-0822.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in these proceedings?

A. My testimony documents the status of existing and emerging electric system infrastructure in Arizona. I will first address the adequacy of Arizona's existing electric system to ensure reliable electric service to Arizona amidst a competitive wholesale

market. Secondly, I will address to what degree emerging new power plants and new transmission lines resolve Staff's system reliability concerns and effectively support the development of a robust competitive wholesale market in Arizona. My testimony will also identify some prevailing risks and operational uncertainties related to Arizona's utility infrastructure. I will conclude with a discussion of the role of Arizona's transmission system in restructuring of the electric utility industry.

Q. How have you prepared for your testimony?

A. I have reviewed information on file with the Commission in the form of annual utility operational presentations, data gathered in the Commission's first Biennial Transmission Assessment, and recently filed ten-year transmission plans. I have also reviewed evidentiary records of power plant and transmission line siting cases. In addition I have reviewed data requests, the Staff Report and evidentiary records filed in the Commission's restructuring docket, and the related APS and Tucson Electric Power Company ("TEP") variance cases (Docket Nos. E-01345A-01-0822 and E-01933A-02-0069).

Q. What conclusions does your testimony reach?

A. A summary of my testimony is reflected in the following general conclusions and recommendations. Staff has concluded that generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona. Utilities are presently dependent upon use of reliability must-run generation and load tripping schemes to meet local load requirements due to local transmission import constraints. Transmission and natural gas pipeline capacity also pose barriers to development of a competitive supply margin with new generators.

Adequate generation is developing in Arizona which may establish a competitive supply margin once transmission reliability constraints are resolved and new gas pipeline capacity is constructed. New transmission solutions are beginning to emerge in the ten-

year plans being filed with the Commission. However, considerably more planning is required to ensure sufficient transmission is in place to provide reliable service to Arizona at just and reasonable rates via a competitive wholesale market.

Staff recommends a variety of actions in this testimony. These actions are collectively intended to accelerate development of transmission solutions in Arizona for reliability purposes. These recommendations will also facilitate restructuring of the electric industry to reliably serve consumers at just and reasonable rates via a competitive wholesale market at the earliest possible date. Staff's recommendations include an industry-wide collaborative planning process engaging all sectors of the electric utility industry to resolve local transmission import constraints and transmission constraints prevailing at plant interconnections with the transmission grid.

ADEQUACY OF ARIZONA'S ELECTRIC SYSTEM

Q. Is Arizona's existing electric system adequate to ensure reliable service via a competitive market?

A. Staff is of the opinion that Arizona's electric system in 2002 is currently inadequate to ensure reliable service via a competitive wholesale market. At present, the West's existing wholesale power supply margin is thin and Arizona transmission constraints limit delivery from some new Arizona power plants. Nevertheless, Staff believes the number of Arizona power plants and transmission projects planned and under construction will establish a marginally reliable electric system with an Arizona supply margin of sufficient capacity to facilitate emergence of a competitive wholesale market in Arizona within the next few years.

Q. Please cite any evidence that a thin wholesale market currently exists?

A. APS and TEP provided evidence that a thin wholesale market currently exists during a February 16, 2001, ACC Energy Workshop 2001 - 2002. APS presented its load forecast and expected generating resources as depicted by Exhibits JS-1 and JS-2. Concerns at the

workshop focused on the fact that APS was taking extraordinary measures to develop adequate resources for 2001 and 2002 due to inadequacies of the wholesale market in the Western Interconnection ("WI"). Such measures included upgrades to existing APS combined cycle and combustion turbine units, reactivating mothballed APS steam turbine units at West Phoenix Power Plant, and Pinnacle West Energy Corporation ("PWEC") placing 99 megawatts ("MW") of temporary small combustion turbine units at both the West Phoenix and Saguaro plant sites. In addition, the APS resource plan depended on energy from new PWEC combined cycle units at West Phoenix in 2001and at Redhawk in 2002.

TEP loads and resources information for 2002 presented at the February 16, 2001 ACC Energy Workshop is provided as Exhibit JS-3 and JS-4. TEP constructed two combustion turbine units in 2001 with an aggregate capacity of 100 MWs. The new peaking units are located internal to TEP's local transmission system and increased TEP's total generating capacity to approximately 2000 MWs. TEP's total peak demand is projected to be approximately 1990 MWs in 2002 of which 1830 MWs is retail load. TEP's reserve requirement significantly exceeds the 10 MWs differential between its generating capacity and total demand in 2002. Therefore, TEP is dependent upon a firm purchase of 110 MWs from Southern California Edison and 50 MWs of summer peak contingency purchase to meet its 2002 peak demand and reserve requirements.

Q. Is the natural gas pipeline infrastructure adequate to support existing and all new gas-fired generation plants?

A. Staff has consistently testified during power plant siting hearings that the existing natural gas infrastructure serving Arizona is inadequate. The natural gas infrastructure in Arizona at this time largely consists of El Paso Natural Gas Company's ("El Paso") northern and southern interstate pipeline systems and associated laterals. The Transwestern pipeline in northern Arizona also serves a small amount of Arizona's natural gas needs. Currently there are no appreciable instate natural gas production, natural gas storage, or liquid

natural gas facilities in Arizona. Therefore, natural gas consumers in Arizona, whether residential or power generating in nature, rely on the on-going flow of natural gas on the interstate pipeline system to meet their service needs.

There is a growing uncertainty regarding pipeline capacity available for shippers on the El Paso pipeline system. The rights, obligations, and needs of shippers and El Paso are being disputed in a number of proceedings at the Federal Energy Regulatory Commission ("FERC"). It is unclear how or when the disputes regarding pipeline capacity will be resolved. However, it is clear that during periods of high demand, the El Paso system is unable to fully meet the needs of its existing shippers. During periods of relatively low demand on the interstate pipeline system, it appears that the system is generally able to meet the current needs of its shippers. This situation exists at a time when few of the new natural gas-fired generating units in Arizona or New Mexico are operational. As additional natural gas-fired generating units come on line in Arizona and other southwestern states utilizing the same pipeline systems, the inability of the existing pipeline system to serve all customer demands will become increasingly apparent.

Q. Are there transmission constraints inside or outside Arizona that currently impede wholesale market access to Arizona customers during any seasons of the year or times of the day?

A. Yes, significant transmission constraints around Arizona's major load centers are another factor contributing to the thinness of the wholesale market in Arizona. Transmission constraints both inside and outside Arizona currently impede energy from the wholesale market from reaching Arizona customers during summer peak hours. These constraints were reported in Staff's Biennial Transmission Assessment revised July 2001 and adopted by the Commission. The report established that three geographical load zones (Phoenix, Tucson and Yuma) are transmission import constrained at peak load conditions. These transmission import constrained geographical load zones are depicted in Exhibit JS-5 and are dependent upon local reliability must-run ("RMR") generation.

Two additional transmission constraints have been identified since Staff's Biennial Transmission Assessment was completed. Toltec Power Plant siting hearings (Case #112) revealed that the new Reliant Desert Basin Power Plant in Casa Grande could not deliver its full capacity to SRP in the Phoenix area because of 115 kV and 230 kV transmission system constraints between the plant and the Phoenix load zone. Testimony during Case #111 siting a TEP 345 kV transmission line and Citizens Communications 115 kV transmission line to serve Nogales and Santa Cruz County revealed another transmission constraint. Citizens Communications presented a load forecast that indicated that as early as summer peak 2003 the load in Santa Cruz County may exceed the delivery capability of the existing 115 kV line serving the area. Even with the proposed new transmission line to Nogales, continuity of service to customers is of concern in case of the outage of the new line.

Similarly, new generation capacity under construction and interconnecting at the Palo Verde commercial hub will be constrained by existing 500 kV transmission lines interconnected at the hub. The Biennial Transmission Assessment references Palo Verde Interconnection Studies that have shown that no more than 1,800 to 3,360 MWs of new generation can be accommodated at the Palo Verde hub without transmission upgrades. This capacity is over and above the transmission capacity committed to the Palo Verde nuclear generating units. Four generating projects totaling 3,930 MWs are currently under construction and will be interconnected at the Palo Verde hub over the next 12 months. Two of the projects totaling 1,640 MWs are expected to be operational this summer.

Q. How does reliability must-run ("RMR") generation relate to transmission reliability?

A. Generation existing within a local system can be operated to serve load that would otherwise be served by the importing transmission system. However, when the load being

served by a transmission system exceeds the system's transmission import capacity, the system is said to be reliability constrained. Generation internal to such reliability constrained load zones "must run" at sufficient capacity to avoid system overloads and voltage problems for outage of critical lines. Generating units operated for this purpose are called reliability must-run ("RMR") units during the period for which the transmission constraint exists.

Utilities have traditionally used RMR generating strategies as an operational safety net when siting or construction of new transmission facilities was impeded, delivery of new equipment was delayed, capital financing was constrained or to restore service following a transmission outage. Utilizing RMR generation to defer capital investment in reliability enhancements in a utility's transmission system may also have merit when:

1. The total operating cost of local must-run generators is less than that of generators external to the constraint and the avoided annual cost of the deferred capital investment in new transmission facilities,
2. Environmental standards are not compromised and
3. Such action does not pose unacceptable system service risks.

A transmission system is considered reliable when it is of sufficient capacity to deliver its power (demand and energy) at all times without interruption of service to its customers for loss of any single transmission system element. Annual dependency on RMR generation can be an indicator that a transmission system's import capacity is inadequate. This is particularly true when must-run generation costs are simply passed through the regulatory rate base without balancing in the public's interest the reliability, economics and environmental merits of investments in additional transmission capacity to provide access to less costly or more environmentally friendly generation external to the constraint.

Q. What evidence can you provide relative to APS' and TEP's dependency on RMR generation for the Yuma, Phoenix and Tucson transmission import constrained load zones?

A. Mr. Cary Deise of APS gave rebuttal testimony regarding the Yuma area in the APS variance request case.[1] He described how Yuma transmission import constraints have ebbed and flowed over time as local load growth occurred. As Yuma load grew it would reach a point where it exceeded the transmission system's import capability. RMR generation would then be utilized and such requirements would increase in both duration and capacity over time as load continued to grow. New infrastructure was constructed when the Yuma area load was projected to exceed the combined load serving capability of its transmission system and local generation.

Both new transmission lines and new local generation have been constructed at various points in time to enhance APS' Yuma load serving capability. Such infrastructure improvements were selected based upon economic choices driven by consideration of APS' broader integrated resource planning needs. When new system generation was needed and it could be located in Yuma so as to avoid the need to also build a transmission line to Yuma it was logical to do so. When APS' generating capacity was adequate then transmission was constructed. Therefore, Yuma's RMR generation requirements have gone through cycles of increasing to the point of requiring either new local generation or a new line. Then for a period of years the transmission constraint was mitigated and RMR generation requirements were either retracted or diminished in both duration and capacity.

Restructuring of the electric industry may result in a Utility Distribution Company ("UDC") not having the same planning choices for infrastructure as an integrated utility. If a UDC transfers all of its generation assets and secures all of its resource requirements

[1] Rebuttal Testimony of Cary Deise, APS Request for Variance to Certain Requirements of A.A.C. R14-2-1606, April 22, 2002, pages 7-10.

from a competitive market, it may not be able to depend on the power plant industry locating or timing construction of new generation to minimize the UDC's transmission expansion requirements. Therefore, the traditional planning practices of vertically integrated utilities cited by Mr. Deise[2] may no longer be applicable. Considerable industry discussion is ongoing in an effort to define how coordinated and collaborative planning can best take place in the West. Such planning in Arizona is evolving in a way so as to consider the collective needs of the Arizona transmission providers and independent power producers.

The UDC is no longer in the business of constructing generation but remains responsible for assuring that its customers continue to have access to just and reasonably priced energy via a reliable transmission system. Nevertheless, dependence upon existing local generation for RMR purposes may continue to afford a transmission provider an operational safety net and facilitate the deferral of costly transmission improvements under favorable wholesale market prices and environmental conditions.

Mr. Deise provided an exhibit documenting the APS Phoenix area RMR requirements in his rebuttal testimony in the APS request for variance case.[3] His data assumes the Palo Verde to Southwest Valley 500 kV line will be successfully constructed by the Summer of 2003 thereby raising the APS transmission import capacity by 600 MWs to 3,685 MWs. With a total of 3,685 MWs of transmission import capability Mr. Deise reveals that APS' RMR generation requirements for the Phoenix area will grow from 427 MWs in 2003 to 1,034 MWs by 2007. A segment of Mr. Deise's data is presented in the following table.

[2] Ibid., at page 9.
[3] Rebuttal Testimony of Cary Deise, APS Request for Variance to Certain Requirements of A.A.C. R14-2-1606, April 22, 2002, Schedule CD-3R.

Table 1.

Year	APS Valley Load (MW)	APS Import Capability (MW)	APS RMR Gen. Requirement (MW)
2003	4112	3685	427
2004	4256	3685	571
2005	4405	3685	720
2006	4559	3685	874
2007	4719	3685	1034

Exhibit JS-6 was presented as evidence during transmission line siting Case #115 and depicts APS' capability to serve load within the Phoenix transmission constrained area. It demonstrates APS' dependency upon existing units and new PWEC units to meet its RMR requirements. It is important to note that a Phoenix area load tripping scheme was implemented by APS and SRP for the 2001 summer peak season. The load tripping scheme will continue through the 2002 summer peak season and until construction of the Palo Verde to Southwest Valley 500 kV line is completed. This scheme is necessary to avoid critical single contingency line outages or generator outages causing protection and control systems to interrupt other electric facilities. Such cascading events would not be in compliance with Western Electricity Coordinating Council ("WECC") reliability criteria.

TEP provided Staff an update regarding its Tucson transmission import capability and associated RMR generation requirements in response to a data request in this case. A portion of that data is displayed in Table 2. The Tucson transmission import limit is expected to increase by approximately 200 MWs in 2003 due to the planned construction

of a second Saguaro to Tortolito 500 kV tie and transformer. For load and resource planning purposes TEP has utilized 1,535 MWs as its import limit. TEP's local area peak demand grows from 1,889 MWs in 2003 to 2,099 MWs in 2007. Therefore TEP's RMR requirement grows from 354 MWs to 564 MWs over the same time period. TEP's total local generation capability is 640 MWs through 2007. This leaves a local supply margin of only 76 MWs in 2007.

Table 2.

Year	TEP Tucson Load (MW)	TEP Import Capability (MW)	TEP RMR Gen. Requirement (MW)
2003	1899	1535	364
2004	2001	1535	466
2005	2025	1535	490
2006	2082	1535	547
2007	2099	1535	564

Staff is of the opinion that UDCs have a responsibility to demonstrate the merits of continuing or increasing their dependence upon local RMR generation. Is continuing to depend on RMR generation in consumers' best interest and does it economically justify deferral of transmission improvements that would resolve transmission reliability constraints? Neither APS nor TEP has provided such an assessment to Staff. Staff offers a recommendation in this testimony that the Commission require all jurisdictional utilities utilizing RMR for their load requirements to provide Staff with such an analysis.

In the meantime, Staff has performed an assessment contrasting the annual cost of RMR generation with the avoided annual cost of a new EHV transmission line. Exhibit JS-7 offers a demonstration of when the economics of RMR generation appears to justify

deferral of EHV transmission investment. The formulas, definition of terms and assumptions of parameters used in this analysis are provided as Exhibit JS-8. The cost of RMR energy produced during a constraint period of 400 hours has been plotted as a function of the peak RMR generation requirement. A solid line depicts that cost for each of four generic generating units. The unit operating cost ranges from $50/MWhr to $150/MWhr. Similarly, the annual avoided cost of an EHV transmission line investment has been plotted as a function of line length. A dashed line depicts the avoided annual cost of EHV lines of lengths 50, 100 and 150 miles. A breakeven point exists where solid lines intersect dashed lines. Economics favor transmission line construction when the actual cost of RMR exceeds the annual avoided cost of such line construction.

One can conclude from Exhibit JS-7 that generally an EHV transmission line 50 miles in length or greater is economically justified when the RMR generating unit hourly operating cost is $75/MWhr or greater and when the RMR requirement is greater than 400 MW. APS' and TEP's RMR generation requirements documented in Tables 1 and 2 generally exceed the 400 MW identified by the above conclusion by several hundred MWs. Staff believes that the hourly operating cost of APS and TEP RMR units used at peak are in excess of the $75/MW value referenced in the above conclusion. Therefore, Staff believes APS and TEP may find it difficult to economically justify deferral of transmission improvements given the magnitude and duration of RMR generation utilized and actual total operating cost of their local generators.

EFFECT OF NEW INFRASTRUCTURE

Q. Staff suggested in its power plant update to the Commission that a competitive supply margin is necessary for a competitive market to flourish. What is Staff's definition of "competitive supply margin?"

A. Staff believes a "competitive supply margin" exists for any given area when generation capacity within that area exceeds load, net export obligations and reserve requirements of that area by an amount sufficient to result in competitive pricing among the generators

within that area. Refer to Exhibit JS-9 for a visual depiction of this concept. This model assumes all generators in the area are available to compete for wholesale market services and are not constrained by transmission capacity. This definition of supply margin is consistent with FERC's use of the term in its pivotal test for market power. Mr. Schlissel has provided testimony in this case that explores to what degree market power exists in Arizona using this test.[4]

Staff has not ascertained what percentage of supply margin would be necessary to ensure competitive pricing in the local wholesale market. It is Staff's belief that the composition of the area's generation portfolio regarding vintage, types of generating technology, and fuel sources would have a significant bearing on the competitive supply margin appropriate for a given area. In addition, there are known local transmission constraints that may inhibit just and reasonably rates via competitive generation pricing from being realized in the local market in the short-term.

Q. Is a competitive supply margin emerging in Arizona?

A. It is Staff's opinion that an adequate supply margin is emerging in Arizona. However, the determination of how competitive that supply margin will be is still yet to be determined. It does not matter how many new plants are constructed and competing if the transmission system is not sufficient to deliver the power from these plants to the intended load centers. Local transmission constraints may be a barrier to effective competition of new generators entering the Arizona wholesale market. Mr. Schlissel has provided testimony in this case regarding how transmission plays a role in market power concerns for an emerging competitive wholesale market. Once local transmission constraints are resolved, it is Staff's opinion that the number of new generators constructing or planning to construct in Arizona will be of sufficient number and capacity to result in a competitive supply margin in this state. Such a competitive supply margin may not be fully realized in Arizona until the last half of this decade.

[4] Direct Testimony of David A. Schlissel, Docket No. E-00000A-02-0051, pages 4-8.

The Biennial Transmission Assessment documented that 22 plants located in Arizona existed in 2000 with an Arizona utility owned capacity of 11,724 MWs. The actual 2000 summer peak load in Arizona served by those same units was approximately 13,000 MWs. Arizona has in recent years been progressively more dependent upon import of supply from other states at peak load conditions.

Exhibit JS-10 depicts the status of new proposed power plants in Arizona. We are quickly moving towards an adequate supply margin in Arizona with 1,830 MWs of new generation that became operational in 2001 and 7,210 MWs of new generation under construction that is planned for operation by Summer 2003. An additional 5,180 MWs of new generation has obtained ACC approval of a Certificate of Environmental Compatibility and is scheduled to come on line between 2003 and 2007. These new generating units total 14,220 MWs of new generation in Arizona.

In the same time period Arizona's peak load will grow at approximately 600-700 MWs per year. This would yield an Arizona peak load in 2007 of approximately 18,000 MWs, a 5,000 MW load growth from the year 2000 peak. The implications are that Arizona generation expansion will likely occur at a three to one ratio compared to Arizona load growth. This bodes well for establishing a robust supply margin in Arizona and allows Arizona to contribute substantially to the supply needs of the Western Interconnection.

However, the transmission and natural gas supply problems discussed elsewhere in my testimony may impede the development of competition in the wholesale market in spite of the emerging supply margin.

Q. What plans are in place to relieve transmission constraints?

A. APS has planned a new 230 kV line from Gila Bend to Yuma by 2006. This line will eliminate the transmission import constraint for the Yuma area. In addition, York and

Welton Mohawk Irrigation and Drainage District have proposed a new Yuma area generation project for 2004. The generation project is active in the state siting process as Case #114.

A new 500 kV line from the Palo Verde hub to the new Southwest Valley switching station has been approved in Line Siting Case #115. That line is under construction for a Summer 2003 completion. It will help mitigate the Phoenix import constraint and lessen the dependence on local RMR generation. During the past year, two additional 500 kV transmission lines have been announced for 2006 and 2008 that will help relieve the transmission import constraint for this area: a Palo Verde to Southeast Valley Switching Station line and a Palo Verde to Table Mesa line.

PWEC is a partner in expanding generation at the West Phoenix Power Plant. Similarly, SRP is expanding its Kyrene Power Plant and Santan Power Plant. All three power plant projects are internal to the transmission import constrained Phoenix load zone. These new plants may compete with other new merchant plants developing in Arizona and will operate under more stringent environmental standards than existing local units.

TEP is proposing to construct a second 500 kV transmission line and transformer between Saguaro and Tortolito Substations by summer of 2003. This project increases the Tucson import capacity by approximately 200 MWs. TEP's proposed 345 kV transmission line interconnecting with Mexico will likely improve TEP's import capability to its Tucson service area. Several other new transmission line alternatives are still being evaluated in the Central Arizona Transmission Study ("CATS") that will relieve the Tucson import constraint.

In addition to the three new Palo Verde transmission lines identified above, the Commission has conditioned Duke's Arlington Valley II Power Plant with the upgrade of the Palo Verde to Kyrene and Palo Verde to North Gila 500 kV lines. A number of other

Palo Verde line projects have been discussed but applications for Certificates of Environmental Compatibility ("CEC") have not yet been filed with the Commission. Public Service Company of New Mexico ("PNM") still has a transmission line from Palo Verde to Mexico under study through CATS. The PNM line is active in a federal Environmental Impact Study("EIS") and Presidential Permit process with the US Department of Energy as the lead agency. There has been recent discussion of upgrading the existing Palo Verde to Devers line and building a second Palo Verde to Devers 500 kV line. Similarly, a merchant transmission project to build a 500 kV line from Gila Bend to North Gila in conjunction with other transmission enhancements in California continues to seek a funding source.

Q. Is it certain that all of these transmission projects will be built?

A. There remains some risk of public opposition to new transmission lines planned for construction in the short-term. The same risks would exist for any other presently unidentified transmission lines required to keep pace with forecasted load growth or eliminate RMR generation requirements. Some of the longer-term transmission improvements remain very speculative and lack any definitive funding sponsor, specific scope or well-defined in-service date. I speak to the uncertainties and risks of such projects in the next section of my testimony.

PREVAILING RISKS AND UNCERTAINTIES

Q. What electric supply risks and uncertainties is Arizona likely to face?

A. Even though APS has taken extraordinary steps with its affiliate to develop its own short-term resource solutions, it remains vulnerable to short-term contracts in a tight wholesale market.[5] The short-term wholesale market in the West is faced with continued market price caps, on-going California supply deficiencies, and natural gas supply and delivery concerns. These concerns were borne out in the summer of 2001. Precautionary steps were taken by Arizona utilities when the natural gas industry announced pending gas

[5] See this testimony, page 5.

curtailments. Furthermore, on July 4, 2001, APS was within one half hour of activating rolling blackout procedures due to unavailability of several generating units due to repairs and the subsequent outage of the Saguaro Power Plant due to a lightning storm. Rolling blackouts were avoided when APS successfully obtained emergency short-term purchases from its neighboring utility, the Salt River Project.

Four new merchant power plants have begun commercial operations since the February 16, 2001, Energy Workshops. A technical summary of the four plants is provided as Exhibit JS-11. The total nominal capacity of these plants is 1,830 MWs. The Griffith Power Plant and South Point Power Plant are located in Mohave County. The new PWEC combined cycle plant is located at the APS West Phoenix power plant site. Reliant's Desert Basin plant is located in Casa Grande. Each new plant has faced difficulties becoming operational over the past year. Operational testing and FERC exempt wholesale generator certification challenges normally encountered by new power plants have also been accompanied by transmission concerns for several of the new plants.

Numerous power plants under construction and listed in Exhibit JS-12 lack certainty regarding their commercial in-service date. Pipeline capacity and associated contractual rights to deliver natural gas to fuel existing and new power plants is also questionable. Similarly, potential delays in rights of way procurement or legal challenges of construction authority granted via Commission approved Certificates of Environmental Compatibility could lead to uncertainty regarding the operational date of proposed new transmission lines proposed for service in 2003. Supply from new generation in Arizona is dependent upon the favorable resolution of each of these risks and uncertainties.

Q. What risks and uncertainties are associated with natural gas supply and delivery?

A. El Paso Natural Gas Company has failed to address the growing demands for natural gas transportation in Arizona and the Southwest. New generating facilities appear to be relying on a number of possible sources of pipeline capacity for their facilities, including:

use of existing contract rights, acquiring released pipeline capacity from other shippers, purchasing rights on new pipelines or pipeline expansions, and swapping of gas supplies on different pipeline systems.

In the long term, market players are likely to build additional pipeline capacity and/or natural gas storage capacity to serve additional demand for natural gas in Arizona and the Southwest. Exhibit JS-13 depicts two gas pipeline projects and a gas storage facility that have been announced for Arizona. However, it is unclear at this time how well the availability of additional pipeline capacity in the future will coincide with the additional natural gas demand of the new generating facilities in the next few years. The on-going uncertainty regarding existing shippers' rights on the El Paso system has made it difficult for both shippers and potential capacity expansion developers to accurately gauge what the demand/need is for additional capacity. Most new gas-fired generating units in Arizona are located near El Paso's southern pipeline system, and this is likely to be the area of greatest concern regarding the shortfall of interstate pipeline capacity, although several recently announced pipeline projects may at least partially address the shortfall.

Q. How long will it take to relieve any existing transmission constraints and what factors are affecting and will affect prospects for relief?

A. Phoenix-area 500 kV transmission additions increase import capacity by 3,200 MWs in the 2003 through 2008 time period. When this new import capacity is coupled with new power plants and expansions internal to the constrained area, local utilities' dependence upon older, more costly, and higher polluting local generation should be reduced through about 2008. Appropriateness of additional transmission to further mitigate RMR generation requirements during this time period is still to be determined. However, Staff has yet to see transmission solutions proposed for the Phoenix area that will eliminate the transmission import constraints in the long term. Since two of the three new 500 kV lines from Palo Verde must still go through the rigors of a state line siting process, there remains some risk of public opposition for the new lines. The same risks would exist for

any other presently unidentified transmission lines required to keep pace with forecasted load growth or eliminate RMR generation requirements.

The Tucson transmission import area faces the same line siting risks as the Phoenix area. In fact the environmental community and public at large have already been very vocal regarding a variety of transmission projects in Central and Southern Arizona. Nevertheless, there appear to be sufficient transmission options under investigation to resolve the Tucson import constraint within the next few years.

The Yuma transmission import constrained area appears to have several competing line solutions moving forward towards a 2004 resolution. New proposed merchant generation in the local area may also offer Yuma a remedy as early as 2004. It is premature to judge how quickly the Nogales constrained area will be resolved until Citizens Communications identifies its proposed solution.

Resolution of transmission constraints at the Palo Verde hub are the most difficult to project. Except for the new 500 kV lines proposed by Arizona transmission providers, all other transmission improvements remain very speculative and lack any definitive funding sponsor, specific scope or well-defined in-service date. Most of these proposed 500 kV transmission projects improving the Arizona / California transfer capability will require Arizona line siting approval. At best, these projects are likely to formally emerge in the last half of this decade.

ROLE OF TRANSMISSION IN ELECTRIC RESTRUCTURING

Q. What role does Arizona transmission play in the restructuring of the electric utility industry?

A. The transmission system plays a vital role in the restructuring of the electric utility industry. Transmission systems constructed to deliver power from specific resources to specific load centers already exhibit both local and regional reliability constraints. These

constraints are presently resolved operationally by established congestion management techniques such as commitment of RMR generation units, generation re-dispatch, schedule curtailments, and finally voluntary or involuntary load curtailments. These measures are taken to relieve reliability constraints with little regard for the commercial effects on the industry.

It is reasonable to presume that the same transmission system will likely exhibit even greater constraints or barriers to delivery from alternative power plants to the same load center, delivery from the same power plants to different load centers or delivery from newly interconnected power plants to undetermined load centers. This is particularly true in the West because of the unique topology of the transmission system and the general sparsity of the interconnected EHV transmission system and local transmission networks. This presumption is based purely on the laws of physics rather than any market pricing or economic principles.

Timely construction of new infrastructure resolving prevailing and yet to be discovered transmission reliability constraints is paramount to ensuring that the UDC's consumers continue to benefit from reliable service at just and reasonable rates. Transmission enhancements are also a prerequisite for emergence of a reliable and economically viable competitive wholesale market. Interconnecting new generation projects without considering the transmission system necessary to reliably deliver the merchant's commodity to a market is simply commercial folly. Merchant plants certainly have the right to take such commercial risks. However, interconnection of such plants to the grid without a demonstration of the ability to reliably deliver to a market can result in placing the entire Western grid at operational risk. Staff also contends that new generation located on the load serving side of a transmission constraint is a reasonable alternative to new transmission if such projects:

1. are constructed early enough to allow the transmission provider certainty of compliance with WECC and local reliability criteria,

2. willingly commit to a "reliability must-offer" arrangement when capacity is not already utilized. Such arrangements should be void of market pricing greater than that prevailing external to the constraint,
3. do not unduly compromise local environmental standards, and
4. pose no unreasonable service risks such as fuel supplies subject to curtailments or price uncertainty.

Otherwise it would be prudent for the UDC to proceed with construction of appropriate transmission facilities.

Q. Are transmission owners currently doing things that will allow them to exert more or less control in the future? If so, please detail.

A. It is Staff's opinion that Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions to resolve local transmission import constraints and mitigate perceived transmission market power within Arizona. While it will take a number of years for these new lines to be sited and constructed, there has certainly been a good faith demonstration by Arizona utilities of their commitment to respond favorably on a forward looking basis. The recent transition from a Desert STAR RTO to a WestConnect RTO is also reflective of a commitment to have an RTO with the authority to build transmission lines if others do not.

Q. Will the transmission system be adequate prospectively (e.g., in the next 5, 10, 15, 20 years) to deliver power from new generation plants?

A. Based upon a preliminary review of all transmission plans approved with a CEC and those filed with the Commission, Staff believes Arizona transmission system adequacy for new generating plants will be achieved in the last half of this decade. FERC anticipates that a regional RTO will, in time, be the entity responsible for ensuring the adequacy of transmission capability in the Southwest or West. FERC has suggested that some form of incentive ratemaking could be used to encourage appropriate transmission upgrades identified through an RTO planning process. The process of getting a regional

planning and incentive pricing structure in place will likely take several years. The Western Governors' Association ("WGA") has recognized the need to push this agenda on an interim basis.[6] The West simply cannot wait on FERC and RTOs to address this transmission need via market driven solutions.

Staff is not in a position to accurately assess the adequacy of planned transmission system enhancements filed with the Commission as of January 31, 2002. Such an assessment will be rendered upon completion of a second ACC biennial transmission assessment that will likely commence in June. **Nevertheless, Staff believes that accelerated development of transmission solutions beyond that which has been filed with the Commission is needed in order to facilitate restructuring of the electric utility industry to reliably serve Arizona consumers at just and reasonable rates via a competitive wholesale market.** The Commission can ill afford to wait for market failures to drive solutions when our state is dependent upon the new generation developing in Arizona. A proactive approach to resolving Arizona's local transmission needs should be adopted and implemented by the Commission as part of this generic restructuring case.

Q. How has the restructuring electric industry responded to transmission needs in Arizona?

A. Establishing a framework for transmission expansion that retains traditional system reliability-based service values and yet assures consumers are not harmed by others' direct access of the same transmission system for competitive wholesale market transactions is a challenge. One must first recognize the diversity of regulatory objectives regarding restructuring and associated layers of evolving jurisdictional authority. Secondly, business objects of different sectors of the restructuring industry are counter-poised and in conflict. This is most evident by the tug of war being exercised by parties in this case.

[6] WGA's August 2001 "Conceptual Plans for Electricity Transmission in the West" report.

Staff does not profess to have the magical answer that can resolve the chaos of electric restructuring. However, Staff believes that an industry-wide need exists for the timely development and construction of necessary transmission enhancements to mitigate reliability concerns. Consumers need assurances that the UDC will not abandon its obligation to continue providing reliable service at just and reasonable rates. UDCs are uncertain who their energy supplier of the future will be and what transmission is needed to gain access to those resources. Therefore, UDCs are playing the waiting game and deferring transmission investments by relying on RMR generation opportunities. Meanwhile, new merchant power plants and market participants are dependent upon transmission to deliver their commodity to market. However, they too have not predetermined their intended market and therefore are seeking only to interconnect with the grid (or hub) in hopes that whomever wants the power will "come and get it" and make the necessary transmission provisions.

Hence, a game of chicken prevails regarding transmission required to support a competitive wholesale market. Who will be harmed if the game is protracted - the consumer. Deterioration in quality of service and uncontrolled and volatile market pricing of generation and transmission services would be likely outcomes. Fortunately, Arizona's CATS study effort has managed to bring both the transmission providers and interested merchant power plants together in a common forum to look at transmission options that can fulfill the needs of all parties. As a result several transmission lines have been announced and invitations made to all parties interested in participating in the projects. This is a good beginning. Staff's recommendations regarding resolving Arizona's transmission constraints build on this model and engages all affected sectors of the restructuring industry.

Q. What action does Staff recommend to assure timely development and construction of necessary transmission enhancements?

A. Both transmission providers and power plants share the burden and obligation to resolve Arizona transmission constraints. Staff recommends that the Commission adopt the following two reliability standards and require both sectors of the electric industry to work collaboratively to build sufficient Arizona transmission to comply with these reliability standards at the earliest possible date. Staff first recommended these two reliability principles in its Biennial Transmission Assessment.[7]

1. There should be sufficient transmission import capability to reliably serve all loads in a utility's service area without limiting consumer access or benefit to more economical or less polluting generation located external to the service area.
2. A power plant must have sufficient interconnected transmission capacity to reliably deliver its full output without use of remedial action schemes for single contingency (N-1) outages or displacing a priori generation interconnected at the same switchyard or on the same transmission lines.

Staff contends compliance with the above transmission reliability objectives will ensure reliable service to Arizona consumers at just and reasonable rates while providing an opportunity for a competitive Arizona wholesale market to emerge unbridled by local transmission constraints. Staff recommends the Commission approve the following five actions to foster resolution of transmission reliability concerns in a responsible and managed manner.

1. Staff recommends that the Commission order that all sectors of the electric industry affected by existing transmission constraints collaborate in studies to determine the most effective solutions to resolve reliability concerns and agree to support and advance the construction of such projects for service at the earliest possible date.

[7] ACC Staff, Revised Biennial Transmission Assessment 2000-2009, Revised July 2001, page 3.

2. Matt Rowell gave testimony recommending that the Commission order APS and TEP to submit a market power study prior to transfer or divestiture of any generation asset. That market power study should address known Arizona transmission constraints and identify how transferring generating units will impact other market participants uses of transmission services over those constrained paths.
3. Staff recommends that the Commission order jurisdictional utilities to resolve RMR generation concerns by:
   a. Performing and completing, within 30 days of a decision of Track A issues in this docket, a study analyzing the merits of existing dependence on RMR generation rather than building transmission to resolve local transmission import reliability constraints,
   b. Perform a study analyzing the merits of any future contemplated utilization of RMR generation to defer transmission projects, and that
   c. Such RMR study reports be filed with the Commission for review within 30 days of completion of such studies and prior to implementing any new RMR generation strategies.
4. Staff recommends the Commission further order jurisdictional utilities to proceed to resolve any transmission import reliability constraint by constructing needed transmission facilities as soon as practical if the Commission finds their RMR generation strategy to not be in consumers' best interest.
5. Merchant power plants should not be left out in this matter of resolving transmission reliability constraints. Therefore, Staff recommends that the Commission establish the following two standards regarding future power plant applications for a CEC.
   a. Future power plant applications for a CEC should be denied for sufficiency purposes if they have not fulfilled the statutory technical study requirements demonstrating the impact of their project on the existing Arizona transmission system.
   b. Power plants that fail to demonstrate the ability to reliably deliver to a market without displacing a priori generation interconnected at the same location or

utilizing the same interconnected transmission system should not be granted a CEC.

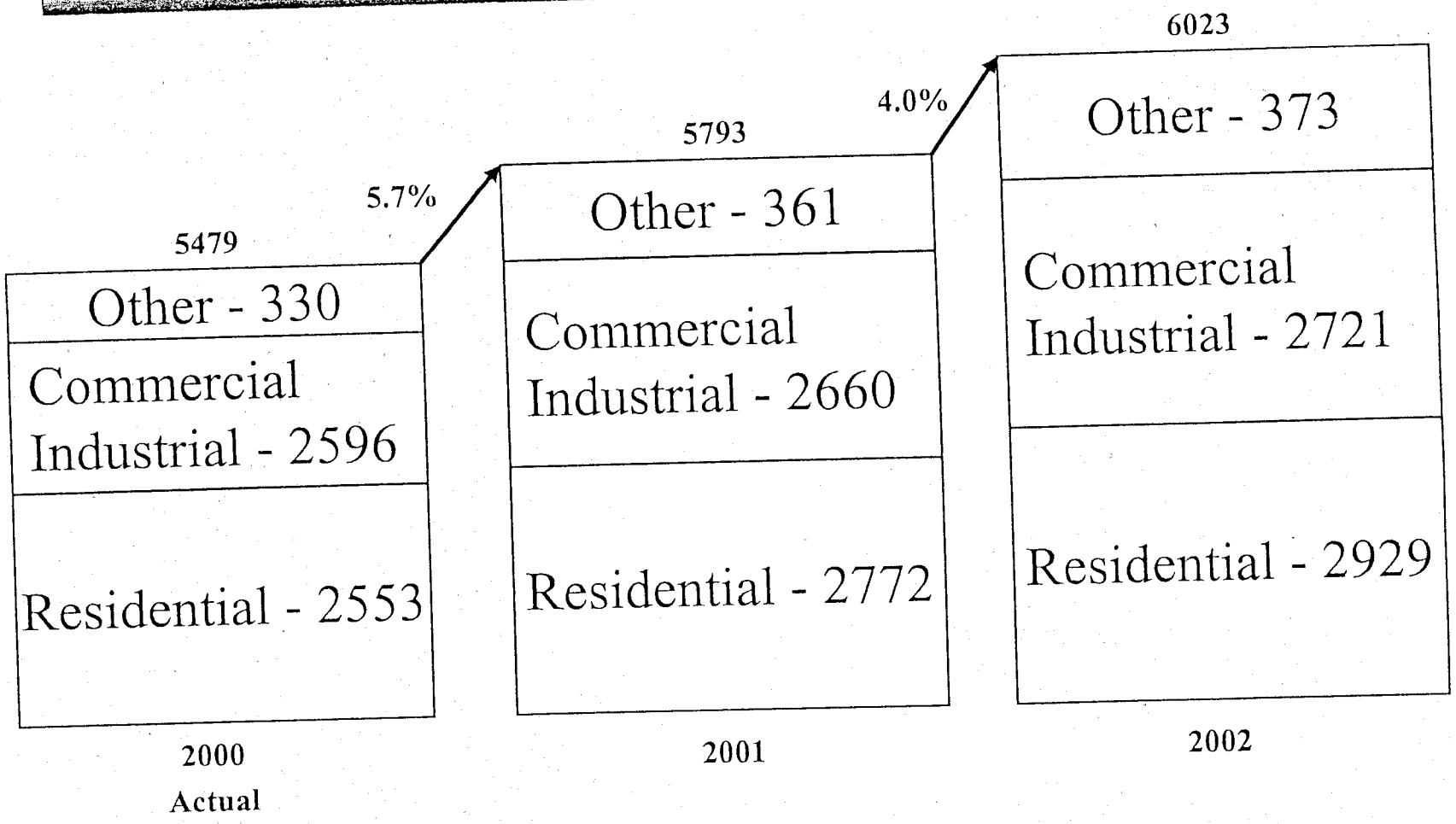
These two standards will encourage new power plants to participate in the collaborative transmission process defined by Staff's first recommended in this testimony.

Q. Does this conclude your testimony?

A. Yes it does. However, Staff requests the right to modify or supplement its testimony to allow alignment and reconciliation with related electric restructuring issues that emerge during future tracks in these proceedings.

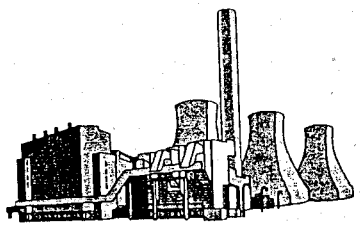
EXHIBITS

APS
Peak Load Forecast



Values in MW

Exhibit JS-1



APS Resources

	2001	2002
= Existing Generation	3982	4497
Renewable	9	13
= Additions		
Upgrade of existing CC&CT	107	-
Reactivate WPhx Steam 4&6	96	-
WPhx CC 4	114	-
Temporary WPhx CT's - 5 units	99	(99)
Temporary Saguaro CT's - 5 units	99	(99)
Redhawk CC 1&2	-	988
Subtotal	515	790
= Long-term Contracts		
Pacificorp Exchange	480	480
SRP	336	343
Subtotal	816	823
= Short-term Contracts	1176	638
= Total Resources	6498	6761

Exhibit JS-2

2002
TEP Loads and Resources

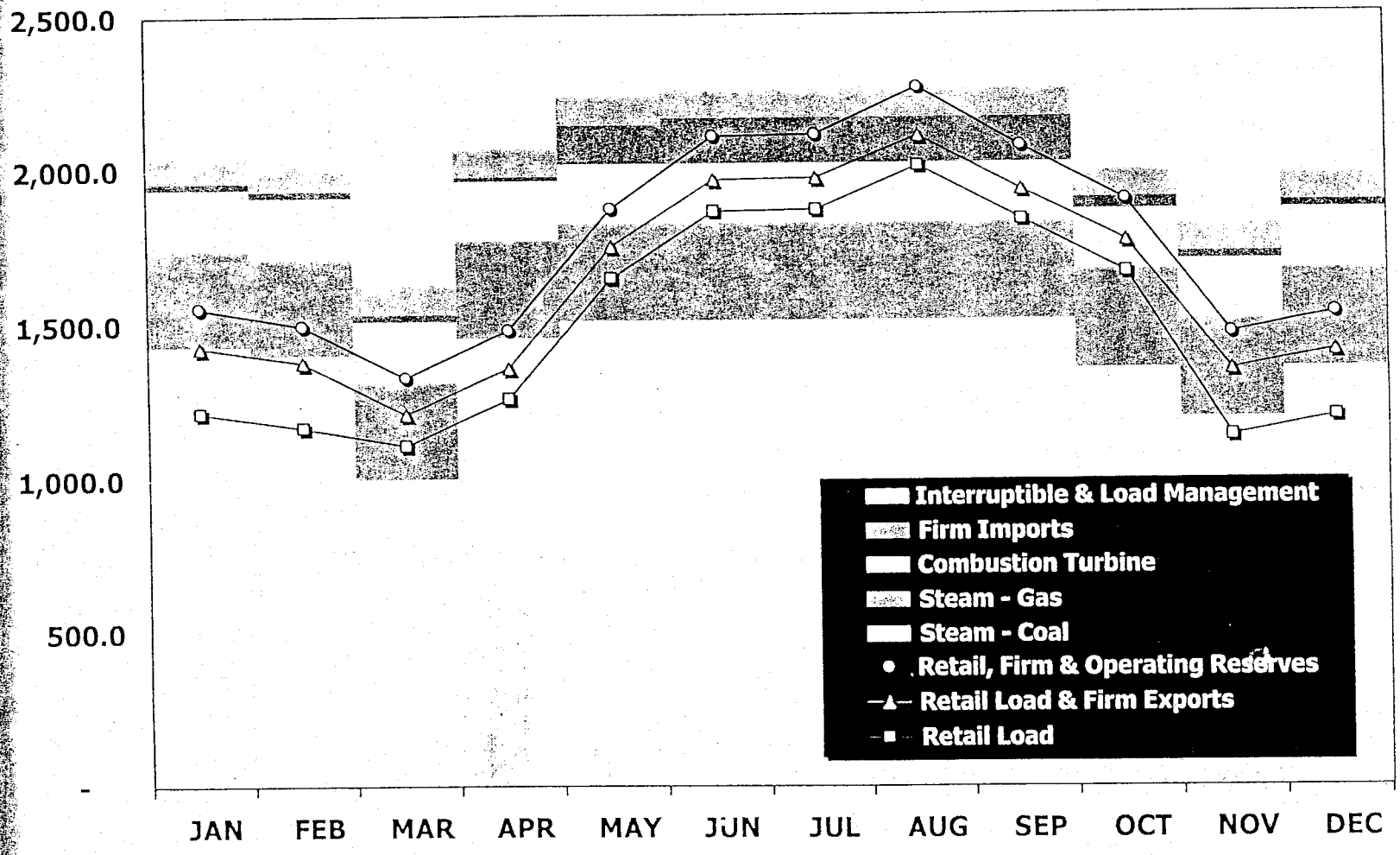


Exhibit JS-3

Generation Capacity

- 1520 MW of Base load Coal
- 255 MW of Intermediate Gas Steam
- 125 MW of Combustion Turbines
- 75 MW new Combustion Turbine (June 1, 2001)
- 25 MW new Combustion Turbine (permitting in progress, May 1, 2001)
- <u>2000 MW Total Generation Capacity</u>

Note:

TEP receives 110 MW from SCE during summer period

Exhibit JS-4

Arizona EHV Transmission

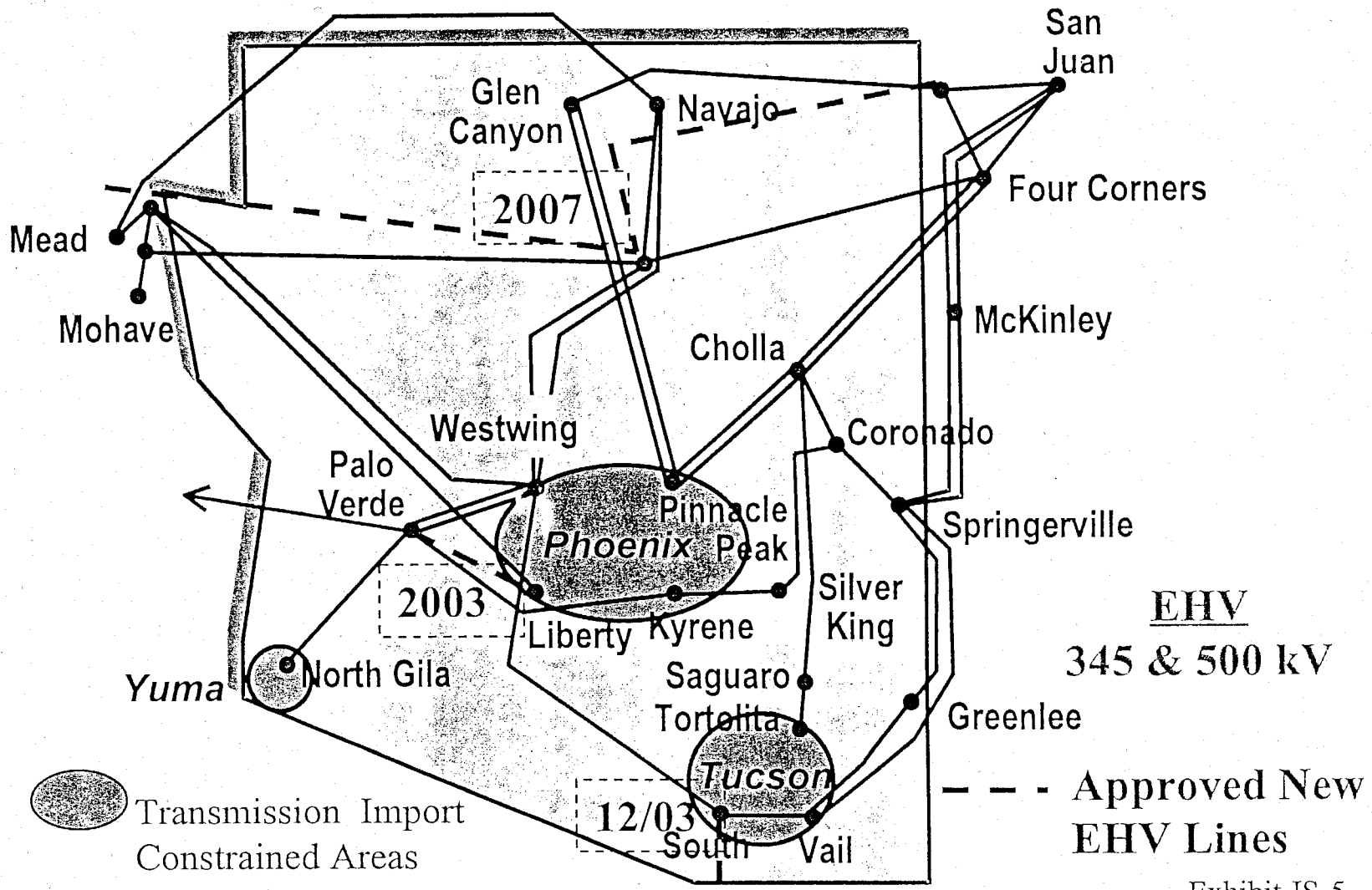


Exhibit JS-5

Case #115

Recreated in Excel using Exhibit D - 12

Districts' Second Revision Figure 14 from the Revised Biennial Transmission Assessment

APS Phoenix Metropolitan Area Load Serving Capability

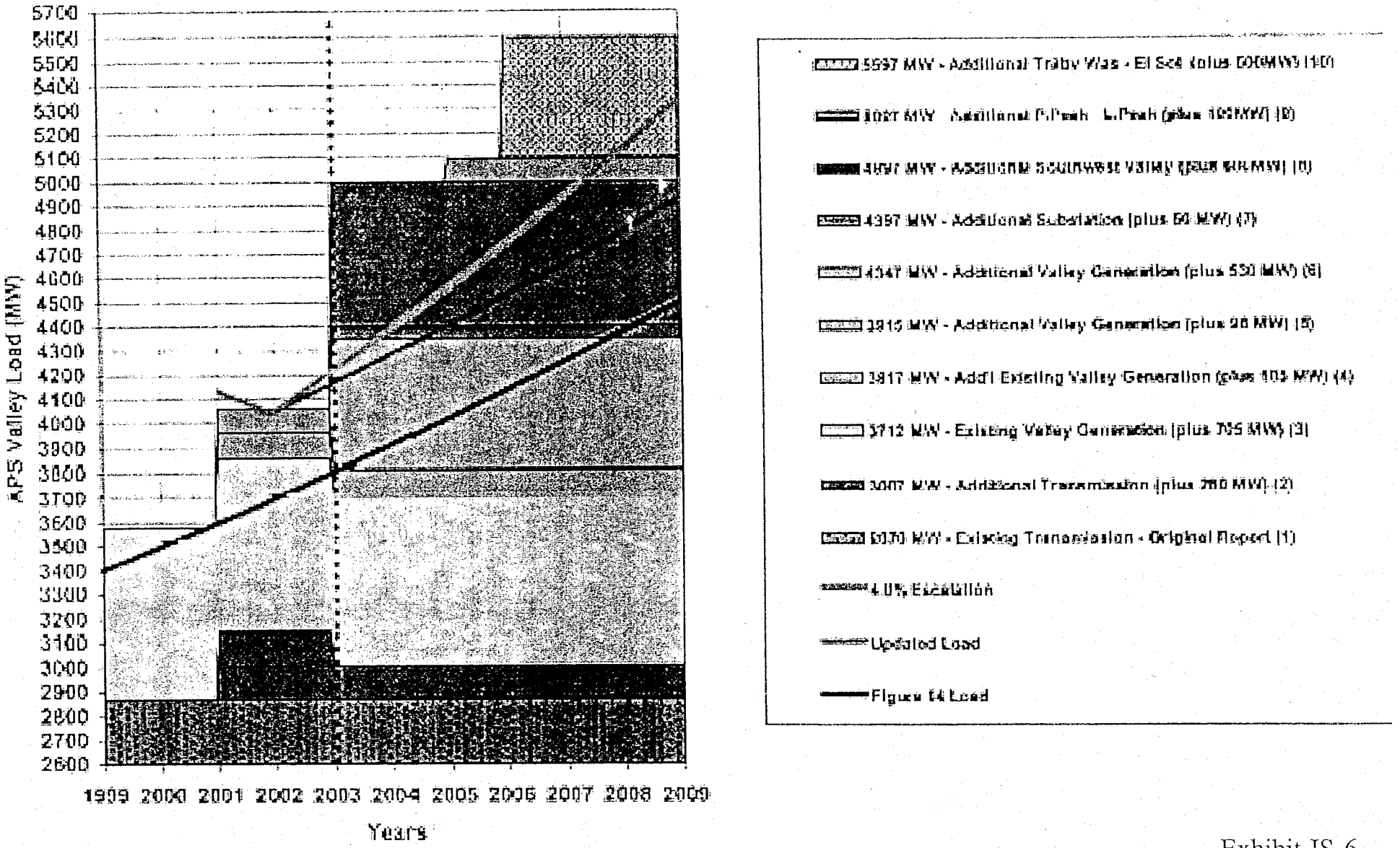


Exhibit JS-6

RMR Generation vs Transmission

RMR is economically prudent when $C_{rmr} \leq C_a$

where C_{rmr} = Cost of reliability must-run energy during the constraint period and

C_a = Annual avoided cost of transmission line investment

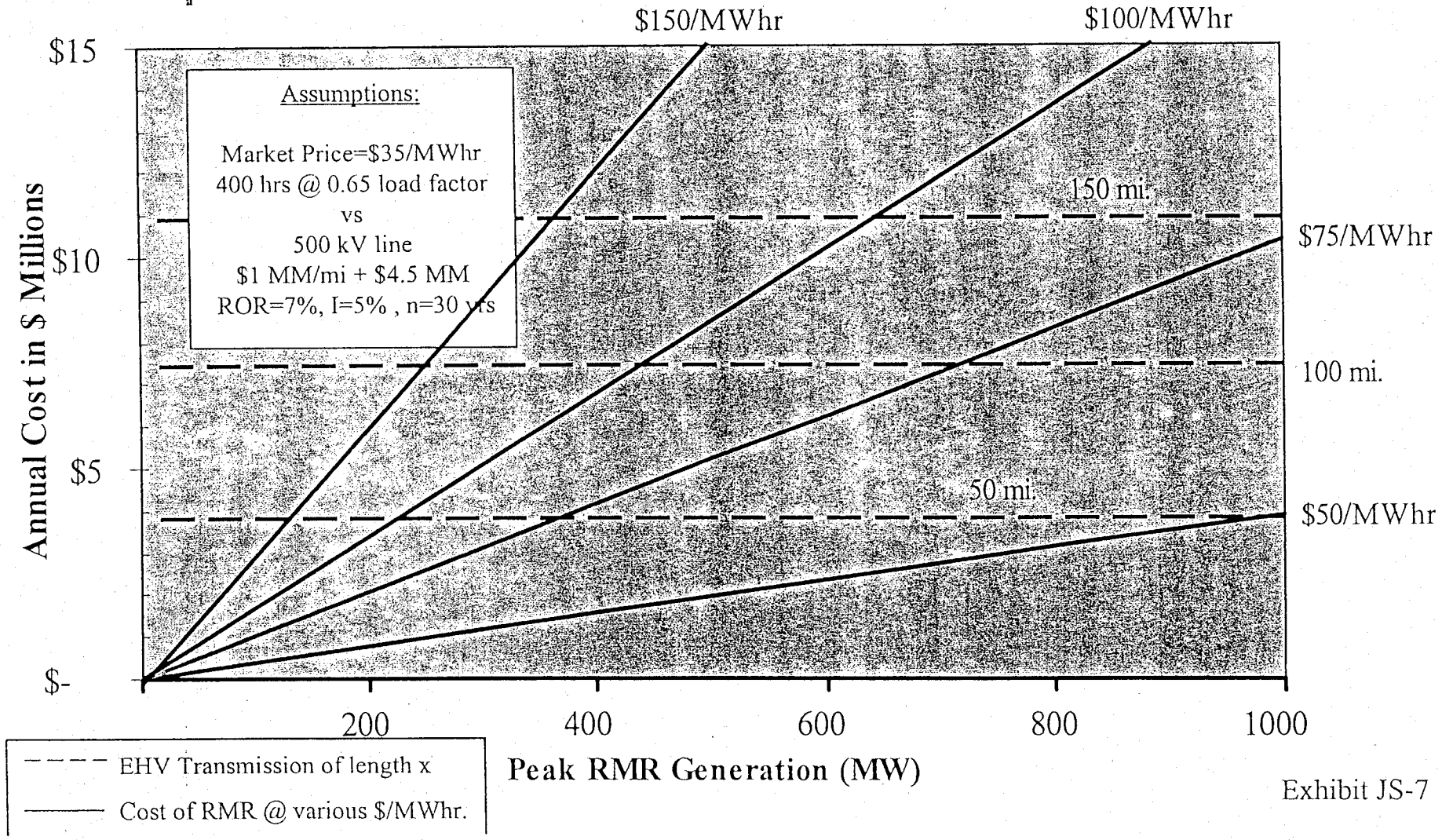


Exhibit JS-7

Formulas, Definitions, Assumptions For Exhibit JS-7

"Reliability Must-Run" is economically prudent when $C_{rmr} \leq C_a$

Where:

C_{rmr} = Cost of RMR energy during the constraint period and
C_a = Annual avoided cost of transmission line investment

$$C_{rmr} = (G_{rmr} - G_m)^* L_f^* P^* y \quad \text{and} \quad C_a = (1 + ROR)(T_t + T_l^* x)^* i(1+i)^n / [(1+i)^n - 1]$$

Where:

G_{rmr} = Total operating cost of RMR unit(s) in $/MWhr.
G_m = Marginal market price of generation ($35/MWhr).
Per WGAs August 2001 Conceptual Plans for Electricity Transmission in the West report, FERCs February 2002 Economic Assessment of RTO Policy, and current WI market trends.
L_f = Seasonal load factor during constraint period (0.65 for summer).
P = Peak load in excess of transmission import capability in MW.
Begins at 427 MW in 2003 and grows to 1034 MW in 2007 for APS; begins at 354 MW in 2003 for TEP and grows to 564 MW in 2007.
y = Duration of RMR constraint in hours (400 hrs)

ROR = Annual rate of return allowed on capital investment (7%).
T_t = Transmission termination cost of new line ($4.5 million).
Assumes a breaker and a one half scheme at each end of the line.
T_l = Transmission line capital cost per mile ($1 million/mi.).
Assumes $1 million per mile for 345kV and 500 kV using steel poles.
n = Economic life of new transmission line (30 yrs).
i = Annual interest rate (5%).
x = Length of new EHV transmission line (mi.)

Competitive Generation Requirement*

Area = WSCC,
Control Area,
RTO,
State,
or Utility

Area Load
- Interruptible
+ Net Export

Reserve Load Responsibility
+ Reserves

Min. Gen. Req.
+ Comp. Supply Margin

Total Gen. Req.

Plng Reserves
Capacity Margin
Operating Reserves

Sufficient to
ensure competitive
market prices

* Assumes no Transmission constraint

Exhibit JS-9

Proposed Plants in Arizona

Status	Year							Total MWs
	2001	2002	2003	2004	2005	2006	2007	
Commercial Operation	1,830	-	-	-	-	-	-	1,830
Under Construction	-	3,880	3,330	-	-	-	-	7,210
Reg. Approval Received	-	-	600	2,645	1,865	620	530	6,260
Application Under Review	-	-	520	-	-	-	-	520
Application Filed	-	-	-	-	-	-	-	-
Announced	-	-	520	580	-	-	2,500	3,600
Total MWs	1,830	3,880	4,970	3,225	1,865	620	3,030	19,420

05/29/2002

Note: Montezuma 520MW plant suspended plans w/o filing CEC application

Denied Projects = Big Sandy (720 MW) and Toltec (1800 MW)

Exhibit JS-10

New Power Plants 2001

Plant	Nominal Capacity (MW)	Gas Use (MMBtu/Yr)	Water Use (Acre-Ft/Yr)
Desert Basin	520	33,100,000	4,200
Griffith	650	36,266,400	3,060
W. Phoenix	120	6,619,200	1,083
South Point	540	35,000,000	4,500
TOTAL	**1,830**	**110,985,600**	**12,843**

Exhibit JS-11

2003
Competitive Generation (MW)

Operational 2001		2002	
Griffith Energy	650	Arlington Valley I	580
Desert Basin	520	Gila River 1,2	1,040
South Point	540	Kyrene	250
W. Phoenix	120	Redhawk 1,2	1,060
	1,830	Sundance CTs	450
		W. Phoenix	500
			3,880

2003			
Arlington Valley II	600	Harquahala	1,040
Gila River 3,4	1,040	Mesquite	1,250
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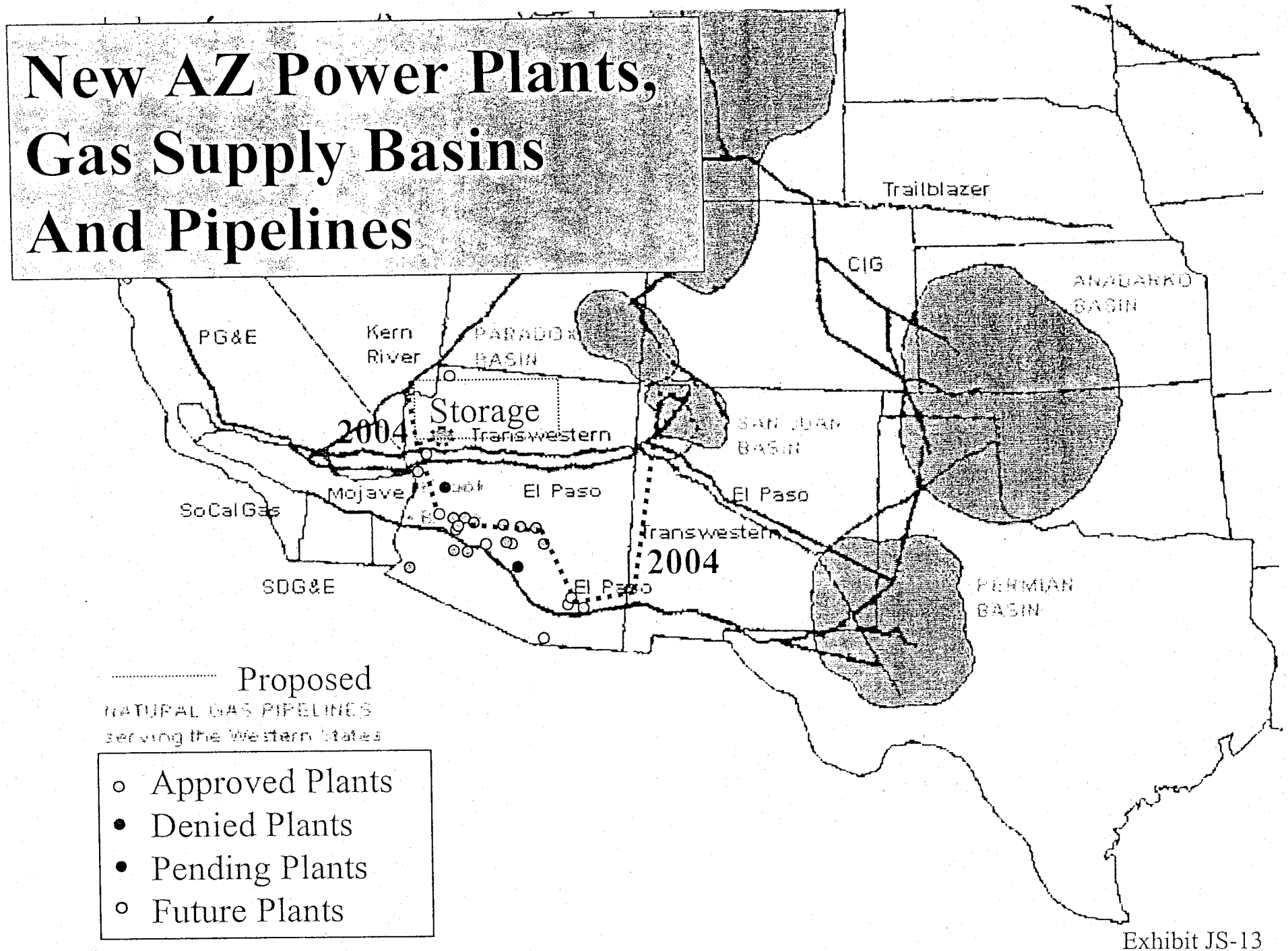
Exhibit JS-12

New AZ Power Plants, Gas Supply Basins And Pipelines



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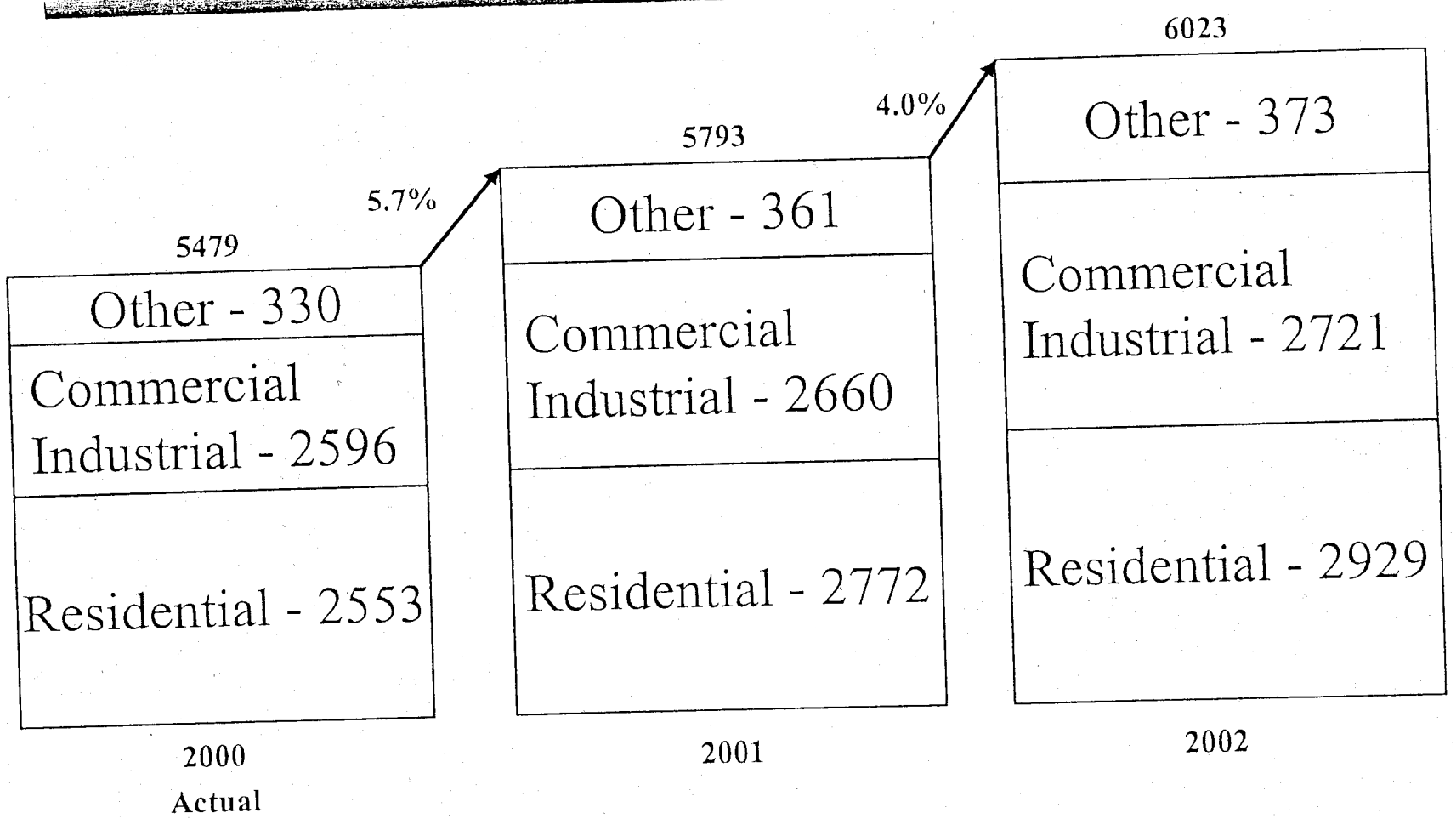

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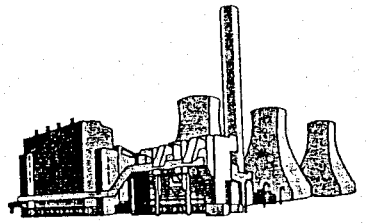

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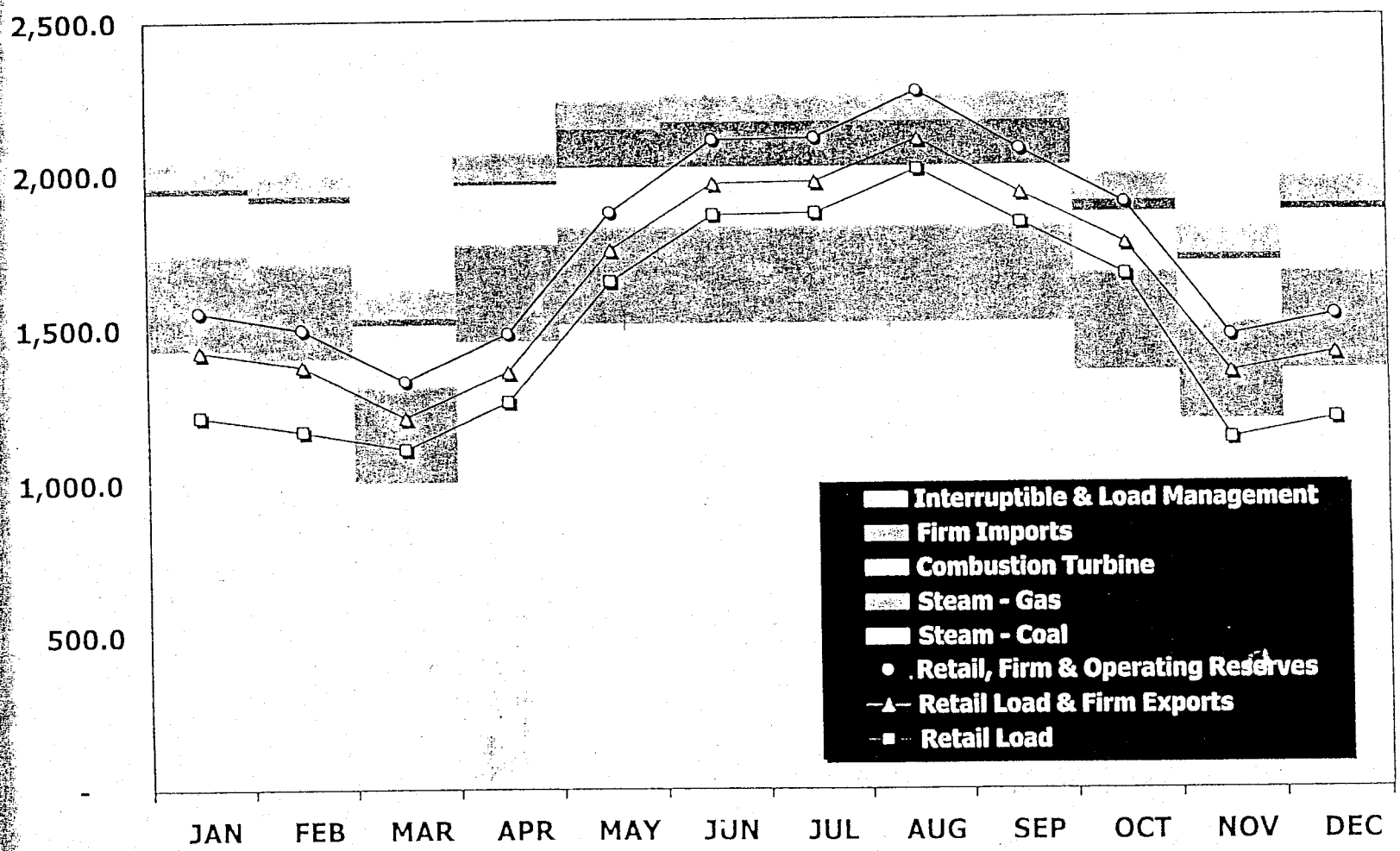

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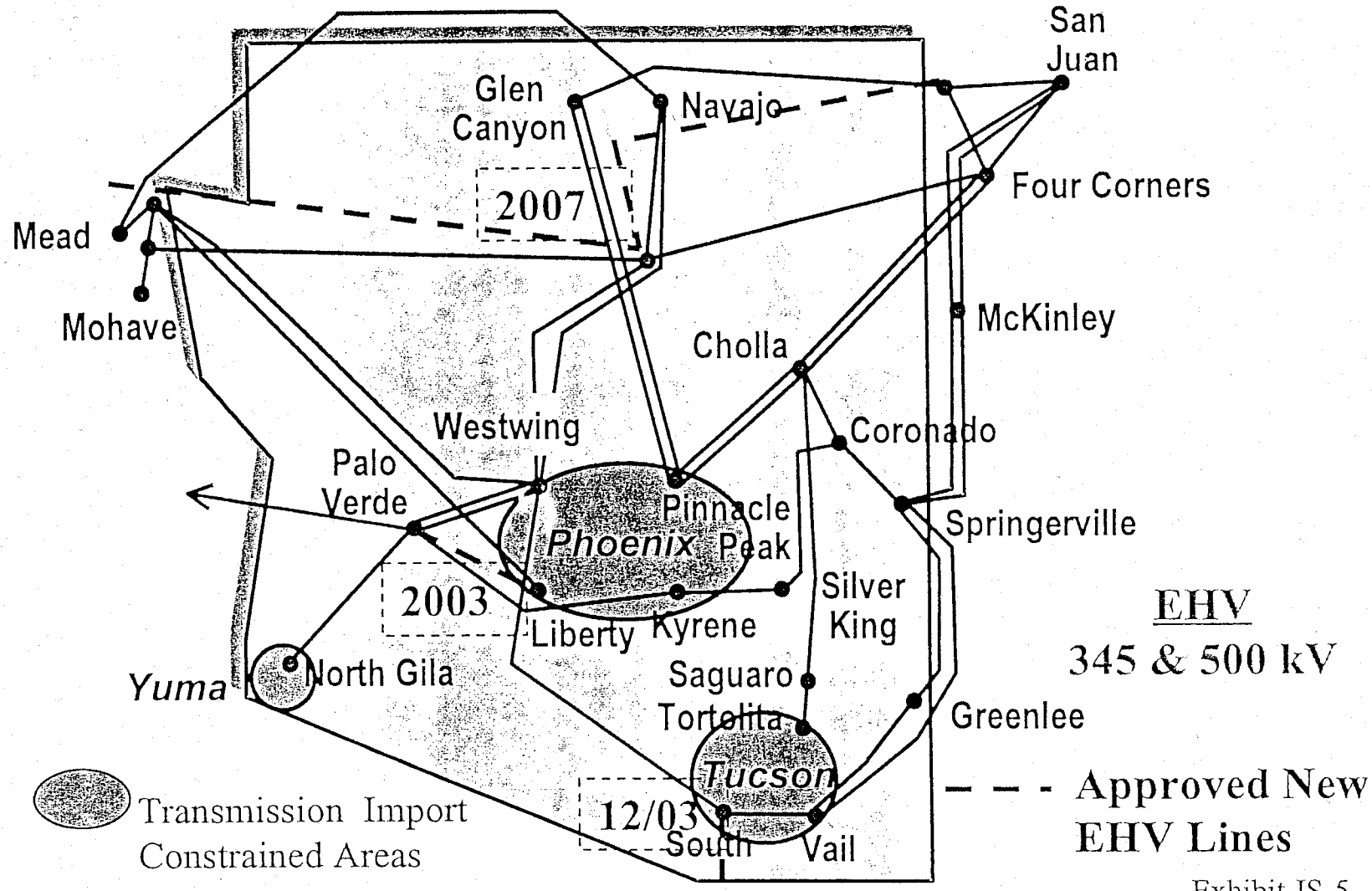

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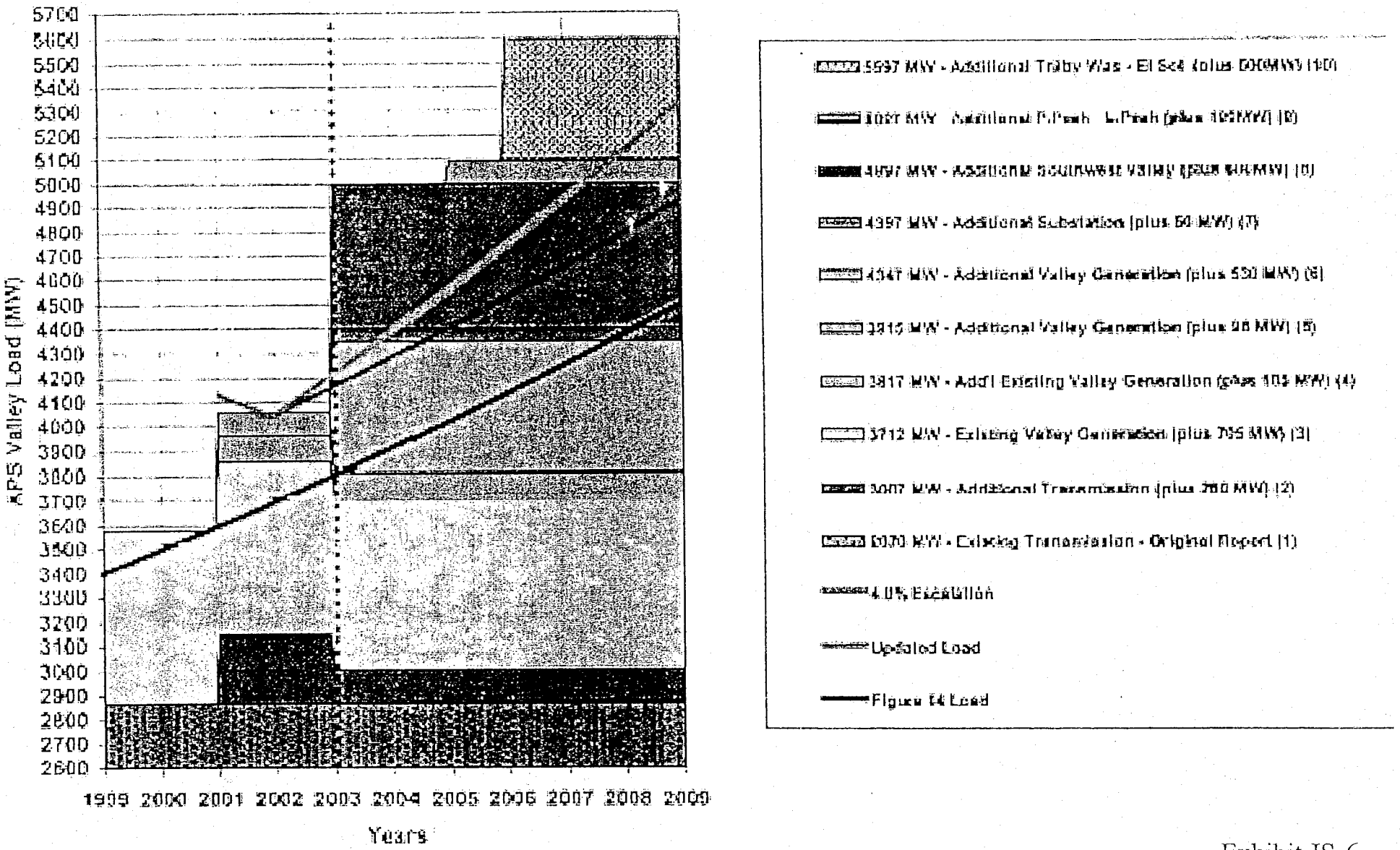

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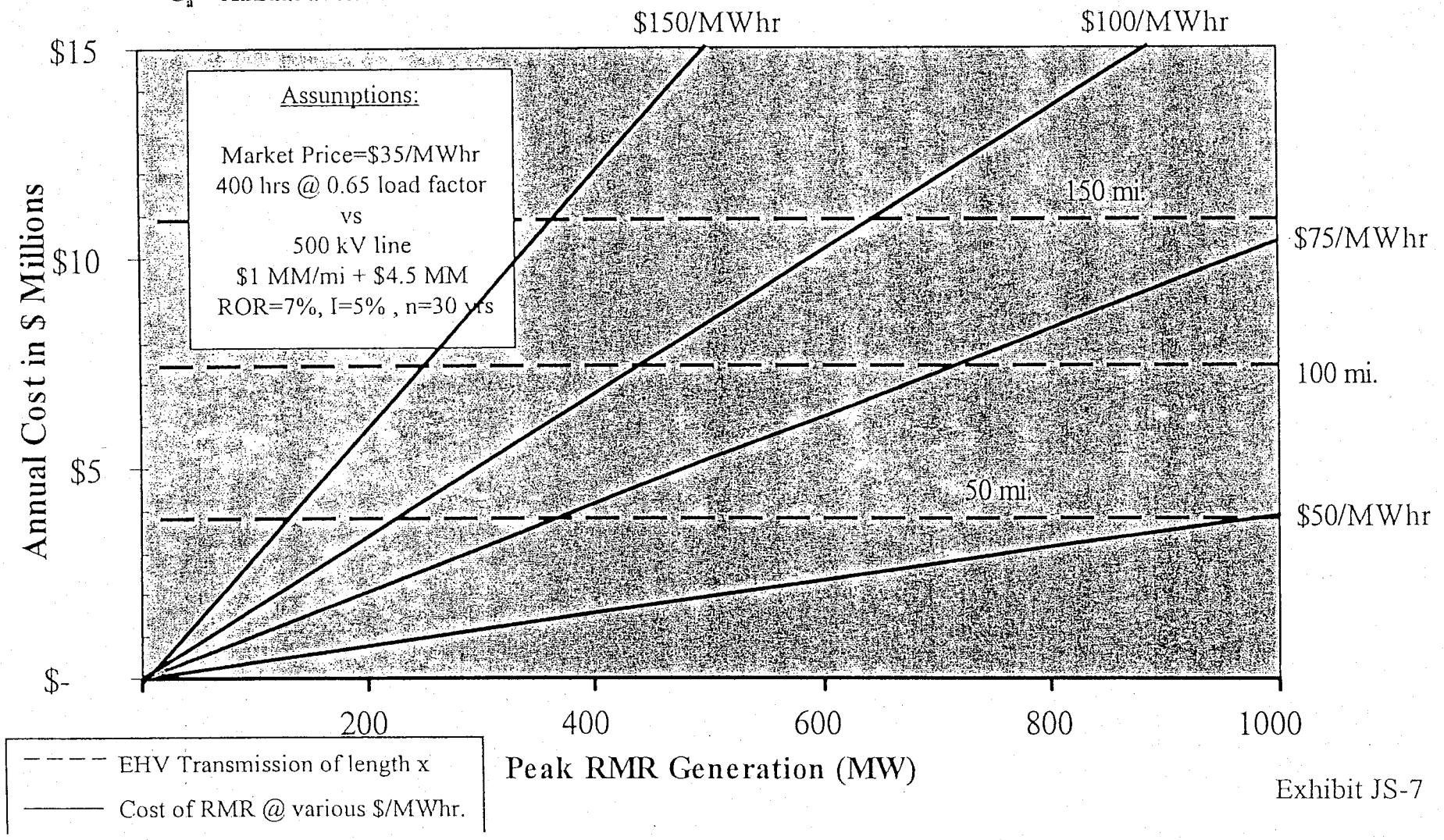

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Exhibit JS-12

New AZ Power Plants, Gas Supply Basins And Pipelines

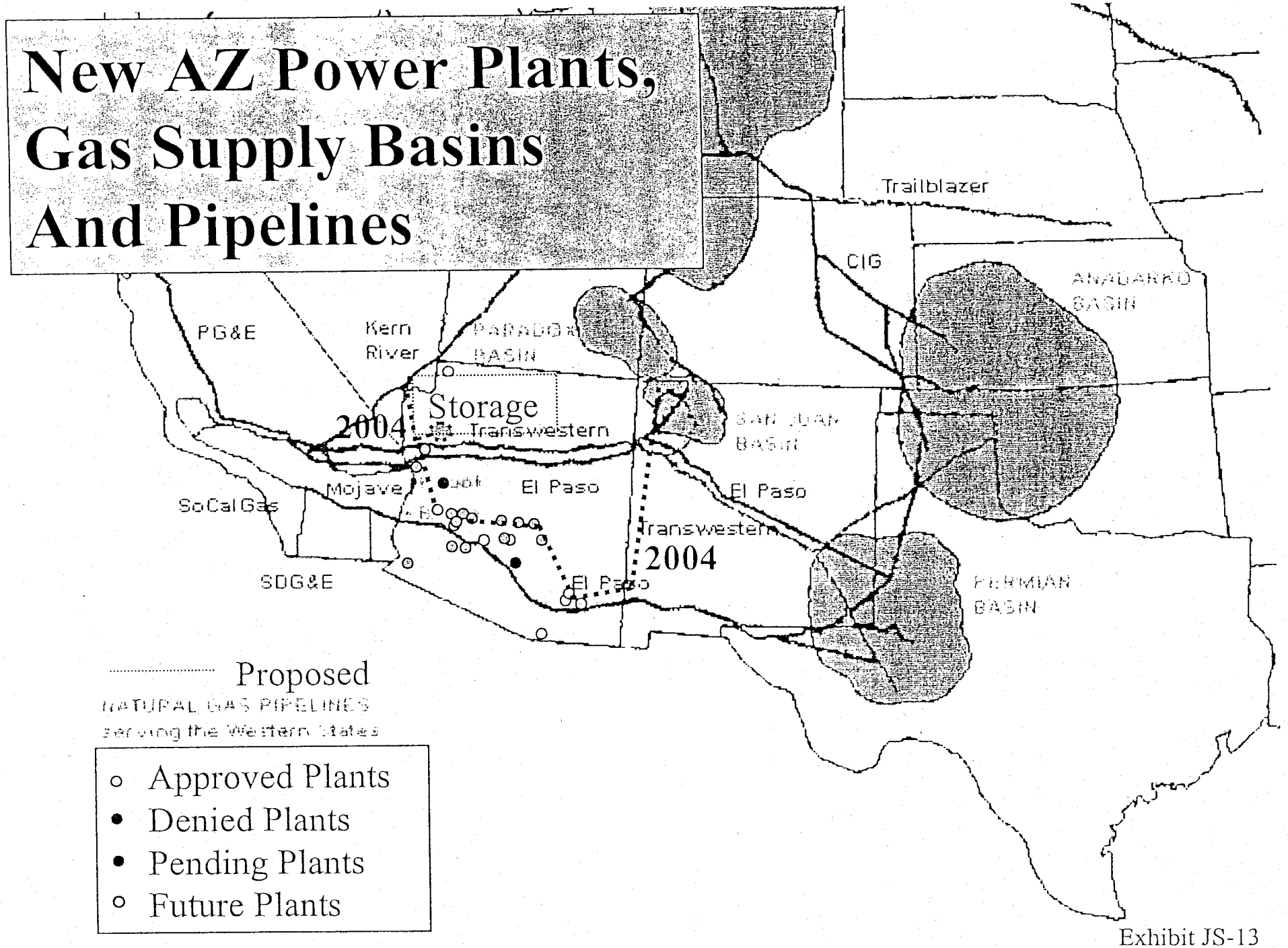

Exhibit JS-13

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
S-14
admitted

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

REBUTTAL

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

June 11, 2002

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INTRODUCTION

Q. Please state your name and business address.

A. Jerry D. Smith, 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer for the Utilities Division.

Q. Have you previously submitted direct testimony in these proceedings?

A. Yes.

PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony in these proceedings?

A. My rebuttal testimony will respond to specific segments of testimony provided by Mr. Michael J. DeConcini, Mr. William H. Hieronymus, Mr. Kevin C. Higgins, Dr. Craig R. Roach, and Mr. Curtis L. Kebler. My rebuttal testimony focuses on the following topics:

1. Relieving transmission constraints,
2. Market power tests regarding local transmission constraints,
3. AzISA and Westconnect mitigation of reliability must-run ("RMR") generation, and
4. Network Resources and associated transmission rights.

Q. Please summarize the contents of your rebuttal testimony.

A. My rebuttal testimony deals exclusively with transmission and transmission service. The first conclusion derived from my rebuttal is that others support Staff's view that local transmission constraints need to be resolved. Transmission improvements are needed to resolve Staff's reliability concerns, avoid vertical market power associated with transmission, and facilitate the emergence of a competitive wholesale market and retail competition. The need for mitigating transmission related vertical market power

complements and supports my direct testimony that expedient resolution of transmission constraints is paramount to ensuring reliable service to consumers at just and reasonable rates.

The second conclusion is that established market power tests fail to adequately address transmission constraints. Furthermore, FERC's solutions to transmission market power are not likely to address local transmission constraints. Therefore, Staff recommends adoption and compliance with the two reliability principles proposed in my direct testimony as the best means for eventual elimination of local transmission constraints.[1] Such action will consequently mitigate local transmission market power.

Thirdly, Staff concludes that reliance on the AISA and Westconnect protocols as the sole mitigation measures for RMR generation requirements caused by local transmission import constraints is not in the public's interest. The protocols are effective operational tools for managing RMR generation requirements but were never designed nor intended as market power mitigation measures. Staff recommends three actions to mitigate RMR generation including constructing needed transmission facilities as soon as practical if the Commission finds a UDC's RMR generation strategy to not be in consumers' best interest.

The final conclusion of my rebuttal testimony is that the proper and non-discriminatory designation of power plants as Network Resources and use of available transmission capacity for Network Integrated Transmission Service is critical to emergence of a competitive wholesale market in Arizona. While FERC proposed Energy Resource Interconnection Service and Network Resource Interconnection Service may be in the best interest of generators, they may not be in the best interest of Arizona's consumers. Therefore Staff endorsement of proposed power plant interconnections is contingent upon resolution of any transmission delivery problems associated with the interconnection.

[1] Jerry D. Smith, at lines10-16, page 25.

Once again, adoption and compliance with the two reliability principles proposed in my direct testimony offers the best means of ensuring a merchant's delivery of power to local markets.

RELIEVING TRANSMISSION CONSTRAINTS

Q. Do others provide testimony supporting Staff's proposition that local transmission constraints need to be resolved to ensure reliable service to Arizona's consumers at just and reasonable rates via a competitive wholesale market?

A. Yes. Mr. DeConcini indicates that he broadly agrees with my testimony in the APS variance request proceedings (Docket No. E-01345A-01-0822) regarding transmission access and relieving constraints.[2] He further states that relieving transmission constraints is one of four key steps that needs to be taken in order to provide the opportunity for significant retail competition.[3] However, Mr. DeConcini does not believe that all transmission constraints must be eliminated for effective competition to exist. This statement seems to align well with Staff's position that there may be occasions when generation is justified as a solution to a transmission constraint.[4]

Mr. Hieronymus states that vertical market power has far greater potential to destroy competitive electricity markets than horizontal market power.[5] He further describes a transmission system owner's use of its monopoly over an "essential facility" to exclude or disadvantage competitors in related activities such as generation or serving retail customers as a relevant example of vertical market power.[6] Furthermore, Mr. Hieronymus acknowledges that in earlier testimony he conceded that some APS generating units are RMR and could exercise market power.[7]

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[2] Direct Testimony, Michael J. DeConcini, May 29, 2002, Docket No. E-00000A-02-0051, et. al, page 9.
[3] Ibid., at page 8.
[4] Direct Testimony, Jerry D. Smith, May 29, 2002, Docket E-00000A-0051, et. al, at page 21-22.
[5] Direct Testimony, William H. Hieronymus, May 29, 2002, Docket No. E-00000A-02-0051, et. al, at page 26.
[6] Ibid., at line 13-15, page 26.
[7] Ibid., at page 28.

Mr. Hieronymus' testimony corroborates Mr. David A. Schlissel's testimony for Staff regarding how APS and TEP transmission constraints create such vertical market power.[8] Mitigation of market power caused by transmission constraints is necessary for a competitive wholesale market to emerge in Arizona. This need for mitigating vertical market power complements and supports my testimony that expedient resolution of transmission constraints are paramount to ensuring reliable service to consumers at just and reasonable rates.

MARKET POWER TEST REGARDING TRANSMISSION CONSTRAINTS

Q. How does your prior testimony regarding system reliability relate to the subject of market power as contained in your rebuttal testimony?

A. My direct testimony focused on the capability of the existing and planned Arizona energy infrastructure to provide reliable service at just and reasonable rates via a competitive wholesale market. Others have testified that transmission constraints identified in my earlier testimony in the APS Variance proceeding also provide the physical opportunity for market power to be exhibited. Although I am not an economist and therefore do not purport to conduct an economic analysis of market power, I do have concerns that the various market power tests do not include the proper system elements specifically, these tests do not adequately include the effects of transmission constraints. I further contend that resolving Staff's reliability concerns is the best means of mitigating any local transmission system related market power.

Q. Is there testimony supporting use of particular market power tests to address transmission constraints?

A. Several parties to this case cite tests used to address horizontal market power for supply. However, these market power test models seem ill suited to addressing local transmission constraints and load pockets within a utility's transmission network. Although my testimony does not analyze the results of the application of various market power tests, I

[8] Direct Testimony, David A. Schlissel, May 29, 2002, Docket E-00000A-02-0051, et. al, pages 7-8, and 13.

will cite the testimony of others to show that none of these tests purports to account for all the efforts of transmission constraints.

Several parties acknowledge that FERC's "hub and spoke" test that utilizes the Herfindahl-Hirshman Index ("HHI") addresses market concentration ignores transmission constraints.[9] Dr. Roach[10] and Mr. Higgins[11] contend the supply margin assessment ("SMA") or "pivotal test" adopted by FERC as an interim test does consider transmission import limitations to the relevant market but fails to consider reserves and transmission constraints or load pockets within the market area. Dr. Roach contends that generation that cannot compete within the market should be excluded from the SMA test. On the other hand, Mr. Higgins recommends that the California ISO ("CAISO") Residual Supply Index ("RSI") is a more accurate model for determining market power on an hourly basis. The RSI purports to resolve the reserve modeling deficiency of the SMA model. However, it still lacks the ability to adequately consider transmission constraints. Therefore, Staff concludes that no formal market power test has been presented in this proceeding to adequately address the effects of transmission constraints on the market.

Staff contends that compliance with the two reliability principles contained in my direct testimony offers means for the eventual elimination of local transmission constraints.[12] Parties are not likely to find Staff's reliability principles appealing because they will require construction of new transmission lines. That is fundamentally why a game of chicken is being played by the generation and transmission sectors of the industry. Continuing such action will simply perpetuate a dysfunctional wholesale market and is not in consumers' best interest.

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[9] William H. Hieronymus, at page 31.
[10] Craig R. Roach, Ph.D., at page 10.
[11] Direct Testimony, Kevin C. Higgins, May 29, 2002, Docket No. E-00000A-02-0051, et. al, at pages 12-14.
[12] Jerry D. Smith, at lines 7-16, page 25.

AISA AND WESTCONNECT MITIGATION OF RMR GENERATION

Q. How do parties to this case suggest market power within load pockets be mitigated?

A. According to Mr. Hieronymus, the potential market power inherent in must-run units will be mitigated by APS' Open Access Transmission Tariff ("OATT") provisions and by a future RTO's market power mitigation measures.[13] He is indirectly referring to the AISA and Westconnect RMR protocols. These protocols apply to all transmission entities that are members of the two respective transmission organizations and parties that take transmission service over such transmission owners' system. Both APS and TEP are founding members of the two transmission organizations. Mr. Higgins offers an effective description of the two must-run protocols in his testimony.[14]

Q. Are you familiar with the AISA and Westconnect RMR protocols?

A. Yes. I participated in and monitored the AISA Operating Committee's development of the AISA protocols. I also served as an Ex-Officio Board member during DesertSTAR's development of its protocols that have since been adopted by Westconnect in its RTO filing at FERC.

Q. Does Staff believe the AISA and Westconnect protocols effectively mitigate RMR generation requirements?

A. Staff believes the AISA and Westconnect protocols are effective operational tools assuring nondiscriminatory assess to constrained load pockets at nondiscriminatory prices during conditions that require RMR generation. However, these protocols were never designed nor intended as market power mitigation measures. While the protocols are based upon sound market practices, Staff disagrees with Mr. Higgins assertion that the two protocols adequately mitigate load pocket market power.[15]

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[13] William H. Hieronymus, at line 11, page 40.
[14] Kevin C. Higgins, at pages 8-9.
[15] Ibid., page 9.

Reliance solely on these protocols as market mitigation measures is not in the public's interest. The protocols simply perpetuate the status quo; they do nothing to displace existing RMR units. Restricting a load pocket's access to the larger wholesale market may not be in Arizona consumers' best interest when a RMR generator's cost exceeds the market price of generation external to the constrained load pocket. Similarly the two protocols do not adequately address reliability and risk of local supply concerns or assure the best price for the UDC's consumers.

Staff acknowledges that both RMR protocols are attempting to level the playing field for all parties trying to schedule energy into the constrained load pocket. The two RMR protocols in large part are non-discriminatory relative to pricing of RMR generation and in providing non-discriminatory transmission access. However, the concepts of non-discriminatory transmission access and non-discriminatory pricing within a transmission constrained load pocket are fundamentally different than the concept of market power mitigation. The protocols do not address the fundamental issue of vertical market power that exists when the transmission provider or its affiliates own the local must-run or must-offer generation.

Fundamental to this vertical market power argument is the fact that the transmission provider has elected to rely on RMR generation rather than build additional transmission import capacity to the load pocket.[16] This assures that local generation has access to the local market irrespective of price. Such action also precludes the opportunity to purchase power for the load pocket from power plants external to the constraint for the duration of the transmission constraint. Restricting access to the larger wholesale market may not be in Arizona consumers' best interest when RMR generation costs exceed the market price of generation external to the constrained load pocket.

[16] Rebuttal Testimony, Cary Deise, APS Request for Variance to Certain Requirements of A.A.C. R14-2-1606, April 22, 2002, pages 7-10.

Q. How do the AISA and Westconnect protocols differ regarding pricing of RMR generation requirements and is such pricing in Arizona consumers' best interest?

The AISA protocol requires generation owners internal to the constraint to offer to sell to scheduling coordinators, *on a cost-of-service basis*, sufficient generation to serve load within the load pocket that exceeds the areas' transmission import capability. When cost-of-service prices of RMR generation exceed the price of generation external to the constraint, the AISA protocol simply caps the price of RMR generation and manages market participants' behavior in a non-discriminatory manner.

The Westconnect protocol allows the generation owner to sell *at market based prices* prevailing external to the load pocket. This protocol once again sets a price cap but does not necessarily resolve the exertion of market power. FERC has not acted on the Westconnect protocol but has not allowed market based pricing in a number of cases that failed the SMA test.

Neither of the two protocols approaches pricing from the context of the UDC's obligation to provide reliable service to its customers at just and reasonable rates. Neither protocol provides a means whereby RMR units are displaced if other units outside the constraint can provide power at a lower price. Neither protocol factors in the risk or possible deterioration of reliable service to consumers if the local generation fails to be available. Such an event occurred in the Phoenix area in July 2001 when a rolling blackout was narrowly avoided. Even though the two protocols offer non-discriminatory pricing of RMR generation they may not assure the best price for the UDC's consumers. For these reasons, the provisions of the two RMR protocols do not by themselves sufficiently mitigate market power.

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Q. How do Staff's recommended RMR generation mitigation measures differ from the AISA and Westconnect protocols?

A. Staff's recommendations for mitigating RMR generation requirements are based on the premise that the UDC has an obligation to reliably serve its customers at just and reasonable rates. Staff has recommended three actions to mitigate RMR generation. Staff recommends that RMR units not be transferred until the Commission has considered their must-run status and determined that they no longer have the potential to exercise market power.[17] Such a determination would emerge from the market power studies and mitigation plans that Staff recommends be filed prior to transfer of any generation asset.[18] Staff also recommends that jurisdictional utilities proceed to resolve any transmission import constraint by constructing needed transmission facilities as soon as practical if the Commission finds their RMR generation strategy to not be in consumers' best interest.[19] Staff supports use of the AISA and Westconnect RMR protocols to operationally manage RMR generation requirements when such system conditions exist.

NETWORK RESOURCES AND ASSOCIATED TRANSMISSION RIGHTS

Q. What are network transmission service and Network Resources?

A. Network Integrated Transmission Service ("NITS") and Retail Network Integrated Transmission Service ("RNITS") provisions are defined by the respective utility's OATT filed and approved by FERC. Network Resources are generating units interconnected within the transmission network designated by the Network Customer for service to their Network Load via a network transmission service agreement. Network transmission service, as currently defined, is intended to be used by Network Customers for the purpose of delivering energy from designated Network Resources and other non-designated generating resources to their Network Load.

[17] Direct Testimony, Matthew Rowell, at pages12-13.
[18] Ibid., at pages 10-12.
[19] Jerry D. Smith, at page 26.

Q. Why are network transmission service and Network Resource designation important to these proceedings?

A. The proper and non-discriminatory designation of power plants as Network Resources and use of available transmission capacity ("ATC") for Network Integrated Transmission Service is critical to emergence of a competitive wholesale market and retail competition in Arizona. There are pre-existing committed uses of the total transmission capacity ("TTC"). Among the committed uses is transmission service to native load or standard offer customers in each utility's service area. ATC is what remains for others non-discriminatory use after subtracting all committed uses. This is what gets posted on a utility's OASIS. Similarly, utilities have already designated existing owned plants as Network Resources to serve their native Network Load. This allows the respective utility to take NITS or RNITS transmission service via the transmission provider's tariff.

Very little ATC is available for use by the competitive wholesale market or Electric Service Providers ("ESP") desiring to offer competitive retail service. This is the reason that the AISA has an interim protocol that sets aside up to 300 MW of RNITS for ESPs. Many New merchant power plants have chosen to not invest in transmission enhancements. Therefore, they face the same delivery restrictions of an ESP.

It is for the above reasons that merchant power plants are anxious to see the transmission providers drop the Network Resource designation for existing plants when they fail to be selected by the UDC during the competitive solicitation process. Similarly, the merchant plants want to make sure the NITS and RNITS committed uses for standard offer customers are available for network transmission service delivery from plants that are selected by the same competitive process. Otherwise, the transmission system becomes a barrier for the competitive wholesale market's delivery to a UDC's standard offer load.

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Q. Does Staff agree with the position taken by Panda and Reliant regarding designation of power plants as Network Resources and associated disposition of network transmission service rights?

A. The arguments offered by Panda and Reliant regarding designation of plants as Network Resource and use of network transmission service do have merit but are also very self-serving. Staff agrees with Mr. Kebler[20] that network transmission service rights are not assigned to generation assets. The Network Customer that has Network Load is the party that seeks and retains network transmission service rights. Therefore, generating assets owned by APS, TEP and their affiliates that are not selected via the competitive procurement process must obtain transmission service as necessary for power delivery to other than standard offer customers.

Reliant's claim that APS must designate Network Resources on behalf of its native load customers in the same manner as any other customers taking network transmission service under their tariff is accurate. But Reliant's argument is somewhat flawed in its application.[21] Reliant presumes that winners of the competitive procurement will necessarily be interconnected to the utility's transmission network and thus must be designated as Network Resources. Staff disagrees. For example, designation of a plant in Nevada as a Network Resource for APS seems inappropriate to Staff since such a plant is not located within the APS transmission network.

The Network Resource designation is not applicable for sales to third parties or for service to other than Network Load. Therefore, Staff also disagrees with Panda's supposition that APS should be required to designate as Network Resource all generation with an interconnection agreement or for whom interconnection studies have been completed.[22] Such a requirement would only be practical if the full output of each plant were dedicated for standard offer service to the UDC. Staff agrees that a power plant can

[20] Curtis L. Kebler, at line 18, page11.
[21] Ibid., at page 11.
[22] Craig R. Roach, Ph.D., at line 8, page 18.

be designated as a Network Resource if it has a Network Load and network transmission service has been established. Such a designation may even be desirable. For example, Staff understands PWEC's Redhawk units 1 and 2 have been designated as Network Resources for APS.

Dr. Roach also espouses the merits of the two types of interconnection services contained in FERC's pending Interconnection NOPR.[23] The generation industry has done an excellent job of lobbying FERC for such interconnection services. However, neither the Energy Resource Interconnection Service nor the Network Resource Interconnection Service referenced by Dr. Roach considers the reliability impacts of such interconnections. These two types of interconnection services as currently defined are simply a means of generators avoiding any obligations for transmission improvements.[24] While such interconnections may be in the best interest of the generators, they may not be in the best interest of Arizona's consumers.

Staff has consistently taken exception to interconnections such as proposed by Dr. Roach throughout numerous power plant siting cases over the last two years. The fact that power plants have chosen to not ensure delivery to a market is a risk they alone must bear. In fact, Staff has taken a position in this generic electric restructuring case that both Transmission Providers and Plant Owners have an obligation to resolve transmission delivery problems.[25] Adherence to such proposed reliability principles is the foundation for recommendations contained in my direct testimony.

Q. Does that conclude your testimony?

A. Yes, it does.

[23] Ibid., at line 16, page 18.
[24] Ibid., at lines 1-3, page 19.
[25] Jerry D. Smith, at page 25.

EXHIBIT
S-15
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	)	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

MATTHEW ROWELL

CHIEF: TELECOMMUNICATIONS AND ENERGY SECTION

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 29, 2002

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INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Matthew Rowell. My business address is Arizona Corporation Commission, 1200 W. Washington, Phoenix, AZ 85007.

Q. By whom are you employed, and in what capacity?

A. I am employed by the Arizona Corporation Commission as the Chief of the Telecommunications and Energy section of the Commission's Utilities Division.

Q. Please describe your education and professional background.

A. I received a BS degree in economics from Florida State University in 1992. I spent the following four years doing graduate work at Arizona State University where I received a MS degree and successfully completed all course work and exams necessary for a Ph.D. My specialized fields of study were Industrial Organization and Statistics. I was hired by the Commission in October of 1996 as an Economist II. Prior to my Commission employment I was employed as a lecturer in economics at Arizona State University, as a statistical analyst for Hughes Technical Services, and as a research analyst at the Arizona Department of Transportation.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain in detail Staff's recommendations concerning the transfer and separation of generating assets and to provide a general outline of all of Staff's testimony. An explanation of the outline of all of Staff's testimony is necessary in order for the reader to be able to put the various testimonies into context.

Q. Can you explain the general outline of Staff's testimony?

A. Staff's testimony focuses on the issues identified in the May 2, 2002 Procedural Order:

- market power,
- transfer of generation assets,
- code of conduct
- jurisdictional issues.

These issues stem from the Commission's Retail Electric Competition Rules (Title 14, Article 16 of the Arizona Administrative Code) and the associated settlement agreements.

These rules and settlement agreements were originally intended to provide for the development of *retail* competition. However, retail competition has yet to develop in Arizona and retail competition as envisioned by the rules has yet to develop anywhere in the US. Staff is not of the opinion that the development of retail competition is on the near horizon. Thus, the issues that are currently before the Commission largely concern the development of *wholesale* competition. Staff's recommendations will focus on allowing a competitive wholesale market for power to develop. However, there is no guarantee that a competitive wholesale market actually will develop for Arizona. Thus, Staff's recommendations will also focus on ensuring that retail customers receive reliable power at just and reasonable rates (whether the wholesale market develops or not.) While the development of a competitive wholesale market may be a necessary precursor to retail competition, it is no guarantee that retail competition will follow. Staff contends that consumers may benefit from wholesale competition even if retail competition never occurs. Thus, Staff's testimonies should not be construed to imply that retail competition will (or will not) develop if Staff's recommendations are implemented.

Staff's testimonies follow the following basic outline:

- Neil Talbot provides justification for Staff's contention that there is a rebuttable presumption of market power on the part of incumbent utilities.
- David Schlissel's testimony discusses Staff's concerns regarding the market power that may result from the transfer and separation of generation assets from the incumbent utilities.
- Paul Peterson's testimony discusses recent developments at the FERC regarding standard market design and the recent restructuring experience of other states.
- Jerry Smith's testimony discusses the adequacy of Arizona's existing electric system and plans for new transmission lines.
- Barbara Keene's testimony explains Staff's concerns regarding transactions between affiliates in a post-transfer world and provides recommendations to address these concerns.
- Erinn Andreasen's testimony describes Staff's recommendation regarding the need for an Electric Competition Advisory Group.
- My testimony provides Staff's recommendations regarding the mitigation of market power resultant from the transfer of generation assets.

Q. Has the lack of retail competition in Arizona influenced Staff's recommendations?

A. Only indirectly. While the subject of this proceeding does not directly involve retail competition, consumers' lack of any real alternatives to the UDCs for the provision of electric service is a consideration. Presently, consumers have no viable alternative but to purchase power from their UDCs. The UDCs' cost of procuring power on the wholesale market will flow through to consumers in terms of retail rates. Captive consumers will be exposed to the procurement practices of the UDCs. Thus, those procurement practices will require scrutiny by the Commission.

OVERRIDING GOALS

Q. What is the overriding goal of Staff's recommendations?

A. The overriding goal of Staff's recommendations is to ensure that consumers will receive reliable electric service at just and reasonable rates. This, of course, is the Commission's constitutional mandate and is also one of the goals of traditional cost-of-service regulation. Staff believes it is important to ensure that consumers are no worse off under the restructured environment than they were under traditional cost-of-service regulation. As the restructuring of the electric utility industry continues, Staff is concerned that the goal of providing retail customers with reliable power at just and reasonable rates may be subverted. Staff believes that the *goal* of just and reasonable rates is the primary concern, the *process* that is used to get there is secondary. Focus on the process may result in a lack of focus on the goal. Staff's recommendations are intended to ensure that as restructuring continues the goal of reliable electric service at just and reasonable rates is not forgotten. Of course, many considerations enter into this inquiry. Staff understands that reliability is, and always will be, an essential consideration. Also, the financial health of the UDCs cannot be forgotten. Staff does not intend for its recommendations to impose undue restrictions on the UDCs. On the contrary, Staff believes that the UDCs must be afforded a great deal of flexibility in order for them to procure (or produce) power in a just and reasonable manner. However, the UDCs must be held accountable by the Commission for the decisions they make concerning the procurement (or production) of power.

Q. Why are existing cost of service rates relevant to competition?

A. The Commission, in every rate order it issues, concludes that the rates contained therein are just and reasonable. Accordingly, the utilities are currently charging just and reasonable rates. Traditionally, these regulated rates have been based on the utilities' reasonable cost of providing service plus a reasonable rate of return.

The proponents of electric competition hoped that competition would bring increased efficiencies to the industry, thereby lowering costs to the end user. But for these competitive efficiencies to come to fruition, it is necessary to have a number of competitive providers in the market. As I discussed earlier, this has simply not occurred. To date, Arizona has virtually no retail competition. And although some believe that the market for wholesale supply is adequate to support the competitive bid requirements of rule 1606(B), others have come to the opposite conclusion. Finally, even aside from issues about the number of potential competitors, there may not be adequate transmission to support a competitive market. In short, without new competitors and/or without adequate access to the market, the price benefits of competition will not develop.

In such circumstances, the Commission must determine what it can do to encourage the development of competition while at the same time protecting end users. Because we know that existing cost of service rates are just and reasonable, we can use them as a benchmark for evaluating competitive rates during this transitional period.

Q. What do you mean by this transitional period mentioned in the previous question?

A. The transitional period is the period from now until the Commission determines that the wholesale market for power delivered to the UDCs' service territories is workably competitive.

Q. Can you explain Staff's recommendations that are specific to the goal of ensuring adequate electric service at just and reasonable rates?

A. Yes. Staff believes that the UDCs must obtain or produce reliable power for Standard Offer customers at the best price. By the best price Staff means that the utility must choose the best combination of lowest price and lowest risk. Staff believes that UDCs should be free to obtain power through whatever means will result in the best price. This

includes auctions, RFPs, negotiated bilateral contracts, self-generation, or any combination of these or other means. Auctions, RFPs and negotiated bilateral contracts may all result in purchase power agreements. The UDCs should develop a procurement strategy that is designed to provide adequate service to its customers at the best price. As part of their ongoing procurement planning process, the UDCs should be required to perform an assessment or analysis that demonstrates that they are obtaining and/or producing reliable power for Standard Offer customers at the best price.

Q. In your previous answer, you mentioned that UDCs could obtain power through a variety of means, including self-generation. How do you reconcile that recommendation with the requirements of A.A.C. R14-2-1615?

A. Staff believes that Rule 1615 should be modified. Specifically, Staff sees no reason at this time to *require* the transfer of all competitive generating assets to an affiliate. Staff does, however, believe that the utilities should have the discretion to effect such a transfer, as long as appropriate protections are in place.

Q. Does your recommendation regarding A.A.C. R14-2-1615 affect the implementation of A.A.C. R14-2-1606?

A. Yes, it potentially does. If a utility were to choose not to divest, the provisions of rule 1606(B) would likely not be achievable. But until we know what election the utilities make, it is premature to suggest specific changes to rule 1606(B). Applications for relief from 1606(B) should be supported by *demonstrated evidence* that the UDC attempted to comply with 1606(B) but that compliance was either not possible or would not result in just and reasonable rates.

Regardless of the provisions of rule 1606(B) the Commission should consider measures that ensure that consumers are no worse off because of competitive procurement than they

would have been under traditional cost of service regulation. Specifically, during this transitional period, the established cost of service should be used as both a standard for UDC recovery and as the price to beat for any competitive solicitation process. Staff recommends that prudence reviews of purchases by UDCs from their affiliates or others should use the already established cost of service of the assets the utility has chosen to transfer as the baseline for the prudence evaluation. Also, the established cost of service for the utilities' existing generation units should be used as the price to beat during competitive solicitations whether the utility has transferred its generation assets or not. Generally, Staff does not believe it is appropriate for a UDC to procure power at a higher price than its own cost of service before transfer or its affiliate's cost of service after transfer. Of course, these standards could not be applied to cases where the UDC is procuring power to serve load which it, or its affiliate, does not have the capacity to serve (i.e., load growth beyond the utilities' current capacity.)

Q. Does Staff have any other recommendations concerning the procurement of power?

A. Yes, Staff recommends that the UDC should be responsible for obtaining power for its Standard Offer customers. The UDC should be prohibited from delegating this responsibility to any of its affiliates, including its parent company.

Transfer of Assets

Q. What are Staff's concerns with regards to the transfer of generating assets?

A. Staff believes that there is a rebuttable presumption that incumbent vertically integrated utilities posses market power.[1] The testimony of Neil Talbot demonstrates that such a presumption is reasonable and appropriate. Under the traditional regulatory regime, the Commission has the authority to hold the market power of the incumbent utilities in check. If the generating assets are transferred from an incumbent utility to its affiliate(s),

[1] By "market power" Staff means the ability to maintain artificially high prices for power *delivered to the UDC's service territory.*

Staff believes that the market power effectively stays the same but the Commission's ability to respond to it is weakened. Thus, although the market power may be no different in an abstract sense, the potential for market abuse is increased. The horizontal market power that the utility had in the generation market is simply transferred to the affiliate.[2] The vertical market power the utility possessed by virtue of it owning both generation and transmission assets may be somewhat complicated by the transfer; however, it is naive to believe that the affiliated generation and transmission companies would not have a strong economic incentive to act in concert to maintain their vertical market power in the absence of appropriate monitoring and mitigation measures.

While the market power of the company is effectively unchanged, the Commission's ability to mitigate that market power will change substantially as a result of the transfer of generating assets because the Commission will not be able to regulate the wholesale rates the generation owning affiliate charges for power. This includes the rates the generation owning affiliate charges the affiliated UDC. Thus, the generation owning affiliate (perhaps working in concert with the UDC) may be able to artificially inflate the price for power delivered into the UDC's service territory and pass that inflated price on to the UDC. The UDC would then in turn attempt to pass the inflated prices on to its retail customers. Thus, the goal of providing customers with reliable power at just and reasonable rates would not be realized.

The FERC does have some authority to prevent such market power abuses. However, recent experience suggests that the FERC may be slow to act. The FERC's standard market design proceeding is meant to address concerns regarding market power abuses. However, that proceeding is ongoing. As the testimony of Paul Peterson demonstrates,

[2] This would hold true if the generating assets were transferred in bulk to a non-affiliate as well. Such a transfer would have its own set of problems but since such a transfer is not being contemplated by any of the parties in AZ Staff will not dwell on that eventuality.

development of comprehensive structures and practices to conclusively alleviate market power abuse issues is difficult and time consuming. In the short run, reliance on FERC to control market power abuse is ill advised.

Implementing a strategy like the one outlined above is clearly in the economic interests of the utilities. If recent experience across the country has taught us anything, it is that power providers will have an economic incentive to game the system. It would be naive and unwise to leave the door open for such activity. Staff's recommendations are designed to allow restructuring to move forward while providing safeguards that prevent the above scenario from playing out.

Staff also believes that the timing of the asset transfers is problematic. There is currently a great deal of uncertainty regarding the electric industry that was not contemplated at the time the Retail Electric Competition Rules and Settlement agreements were finalized. Specifically, there are currently serious concerns regarding the delivery of natural gas into Arizona over El Paso's pipeline system (discussed in detail in Jerry Smith's testimony.) Also, FERC may lift the price caps imposed on the West this September and the FERC has not completed its standard market design proceeding.

Q. What are Staff's recommendations concerning the transfer of generation assets?

A. Staff has four basic recommendations regarding the transfer of generation assets:

1. Prior to the transfer of any generation assets, the utilities should be required to file a market power study and market power mitigation plan for Commission approval.
2. Generation assets identified as must-run units may only be transferred subsequent to the Commission's consideration of their must-run status.
3. Other generating units can be transferred at the utilities' discretion.
4. The recommendations concerning codes of conduct outlined in Barbara Keene's testimony should be implemented prior to transferring the assets.

MARKET POWER STUDIES

Q. What is the purpose of the market power study and the market power mitigation plan that Staff recommends the utilities must file for Commission approval before transferring their assets?

A. The purpose of that requirement is to provide the Commission with the information it needs to evaluate the appropriateness of taking the irrevocable step of transferring assets. The Commission may decide to impose market power mitigation requirements on the UDCs. Staff believes that it would be better for all involved that such analysis and decisions be made *before* the assets are transferred so that the utilities can make an informed choice about whether to transfer their generation assets and the Commission is aware of the state of the market.

Q. What are the minimum requirements of the market power study and the market power mitigation plan that Staff recommends?

A. The market power study and mitigation plan should contain enough relevant information for the Commission to make an informed decision. To that end, Staff recommends that at the time the study and plan are filed the utility should also file written testimony and

exhibits which explain and identify in detail the quantitative data used in the analysis and the conclusions drawn from the analysis. The market power study should consider any and all factors that could adversely impact the ability of new or alternate suppliers to enter the Arizona retail or wholesale markets. The market power study shall examine horizontal and vertical market power, the effect on competition of distribution and transmission access and pricing, contractual arrangements, and other potential barriers to entry into the Arizona wholesale and retail electric market. The analysis of horizontal market power should be consistent with the U.S. Department of Justice and Federal Trade Commission's Horizontal Merger Guidelines, as revised April 8,1997 ("DOJFTC Merger Guidelines.") The DOJFTC Merger Guidelines, standards, and methods, which are designed to apply to mergers, should be adapted and modified as necessary to the circumstances specific to the deregulation of generation and the introduction of retail open access. The analyses should also be consistent with current FERC market power tests such as the pivotal supply test and analytical methods such as strategic behavior analysis. The horizontal market power analysis for retail and wholesale products should include analyses of market concentration and barriers to entry for non-affiliated providers for each customer class. The vertical market power analysis should demonstrate that the functional separation, codes of conduct, affiliate transactions, and interconnection and open access policies and tariffs are or will be structured and implemented to assure that all wholesale and retail competitors have access to the competitive markets equal to that of the utility and its ESP affiliates. If the results of the above described analysis reveal areas of concern the Commission may require that additional analysis be conducted such as strategic behavior analysis. The Arkansas Public Service Commission's Minimum Filing Requirements for Market Power Analysis approved on June 27, 2000, provides additional detail on the content of market power studies.

Q. What is the relevant market that should be considered when analyzing wholesale market power?

A. The relevant market to consider is the market for power *delivered into* the UDC's service territory. All practical and economic sources of generation should be included in the analysis.

Q. How will the market power studies and mitigation plans filed by the utilities be evaluated?

A. The Commission should evaluate the market power studies and mitigation plans to determine that the opportunity for competition exists. The Commission may seek input from relevant parties including Staff. Staff may request that the Electric Competition Advisory Group (described in the testimony of Erinn Andreasen) provide input for Staff's analysis. A hearing may be necessary if the issues raised by the market power study are contested.

Q. Is Staff's recommendation concerning market power studies and mitigation plans designed to delay the asset transfers provided for in the settlement agreements?

A. No, Staff's recommendation is designed only to ensure that proper safeguards accompany the transfer.

RELIABILITY MUST RUN GENERATION

Q. What does Staff recommend concerning the transfer of generating assets that are identified as reliability must run?

A. Staff is concerned that the existence of (reliability) must run units (as defined in A.A.C. R14-2-1601) will present serious market power concerns. The testimony of David Schlissel addresses these market power concerns in detail. Thus, Staff recommends that these units only be transferred after the Commission has considered their must run status

and determined that they no longer have the potential to exercise market power. Potential options for relieving the reliability concerns associated with load pockets and reliability must run units are discussed in the testimony of Jerry Smith. Until these market power concerns are adequately addressed, Staff recommends that these reliability must run generation units should remain subject to rate regulation by the Commission and should not be able to participate in any competitive bidding for Standard Offer Service. Also, while these units are still owned by the UDC wholesale profits associated with them should be retained by the UDC for the benefit of its standard offer customers. This and other issues related to off system sales will be addressed in APS' next rate case.

Staff believes that its recommendations concerning reliability must run units are consistent with A.A.C. R14-2-1615 which calls for the separation of "competitive generation assets." A.A.C. R14-2-1601 (the definitions section of the Retail Electric Competition Rules) specifically classifies (reliability) must run generation as "Noncompetitive Services."

OTHER GENERATING UNITS

Q. What does Staff recommend concerning the transfer of generating assets that are not must run units?

A. Staff believes that these generation units can be transferred at the discretion of the utilities after the Commission has completed its review of their market power study discussed above. Staff believes that the utilities should be allowed to transfer their assets, even to an affiliate, but Staff sees little value in ***requiring*** them to do so. Staff sees little value to consumers in a bulk transfer of generating assets to an entity outside of the Commission's jurisdiction.[3] Thus, *forcing* utilities to do so does not seem appropriate at this time.

[3] It could be argued that the separation of assets would make the competitive bidding process easier to manage. However, several states (e.g., Florida and Colorado) have implemented competitive bidding processes without the transfer of assets.

Q. After a utility transfers its generation assets to an affiliate, how should the UDCs recover the cost of power purchased from that affiliate?

A. Staff does not believe that consumers should lose the cost benefits of generation assets simply because those assets are transferred to an affiliate. To that end, Staff recommends that if a utility chooses to transfer its generation assets to an affiliate, purchases of power from the affiliate by the UDC should be subject to an enhanced prudence review by the Commission. Specifically, the prudence of purchases by the UDC from any of its affiliates or from any other wholesale provider should be evaluated based on (1) the costs of other competitive alternatives and (2) the costs the UDC would have borne had the transfer of assets not happened. That is, the established cost of service for the transferred assets should be used as the baseline for evaluating the prudence of power purchases by the UDC from its affiliates and other suppliers.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
S-16
admitted

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471

REBUTTAL

TESTIMONY

OF

MATTHEW ROWELL

CHIEF: TELECOMMUNICATIONS AND ENERGY SECTION

UTILITIES DIVISION

JUNE 11, 2002

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INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Matthew Rowell. My business address is Arizona Corporation Commission, 1200 West Washington Street, Phoenix, AZ 85007.

Q. Are you the same Matthew Rowell who filed direct testimony in this proceeding on May 29, 2002?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss some of the points raised in the initial testimonies of Jack E. Davis, for APS and Michael J. DeConcini, for TEP. Specifically, Mr. Davis' testimony starting at page 3, line 20 addresses several issues regarding the transfer of APS' generation assets to PWEC and Mr. DeConcini's testimony starting at page 4, line 11 discusses several issues regarding the wholesale electric market place.

TRANSFER AND SEPARATION OF GENERATION ASSETS

Q. On page four line fifteen of his testimony Mr. Davis states that, "...divestiture was fully subject to the review and comment process of Arizona rulemaking ... not once but on at least four separate occasions." Can you comment on Mr. Davis' assertion that the Commission has already approved the divestiture of APS' assets four times?

A. Yes. Mr. Davis cites four Commission decisions in his discussion, 61071 (August 10, 1998), 61272 (December 11, 1998), 61969 (September 9, 1999), and 61973 (October 6, 1999). Mr. Davis implies that transfer and separation of assets *as currently*

planned by APS was approved by the Commission in each of those four decisions. I would like to clarify that at the time of the earlier two decisions (61071 and 61272) the Commission was still contemplating a divestiture of generation assets to unaffiliated entities.

Q. Are there any other Commission decisions that may be of interest regarding the transfer of separation of assets?

A. Yes, in decision number 61677 dated April 27, 1999, the Commission established that divestiture of assets to unaffiliated entities was one method to determine stranded cost. Thus, even at that late date the Commission was still contemplating a divestiture of generation assets to unaffiliated entities.

Q. Given that the Commission did approve the transfer of assets to an affiliate in decisions 61969 and 61973 why does Staff believe that it is appropriate to reexamine that issue now?

A. Those decisions were entered into in September and October of 1999 respectively. A lot has happened since then that should and has given us reason to pause. The disaster in California that unfolded over 2000 and 2001 has already been discussed at length and I will not explain it in detail here. However, it would be unwise for this Commission to move forward without even considering this dramatic event. While Staff recognizes that there are significant differences between the California and Arizona restructuring plans, Staff still believes that it is appropriate to learn from the mistakes of our neighbors. The California crisis highlighted the fact that flawed regulatory policy can have dramatic negative effects; thus, it would be difficult for Staff to recommend moving forward without a careful assessment of Arizona's restructuring plan. In addition to California, restructuring efforts across the country

have had decidedly mixed results. (See the rebuttal testimony of Neil Talbot and the Staff report filed in this docket on March 22, 2002 for discussion.) Given the difficulties encountered by many states since 1999, Staff believes that it is appropriate to reexamine Arizona's restructuring plan.

Q. In your previous answer you cited problems in other states, but are there any issues directly related to Arizona that Staff believes warrant a reexamination of the transfer and separation of assets?

A. Yes. There have been two developments since 1999 that have influenced Staff's thinking on this matter. First, there has been virtually no retail competition in Arizona. Currently, Staff is unaware of *any* customers who are taking service from a competitive electric service provider ("ESP") in Arizona. Retail competition was the cornerstone of this Commission's restructuring efforts. Countless hours were spent by the parties involved in workshops and other meetings to develop the necessary underpinnings for retail electric competition. At this point, it all seems to have been for naught. Also, one of the principal arguments in favor of the transfer of assets is that it would help to prevent cross subsidization of the utilities' competitive retail affiliate. The utter lack of retail competition makes this argument essentially irrelevant.

The second development that has influenced Staff's thinking on these matters is the October 18, 2001, filing by APS that requested a variance to A.A.C. R14-2-1606(B) and requested that the Commission approve a long term Purchase Power Agreement ("PPA"). In that filing, APS asserts that complying with the competitive power procurement requirements of Rule 1606(B) would be impossible. In other words, APS claimed that the competitive wholesale market would not be able to provide

reasonably priced and reliable power for its Standard Offer customers. Additionally, new wholesale market structures (such as RTOs) have been developing only slowly in the West, and the FERC is still in the process of developing what it calls its Standard Market Design.

These factors taken together, the complete lack of retail competition and the assertion by APS that wholesale competition is unlikely to afford consumers any advantages in the near future, certainly provide us with enough motivation to reexamine Arizona's plan to develop retail and wholesale competition.

Q. On page ten, lines seven through ten of Mr. Davis' testimony, Mr. Davis argues that "it would make little sense for a still vertically-integrated utility to bid for resources it already owns..." Does Staff agree with Mr. Davis' assessment regarding competitive bidding in the absence of the transfer of assets?

A. Staff believes that there are ways to provide for competitive bidding even if the transfer of assets does not occur. Mr. Davis is right that it would not make sense for APS to bid for resources it already owns. However, if it is more economical for a utility to purchase power than it is to run its own generation, the utility should (and historically utilities have) purchased power rather than run their own plants. A bidding process could certainly be set up to facilitate such purchases.

Additionally, in instances where the utility is short power, a competitive bidding process can be used to purchase the power in excess of the utilities' current generation capacity. Both Florida and Colorado have implemented such a process.

THE WHOLESALE ELECTRIC POWER MARKET

Q. On page nine, line thirteen of Michael J. DeConcini's initial testimony he states that "a portfolio approach to the purchase of wholesale generation by the UDC" is important and advantageous. Does Staff agree with this assertion?

A. Yes, Staff strongly agrees with the portfolio concept advocated by Mr. DeConcini. Staff agrees that such an approach will lessen price volatility and provide appropriate incentives to wholesale generators. California's reliance on the spot market only was proven to be unfortunate. This issue should be developed further in Track B of this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT
S-17

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345A-01-0822
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IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

SUPPLEMENTAL

TESTIMONY

OF

MATTHEW ROWELL

CHIEF: TELECOMMUNICATIONS AND ENERGY SECTION

UTILITIES DIVISION

JUNE 17, 2002

Introduction

Q. Please state your name and business address for the record.

A. My name is Matthew Rowell. My business address is Arizona Corporation Commission, 1200 West Washington, Phoenix, Arizona 85007.

Q. Are you the same Matthew Rowell who filed direct testimony in this proceeding on May 29, 2002?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide a supplement to my pre-filed testimony that is intended to clarify some of the points made in my direct testimony. Specifically, I will address the Staff's recommendations regarding a cost of service standard in a post transfer world.

Q. On Page 7, Line 6, of your direct testimony you state that, "the established cost of service for existing generators should be used as the price to beat during competitive solicitations whether the utility has transferred its generation assets or not." By this statement, did you mean that utilities that choose not to transfer their assets should be subjected to the same sort of prudence review that Staff is recommending for those that choose to transfer their assets to affiliates?

A. No. This statement is meant to cover the eventuality of a utility that has chosen not to transfer its assets and has also chosen to procure some of its necessary power from a competitive solicitation process (excepting of course power procured to service load growth beyond the utilities current capacity.) A utility that chooses not to transfer its assets and uses its retained assets to serve its native load should not be required to demonstrate that there are no market-based alternatives available. In other words, utilities that chose not to transfer should be subject to traditional cost of service regulation.

Q. Specific to the case of a utility that chooses to transfer its generation assets from a UDC to an affiliate, under what conditions does Staff recommend that the cost of service of the transferred assets be considered?

A. The cost of service along with market prices should be considered during prudence evaluations for retail ratemaking purposes. Of course, cost of service considerations could not be applied when evaluating the prudence of power purchases by a UDC to serve load that is beyond the utilities current capacity to supply.

Q. How does Staff envision such a process working?

A. For illustrative purposes, suppose a UDC which has transferred its generation assets to an affiliate procures a portfolio of power resources to serve its standard offer load. Staff expects the UDC's portfolio to contain a balanced mix of short-term contracts, long-term contracts, and possibly a component of spot market purchases. During a rate case to determine the UDC's *retail* rates, the prudence of that portfolio would need to be evaluated. As is usual, the prudence review would only hold the UDC accountable for the information available to it at the time decisions were made. For instance, if the UDC were to enter into a multi-year contract and spot prices were to decline dramatically during its latter years, the costs of that contract should not be automatically disallowed. Multi-year contracts are an appropriate means to manage the risk of price fluctuations. UDCs should not be punished for insuring against price spikes if prices happen to fall.

The cost of service of the transferred assets enters into the analysis if the cost of the UDC's portfolio of power purchases is substantially higher than the cost of service of the transferred assets. If that is the case, the UDC should expect to be subjected to enhanced scrutiny during the prudence review. This will especially be the case for components of the portfolio that have been purchased from the affiliate at prices above the cost of service. Staff is not proposing an absolute lower of cost or market standard; the utilities should be afforded the opportunity to justify their procurement strategy. Staff is simply stating that if a UDC's costs rise because

of the transfer of assets, it will and should be subjected to intense scrutiny during ratemaking proceedings. This is a consideration the utilities should keep in mind when deciding whether to transfer their assets or not. Staff recognizes that prudence reviews are not easy endeavors to undertake; however, they are much more appropriate than the alternatives: an absolute lower of cost or market standard or a straight pass through to retail customers that does not hold the UDC accountable at all.

Q. Will the utilities' cost of service always be relevant to prudence reviews?

A. No. Staff sees the use of the cost of service during prudence reviews as a temporary measure. Currently, the wholesale power market lacks a consistent and developed structure in the West. With the lack of an RTO, the FERC's Standard Market Design proceeding unresolved, and an untested AISA; Staff cannot recommend that we rely solely on the wholesale market to arrive at just and reasonable rates. Once the wholesale market is functioning in a robust and competitive manner, the cost of service standard will no longer be necessary.

Q. Does this conclude your testimony.

A. Yes, it does.

APS

1 – 8

APS-6

REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

June 11, 2002

EXHIBIT
APS-6
Admitted

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Rebuttal Testimony of Cary Deise

DOCKET NO. E-00000A-02-0051, et al.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Cary Deise. My business address is 502 South Second Street, Phoenix, Arizona 85003. I am Director of Transmission Operations and Planning for Arizona Public Service Company ("APS" or "Company").

Q. ARE YOU THE SAME CARY DEISE THAT FILED REBUTTAL TESTIMONY SUPPORTING APS' REQUEST FOR A PARTIAL VARIANCE IN DOCKET NO. E-01345A-01-0822?

A. Yes.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, PROFESSIONAL BACKGROUND, AND YOUR RESPONSIBILITIES AT APS.

A. I have a Bachelor's Degree in Engineering from California State University–Long Beach, and I am a registered Professional Engineer in the state of Arizona. I have over 32 years of experience in transmission planning and operations, and I have worked for APS in numerous different positions relating to transmission and system planning and operations continuously for the last 30 years. I am Chair of the WestConnect Interim Committee, the WestConnect representative on the Seams Steering Group-Western Interconnection ("SSG-WI"), and I serve on the Western Electricity Coordinating Council's Reliability Compliance Committee, Planning Coordination Committee and Operation Transfer Capacity Policy Group.

In my current capacity as Director of Transmission Planning and Operations, I am responsible for 10-year and general transmission system planning for APS, as well as the overall operation of APS' transmission system. Among other activities, I oversee all technical study work on APS' system, all scheduling over the APS system, the operation of APS' Open Access Same-Time Information System ("OASIS"), merchant generator interconnections, and the preparation of the Company's Ten-Year Transmission Plans.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to Staff's suggestion that APS' transmission system is somehow "inadequate." I will also respond to the assertion in Staff witness Jerry Smith's testimony that reliance on local generation or "must run" is inappropriate for the Valley. In conjunction with that discussion, I will explain how Staff's proposal to significantly overbuild transmission, while largely ignoring local generation, load-related opportunities, and accepted utility planning practices, is both unprecedented in nature and unwise from a policy standpoint. Specifically, Staff's proposal ignores the significant costs (economic, environmental, social and opportunity) associated with overbuilding transmission and dismisses the institutions that are emerging to effectively deal with transmission planning in a competitive marketplace. Finally, I will respond to the claims of Staff and some intervenors, such as Panda witness Roach and RUCO witness Rosen, that APS can exercise market power in transmission or inappropriately control network transmission service in a manner that favors APS or affiliated generation.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Without offering any actual system study or detailed analysis, Staff has taken the position that "generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona." At least as to APS, Staff's conclusion is totally incorrect. APS' transmission system and load-serving capability are adequate today, and we continue to plan prudent, timely and appropriate additions to the system.

Staff's analysis of the role of local generation, which at times is considered "reliability must run" or "RMR" generation, is also flawed. As I discussed in my rebuttal testimony in the APS Variance Docket, local generation and transmission investments are trade-offs that largely depend on the circumstances prevailing at the time the choice of investment is made. Often, installing local generation that may operate as "must run" at limited times during the year makes more sense than siting and building a largely unused or significantly more expensive transmission line through an urban area. Additionally, local generation provides needed reliability to the local system, such as voltage support, that cannot be provided by a more remote generator, no matter how "cheap." Staff's must-run analysis misses many of the significant issues in this trade-off between local generation and new transmission investment. Correcting the flawed assumptions in Mr. Smith's cost-benefit analysis shows that additional, unplanned transmission lines are not warranted at this time. Also, Staff ignores the point that merchant generators voluntarily decided to build their facilities outside the Valley; APS has not prevented any merchant plant from siting generation inside any constrained area or from agreeing to fund new transmission.

Staff's proposal wrongly urges the Commission to require jurisdictional utilities—but not SRP, the Western Area Power Administration ("WAPA"), or

merchant generators—to embark on overbuilding transmission in an uneconomic, fractured, and likely futile effort to relieve all existing or potential transmission constraints in Arizona under all conceivable generation marketing patterns. This would be poor policy anywhere, but in the Desert Southwest, where load centers are both relatively concentrated and widely separated from each other, it makes absolutely no sense. In fact, I know of no jurisdiction that has taken the position or even suggested that all transmission constraints should be remedied by constructing more transmission. Staff also vastly underestimates the costs, including economic, environmental, social and opportunity costs, associated with a policy focused on so overbuilding transmission. Further, the suggested "reliability" standards associated with this policy—standards which were unilaterally developed by Staff without a rulemaking process—are substantively deficient and far too vague to ever realistically implement.

Staff also appears to disregard, or at least marginalize, the developing institutions that are intended to facilitate system planning appropriate for a competitive market. The WestConnect RTO, the WECC, FERC and the Western Governors' Association ("WGA") are all appropriately advocating or developing an integrated, regional approach to system planning recognizing the potentially different planning needs of a competitive market. Unlike Staff's go-it-alone proposal, these institutions can embrace all affected entities, including public power, federal power marketing agencies, and merchant plants and can actually resolve issues such as cost allocation and cost-benefit trade offs.

Lastly, Staff and some intervenors have alleged that because APS or its affiliates would own both transmission and generation, there is the potential for the exercise of vertical market power. For a FERC-jurisdictional transmission owner such as APS, that is incorrect. In Orders 888 and 889, FERC required non-discriminatory access to transmission and imposed restrictions on the inappropriate sharing of

information between those involved in transmission and generation. Pinnacle West and its affiliates' FERC-mandated Standards of Conduct also would prohibit the exercise of such market power. Panda witness Roach asserts that the designation of generation as a network resource has "market power" implications for APS and its affiliates. This is simply incorrect—transmission, network transmission service and network resource designation are all related to load and are driven by load. They are unaffected by transmission ownership. If a generator (whether or not affiliated with APS) is serving APS' loads, it will be given the appropriate network designation and have the appropriate network transmission rights. However, simply calling a power plant a "network resource" will not change physical transmission limits. So, for example, all of the new capacity being constructed at Palo Verde could still not simultaneously serve all of APS' load requirements regardless of whether all were designated as "network resources"

REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

June 11, 2002

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Rebuttal Testimony of Cary Deise

DOCKET NO. E-00000A-02-0051, et al.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Cary Deise. My business address is 502 South Second Street, Phoenix, Arizona 85003. I am Director of Transmission Operations and Planning for Arizona Public Service Company ("APS" or "Company").

Q. ARE YOU THE SAME CARY DEISE THAT FILED REBUTTAL TESTIMONY SUPPORTING APS' REQUEST FOR A PARTIAL VARIANCE IN DOCKET NO. E-01345A-01-0822?

A. Yes.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, PROFESSIONAL BACKGROUND, AND YOUR RESPONSIBILITIES AT APS.

A. I have a Bachelor's Degree in Engineering from California State University–Long Beach, and I am a registered Professional Engineer in the state of Arizona. I have over 32 years of experience in transmission planning and operations, and I have worked for APS in numerous different positions relating to transmission and system planning and operations continuously for the last 30 years. I am Chair of the WestConnect Interim Committee, the WestConnect representative on the Seams Steering Group-Western Interconnection ("SSG-WI"), and I serve on the Western Electricity Coordinating Council's Reliability Compliance Committee, Planning Coordination Committee and Operation Transfer Capacity Policy Group.

In my current capacity as Director of Transmission Planning and Operations, I am responsible for 10-year and general transmission system planning for APS, as well as the overall operation of APS' transmission system. Among other activities, I oversee all technical study work on APS' system, all scheduling over the APS system, the operation of APS' Open Access Same-Time Information System ("OASIS"), merchant generator interconnections, and the preparation of the Company's Ten-Year Transmission Plans.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to Staff's suggestion that APS' transmission system is somehow "inadequate." I will also respond to the assertion in Staff witness Jerry Smith's testimony that reliance on local generation or "must run" is inappropriate for the Valley. In conjunction with that discussion, I will explain how Staff's proposal to significantly overbuild transmission, while largely ignoring local generation, load-related opportunities, and accepted utility planning practices, is both unprecedented in nature and unwise from a policy standpoint. Specifically, Staff's proposal ignores the significant costs (economic, environmental, social and opportunity) associated with overbuilding transmission and dismisses the institutions that are emerging to effectively deal with transmission planning in a competitive marketplace. Finally, I will respond to the claims of Staff and some intervenors, such as Panda witness Roach and RUCO witness Rosen, that APS can exercise market power in transmission or inappropriately control network transmission service in a manner that favors APS or affiliated generation.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Without offering any actual system study or detailed analysis, Staff has taken the position that "generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona." At least as to APS, Staff's conclusion is totally incorrect. APS' transmission system and load-serving capability are adequate today, and we continue to plan prudent, timely and appropriate additions to the system.

Staff's analysis of the role of local generation, which at times is considered "reliability must run" or "RMR" generation, is also flawed. As I discussed in my rebuttal testimony in the APS Variance Docket, local generation and transmission investments are trade-offs that largely depend on the circumstances prevailing at the time the choice of investment is made. Often, installing local generation that may operate as "must run" at limited times during the year makes more sense than siting and building a largely unused or significantly more expensive transmission line through an urban area. Additionally, local generation provides needed reliability to the local system, such as voltage support, that cannot be provided by a more remote generator, no matter how "cheap." Staff's must-run analysis misses many of the significant issues in this trade-off between local generation and new transmission investment. Correcting the flawed assumptions in Mr. Smith's cost-benefit analysis shows that additional, unplanned transmission lines are not warranted at this time. Also, Staff ignores the point that merchant generators voluntarily decided to build their facilities outside the Valley; APS has not prevented any merchant plant from siting generation inside any constrained area or from agreeing to fund new transmission.

Staff's proposal wrongly urges the Commission to require jurisdictional utilities—but not SRP, the Western Area Power Administration ("WAPA"), or

merchant generators—to embark on overbuilding transmission in an uneconomic, fractured, and likely futile effort to relieve all existing or potential transmission constraints in Arizona under all conceivable generation marketing patterns. This would be poor policy anywhere, but in the Desert Southwest, where load centers are both relatively concentrated and widely separated from each other, it makes absolutely no sense. In fact, I know of no jurisdiction that has taken the position or even suggested that all transmission constraints should be remedied by constructing more transmission. Staff also vastly underestimates the costs, including economic, environmental, social and opportunity costs, associated with a policy focused on so overbuilding transmission. Further, the suggested "reliability" standards associated with this policy—standards which were unilaterally developed by Staff without a rulemaking process—are substantively deficient and far too vague to ever realistically implement.

Staff also appears to disregard, or at least marginalize, the developing institutions that are intended to facilitate system planning appropriate for a competitive market. The WestConnect RTO, the WECC, FERC and the Western Governors' Association ("WGA") are all appropriately advocating or developing an integrated, regional approach to system planning recognizing the potentially different planning needs of a competitive market. Unlike Staff's go-it-alone proposal, these institutions can embrace all affected entities, including public power, federal power marketing agencies, and merchant plants and can actually resolve issues such as cost allocation and cost-benefit trade offs.

Lastly, Staff and some intervenors have alleged that because APS or its affiliates would own both transmission and generation, there is the potential for the exercise of vertical market power. For a FERC-jurisdictional transmission owner such as APS, that is incorrect. In Orders 888 and 889, FERC required non-discriminatory access to transmission and imposed restrictions on the inappropriate sharing of

information between those involved in transmission and generation. Pinnacle West and its affiliates' FERC-mandated Standards of Conduct also would prohibit the exercise of such market power. Panda witness Roach asserts that the designation of generation as a network resource has "market power" implications for APS and its affiliates. This is simply incorrect—transmission, network transmission service and network resource designation are all related to load and are driven by load. They are unaffected by transmission ownership. If a generator (whether or not affiliated with APS) is serving APS' loads, it will be given the appropriate network designation and have the appropriate network transmission rights. However, simply calling a power plant a "network resource" will not change physical transmission limits. So, for example, all of the new capacity being constructed at Palo Verde could still not simultaneously serve all of APS' load requirements regardless of whether all were designated as "network resources" or have network transmission service.

Q. BEFORE YOU DISCUSS THESE POINTS IN MORE DEPTH, ARE THERE PARTS OF MR. SMITH'S TESTIMONY WITH WHICH YOU AGREE?

A. Yes. I am not suggesting that APS won't need additional transmission and access to load-serving resources. As our 2002-2011 Ten-Year Plan indicates, APS will be siting and constructing over $750 million of new transmission upgrades and additions, and we intend to continue to work closely with Staff on these projects. So I agree with Mr. Smith when he states that "there has certainly been a good faith demonstration by Arizona utilities of their commitment to respond favorably on a forward looking basis." (J. Smith Test. at p. 22.) I also agree that transmission planning needs to be a broadly collaborative process, and that the Central Arizona Transmission Study ("CATS") was a good example of such collaboration.(J. Smith Test. at p. 24.) And, I further agree that system planning is more challenging in a competitive environment, and that RTOs will be important institutions in that process. Mr. Smith also has acknowledged that there

are trade-offs between using local generation and constructing additional transmission especially considering that must-run generation is only required for limited times during the summer. (J. Smith Test. at p. 13.) But my agreement with Staff on these issues does not change my conclusion that Staff's analysis and recommendations are neither correct nor appropriate.

III. LOAD SERVING ADEQUACY AND RELIABILITY

Q. DO YOU AGREE WITH STAFF'S CONCLUSIONS ON GENERATION AND TRANSMISSION ADEQUACY?

A. No. One of the conclusions that Mr. Smith reached in his direct testimony was:

> that generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona. Utilities are presently dependent upon [the] use of reliability must-run generation and load tripping schemes to meet local load requirements due to local transmission import constraints.

(J. Smith Test. at p. 3).

As noted in my summary, as to APS, that "reliability" conclusion is neither supported by evidence nor factually accurate. Electric system reliability, as defined by the North American Electric Reliability Council ("NERC"), the national body responsible for electric system reliability, involves two core concepts—adequacy and security. "Security" refers to the ability of the interconnected electric system to withstand contingencies, such as the sudden loss of a transformer or the unexpected tripping of a generator. Security focuses largely on the operation of the electric system, and there are detailed operating requirements for member systems (including APS) in the Western Electricity Coordinating Council's ("WECC")[1] published Minimum Operating Reliability Criteria. "Adequacy" looks to whether there are sufficient

[1] The WECC was formerly known as the Western Systems Coordinating Council or "WSCC."

generation and transmission resources to serve expected load. As with security, there are detailed NERC and WECC planning standards to ensure adequate and reliable interconnected electric systems.

APS meets these and other accepted, industry-standard requirements for system adequacy and security, and thus satisfies all applicable reliability requirements. The transmission projects already identified in APS' Ten-Year Plan will allow us to meet both adequacy and security requirements in the future. Mr. Smith, on the other hand, cites no recognized reliability standard that APS has violated, and he does not present any study or analysis showing how APS' system is "inadequate" or "unreliable." Neither does he identify any specific transmission project or upgrade that must be constructed to address a reliability or adequacy issue on APS' system.

Mr. Smith's discussion of the APS' "load-tripping" scheme as evidence of a reliability deficiency is incorrect as well. The load-tripping scheme that APS and SRP jointly developed is not necessary for single contingency outages under system normal conditions, but rather it is a second line of defense, a "safety net" if you will, should load ever be higher than anticipated when multiple generating units are out of service. Since it was developed, APS has not had to arm the load-tripping scheme even once. Considering a prudent emergency planning and operating measure like this load-tripping scheme as evidence of a deficient transmission system is like characterizing a driver as "reckless" just because he purchases car insurance.

Mr. Smith also asserted that on July 4, 2001, "APS was within one-half hour of activating rolling blackout procedures due to unavailability of several generating units...." (J. Smith Test. at p. 18.) This too is incorrect. On July 2, 2001, there was a multiple contingency on the system, but APS was within one-half hour of initiating a public request to voluntarily curtail electricity use, not to commence "rolling blackouts." This voluntary curtailment effort was to maintain adequate operating

reserves under a multiple contingency situation. It was ultimately avoided by a wholesale purchase, and is not evidence of any system-wide adequacy or reliability problem.

Q. MR. SMITH STATES THAT THE ENTIRE WESTERN GRID MAY BE PLACED AT RISK IF TOO MUCH GENERATION IS INTERCONNECTED WITHOUT THE ABILITY TO DELIVER TO LOADS. ISN'T THAT A RELIABILITY ISSUE?

A. No. Mr. Smith states: "interconnecting such plants to the grid without a demonstration of the ability to reliably deliver to a market can result in placing the entire Western grid at operational risk." (J. Smith Test. at p. 21.) Generators must have transmission rights to dispatch generation over the grid, they must satisfy minimum reliability criteria when interconnecting to the grid, and they are monitored by transmission system operators for compliance. If there is not enough transmission capacity available, all of the generators cannot simultaneously dispatch energy into the grid, and some will have to be offline or operate at reduced capacity. Certainly, generator output cannot be sold as "firm" without firm transmission rights, and generation without such rights will not depended upon for reliability purposes. While this may be a financial concern to those generators, it is not nor can it be a reliability concern to the system. And it certainly doesn't suggest that APS or other UDCs should be required to construct additional transmission to address non-reliability related commercial concerns of merchant generators simply because they decided to site their plant in a location without sufficient transmission.

Q. DOES THE USE OF LOCAL GENERATION, AS MR. SMITH SUGGESTS, INDICATE THAT APS' SYSTEM IS INADEQUATE OR UNRELIABLE?

A. No. The use of local generation (whether "reliability must run" or otherwise) is not a reliability defect or evidence of an "inadequate" system. No accepted reliability standard (i.e., those of the NERC or the WECC) holds that the use of local generation

is either "inadequate" from a system planning or operational standpoint or is evidence of "inadequacy." Local generation actually contributes to the reliability of a system. In fact, when it adopted the Electric Competition Rules, the Commission specifically recognized that a UDC's obligation to provide reliable electric service "depends upon the adequacy of its distribution, local generation and interconnections with the bulk transmission system..." (emphasis added). Decision No. 61969 (Sept. 29, 1999).

IV. LOCAL GENERATION AND "MUST RUN" REQUIREMENTS

Q. HAVE YOU REVIEWED MR. SMITH'S TESTIMONY AND ANALYSIS REGARDING "RELIABILITY MUST RUN" GENERATION?

A. Yes.

Q. DO YOU AGREE WITH MR. SMITH'S ASSERTION THAT MUST-RUN "GENERATING STRATEGIES" ARE "SAFETY NETS" FOR THE SYSTEM?

A. No. In his testimony, Mr. Smith claimed that:

> Utilities have traditionally used RMR generating strategies as an operational safety net when siting or construction of new transmission facilities was impeded, delivery of new equipment was delayed, capital financing was constrained, or to restore service following a transmission outage.

(J. Smith Test. at p. 8.) Such a characterization of the role local generation, even when it is required to run for system reliability purposes, is simply not correct. Local generation was, and is, a central and essential component of resource planning, not "an operational safety net." In many cases in the past, and I would expect in the future as well, the construction of local generation rather than new transmission lines is the most efficient solution for meeting the resource needs of a utility's customers.

In addition to economic trade-offs between new transmission line investments and local generation investments, there are significant system operation and reliability reasons that justify local generation. For example, local generation offers critical voltage support, particularly to large load centers like the Valley, and is absolutely

necessary to provide a dynamic reactive reserve margin, as reactive power cannot be transmitted over long distances. Local generation is also important as contingency support for the Valley. By that, I mean that such generation is available to meet local load requirements when, for example, there is a disturbance on or loss of a transmission line outside of the local area that trips remote generation. I would never recommend relying solely on importing remote power over transmission lines to support the entire Valley system at peak load. Finally, local generation (and generation located near load centers) minimizes transmission line losses.

Mr. Smith also appears to ignore the environmental and non-economic costs associated with transmission line construction. For example, in his testimony he refers to the "environmental merits" of transmission capacity in providing access to "more environmentally friendly generation external to the constraint." (J. Smith Test. at p. 8.) This assertion misses several key issues. First, is a remote coal-fired generator "more environmentally friendly" than a local gas-fired plant? And, how does one quantify the difference? Second, local generation is not necessarily less efficient than remote generation and is often subject to more stringent air permitting requirements and emission offset requirements than remote generation, which may actually make it "more environmentally friendly." Third, while local generation may only run several hundred hours per year, transmission lines are permanent and have their own environmental impacts. Fourth, transmission lines may directly impact more people and their property than local generation due to the right-of-way requirements for such lines. Fifth, the premature or unwarranted construction of transmission has significant opportunity costs, both in terms of the finite resources that APS can devote to such construction and in foregoing possible future developments in advanced transmission technologies. This list is not exhaustive; there are undoubtedly other non-economic

costs that should be considered when balancing the need for transmission or local generation.

Q. HAVE YOU REVIEWED MR. SMITH'S ECONOMIC ANALYSIS OF RMR GENERATION?

A. Yes. He concluded that APS and TEP "may find it difficult" to justify the economics of deferring transmission investment to reduce the need for local generation. (J. Smith Test. at p. 13.)

Q. DO YOU AGREE WITH THAT ANALYSIS?

A. No. But before getting to the specifics of his analysis, let me put the "must run" issue in context and make sure that certain terms I will use are understood. APS' Valley local generation was considered "reliability must run", in other words, required to operate for reliability reasons and "out of market" in terms of economic dispatch, for only 9 hours in 2001—1/10th of one percent of all hours that year—and for only 6 hours in 2000. When local generation is considered "reliability must run," its price is capped at demonstrable cost. This cost-based price cap means that, contrary to the arguments of some intervenors, "reliability must run" generation cannot exercise market power. Transmission import limitations did exist for more than 9 hours, but during virtually all of the time the dispatch cost of local generation was less than the market price at the Palo Verde hub.[2] Given this context, it obviously makes no sense to spend hundreds of millions of dollars on a 365-days per year transmission "solution" to address a nine-hour-a-year generation "problem" costing far less than a million dollars.

A correct cost-benefit analysis would compare "reliability must run"—that is, when local generation is both required and out of the market—with the cost of

[2] At page 10 of his testimony, Mr. Smith has misapplied the concept of "reliability must run" to the concept of the Local Generation Requirement that I included in Schedule CD-3R in my Rebuttal Testimony in the APS Variance Docket. In that testimony, I noted that Local Generation Requirements for the Valley were around 400 hours per year, or roughly 5 percent of all hours in a year.

additional transmission line investment. However, Mr. Smith's analysis addressed not just "reliability must run," but all times that local generation was required whether it was economically dispatched or not. Even using this broader analysis, there is no economic case for new, unplanned transmission investment because many of the assumptions Mr. Smith used are incorrect. As a result, even using Mr. Smith's methodology applied to all local generation requirements and even without considering the unquantified environmental, social and opportunity costs that I just discussed, his conclusions are not supported or supportable.

Q. PLEASE DISCUSS THE MORE SIGNIFICANT ERRORS IN MR. SMITH'S ANALYSIS.

A. Let me start with Mr. Smith's formula for determining avoided costs associated with transmission line investment. In general, the assumed transmission line capital cost of $1 million per mile is significantly understated, particularly if part or all of a project will be constructed in urban or suburban areas. For monopole construction, the cost of facilities, excluding right-of-way, is approximately $1.6 million per mile of 345 kV/500 kV transmission line. Lattice towers cost approximately $1.2 million per mile. Right-of-way costs will add at least $1 million to $2 million per mile for construction. A conservative analysis would use a blended cost assuming 15 miles of monopole with the remainder using lattice tower construction, and $1 million per mile for right-of-way costs. Also, Mr. Smith's assumed transmission termination costs for a new transmission line of $4.5 million is significantly lower than APS' experience. Recently planned source and sink terminations on APS' system average approximately $18 million. However, adding new bulk power feeds into the Valley system also will likely require additional upgrades on the APS and SRP local system, the costs of which are not even captured in that $18 million figure.

Additionally, Mr. Smith's analysis incorrectly omits the carrying costs associated with new transmission lines. Carrying costs are determined by FERC using an annual fixed charge factor that takes into account O&M, A&G, allowed rate of return, depreciation, taxes, general plant, cash working capital, and other accounting costs. The fixed charge factor is applied to the capital costs of the facilities to give an annual carrying cost for a transmission line. APS' current annual transmission fixed charge factor is 14.22 percent. Therefore, the cost for a 50-mile transmission line would be roughly $19 million per year. These annual cost calculations for hypothetical transmission lines of 50, 100 and 150 miles are shown Schedule CD-GD-1R.

Q. WOULD YOU DISCUSS MR. SMITH'S CALCULATION OF RMR GENERATION COSTS?

A. Yes. That calculation also has faulty inputs. Perhaps most significant is Mr. Smith's assumption that the marginal market price for "alternative" generation will be $35/MWh. Because local generation is only required on peak in the June through September period, it is inappropriate in the context of the Mr. Smith's analysis to assume an annualized market price for "alternative" generation of $35/MWh. A more appropriate but still conservative benchmark for such power during June-September peak hours is approximately $56/MWh at the Palo Verde hub. This is conservative because truly "alternative" generation from Palo Verde needed to meet load would be a non-standard product which would add to the $56/MWh figure.

Q. HAVE YOU CONDUCTED A COST-BENEFIT ANALYSIS OF LOCAL GENERATION VERSUS NEW TRANSMISSION INVESTMENT USING MR. SMITH'S GENERAL METHODOLOGY BUT CORRECTING THE ASSUMPTIONS DISCUSSED ABOVE?

A. Yes. Schedule CD-GD-1R is an analysis using two scenarios—427 MW of local generation in 2003 for 400 hours at a 65 percent load factor, and 1034 MW in 2007 for 400 hours at a 65 percent load factor. The cost-benefit was then tested using a $56/MWh price for generation at the Palo Verde hub and a $75/MWh cost for local

generation. I did not use hypothetical local generation costs above $75/MWh because it is unreasonable to assume that local generation costs will significantly increase, due to higher natural gas prices for example, without a corresponding increase in the price of "alternative" generation from Palo Verde. In other words, what is important is not the absolute cost of local generation but the difference between local generation and "alternative" generation. The result is then compared to the same three transmission line length alternatives (50, 100 and 150 miles) used by Mr. Smith in his analysis. Attached as Schedule CD-GD-2R is a graphical summary of this analysis in the same format used by Mr. Smith.

Q. WHAT DID YOUR COST-BENEFIT ANALYSIS SHOW?

A. APS' analysis shows that the economic costs associated with local generation do not warrant building significant new, unplanned transmission lines. Additionally, Mr. Smith incorrectly concluded that APS' hourly operating costs for RMR generation are "in excess of $75/MWh." In fact, the cost for RMR generation in 2001 was slightly less than $75/MWh ($73.11/MWh). Further, new combined cycle units, such as West Phoenix 4 and 5, are expected to have lower per-MWh costs than existing local generation. So I expect the cost of local generation, let alone RMR generation, after 2002 to decrease and it will be significantly less than $75/MWh. Thus, a cost-benefit analysis does not support the construction by APS of additional, unplanned transmission into the Valley—even without considering the other significant environmental, social and opportunity costs that I discussed earlier.

V. STAFF'S "ACCELERATED DEVELOPMENT" PROPOSAL IS FUNDAMENTALLY FLAWED

Q. IS STAFF PROPOSING A DIFFERENT STANDARD FOR PLANNING AND CONSTRUCTING TRANSMISSION IN ARIZONA?

A. It certainly appears so from Mr. Smith's testimony and recommendations. Having concluded without study or analysis that Arizona's transmission and generation resources are inadequate, Staff is apparently advocating a vastly expanded transmission system from that currently planned by APS and from any system that would be required by the applicable NERC and WECC standards. This is proposed by Staff in its recommendation for the "accelerated development" of transmission solutions. As part of that expanded system, Staff apparently establishes the goal of removing all transmission constraints from the various permutations of generation dispatch and power flows, presumably including the construction of non-reliability related transmission to allow merchant generators to serve out-of-state markets.

Q. WHAT DOES STAFF'S RECOMMENDATION FOR "ACCELERATED DEVELOPMENT OF TRANSMISSION SOLUTIONS" APPEAR TO MEAN FOR APS?

A. It is somewhat difficult to say, because I am aware of no other jurisdiction that has taken or even considered a position remotely similar to that recommended by Staff, so there is nothing to compare it to. As I discussed earlier in my testimony, APS' transmission system and load-serving resources meet all applicable planning and reliability criteria. So an "accelerated development" of transmission solutions is not necessary from a reliability standpoint.

To the extent that Staff is looking beyond a reliability-driven transmission system to economic factors associated with transmission planning for a competitive energy market, they have not proposed a reasonable or practical alternative by calling for the "accelerated development" of unspecified "transmission solutions" to relieve all

transmission constraints. For example, although Mr. Smith noted the illustrative discussion from my rebuttal testimony in the APS Variance Request on resource selection and least-cost planning for the Yuma area, the remainder of his testimony still appears to take the position that UDCs should be responsible for alleviating all transmission constraints (regardless of cause, cost, duration or impact), and that such constraints are something that generally need to be remedied by building more transmission. This is an inappropriate and overly-simplistic conclusion. In the recently issued National Transmission Grid Study, the Department of Energy noted that:

> [R]emoving bottlenecks is not simply a matter of finding "congested" transmission paths and then reinforcing existing transmission facilities along those paths or constructing new facilities. Because the system is a network, reducing congestion on one part of the system may shift it to another (the next-most-vulnerable) part. Congestion also tends to move around the system from year to year and in response to weather and other seasonal factors.

(National Transmission Grid Study at p. 20.)

Q. IS STAFF'S PROPOSAL BASED ON AN ACCEPTED RELIABILITY STANDARD?

A. It appears to be partly based on the standard that Staff proposed during the last Biennial Transmission Assessment—a standard that appears to require that all loads (local and regional) must be capable of being served without limiting access to an undefined "more economical or less polluting" generation resource. This is not a reliability standard used anywhere in the United States, it has not been adopted as Commission policy, it has not been subject to notice and comment rulemaking, and it is far too vague to allow meaningful compliance.

Q. DOES MR. SMITH IDENTIFY WHAT TRANSMISSION PROJECTS HE BELIEVES WOULD HAVE TO BE BUILT TO SATISFY THIS REQUIREMENT?

A. No.

Q. IS IT REASONABLE TO DESIGN A TRANSMISSION SYSTEM TO MR. SMITH'S APPARENT STANDARDS?

A. The existing transmission system was not planned or constructed to accommodate some vague concept of "least cost" wholesale power trading, where any generator can dispatch its power to any customers in this state or beyond. Such a transmission system would have to be massively overbuilt from a reliability standpoint, and require literally billions of dollars of new transmission investment that would have to be recovered through customer rates. It also would be an impossible moving target. Staff acknowledged as much in response to a data request, by stating that "new transmission constraints may emerge as [UDCs] attempt to take delivery from different generation resources."

Such a system, even if designed as a "best guess" of future loads and resources, and their timing and location, would certainly not be practicable because merchant generators will likely serve multiple customers at different locations over the life of any given power plant. For example, it would be inappropriate for APS to construct several new transmission lines from Palo Verde into the Valley, and also upgrade all necessary Valley facilities to accommodate the new lines, just to allow more generation the opportunity to sell from Palo Verde, when five years from now these same generators may be serving loads in California over a new Arizona-to-California transmission line. In fact, much of the new transmission required by Staff would likely do little more than facilitate merchant generators selling their capacity out-of-state at the expense of Arizona consumers. After all, based on Mr. Smith's testimony, over 19,000 MW of merchant generation is being constructed in or proposed for Arizona. Much of that capacity is obviously intended for out-of-state loads.

To overbuild the transmission system to accommodate all of this capacity would also eliminate any incentive or price signals to merchant generators on where to

appropriately site local generation. This is contrary to existing Commission policy. When the Electric Competition Rules were adopted in 1999, the Commission specifically recognized that "ideally market forces, and not UDC decisions, should drive plant-siting decisions by new market entrants or merchant generators." (Decision No. 61969, Concise Explanatory Statement, at p. 41.)

Q. ARE THE COSTS THAT WOULD BE ASSOCIATED WITH STAFF'S "ACCELERATED DEVELOPMENT" PROPOSAL JUSTIFIABLE?

A. No. As I discussed earlier, Staff's focus on overbuilding transmission, including its proposal to eliminate the need for any local generation, ignores many of the costs that need to be considered when making resource decisions between transmission lines, power plants, and even load-based alternatives such as load reduction or demand response. The analysis that I provided earlier shows that a cost-benefit analysis does not warrant the construction of significant new, unplanned transmission capacity for non-reliability related purposes. Further, the addition of transmission has ripple effects on the system, which means that there will most likely be costs on the local 230 kV and 69 kV systems if additional bulk power terminations are added in the Valley. Not all of these costs will occur on APS' system, and there may be impacts to the interconnected systems of WAPA and SRP or even others.

Apart from the increasing costs of permitting, obtaining right-of-way, constructing, and operating transmission lines, there are also costs in building new transmission lines that are difficult to quantify. For example, transmission lines sited in urban and suburban areas may require the condemnation of residential or commercial properties. While such action is often necessary for the good of our society, I expect that people evicted by unneeded or prematurely-constructed transmission lines would object to Staff's proposal. Also, there is significant progress being made in new advanced transmission technologies, including high-voltage direct current ("HVDC"),

energy storage, superconductor technologies, and new higher-capacity conductor materials. Prematurely constructing transmission using current technology may limit the ability of utilities to take advantage of these new advanced transmission technologies when they become available, or at best the deployment of these technologies will strand transmission investments that become no longer necessary.

Q. ARE THERE OTHER SIGNIFICANT FLAWS IN THE PROPOSAL?

A. Yes. Staff appears to underestimate the time commitment necessary to develop more transmission in Arizona, and the uncertainty inherent in a competitive market. Mr. Smith suggests that "transmission system adequacy" will be achieved in the last half of this decade, but then suggests that Arizona cannot wait "several years" for RTOs to develop. However, any transmission project identified today would require at least three years to site, permit and construct. Projects that involve federal lands (over 45 percent of Arizona is federal land) often require significantly longer lead times to allow compliance with the National Environmental Policy Act ("NEPA"), particularly if the underlying federal action is appealed to a federal court and a stay issued. Thus, APS focuses on what transmission investments are needed over the long-term to provide adequate and reliable service to its customers. Any notion that an "accelerated development" program will result in significant short-term differences in the integrated transmission system is overly optimistic.

Q. DOES STAFF'S PROPOSAL ADDRESS COST RECOVERY FOR THE "ACCELERATED DEVELOPMENT" PROPOSAL?

A. No, and that is another significant flaw. Because so much of Staff's proposal affects non-jurisdictional entities such as merchant generators, public power, and federal entities, all that Staff can propose is "collaboration" and building on existing industry-driven efforts like the CATS program. Cost-recovery issues have been recognized by virtually all commentators as a significant barrier discouraging the coordinated

development of transmission in a competitive market. However, without a specific mechanism or specific authority to address cost recovery, it is unrealistic to think that through collaboration merchant generators or other parties will volunteer to make significant transmission investment—particularly if they believe that a UDC will ultimately be forced to "ante up" if they don't contribute. The Southeast Valley Project is a good example, in that several merchant generators expressed interest in the early project scoping, but when it came time to make a financial commitment only APS, SRP, Tucson Electric Power Company and a group of public power districts actually committed dollars to the project.

I also do not believe that the Commission's siting authority over merchant plants will, as Staff suggests in its Recommended Action No. 5, significantly support Staff's proposal. Most of the new merchant plants that will be constructed in Arizona in the foreseeable future already possess Certificates of Environmental Compatibility ("CECs") and, apart from some limited investment by Duke, no significant new transmission line construction has been funded through the generator CEC process. In any event, merchant generators could avoid any Commission-imposed requirement by either siting a facility on Indian land or just outside Arizona. Also, I would note that while the Commission may attempt to place restrictions on merchant generator interconnections, APS and other FERC-jurisdictional transmission owners cannot enforce these restrictions. In fact, FERC has made it clear that generators may request "interconnection-only" service without making any request for transmission service from the underlying transmission owner. Thus, for example, APS could not require any merchant plant to demonstrate its ability to deliver to a market without as a condition of interconnection. Finally, even if the Commission could address these issues among Arizona utilities, it would not address seams issues or interstate transmission that are significant for regional transmission planning.

VI. TRANSMISSION PLANNING IN A COMPETITIVE MARKETPLACE

Q. WILL SYSTEM PLANNING BE DONE DIFFERENTLY IN A COMPETITIVE WHOLESALE ENVIRONMENT.

A. It is certainly possible, if not likely, that transmission planning will begin to include more projects that might not be justifiable for a single utility or which could offer economic rather than reliability advantages to one or more load serving utilities. As Mr. Smith recognizes, APS is at present planning appropriate transmission additions well into the future that are driven by the needs of its system. He noted that:

> It is Staff's opinion that Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions...

(J. Smith Test. at p. 22.) I would not be surprised, however, if additional long-term transmission projects are ultimately identified or pursued by the WestConnect RTO, merchant transmission owners, or jointly pursued by utilities to take advantage of competitive wholesale power opportunities or added interconnection of regional markets. Such efforts, however, must be broadly coordinated (including for example multiple states, public power, federal power marketing agencies, utilities, and other market participants) and still need to address significant issues such as cost recovery for non-reliability related transmission projects.

Q. DOESN'T THE RECENT NATIONAL TRANSMISSION GRID STUDY AND THE WESTERN GOVERNORS' ASSOCIATION TRANSMISSION REPORT SAY THAT THERE NEEDS TO BE MORE TRANSMISSION?

A. Yes, but both the Department of Energy's May 2002 National Transmission Grid Study and the August 2001 Report to the WGA were primarily focused on regional transmission interconnections, not an uneconomic effort to relieve every local transmission constraint on utility systems. For example, the principles outlined in the August 2001 WGA Report recognize that transmission expansion can and should have

regional as well as local benefits, and should be coordinated on as broadly-based a level as possible. Similarly, the National Transmission Grid Study emphasizes the importance of coordinated regional efforts to address inter-regional transmission constraints.

While the National Transmission Grid Study did recognize the need for additional transmission to better accommodate regional transmission in a competitive market, that study concluded that:

> Building new transmission facilities or undertaking other strategies to address transmission bottlenecks should depend first and foremost on market participants responding to business opportunities.

(National Transmission Grid Study at p. 8 [emphasis added].) In stark contrast, one of Staff's conclusions in recommending the accelerated development of transmission by UDCs in Arizona is that:

> The West simply cannot wait on FERC and RTOs to address this transmission need via market driven solutions.

(J. Smith Test. at p. 23 [emphasis added].) One of my major concerns with Staff's recommendation, if adopted, would be that Arizona and Commission-jurisdictional utilities will find themselves far "out-of-sync" and even at cross-purposes with more rational, collaborative, and regionally-based efforts addressing transmission infrastructure issues that are being pursued by everyone else.

Q. IS THERE AN ADEQUATE PLAN TO RESOLVE, AT LEAST FROM A TRANSMISSION PLANNING PERSPECTIVE, WHAT MR. SMITH REFERS TO AS THE "CHAOS OF ELECTRIC RESTRUCTURING"?

A. Absolutely. As I noted earlier, I agree with Mr. Smith that planning in a competitive environment may be more difficult than in a vertically-integrated environment. But I don't agree that we are "playing chicken" with reliability for Arizona consumers. (J. Smith Test. at p. 24.) One of the most significant concerns in the current debate over transmission planning in a competitive environment is the problem of coordinating

among varying jurisdictions, regions and interests. However, Staff's proposal to require UDCs on an intrastate basis to commence a "crash course" in new transmission investment within a single control area within a single state threatens simply to add to the fractured nature of system planning when there are so many different constituents.

APS is working hard to help develop the WestConnect RTO, an institution that will have authority to engage in regional planning efforts and plan for non-reliability related investment. WestConnect will be able to provide for prudent and appropriate cost allocations for such non-reliability related investment. Additionally, the regional interconnection of markets is likely more significant on a long-term basis than the resolution of specific local transmission constraints. The Seams Steering Group-Western Interconnection, of which I am the WestConnect representative, is working to address these regional interconnection issues. This regional focus is also evidenced in the National Transmission Grid Study, which concluded that "robust and reliable regional electricity transmission systems are the key to sustaining fair and efficient competition in wholesale markets." (National Transmission Grid Study at p. 8 [emphasis added].) And, the WGA has proposed a regionally-coordinated planning process for transmission system expansion.

We need to let the institutions that have the necessary jurisdiction and authority to coordinate transmission planning in a competitive environment do their jobs and evolve as institutions. Such an outcome is established Commission policy, which has recognized that "eventually, the obligation to ensure adequate transmission import capabilities should rest with the ISO." (Decision No. 61969 at p. 41 and Rule R14-2-1609(B).) Certainly, the Commission will have an important role in this process. But the Commission should reject Staff's recommendation to develop a separate "go it alone" transmission plan for Arizona, which will be limited to Commission-jurisdictional UDCs (apart from any informal collaboration by non-jurisdictional

entities). At best, Staff's recommendation would be a massive misallocation of resources. At worst, it could actually interfere with efforts to coordinate regional and inter-regional transmission planning.

VII. TRANSMISSION "MARKET POWER"

Q. DOES STAFF'S TESTIMONY ALSO DISCUSS MARKET POWER ISSUES INVOLVING TRANSMISSION?

A. Yes. Staff witness Matt Rowell and Mr. Smith in his recommendations note that part of the market power study that APS is to submit prior to divestiture should address how transferring generating units to PWEC will affect "other market participants' use" of constrained transmission paths.

Q. IS THIS SOMETHING THE COMMISSION SHOULD BE CONCERNED ABOUT AS A PRECONDITION TO APS' GENERATION ASSET TRANSFER?

A. No, for several reasons. Under FERC Order 888 and Order 889, and the FERC-approved Standards of Conduct, APS is required to provide non-discriminatory open access to its transmission system. Those orders and the Standards of Conduct prevent APS from favoring PWEC or any other merchant generator in providing transmission service. Also, network transmission rights to serve APS' native load will follow that load. Thus, if Duke or Panda provide service to APS' native load, they would have network transmission rights. If PWEC provides such service, it would have network transmission rights.

Of course, the physical configuration of APS' system necessarily impacts transmission. For example, all of the generators at Palo Verde could not simultaneously dispatch to serve APS' native load (even assuming APS' load was high enough to require that) because the capacity from the Palo Verde/Hassayampa switchyard into the Valley is limited. But if network transmission service had to be allocated, FERC rules

would require that it be allocated on a non-discriminatory basis and would prevent APS from favoring PWEC or any other merchant generator.

Also, as I discussed in my rebuttal testimony in the APS Variance Request, APS has a solid record of working proactively to interconnect merchant generators to its transmission grid. APS obtained rapid and efficient siting approval, including federal NEPA review, for the Panda Interconnection Project and is completing that project on time. APS also reacted quickly to address issues discovered on WAPA's transmission system that affected Reliant's Desert Basin plant. We developed a pro forma generator interconnection agreement that was approved by FERC prior to the initiation of the Generator Interconnection NOPR in May 2001. APS also actively participated in having the Hassayampa Switchyard designated as part of a "common bus" with the Palo Verde switchyard, which allows merchant generators to reach the Palo Verde market hub without having to pay for wheeling over the Palo Verde transmission system. This proven track record should further allay any concerns that APS will act inappropriately on issues affecting merchant generators.

Q. DOES THIS SAME EXPLANATION APPLY TO COMMENTS MADE BY OTHER INTERVENORS.

A. Yes. Dr. Rosen noted that transmission rate "pancaking" gives rise to transmission market power. Although this is an issue that RTOs and appropriate seams policies are intended to address, APS already has shown its proactive response to "pancaking" issues both by its efforts with the Palo Verde/Hassayampa common bus and its support for WestConnect. With respect to Dr. Rosen's discussion of the trade-offs associated with constructing local generation and new transmission, I agree that constructing local generation is often cheaper than building new transmission lines. However, because must-run local generation is capped at cost-based prices when it is "out of the market", this trade off does not result in transmission market power. Also, merchant generators

could always construct their own generation within the constraint or build transmission to relieve the constraint.

Staff witness Talbot stated that the Commission should ensure that APS is not restricting transmission access in a way that favors PWEC generation. However, he then suggests that another code of conduct may be necessary to address this. There already is a code of conduct in the form of the FERC Standards of Conduct that prevents the discrimination to which Mr. Talbot refers. The Commission should not attempt to re-regulate what FERC already covers with its Standards of Conduct.

Panda's witness, Dr. Roach concludes that APS has transmission market power because it is a "transmission monopoly" and recommends that the Commission ensure that competitors have "full access to the 3,685 MW of import transmission capacity into the APS Valley market" and be treated "comparably to APS' own generation." (C. Roach Test. at p. 15.) Because I am not an economist, Dr. Hieronymus will address in his rebuttal testimony the economic aspects of Dr. Roach's testimony. However, Dr. Roach's testimony seems to ignore that transmission, network transmission service and network resource designation are all related to load and are driven by load. If a merchant generator (whether or not affiliated with APS) is serving APS' loads, it will be given the appropriate designation and have the appropriate transmission rights. Also, APS is not a transmission "monopoly" in that merchant transmission could certainly construct into the Valley or elsewhere on APS' system.

VIII. CONCLUSION

Q. WHAT CONCLUSIONS HAVE YOU REACHED BASED ON YOUR REVIEW OF THE INTERVENOR AND STAFF TESTIMONY?

A. Staff's conclusion that APS' transmission system is inadequate to reliably serve APS' customers is simply not true. Staff's analysis regarding the economics of local generation versus transmission line construction is also incorrect, and by a very large

margin. A more reasonable analysis currently does not support the "accelerated development" of additional transmission lines, as Staff recommends. Moreover, such a plan ignores the developing regional and inter-regional planning institutions, such as RTOs, that should effectively address any new planning required in the transition to a competitive marketplace. Thus, the Commission should decline to adopt any of Staff's recommendations regarding transmission and local generation. Finally, the assertions in Staff's testimony and that of some intervenors that APS can exercise market power in transmission ignores applicable FERC rules and APS' FERC Standards of Conduct. The intervenor recommendations that are premised on this assertion should also be rejected.

Q. DOES THAT CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY IN THIS GENERIC DOCKET?

A. Yes.

1194932.1

ANNUAL COST OF NEW TRANSMISSION FACILITES

Estimated Cost of New Transmission Facilities:

50 Mile Line = (50 Mi * $2.32M/Mi) + $18M = $134.0 M
100 Mile Line = (100 Mi * $2.26M/Mi) + $18M = $244.0 M
150 Mile Line = (150 Mi * $2.24M/Mi) + $18M = $354.0 M

Annual Carrying Cost of New Transmission Facilities:

AC = OC * FCF

Where:

AC = Annual economic cost for new transmission facilities
OC = Original cost of new transmission facilities
FCF = Annual fixed charge factor for transmission facilities (14.22%)

Length of Line	Annual Cost
50 Miles	$19.05 M
100 Miles	$34.70 M
150 Miles	$50.34 M

Annual Cost for Acquiring Market Price Power In Lieu of RMR Generation

Incremental Generation Cost:

IGC = (AC-MKT)*T*MW*LF

IGC = Annual incremental cost of generation.
AC = Assumed cost of RMR generation.
MKT = Market price for generation.
T = The number of hours such purchases are needed annually (400 hours).
MW = The number of peak MW needed in lieu of RMR generation.
427MW for 2003, 1034MW for 2007
LF = The load factor during constraint period (.65).

427MW = $2.14M/yr

1034MW = $5.18M/yr

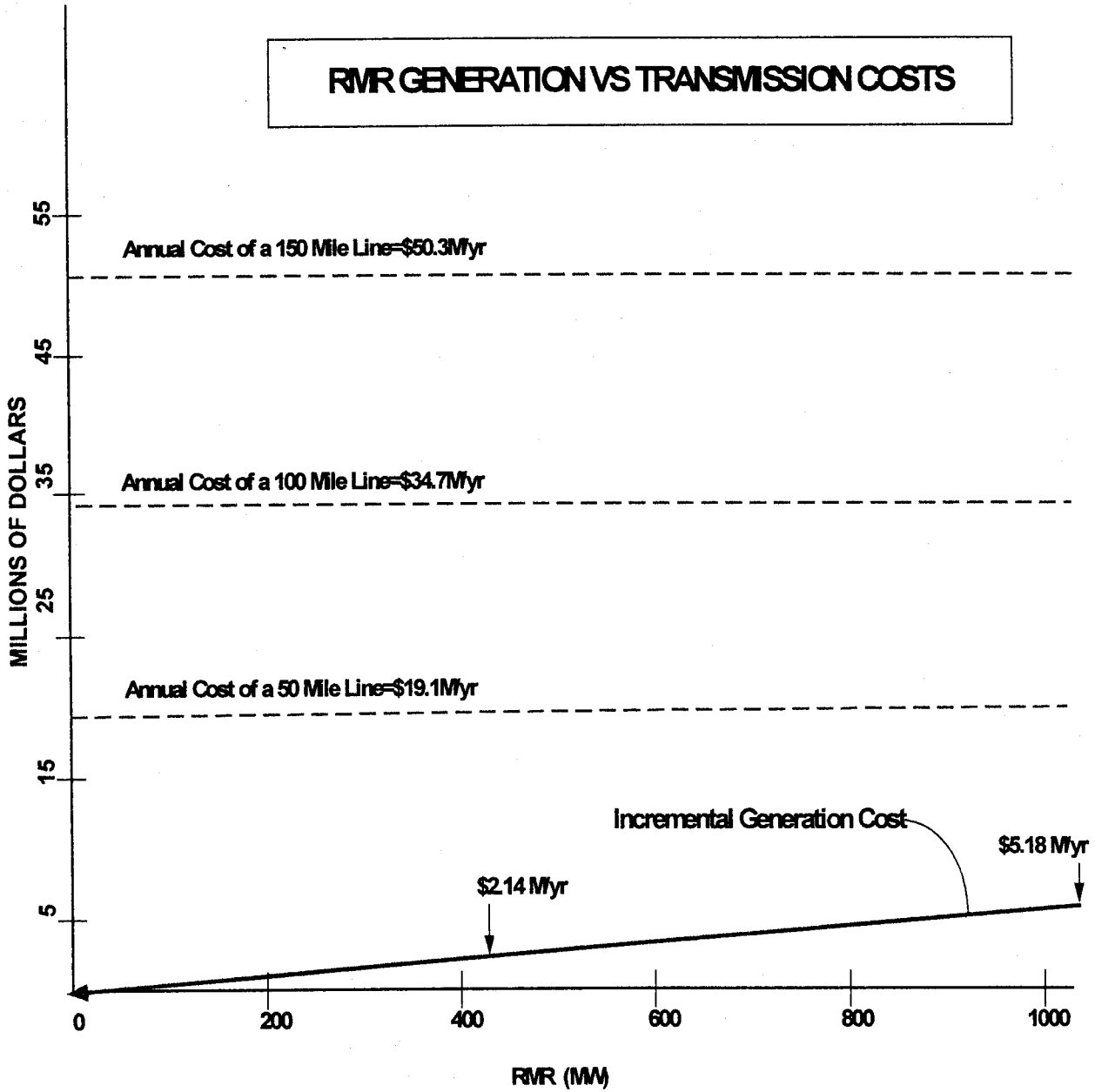
RMR GENERATION VS TRANSMISSION COSTS
MILLIONS OF DOLLARS
55
45
35
25
15
5
Annual Cost of a 150 Mile Line=$50.3M/yr
Annual Cost of a 100 Mile Line=$34.7M/yr
Annual Cost of a 50 Mile Line=$19.1M/yr
Incremental Generation Cost
$5.18 M/yr
$2.14 M/yr
0
200
400
600
800
1000
RMR (MW)

EXHIBIT
PENGAD-Bayonne, N. J.
APS-1
admitted

TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

May 29, 2002

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APPENDIX A ..... Statement of Qualifications

SCHEDULE JED-1GD ..... Decision No. 61973 (October 6, 1999), including all the Amendments to the 1999 APS Settlement Agreement approved therein

TESTIMONY OF JACK E. DAVIS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jack E. Davis. My business address is 400 North Fifth Street, Phoenix, Arizona 85072. I am President of Energy Delivery and Sales for Arizona Public Service Company ("APS" or "Company"). I am also President of Pinnacle West Capital Corporation ("PWCC").

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS CONSOLIDATED DOCKET?

A. Yes. I filed both direct and rebuttal testimony in Docket No. E-01345A-01-0822. However, since that testimony was never actually heard by the Arizona Corporation Commission ("Commission"), I have provided a Statement of Qualifications as an attachment to this testimony. *See* Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS GENERIC PROCEEDING?

A. In response to the Commission's Procedural Order dated May 2, 2002 ("Procedural Order"), I will discuss the reasons behind the transfer of most of the Company's generating assets to Pinnacle West Energy Corporation ("PWEC"). As also requested in the Procedural Order, I will address (from a layman's point of view) the issues of affiliate transactions, codes of conduct and the division of jurisdictional authority over pricing as between this Commission and the Federal Energy Regulatory Commission ("FERC").

Q. WILL APS PRESENT OTHER WITNESSES?

A. Yes. Dr. William Hieronymus will address the questions raised by Staff concerning the potential for PWEC to exercise meaningful market power post-divestiture. Market power was explicitly identified as a "Track A" issue in the Procedural Order. Dr. Hieronymus also discusses the reasons why divestiture of APS generation assets to PWEC remains in the public interest.

Q. WILL ANY OF THE COMPANY WITNESSES DIRECTLY DISCUSS COMPETITIVE BIDDING PROCEDURES AND OBJECTIVES IN THEIR TESTIMONY?

A. No. The Procedural Order has designated these as "Track B" issues. The Company has proposed a separate but parallel process of addressing and resolving "Track B" issues.

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*) specifically mandated divestiture of all APS generation assets by December 31, 2000. At the Company's request, this divestiture was both expressly authorized by the Commission and postponed by up to two years as a result of the 1999 APS Settlement Agreement, which settlement was approved and adopted by the Commission in Decision No. 61973 (October 6, 1999). *See* Schedule JED-1GD, attached. An earlier settlement agreement negotiated with Commission Staff in 1998 but eventually withdrawn, also provided for divestiture of APS generation to an affiliated entity. The reasons prompting these various actions by the Commission and/or Staff are as valid today as they were in 1998 and 1999. They also explain why the divestiture of generation by electric utilities to subsidiaries or other affiliated entities has been a common part of industry

restructuring in other jurisdictions. The Commission has had in place comprehensive Affiliate Rules (A.A.C. R14-2-801, *et seq.*) since 1990. Affiliate transactions are also reviewed in individual proceedings, both rate and otherwise. Similarly, the Commission and FERC have approved Codes of Conduct. In addition, APS has in place implementing Policies & Procedures (Commission) for its Commission-approved Code of Conduct and Standards of Conduct (FERC) that govern the interaction between affiliated merchant energy functions (e.g., PWM&T) and the wire (transmission) functions of APS. These existing regulatory policies and powers have proven effective as to those utilities covered by such provisions.

Finally, I am aware that sales to APS of power from the wholesale electric market are regulated by FERC. This has been true since long before I came to the Company, and I am not aware of any proposals to change this jurisdictional fact of life. That does not mean, however, that the Commission is powerless to either effectively participate in FERC proceedings affecting Arizona consumers or that it has surrendered its ability to review discretionary decisions by APS management to determine whether they were prudent given the facts and circumstances known to APS at the time such decisions were made.

III. TRANSFER OF APS GENERATION TO PWEC

Q. DO THE ELECTRIC COMPETITION RULES DISCUSS THE ISSUE OF DIVESTITURE OF GENERATION ASSETS TO AN AFFILIATE?

A. Yes. In Decision No. 61969 (September 29, 1999) the Commission reaffirmed the already existing provisions of the Electric Competition Rules requiring divestiture of competitive generation and other competitive assets. Specifically, A.A.C. R14-2-1615 (A) states:

> All competitive generation assets and competitive services shall be separated from an Affected Utility prior to January 1, 2001.

But this story goes back over a year prior to Decision No. 61969. In Decision No. 61071 (August 10, 1998), the Commission, at Staff's urging, added a mandatory divestiture provision to the Electric Competition Rules. Although originally proposed as a California-style divestiture to out-of-state merchant plant developers, APS and Tucson Electric Power successfully argued for a third option — divestiture to an Arizona affiliate. *See* A.A.C. R14-2-1615. That provision was later reaffirmed in Decision No. 61272 (December 11, 1998) and, of course, in Decision No. 61969.

Q. WERE THE PROS AND CONS OF DIVESTITURE DEBATED DURING THE VARIOUS RULEMAKING PROCEEDINGS THAT EVENTUALLY RESULTED IN THE PRESENT ELECTRIC COMPETITION RULES?

A. Yes. It had been a topic of considerable debate and analysis since the original consideration of the Electric Competition Rules in 1996. Unlike the 50% competitive bidding requirement, divestiture was fully subject to the review and comment process of Arizona rulemaking — not once but on at least four separate occasions. In conclusion, the Commission found that:

> only through the divestiture of competitive services or the transfer of competitive services to an affiliate would the subsidization and crossovers between monopoly and competition be prohibited.

Decision No. 61272 at Appendix C, p. 33.

Nearly a year after that Decision, the Commission again considered the issue of generation divestiture to an affiliate or affiliates of an Affected Utility and again concluded after yet another full-blown rulemaking proceeding that:

> [the] separation of monopoly and competitive services by the incumbent Affected Utilities must take place in order to foster development of a competitive market in Arizona

. . .

> the requirement that competitive generation assets and Competitive Services be separated to an unaffiliated party or to a separate corporate affiliate or affiliates, will provide greater protection against cross-subsidization than would separation to a subsidiary.

Decision No. 61969 at 60-61 (emphasis supplied).

Q. DO THE ELECTRIC COMPETITION RULES IMPOSE ANY DUTIES OR RESTRICTIONS ON THE TRANSFEREE(S) OF DIVESTED ELECTRIC GENERATION?

A. No.

Q. WHAT DID THE 1999 APS SETTLEMENT AGREEMENT AND THE COMMISSION DECISION APPROVING AND ADOPTING SUCH SETTLEMENT AGREEMENT HAVE TO SAY ABOUT THE DIVESTITURE OF APS GENERATION ASSETS TO AN AFFILIATE?

A. Decision No. 61973 reaffirmed for the fourth time that divestiture of the Company's generation to an affiliate was "in the public interest" and thus granted:

> all requisite Commission approvals for . . . the creation by APS or its parent of new corporate affiliates . . . and the transfer thereto of APS' generation assets ...

See 1999 APS Settlement Agreement at §§ 4.2 and 4.4.

In its adoption of the 1999 APS Settlement, the Commission went on to state:

> [T]he Commission supports and authorizes the transfer by APS to an affiliate or affiliates of all its generation and [other] competitive electric service assets as set forth in the Agreement Agreement no later than December 31, 2002."

Decision No. 61973 at 10.

The Commission further adopted the following language as set forth in the Agreement:

> The Commission has determined that allowing the Generation

> Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG ["Exempt Wholesale Generator"] affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

Id. at Attachment 1, p.7.

Unlike most settlements before the Commission, the 1999 APS Settlement Agreement provided for the Commission itself to become a party to the settlement by virtue of its approval of that settlement in Decision No. 61973. The legality of the 1999 APS Settlement Agreement, including the Commission's inclusion as a party to the settlement, and Decision No. 61973 survived unscathed through two separate judicial appeals, the last of which was finally decided in December of 2001. In upholding the 1999 APS Settlement Agreement, the Arizona Court of Appeals stated:

> The agreement requires APS to divest its generation assets by December 31, 2002, and requires the Commission approve the formation of an APS affiliate to acquire those assets at book value. [Opinion at ¶ 8.]
>
> . . .
>
> Section 6.1 [of the Settlement] makes the Commission a party to the agreement, and section 6.2 precludes the Commission from taking or proposing any action inconsistent with the agreement and requires the Commission to actively defend it. [Opinion at ¶ 33.]
>
> . . .
>
> The general rule, however, is that a contract that extends beyond the terms of the members of a public board is valid if made in good faith and if its does not involve the performance of personal or professional services for the board. [Citation omitted.] The [Arizona Consumers] Council has not alleged that the [settlement] contract was not entered into in good faith, and the contract does not involve personal services for Commission members. The [settlement] contract can therefore bind future commissions. [Citation omitted.] [Emphases supplied.] [Opinion at ¶ 38.]

Q. WAS DIVESTITURE A KEY ELEMENT OF THE SETTLEMENT?

A. Yes. Divestiture of APS generation was at the very heart of the 1999 APS Settlement Agreement from the time of its original submission to the Commission in May 1999. It was an express part of the Company's bargained-for consideration in the agreement. APS would have never entered into any settlement that did not guarantee its ability to divest its generation to an affiliate or affiliates, that did not require the Commission to make the findings of fact necessary for that affiliate or affiliates to be an "Exempt Wholesale Generator," or that did not allow the recovery of transition costs.

Q. ASIDE FROM THE 1999 APS SETTLEMENT AGREEMENT ITSELF, HAVE APS AND ITS PARENT CORPORATION, PWCC, TAKEN SPECIFIC STEPS IN REGARD TO DIVESTITURE OF APS GENERATING ASSETS TO PWEC?

A. Yes. These include:

1) forming PWEC and subsequently obtaining a financial credit rating (contingent upon transfer of the APS generating assets) for PWEC from major credit rating agencies;

2) reorganization and reassignment of APS personnel to PWM&T and PWEC and the retention by PWEC of new personnel to both operate APS generation and to engage in the construction of new generation;

3) PWEC's initiation of over $1 billion dollars in new generation construction to serve APS retail customers, which decision was wholly dependent upon the ability to acquire existing APS generation under the provisions of the Electric Competition Rules and the 1999 APS Settlement Agreement;

4) provision of interim financing by PWCC for PWEC's construction of new generation to serve APS load, which financing has placed an extreme burden on PWCC without the ability to collateralize the APS generating assets;

5) development of a comprehensive "buy-back" purchase power agreement ("PPA") whereby APS generating assets could remain dedicated to APS retail customers at cost-based prices;

6) notice to or consents from some 3500 co-participants, fuel suppliers, government entities, creditors, etc., for transfer of the APS generation and related contracts, permits, rights-of-way, letters of credit, etc.;

7) preparation of requests for and the securing of several private letter rulings from the IRS addressing the transfer of APS generation to PWEC and the continued tax-advantaged status of the Palo Verde Nuclear Generating Station ("PVNGS") decommissioning trust;

8) preparation of legal documents of transfer (deeds, bills of sale, assignments, etc.);

9) preparation of the data required by Decision No. 61973 to be included in the 30-day notice of transfer, presently to be filed on August 1, 2002; and

10) submission of an application to the Nuclear Regulatory Commission ("NRC") for the transfer of the Company's operating license at PVNGS.

The last two critical path events prior to the actual transfer are: 1) securing NRC approval of a license transfer for the operation of the PVNGS; and 2) securing approval from the owners of or (more likely) a buyout of the secured lease obligation bonds ("SLBs") associated with the previously authorized sale/leaseback of PVNGS Unit 2. APS submitted its application for operating license transfer to the NRC last month. Approval is expected within no more than six months from the date of filing. Also, the Company will initiate buyout of the SLBs in the next couple of months. This buyout will be an extremely

expensive proposition and will significantly increase the divestiture-related expenditures incurred by APS to date.

Q. DID ANYONE OPPOSE THE DIVESTITURE PROVISIONS OF THE 1999 APS SETTLEMENT AGREEMENT?

A. No. Obviously none of the signatories were in disagreement over the necessity of such a restructuring of the Company's lines of business into competitive and non-competitive entities. And no non-signatory participant in the proceeding resulting in approval and adoption of the 1999 APS Settlement Agreement, including Staff, was opposed to divestiture.

Q. YOU PREVIOUSLY MENTIONED A 1998 SETTLEMENT WITH COMMISSION STAFF. DID THAT SETTLEMENT ALSO INCLUDE A DIVESTITURE REQUIREMENT?

A. Yes. Staff, APS and Tucson Electric Power Company ("TEP") negotiated a three-way agreement wherein APS would acquire some of TEP's generation and TEP would acquire the Company's EHV transmission assets. APS would then be required to divest the combined APS/TEP generation to an affiliate.

Q. DID EITHER SETTLEMENT AGREEMENT IMPOSE ANY CONDITIONS ON THE AFFILIATE RECEIVING APS GENERATION ASSETS?

A. No. In fact, neither Staff nor the Commission, or for that matter, any of the signatories to either agreement, ever suggested that any conditions be imposed.

Q. ARE DIVESTITURE AND COMPETITIVE BIDDING UNDER RULE 1606(B) LINKED?

A. Absolutely, both in the historical context of the Electric Competition Rules and in the practical sense. I say historical context because the two provisions [Rule 1606(B) and Rule 1615] arose at the same time and have always been synchronized in their starting date. Even during the approval process of the

1999 APS Settlement Agreement, the variance granted to Rule 1606(B) was referred to as a "corresponding delay," that is, "corresponding" to the delay in implementation of Rule 1615. Moreover, the competitive bidding and other power procurement provisions of Rule 1606(B) refer only to "Utility Distribution Companies," which in the parlance of the Electric Competitions Rules is used only to describe Affected Utilities such as APS in their post-divestiture state of restructuring. Practically speaking, it would make little sense for a still vertically-integrated utility to bid for resources it already owns, a concession that even merchant generators such as Sempra have acknowledged in response to the Company's data requests.

IV. AFFILIATE RULES AND CODE OF CONDUCT

Q. HOW LONG HAS THE COMMISSION HAD COMPREHENSIVE AFFILIATE TRANSACTION REGULATIONS IN EFFECT?

A. The Affiliate Rules were, in their present form, enacted in 1990. They address both specific types of affiliate transactions and more generic issues such as cost allocation, diversification, etc. The Affiliate Rules are organized as follows:

Rule 801 – Definitions

Rule 802 – Applicability (Class A utilities and affiliates)

Rule 803 – Regulates organizations and reorganizations at the holding company level; this includes any acquisition of or divestiture of an affiliate of the Arizona utility and even the acquisition or divestiture of a financial interest in such affiliate

Rule 804 – Requires prior approval of specific transactions between the utility and any affiliate; requires affiliates to make books and records available to the Commission

Rule 805 – Requires annual report on affiliates and affiliated transactions as well as future business plans of the holding company and affiliates

Rule 806 – Allows waivers of Affiliate Rules if "in the public interest"

Q. DID THE COMMISSION ALSO ADDRESS AFFILIATE TRANSACTIONS IN INDIVIDUAL ORDERS PRIOR TO THE ENACTMENT OF COMPREHENSIVE AFFILIATE RULES?

A. Yes. In Decision Nos. 56548 (July 12, 1989) and 55196 (September 18, 1986), the Commission imposed both substantive and procedural provisions governing affiliate transaction specific to APS and its affiliates. These orders were subsequently rescinded or modified by the Commission, but they evidence that the Commission is far from powerless to address concerns about the potential for affiliate abuse. Moreover, the Commission still retains the power to disallow affiliate charges in rate proceedings if it finds them imprudent.

Q. DO SOME OR ALL THE MERCHANT PLANT INTERVENORS HAVE REGULATED ELECTRIC UTILITY AFFILIATES?

A. Yes, although most of them claimed that information was either confidential or claimed not to know what the word "affiliate" meant. Sempra, Reliant, Duke, Panda/TECO, PG&E, AES and PPL all have traditional electric utility affiliates.

Q. WILL ANY OF THEM BE SUBJECT TO THE AFFILIATE RULES?

A. Not unless the Commission chooses to make them so. At present, only entities affiliated with an Arizona electric utility having at least $5 million in annual retail sales are subject to affiliate restrictions, and according to Commission records, no such Arizona retail utility affiliates of the merchant plant intervenors exist.

Q. DOES APS PRESENTLY HAVE IN EFFECT A CODE OF CONDUCT GOVERNING ITS RELATIONS WITH VARIOUS AFFILIATES?

A. It has both a Commission-approved Code of Conduct and a FERC-approved Code of Conduct. Below is a brief description of the origin and purpose of each of these Codes of Conduct:

The Commission-approved Code of Conduct is in accordance with Rule 1616 of the Electric Competition Rules and represented a Staff-APS joint proposal. Subsequent to the Code of Conduct's approval in Decision No. 62416 (April 3, 2000), the Company submitted Policies & Procedures ("P&P") to implement the Code of Conduct, which were in turn reviewed by Commission Staff for conformity with the requirements of Decision No. 62416.

The FERC Code of Conduct is intended to protect captive customers from subsidizing unregulated or competitive activities. The Standards of Conduct prevent discriminatory access to both physical facilities and network information. *See Re Pinnacle West Capital Corp.*, 95 FERC ¶61,300 at 62,026 (2001).

Q. DO YOU BELIEVE THE COMMISSION'S AFFILIATE RULES AND THE COMMISSION AND FERC-APPROVED CODES OF CONDUCT ARE SUFFICIENT TO PREVENT AND REMEDY AFFILIATE ABUSE?

A. Yes. They are more than sufficient, at least for utilities that are covered by them such as APS. As noted above, the Commission can also issue individual orders both in and outside the context of rate proceedings on this issue and can disallow the recovery of specific costs from Arizona consumers. Neither of these is true, of course, with regard to those power suppliers in Arizona that are exempt from the Affiliate Rules and the requirements of Rule 1616, and which are not otherwise "public service corporations." I will concede that most, but not all these entities, have FERC Codes of Conduct and are subject to FERC's Standards of Conduct. Whether that standing alone is sufficient to address any Commission concerns is an issue for the Commission to determine in this or some later proceeding.

V. THE JURISDICTIONAL ISSUE

Q. WOULD DIVESTITURE OF APS' GENERATION TO PWEC RESULT IN THE FERC HAVING JURISDICTION OVER APS PURCHASES OF ELECTRICITY?

A. FERC has had that jurisdiction since the 1930s. The transfer of APS generation to PWEC or, for that matter, to anyone else, would not change that fact. Without significant owned-generation, however, APS will obviously have to purchase most of its Standard Offer service requirements from wholesale suppliers. This too has always been understood since the first additions of Rule 1606 and Rule 1615 to the Electric Competition Rules back in 1998. However, by submitting its proposed PPA to the Commission for its review and approval even prior to filing the agreement with FERC, the Company offered the Commission an opportunity quite possibly not available to it should it be required to purchase power from non-affiliates.

Q. EVEN THOUGH DIVESTITURE DOES NOT CHANGE THE HISTORIC JURISDICTIONAL SEPARATION BETWEEN STATE AND FEDERAL REGULATORS, SHOULDN'T THE COMMISSION BE CONCERNED THAT FERC WILL PERMIT HIGHER RATES THAN WOULD HAVE BEEN THE CASE UNDER THIS COMMISSION'S TRADITIONAL RATEMAKING SYSTEM?

A. No. Such FERC-authorized rates might be either higher or lower than cost-of-service, unless the wholesale transaction itself is cost-based in the same manner as the proposed PPA. But to the extent APS must obtain power from non-affiliated sources, it is a risk the Commission has already decided to accept under the competitive-bidding or other market-based power acquisition strategies contemplated by Rule 1606(B). In the Staff Report dated March 22, 2002, the need for Commission monitoring of and participation in FERC market proceedings is addressed in some detail. Letters in this Docket from two of the Commissioners specifically address such a Commission role. APS supports

these efforts and believes the Commission can be an effective voice in support of Arizona consumers.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Divestiture of APS generation to PWEC has been a requirement of the Electric Competition Rules for years. It was an integral part of two settlements, the second of which was adopted by the Commission and upheld as binding by the Courts. Over the past 20 months, APS has undertaken numerous steps and spent millions of dollars to be in a position to effectuate that divestiture as agreed to in 1999. Divestiture is also the basis for the competitive bidding provision of Rule 1606, which makes absolutely no sense in its absence.

The Commission and FERC have adequate provisions in place to prevent, detect and correct affiliate abuse and discriminatory treatment of any nature. These include comprehensive Affiliate Rules and Codes of Conduct (and the P&P and FERC Standards of Conduct), individual orders, and after-the-fact rate reviews.

APS purchases from the competitive wholesale market are and have been regulated by FERC. The Commission has full power and authority to monitor and participate in FERC proceedings and can review the prudence of discretionary APS procurement decisions after-the-fact in individual rate cases. Under terms of the proposed PPA, Commission involvement would also have been extended to encompass before-the-fact review and approval.

Q. DOES THAT CONCLUDE YOUR INITIAL WRITTEN TESTIMONY IN THIS GENERIC PROCEEDING?

A. Yes, it does.

APPENDIX A

STATEMENT OF WITNESS QUALIFICATIONS

Jack E. Davis is President for Pinnacle West Capital Corporation (PWCC) and President of Energy Delivery and Sales for Arizona Public Service Company (APS). As President of PWCC, Mr. Davis has responsibility for Bulk Power Marketing & Trading. As APS President for Energy Delivery and Sales, Mr. Davis has responsibility for Transmission Planning and Operations, Customer Service, Economic Development, and Pricing and Regulation. Mr. Davis is also on the Boards of PWCC and APS, as well as the Boards of APS Energy Services and Pinnacle West Energy Corporation.

Mr. Davis graduated from New Mexico State University in 1969 with a Bachelor of Science Degree in Medical Technology and in 1973 with a Bachelor of Science in Electrical Engineering. He joined APS in 1973 and has held various supervisory and managerial positions in both the APS System Planning and Power Contracts and APS System Operations Departments. In 1990, Mr. Davis was named APS Director of System Development and Power Operation and thereafter promoted to APS Vice-President of Generation and Transmission in 1993. In October 1996, he was named APS Executive Vice-President of Commercial Operations and in 1998 he was promoted to the position of APS President, Energy Delivery and Sales. In March of 2000, he became the Chief Operating Officer for PWCC and in February 2001, was promoted to President of PWCC.

Mr. Davis has served as the past-Chairman of the Western Systems Coordinating Council (WSCC) and is a member of its Board of Trustees. He is also past-Chairman on the Western Systems Power Pool as well as past-President of Western Energy and Supply Transmission (WEST) Associates. Mr. Davis is presently a member of the National Electric Reliability Council Board of Trustees, and he is a registered professional Engineer in the State of Arizona.

SCHEDULE JED-1GD

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
OCT 06 1999
DOCKETED BY

CARL J. KUNASEK
CHAIRMAN
JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY.	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 *ET SEQ.*	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165 DECISION NO. 61973

OPINION AND ORDER

DATES OF HEARING: July 12, 1999 (pre-hearing conference), July 14, 15, 16, 19, 20, and 21, 1999

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICER: Jerry L. Rudibaugh

IN ATTENDANCE: Carl J. Kunasek, Chairman
Jim Irvin, Commissioner

APPEARANCES: Mr. Steven M. Wheeler, Mr. Thomas Mumaw and Mr. Jeffrey B. Guldner, SNELL & WILMER, LLP, on behalf of Arizona Public Service Company;

Mr. C. Webb Crockett and Mr. Jay Shapiro, FENNEMORE CRAIG, on behalf of Cyprus Climax Metals, Co., ASARCO, Inc., and Arizonans for Electric Choice & Competition;

Mr. Scott S. Wakefield, Chief Counsel, and Ms. Karen Nally on behalf of the Residential Utility Consumer Office;

Ms. Betty Pruitt on behalf of the Arizona Community Action Association;

Mr. Timothy Hogan on behalf of the Arizona Consumers Council;

Mr. Robert S. Lynch on behalf of the Arizona Transmission Dependent Utility Group;

Mr. Walter W. Meek on behalf of the Arizona Utility Investors Association;

Mr. Douglas C. Nelson, DOUGLAS C. NELSON, P.C., on behalf of Commonwealth Energy Corporation;

Mr. Lawrence V. Robertson, Jr., MUNGER & CHADWICK, and Ms. Leslie Lawner, Director Government Affairs on behalf of Enron Corporation, and Mr. Robertson on behalf of PG&E Energy Services;

Mr. Lex J. Smith, BROWN & BAIN, P.A., on behalf of Illinova Energy Partners and Sempra Energy Trading;

Mr. Randall H. Werner, ROSHKA, HEYMAN & DeWULF, P.L.C., on behalf of NEV Southwest;

Mr. Norman Furuta on behalf of the Department of the Navy;

Mr. Bradley S. Carroll on behalf of Tucson Electric Power Company; and

Mr. Christopher C. Kempley, Assistant Chief Counsel and Ms. Janet F. Wagner, Staff Attorney, Legal Division on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

On December 26, 1996, the Arizona Corporation Commission ("Commission") in Decision No. 59943 enacted A.A.C. R14-2-1601 through R14-2-1616 ("Rules" or "Electric Competition Rules").

On June 22, 1998, the Commission issued Decision No. 60977, the Stranded Cost Order which required each Affected Utility to file a plan for stranded cost recovery.

On August 10, 1998, the Commission issued Decision No. 61071 which made modifications to the Rules on an emergency basis.

On August 21, 1998, Arizona Public Service Company ("APS") filed its Stranded Costs plan.

On November 5, 1998, APS filed a Settlement Proposal that had been entered into with the Commission's Utilities Division Staff ("Staff Settlement Proposal"). Our November 24, 1998 Procedural Order set the matter for hearing. On November 25, 1998, the Commission issued

Decision No. 61259 which established an expedited procedural schedule for evidentiary hearings on the Staff Settlement Proposal.

On November 30, 1998, the Arizona Attorney General's Office, in association with numerous other parties, filed a Verified Petition for Special Action and Writ of Mandamus with the Arizona Supreme Court ("Court") regarding the Commission's November 25, 1998 Procedural Order, Decision No. 61259. The Attorney General sought a Stay of the Commission's consideration of the Staff Settlement Proposal with APS and Tucson Electric Power Company ("TEP").

On December 1, 1998, Vice Chief Justice Charles J. Jones granted a Motion for Immediate Stay of the Procedural Order. On December 9, 1998, the Commission Staff filed a notice with the Supreme Court that the Staff Settlement Proposal had been withdrawn from Commission consideration.

On April 27, 1999, the Commission issued Decision No. 61677, which modified Decision No. 60977. On May 17, 1999, APS filed with the Commission a Notice of Filing, Application for Approval of Settlement Agreement ("Settlement" or "Agreement") [1] and Request for Procedural Order.

Our May 25, 1999 Procedural Order set the matter for hearing commencing on July 14, 1999.

This matter came before a duly authorized Hearing Officer of the Commission at its offices in Phoenix, Arizona. APS, Cyprus Climax Metals, Co., ASARCO, Inc., Arizonans for Electric Choice & Competition ("AECC"), Residential Utility Consumer Office ("RUCO"), the Arizona Community Action Association ("ACAA"), the Arizona Consumers Council, the Arizona Transmission Dependent Utility Group, the Arizona Utility Investors Association, Enron Corporation, PG&E Energy Services, Illinova Energy Partners, Sempra Energy Trading, NEV Southwest, the Department of the Navy, Tucson Electric Power Company, Commonwealth Energy Corporation

[1] The Parties to the Proposed Settlement are as follows: the Residential Utility Consumer Office, Arizona Public Service Company, Arizona Community Action Association and the Arizonans for Electric Choice and Competition which is a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs and Raytheon.

("Commonwealth") and Staff of the Commission appeared through counsel. Evidence was presented concerning the Settlement Agreement, and after a full public hearing, this matter was adjourned pending submission of a Recommended Opinion and Order by the Presiding Officer to the Commission. In addition, a post-hearing briefing schedule was established with simultaneous briefs filed on August 5, 1999.

DISCUSSION

Introduction

The Settlement provides for rate reductions for residential and business customers; sets the amount, method, and recovery period of stranded costs that APS can collect in customer charges; establishes unbundled rates; and provides that APS will separate its generating facilities, which will operate in the competitive market, from its distribution system, which will continue to be regulated.

According to APS, the Settlement was the product of months of hard negotiations with various customer groups. APS opined that the Settlement provides many clear benefits to customers, potential competitors, as well as to APS. Some of those benefits as listed by APS are as follows:

- Allowing competition to commence in APS' service territory months before otherwise possible and expanding the initial eligible load by 140 MW;
- Establishing both Standard Offer and Direct Access rates, and providing for annual rate reductions with a cumulative total of as much as $475 million by 2004;
- Ensuring stability and certainty for both bundled and unbundled rates;
- Resolving the issue of APS' stranded costs and regulatory asset recovery in a fair and equitable manner;
- Providing for the divestiture of generation and competitive services by APS in a cost-effective manner;
- Removing the specter of years of litigation and appeals involving APS and Commission over competition-related issues;
- Continuing support for a regional ISO and the AISA;
- Continuing support for low income programs; and
- Requiring APS to file an interim code of conduct to address affiliate relationships.

The Settlement was entered into by RUCO and the ACAA reflecting Agreement by residential customers of APS to the Settlement's terms and conditions. In addition, the Settlement was executed by the AECC, a coalition of commercial and industrial customers and trade associations. AECC opined that since residential and non-residential customers have agreed to the Settlement, the "public interest" has been served. AECC indicated the Settlement was not perfect but was the result of "give and take" by each of the parties. Accordingly, AECC urged the Commission to protect the "public interest" by approving the Settlement and not allow Energy Service Providers ("ESPs") to delay the benefits that competition has to offer.

Legal Issues:

The Arizona Consumers Council ("Consumers Council") opined that the Agreement was not legal because: (1) there was no full rate proceeding[2]; (2) Section 2.8 of the Agreement violates A.R.S. Section 40-246, regarding Commission initiated rate reductions; and (3) the Agreement illegally binds future Commissions. According to the Consumers Council, the Commission does not have evidence to support a finding that the rates proposed in the Agreement are just and reasonable; that the rate base proposed is proper; and asserted the proposed adjustment clause can not be established outside a general rate case.

Staff argued that the Commission in Decision No. 59601, dated April 26, 1996, has previously determined just and reasonable rates for APS which must be charged until changed in a rate proceeding. According to Staff, this case is not about changing existing rates, but instead involves the introduction of a new service - direct access. The direct access rates have been designed to replicate the revenue flow from existing rates. Staff opined that the Commission has routinely, and lawfully, approved rates for new services outside of a rate case. Further, Staff asserted that the rates proposed in the Settlement are directly related to a complete financial review. Staff indicated that the Consumers Council has provided no contrary information and should not be allowed to collaterally attack Decision No. 59601.

APS argued that no determination of fair value rate base ("FVRB"), fair value rate of return

[2] Although the Consumers Council indicated they did not believe a full rate proceeding was necessary, it is unclear as to the type of proceeding the Consumers Council believed was necessary.

("FVROR"), or other financial analysis is legally necessary to justify current APS rate levels, allow the introduction of a new service, or to evaluate a series of voluntary rate decreases. In spite of that, APS did provide information to support a FVRB of $5,195,675,000 and FVROR of 6.63 percent. No other party presented evidence in support of a FVRB or FVROR. Staff supported APS.

We concur with Staff and APS. The Consumers Council has provided no legal authority that a full rate proceeding is necessary in order to adopt a rate reduction or rates for new services. Further, pursuant to the Arizona Constitution, the Commission has jurisdiction over ratemaking matters. We also find that notice of the application and hearing was provided and that APS has provided sufficient financial information to support a finding of FVRB and FVROR. Lastly, this Commission can clearly bind future Commissions as a result of its Decision. However, as later discussed, we agree there are limitations to such legal authority.

Shopping Credit

One of the most contentious issues in the hearing was the level of the "shopping credit." The "shopping credit" is the difference between the customer's Standard Offer Rate and the Direct Access Rate available to customers who take service from ESPs. The ESPs generally argued that the Settlement's "shopping credits" were not sufficient to allow a new entrant to make a profit. AECC opined that such an argument was nothing more than a request to increase ESP's profits.

Staff opined that the "shopping credit" was too low and recommended it be increased without impacting the stranded cost recovery amount of $350 million. Under Staff's proposal, the increased "shopping credit" would be offset by reducing the competitive transition charge ("CTCs"). Further, Staff recommended that any stranded costs not collected could simply be deferred and collected after 2004.

The AECC expert testified that the "shopping credit" under the Agreement was superior to the "Shopping Credit" in the Staff Settlement Proposal as well as the one offered to SRP's customers. APS argued that artificially high shopping credits will likely increase ESP profits without lowering customer rates and will encourage inefficient firms to enter the market. Based on the analysis of the

40kW to 200 kW customer group[3], APS showed an average margin on the "shopping credit" of over 8 mils per kWh or a 23 percent markup over cost. APS asserted that the test for a reasonable "shopping credit" "should not be whether all ESPs can profit on all APS customers all of the time".

Based on the evidence presented, the "shopping credits" appear to be reasonable to allow ESPs to compete in an efficient manner. Further, we do not find customer rates should be increased simply to have higher "shopping credits".

Metering and Billing Credits

The metering and billing credits resulting from the Agreement are based on decremental costs. Several of the ESPs and Staff argued that these credits should be based upon embedded costs and not decremental costs. APS responded that such a result could cause them to lose revenues since its costs would only go down by the decremental amounts. Staff testified that the Company would not lose significant income if it used embedded costs since it would free up resources to service new customers.

We concur. The proposed credits for metering, meter reading and billing[4] will result in a direct access customer paying a portion of APS costs as well as a portion of the ESP's costs. We believe this would stymie the competitive market for these services. As a result, we find the approval of the Settlement should be conditioned upon the use of Staff's proposed credits for metering, meter reading, and billing.

Proposed One-Year Advance Notice Requirement:

Section 2.3 provides that

> "Customers greater than 3MW who chose a direct access supplier must give APS one year's advance notice before being eligible to return to Standard Offer service." [emphasis added]

Several parties expressed concerns that the one-year notice requirement to return to Standard Offer service would create a deterrent to load switching by large industrial, institutional and commercial customers. PG&E proposed that any increased cost could be charged directly to the

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[3] Represents over 80 percent of the general service customers for competitive access in phase one.

[4] For example, the monthly credits for a direct access residential customers are $1.30, $0.30, and $0.30 for metering, meter reading and billing, respectively.

customer as a condition to its return.

We agree that APS needs to have some protection from customers leaving the system when market prices are low and jumping back on Standard Offer rates when market prices go up. The suggestion by PG&E that the customer be allowed to go back to the Standard Offer if the customer pays for additional costs it has caused is a reasonable resolution. Accordingly, we will order APS to submit substitute language on this issue.

Section 2.8

Several of the parties expressed concern that Section 2.8 of the Agreement allows APS to seek rate increases under specified conditions. Additionally, as previously discussed, the Consumers Council opined that Section 2.8 violated A.R.S. Section 40-246. Staff recommended the Commission condition approval of the Agreement on Section 2.8 being amended to include language that the Commission or Staff may commence rate change proceedings under conditions paralleling those provided to the utility, including response to petitions submitted under A.R.S. § 40-246.

We agree that Section 2.8 is too restrictive on the Commission's future action. Accordingly, we will condition approval of the Agreement on inclusion of the following language in Section 2.8:

> Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

Section 7.1

The Consumers Council opined that there was language in the Agreement which would illegally bind future Commissions. While Staff disagreed with the legal opinion of the Consumers Council, Staff was concerned with some of the binding language in the Agreement and in particular with the following language in Section 7.1:

> 7.1. To the extent any provision of this Agreement is inconsistent with any existing or future Commission order, rule or regulation or is inconsistent with the Electric

> Competition Rules as now existing or as may be amended in the future, the provisions of this Agreement shall control and the approval of the Agreement by the Commission shall be deemed to constitute a Commission-approved variation or exemption to any conflicting provision of the Electric Competition Rules.

Staff recommended the Commission not approve Section 7.1.

We share Staff's concerns. We also recognize that the parties want to preserve their benefits to their Agreement. We agree with the parties that to the extent any provision of the Agreement is inconsistent with the Electric Competition Rules as finalized by the Commission in September 1999, the provisions of the Agreement shall control. We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for. With that said, the Commission must be able to make rule changes/other future modifications that become necessary over time. As a result, we will direct the parties and Staff to file within 10 days, a revised Section 7.1 consistent with the Commission's discussions herein and subsequently approved by this Commission.

Generation Affiliate

Section 4.1 of the Agreement provides the following:

> 4.1 The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

Related to Section 4.1 is Section 2.6(3) which allows APS to defer costs of forming the generation affiliate, to be collected beginning July 1, 2004.

According to NEV Southwest, APS indicated that it intends to establish a generation affiliate under Pinnacle West, not under APS. Further, that APS intends to procure generation for standard offer customers from the wholesale generation market as provided for in the Electric Competition Rules. Additionally, it was NEV Southwest's understanding that the affiliate generation company could bid for the APS standard offer load under an affiliate FERC tariff, but there would be no automatic privilege outside of the market bid. NEV Southwest supports the aforementioned concepts and recommended they be explicitly stated in the Agreement.

We concur with NEV Southwest. We shall order APS to include language as requested by

NEV Southwest. Power for Standard Offer Service will be acquired in a manner consistent with the Commission's Electric Competition Rules. We generally support the request of APS to defer those costs related to formation of a new generation affiliate pursuant to the Electric Competition Rules. We also recognize the Company is making a business decision to transfer the generation assets to an affiliate instead of an unrelated third party. As a result, we find the Company's proposed mitigation of stranded costs[5] in the Settlement should also apply to the costs of forming the new generation affiliate. Accordingly, Section 2.6(3) should be modified to reflect that only 67 percent of those costs to transfer generation assets to an affiliate shall be allowed to be deferred for future collection.

Some parties were concerned that Sections 4.1 and 4.2 provide in effect that the Commission will have approved in advance any proposed financing arrangements associated with future transfers of "competitive services" assets to an affiliate. As a result, there was a recommendation that the Commission retain the right to review and approve or reject any proposed financing arrangements. In addition, some parties expressed concern that APS has not definitively described the assets it will retain and which it will transfer to an affiliate.

We share the concerns that the non-competitive portion of APS not subsidize the spun-off competitive assets through an unfair financial arrangement. We want to make it clear that the Commission will closely scrutinize the capital structure of APS at its 2004 rate case and make any necessary adjustments. The Commission supports and authorizes the transfer by APS to an affiliate or affiliates of all its generation and competitive electric service assets as set forth in the Agreement no later than December 31, 2002. However, we will require the Company to provide the Commission with a specific list of any assets to be so transferred, along with their net book values at the time of transfer, at least thirty days prior to the actual transfer. The Commission reserves the right to verify whether such specific assets are for the provision of generation and other competitive electric services or whether there are additional APS assets that should be so transferred.

Unbundled Rates

Several parties expressed concern that the Agreement's unbundled rates fail to provide the

[5] Agreement to not recover $183 million out of a claimed $533 million.

1 necessary information to determine whether a competitor's price is lower than the Standard Offer
2 rate. Further, some of the parties asserted that APS has not performed a functional cost-of-service
3 study and as a result the Settlement's "shopping credit" is an artificial division of costs. In response,
4 APS indicated the Standard Offer rates can not be unbundled on a strict cost-of-service basis unless
5 the Standard Offer rates are redesigned to equal cost-of-service. APS opined that such a process
6 would result in significant rate increases for many customers.

7 AECC asserted that a full rate case would result in additional months/years of delay with
8 continued drain of resources by all interested entities.

9 The ESPs asserted that the bill format proposed by APS is misleading and too complex. In
10 general, the ESPs desired a bill format that would allow customers to easily compare Standard Offer
11 and Direct Access charges in order to make an informed decision. As a result, APS was directed to
12 circulate an Informational Unbundled Standard Offer Bill ("Bill") to the parties for comments.
13 Subsequent to the hearing, a Bill was circulated to the parties for comments to determine what
14 consensus could be reached on its format. In general, there was little dispute with the format of the
15 Bill. However, PG&E and Commonwealth disagreed with the underlying cost allocation
16 methodologies. Enron was concerned that the Bill portrayed the Standard Offer to be more simplistic
17 than the Direct Access portion of the Bill. Enron proposed a bill format that would clearly identify
18 those services which are available from an ESP. Based on comments from RUCO and Staff, APS
19 made general revisions to the proposed Bill.

20 We find the APS Attachment AP-1R, second revised dated 8/16/99 provides sufficient
21 information in a concise manner to enable customers to make an informed choice. (See Attachment
22 No. 2 herein). However, we find the Enron breakdown into a Part 1 versus Parts 2 and 3 will further
23 help educate customers as to choice. We will direct APS to further revise its Bill to have a Part 1 as
24 set forth by the Enron breakdown. We believe Parts 2 and 3 can be combined for simplicity.

25 We concur with APS that it is not necessary to file a revised cost-of-service study at this time.
26 The proposed Standard Offer rates contained in the Settlement are based on existing tariffs approved
27 by this Commission. Further, we concur with AECC that a full rate case with a revised cost-of-
28 service study would result in months/years of additional delay. Lastly, the Standard Offer rates as

proposed in the Settlement are consistent with the Commission's requirement that no customer shall receive a rate increase. The following was extracted from Decision No. 61677:

> "No customer or customer class shall receive a rate increase as a result of stranded cost recovery by an Affected Utility under any of these options."

Code of Conduct

There were concerns expressed that APS would be writing its own Code of Conduct. Subsequently, APS did provide a copy of its proposed Code of Conduct to the parties for comment. Several parties also expressed concern that any Code of Conduct would not cover the actions of a single company during the two-year delay for transferring generation assets.

Based on the above, we will direct APS to file with the Commission no later than 30 days of the date of this Decision, its interim Code of Conduct. We will direct APS to file its revised Code of Conduct within 30 days of the date of this Decision. Such Code of Conduct should also include provisions to govern the supply of generation during the two-year period of delay for the transfer of generation assets so that APS doesn't give itself an undue advantage over the ESPs. All parties shall have 60 days from the date of this Decision to provide their comments to APS regarding the revised Code of Conduct. APS shall file its final proposed Code of Conduct within 90 days of the date of this Decision. Subsequently, within 10 days of filing the Code of Conduct, the Hearing Division shall establish a procedural schedule to hear the matter.

Section 2.6(1)

Pursuant to the Agreement, the Commission shall approve an adjustment clause or clauses which among other things would provide for a purchased power adjustor ("PPA") for service after July 1, 2004 for Standard Offer obligations. Part of the justification for the PPA was the fact that these costs would be outside of the Company's control.

We concur that a PPA would result in less risk to the Company resulting in lower costs for the Standard Offer customers. As a result, we will approve the concept of the PPA as set forth in Section 2.6(1) with the understanding that the Commission can eliminate the PPA once the Commission has provided reasonable notice to the Company.

...

Requested Waivers

Section 4.3 of the Agreement would automatically act to exempt APS and its affiliates from the application of a wide range of provisions under A.R.S. Title 40. In addition, under Section 4.5 of the Agreement, Commission approval without modification will act to grant certain waivers to APS and its affiliates of a variety of the provisions of the Commission's affiliate interest rules (A.A.C. R14-2-801, *et seq.*), and the rescission of all or portions of certain prior Commission decisions.

Staff recommended that the Commission reserve its approval of the requested statute waivers until such time as their applicability can be evaluated on an industry-wide basis, rather than providing a blanket exemption for APS and its affiliates. Additionally, Staff recommended that the Commission not waive the applicability of A.A.C. R14-2-804(A), in order to preserve the regulatory authority needed by the Commission to justify approving Exempt Wholesale Generator ("EWG") status for APS' generation affiliate.

We concur with Staff. Accordingly, the requested statutory waivers shall not be granted by this Decision. Those waivers will be considered in an industry-wide proceeding to be scheduled at the Commission's earliest convenience. The requested waivers of affiliate interest rules and rescission of prior Commission decisions shall be granted, except that the provisions of A.A.C. R14-2-804(A) shall not be waived.

ANALYSIS/SUMMARY

Consistent with our determination in Decision No. 60977, the following primary objectives need to be taken into consideration in deciding the overall stranded cost issue:

A. Provide the Affected Utilities a reasonable opportunity to collect 100 percent of their unmitigated stranded costs;

B. Provide incentives for the Affected Utilities to maximize their mitigation effort;

C. Accelerate the collection of stranded costs into as short of a transition period as possible consistent with other objectives;

D. Minimize the stranded cost impact on customers remaining on the standard offer;

E. Don't confuse customers as to the bottom line; and

F. Have full generation competition as soon as possible.

The Commission also recognized in Decision No. 60977 that the aforementioned objectives were in conflict. Part of that conflict is reflected in the following language extracted from Decision No. 60977:

> One of the main concerns expressed over and over by various consumer groups was that the small consumers would end up with higher costs during the transition phase and all the benefits would flow to the larger users. At the time of the hearing, there had been minimal participation in California by residential customers in the competitive electric market place. It is not the Commission's intent to have small consumers pay higher short-term costs in order to provide lower costs for the larger consumers. Accordingly, we will place limitations on stranded cost recovery that will minimize the impact on the standard offer.

Decision No. 61677 modified Decision No. 60977 and allowed each Affected Utility to chose from five options.

With the modifications contained herein, we find the overall Settlement satisfies the objectives set forth in Decision Nos. 60977 and 61677. We believe the Settlement will result in an orderly process that will have real rate reductions[6] during the transition period to a competitive generation market. The Settlement allows every APS customer to have the immediate opportunity to benefit from the change in market structure while maintaining reliability and certainty of delivery. Further, the Settlement in conjunction with the Electric Rules will provide every APS customer with a choice in a reasonable timeframe and in an orderly manner. If anything, the Proposed Settlement favors customers over competitors in the short run since APS has agreed to reductions in rates totaling 7.5 percent[7]. This Commission supports competition in the generation market because of increased benefits to customers, including lower rates and greater choice. While some of the potential competitors have argued that higher "shopping credits" will result in greater choice, we find that a higher shopping credit would also mean less of a rate reduction for APS customers. We find that the Settlement strikes the proper balance between competing objectives by allowing immediate

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[6] There have been instances in other states where customers were told they would receive rate decreases which were then offset by a stranded cost add-on.

[7] Pursuant to Decision No. 59601, dated April 24, 1996, 0.68 percent of that decrease would have occurred on July 1, 1999.

rate reductions while maintaining a relatively short transition period for collection of stranded costs, followed shortly thereafter with a full rate case. At that point in time the collection of stranded costs will be completed and unbundled rates can be modified based upon an updated cost study.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS is certificated to provide electric service as a public service corporation in the State of Arizona.

2. Decision No. 59943 enacted R14-2-1601 through –1616, the Retail Electric Competition Rules.

3. Following a hearing on generic issues related to stranded costs, the Commission issued Decision No. 60977, dated June 22, 1998.

4. Decision No. 61071 adopted the Emergency Rules on a permanent basis.

5. On August 21, 1998, APS filed its Stranded Costs plan.

6. On November 5, 1998, APS filed the Staff Settlement Proposal.

7. Our November 24, 1998 Procedural Order set the matter for hearing.

8. Decision No. 61259 established an expedited procedural schedule for evidentiary hearings on the Staff Settlement Proposal.

9. The Court issued a Stay of the Commission's consideration of the Staff Settlement Proposal.

10. Staff withdrew the Staff Settlement Proposal from Commission consideration.

11. On May 17, 1999, APS filed its Settlement requesting Commission approval.

12. Our May 25, 1999 Procedural Order set the Settlement for hearing commencing on July 14, 1999.

13. Decision No. 61311 (January 11, 1999) stayed the effectiveness of the Emergency Rules and related Decisions, and ordered the Hearing Division to conduct further proceedings in this Docket.

14. In Decision No. 61634 (April 23, 1999), the Commission adopted modifications to R14-2-201 through-207, -210 and 212 and R14-2-1601 through –1617.

15. Pursuant to Decision No. 61677, dated April 27, 1999, the Commission modified Decision No. 60977 whereby each Affected Utility could choose one of the following options: (a) Net Revenues Lost Methodology; (b) Divestiture/Auction Methodology; (c) Financial Integrity Methodology; (d) Settlement Methodology; and (e) the Alternative Methodology.

16. APS and other Affected Utilities filed with the Arizona Superior Court various appeals of Commission Orders adopting the Competition Rules and related Stranded Cost Decisions (the "Outstanding Litigation").

17. Pursuant to Decision No. 61677, APS, RUCO, AECC, and ACAA entered into the Settlement to resolve numerous issues, including stranded costs and unbundled tariffs.

18. The difference between market based prices and the cost of regulated power has been generally referred to as stranded costs.

19. Any stranded cost recovery methodology must balance the interests of the Affected Utilities, ratepayers, and the move toward competition.

20. All current and future customers of the Affected Utilities should pay their fair share of stranded costs.

21. Pursuant to the terms of the Settlement Agreement, APS has agreed to the modification of its CC&N in order to implement competitive retail access in its Service Territory.

22. The Settlement Agreement provides for competitive retail access in APS' Service Territory, establishes rate reductions for all APS customers, sets a mechanism for stranded cost recovery, resolves contentious litigation, and therefore, is in the public interest and should be approved.

23. The information and formula for rate reductions contained in Exhibit AP-3 Appended to APS Exhibit No. 2 provides current financial support for the proposed rates.

24. RUCO, ACAA, and AECC collectively, represent residential and non-residential customers.

25. According to AECC, the Agreement results in higher shopping credits than in the Staff

Settlement Proposal as well as those offered by SRP.

26. The decremental approach for metering and billing will not provide sufficient credits for competitors to compete.

27. Pursuant to the Settlement, customers will receive substantial rate reductions without the necessity of a full rate case.

28. An APS rate case would take a minimum of one year to complete.

29. ESPs that have been certificated have shown more of an interest in serving larger business customers than residential customers.

30. It is not in the public or customers' interests to forego guaranteed Standard Offer rate reductions in order to have a higher shopping credit.

31. The Settlement will permit competition in a timely and efficient manner and insure all customers benefit during the transition period.

32. Based on the evidence presented, the FVRB and FVROR of APS is determined to be $5,195,675,000 and 6.63 percent, respectively.

33. The terms and conditions of the Settlement Agreement as modified herein are just and reasonable and in the public interest.

CONCLUSIONS OF LAW

1. The Affected Utilities are public service corporations within the meaning of the Arizona Constitution, Article XV, under A.R.S. §§ 40-202, -203, -250, -321, -322, -331, -336, -361, -365, -367, and under the Arizona Revised Statutes, Title 40, generally.

2. The Commission has jurisdiction over the Affected Utilities and of the subject matter contained herein.

3. Notice of the proceeding has been given in the manner prescribed by law.

4. The Settlement Agreement as modified herein is just and reasonable and in the public interest and should be approved.

5. APS should be authorized to implement its Stranded Cost Recovery Plan as set forth in the Settlement Agreement.

6. APS' CC&N should be modified in order to permit competitive retail access in APS'

CC&N service territory.

7. The requested statutory waivers should not be granted at this time. A proceeding should be commenced to consider statutory waivers on an industry-wide basis. The other waivers requested by APS in the Settlement should be granted as modified herein, except that the provisions of A.A.C. R14-2-804(A) shall not be waived.

ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement as modified herein is hereby approved and all Commission findings, approvals and authorizations requested therein are hereby granted.

IT IS FURTHER ORDERED that Arizona Public Service Company's CC&N is hereby modified to permit competitive retail access consistent with this Decision and the Competition Rules.

IT IS FURTHER ORDERED that within 30 days of the date of this Decision, Arizona Public Service Company shall file a proposed Code of Conduct for Commission approval.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file a revised Settlement Agreement consistent with the modifications herein.

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IT IS FURTHER ORDERED that within ten days of the date the proposed Code of Conduct is filed, the Hearing Division shall issue a Procedural Order setting a procedural schedule for consideration of the Code of Conduct.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 6th day of October, 1999.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT _____
JLR:dap

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NOS.: E-01345A-98-0473, E-01345A-97-0773 and RE-00000C-94-0165

Service List for RE-00000C-94-0165

Paul A. Bullis, Chief Counsel
LEGAL DIVISION
1200 W. Washington Street
Phoenix, Arizona 85007

Utilities Division Director
ARIZONA CORPORATION COMMISSION
1200 W. Washington Street
Phoenix, Arizona 85007

ATTACHMENT 1

SETTLEMENT AGREEMENT

May 14, 1999

This settlement agreement ("Agreement") is entered into as of May 14, 1999, by Arizona Public Service Company ("APS" or the "Company") and the various signatories to this Agreement (collectively, the "Parties") for the purpose of establishing terms and conditions for the introduction of competition in generation and other competitive services that are just, reasonable and in the public interest.

INTRODUCTION

In Decision No. 59943, dated December 26, 1996, the Arizona Corporation Commission ("ACC" or the "Commission") established a "framework" for introduction of competitive electric services throughout the territories of public service corporations in Arizona in the rules adopted in A.A.C. R14-2-1601 *et seq.* (collectively, "Electric Competition Rules" as they may be amended from time to time). The Electric Competition Rules established by that order contemplated future changes to such rules and the possibility of waivers or amendments for particular companies under appropriate circumstances. Since their initial issuance, the Electric Competition Rules have been amended several times and are currently stayed pursuant to Decision No. 61311, dated January 5, 1999. During this time, APS, Commission Staff and other interested parties have participated in a number of proceedings, workshops, public comment sessions and individual negotiations in order to further refine and develop a restructured utility industry in Arizona that will provide meaningful customer choice in a manner that is just, reasonable and in the public interest.

This Agreement establishes the agreed upon transition for APS to a restructured entity and will provide customers with competitive choices for generation and certain other retail services. The Parties believe this Agreement will produce benefits for all customers through implementing customer choice and providing rate reductions so that the APS service territory may benefit from economic growth. The Parties also believe this Agreement will fairly treat APS and its shareholders by providing a reasonable opportunity to recover prudently incurred investments and costs, including stranded costs and regulatory assets.

Specifically, the Parties believe the Agreement is in the public interest for the following reasons. First, customers will receive substantial rate reductions. Second, competition will be promoted through the introduction of retail access faster than would have been possible without this Agreement and by the functional separation of APS' power production and delivery functions. Third, economic development and the environment will

benefit through guaranteed rate reductions and the continuation of renewable and energy efficiency programs. Fourth, universal service coverage will be maintained through APS' low income assistance programs and establishment of "provider of last resort" obligations on APS for customers who do not wish to participate in retail access. Fifth, APS will be able to recover its regulatory assets and stranded costs as provided for in this Agreement without the necessity of a general rate proceeding. Sixth, substantial litigation and associated costs will be avoided by amicably resolving a number of important and contentious issues that have already been raised in the courts and before the Commission. Absent approval by the Commission of the settlement reflected by this Agreement, APS would seek full stranded cost recovery and pursue other rate and competitive restructuring provisions different than provided for herein. The other Parties would challenge at least portions of APS' requested relief, including the recovery of all stranded costs. The resulting regulatory hearings and related court appeals would delay the start of competition and drain the resources of all Parties.

NOW, THEREFORE, APS and the Parties agree to the following provisions which they believe to be just, reasonable and in the public interest:

TERMS OF AGREEMENT

ARTICLE I
IMPLEMENTATION OF RETAIL ACCESS

1.1. The APS distribution system shall be open for retail access on July 1, 1999; provided, however, that such retail access to electric generation and other competitive electric services suppliers will be phased in for customers in APS' service territory in accordance with the proposed Electric Competition Rules, as and when such rules become effective, with an additional 140 MW being made available to eligible non-residential customers. The Parties shall urge the Commission to approve Electric Competition Rules, at least on an emergency basis, so that meaningful retail access can begin by July 1, 1999. Unless subject to judicial or regulatory restraint, APS shall open its distribution system to retail access for all customers on January 1, 2001.

1.2. APS will make retail access available to residential customers pursuant to its December 21, 1998, filing with the Commission.

1.3. The Parties acknowledge that APS' ability to offer retail access is contingent upon numerous conditions and circumstances, a number of which are not within the direct control of the Parties. Accordingly, the Parties agree that it may become necessary to modify the terms of retail access to account for such factors, and they further agree to address such matters in good faith and to cooperate in an effort to propose joint resolutions of any such matters.

1.4. APS agrees to the amendment and modification of its Certificate(s) of Convenience and Necessity to permit retail access consistent with the terms of this Agreement. The Commission order adopting this Agreement shall constitute the necessary Commission Order amending and modifying APS' CC&Ns to permit retail access consistent with the terms of this Agreement.

ARTICLE II
RATE MATTERS

2.1. The Company's unbundled rates and charges attached hereto as Exhibit A will be effective as of July 1, 1999. The Company's presently authorized rates and charges shall be deemed its standard offer ("Standard Offer") rates for purposes of this Agreement and the Electric Competition Rules. Bills for Standard Offer service shall indicate individual unbundled service components to the extent required by the Electric Competition Rules.

2.2. Future reductions of standard offer tariff rates of 1.5% for customers having loads of less than 3 MW shall be effective as of July 1, 1999, July 1, 2000, July 1, 2001, July 1, 2002, and July 1, 2003, upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases. For customers having loads greater than 3 MW served on Rate Schedules E-34 and E-35, Standard Offer tariff rates will be reduced: 1.5%, effective July 1, 1999; 1.5% effective July 1, 2000; 1.25% effective July 1, 2001; and .75% effective July 1, 2002. The 1.5% Standard Offer rate reduction to be effective July 1, 1999, includes the rate reduction otherwise required by Decision No. 59601. Such decreases shall become effective by the filing with and acceptance by the Commission of revised tariff sheets reflecting each decrease.

2.3. Customers greater than 3 MW who choose a direct access supplier must give APS one year's advance notice before being eligible to return to Standard Offer service.

2.4. Unbundled rates shall be reduced in the amounts and at the dates set forth in Exhibit A attached hereto upon the filing and Commission acceptance of revised tariff sheets reflecting such decreases.

2.5. This Agreement shall not preclude APS from requesting, or the Commission from approving, changes to specific rate schedules or terms and conditions of service, or the approval of new rates or terms and conditions of service, that do not significantly affect the overall earnings of the Company or materially modify the tariffs or increase the rates approved in this Agreement. Nothing contained in this Agreement shall preclude APS from filing changes to its tariffs or terms and conditions of service which are not inconsistent with its obligations under this Agreement.

2.6. Notwithstanding the rate reduction provisions stated above, the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which

will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent costs of the following:

(1) APS' "provider of last resort" and Standard Offer obligations for service after July 1, 2004, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(2) Standard Offer service to customers who have left Standard Offer service or a special contract rate for a competitive generation supplier but who desire to return to Standard Offer service, which costs shall be recovered only from Standard Offer and "provider of last resort" customers;

(3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS; and

(4) Commission-approved system benefit programs or levels not included in Standard Offer rates as of June 30, 1999, which costs shall be recovered from all customers receiving services from APS.

By June 1, 2002, APS shall file an application for an adjustment clause or clauses, together with a proposed plan of administration, and supporting testimony. The Commission shall thereafter issue a procedural order setting such adjustment clause application for hearing and including reasonable provisions for participation by other parties. The Commission order approving the adjustment clauses shall also establish reasonable procedures pursuant to which the Commission, Commission Staff and interested parties may review the costs to be recovered. By June 30, 2003, APS will file its request for the specific adjustment clause factors which shall, after hearing and Commission approval, become effective July 1, 2004. APS shall be allowed to defer costs covered by this Section 2.6 when incurred for later full recovery pursuant to such adjustment clause or clauses, including a reasonable return.

2.7. By June 30, 2003, APS shall file a general rate case with prefiled testimony and supporting schedules and exhibits; provided, however, that any rate changes resulting therefrom shall not become effective prior to July 1, 2004.

2.8. APS shall not be prevented from seeking a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as the inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission regulated services resulting from federal, tribal,

state or local laws, regulatory requirements, judicial decision, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

ARTICLE III
REGULATORY ASSETS AND STRANDED COSTS

3.1. APS currently recovers regulatory assets through July 1, 2004, pursuant to Commission Decision No. 59601 in accordance with the provisions of this Agreement.

3.2. APS has demonstrated that its allowable stranded costs after mitigation (which result from the impact of retail access), exclusive of regulatory assets, are at least $533 million net present value.

3.3. The Parties agree that APS should not be allowed to recover $183 million net present value of the amounts included above. APS shall have a reasonable opportunity to recover $350 million net present value through a competitive transition charge ("CTC") set forth in Exhibit A attached hereto. Such CTC shall remain in effect until December 31, 2004, at which time it will terminate. If by that date APS has recovered more or less than $350 million net present value, as calculated in accordance with Exhibit B attached hereto, then the nominal dollars associated with any excess recovery/under recovery shall be credited/debited against the costs subject to recovery under the adjustment clause set forth in Section 2.6(3).

3.4. The regulatory assets to be recovered under this Agreement, after giving effect to the adjustments set forth in Section 3.3, shall be amortized in accordance with Schedule C of Exhibit A attached hereto.

3.5. Neither the Parties nor the Commission shall take any action that would diminish the recovery of APS' stranded costs or regulatory assets provided for herein. The Company's willingness to enter into this Agreement is based upon the Commission's irrevocable promise to permit recovery of the Company's regulatory assets and stranded costs as provided herein. Such promise by the Commission shall survive the expiration of the Agreement and shall be specifically enforceable against this and any future Commission.

ARTICLE IV
CORPORATE STRUCTURE

4.1. The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until

December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

4.2. Approval of this Agreement by the Commission shall be deemed to constitute all requisite Commission approvals for (1) the creation by APS or its parent of new corporate affiliates to provide competitive services including, but not limited to, generation sales and power marketing, and the transfer thereto of APS' generation assets and competitive services, and (2) the full and timely recovery through the adjustment clause referred to in Section 2.6 above for all of the reasonable and prudent costs so incurred in separating competitive generation assets and competitive services as required by proposed A.A.C. R14-2-1615, exclusive of the costs of transferring the APS power marketing function to an affiliate. The assets and services to be transferred shall include the items set forth on Exhibit C attached hereto. Such transfers may require various regulatory and third party approvals, consents or waivers from entities not subject to APS' control, including the FERC and the NRC. No Party to this Agreement (including the Commission) will oppose, or support opposition to, APS requests to obtain such approvals, consents or waivers.

4.3. Pursuant to A.R.S. § 40-202(L), the Commission's approval of this Agreement shall exempt any competitive service provided by APS or its affiliates from the application of various provisions of A.R.S. Title 40, including A.R.S. §§ 40-203, 40-204(A), 40-204(B), 40-248, 40-250, 40-251, 40-285, 40-301, 40-302, 40-303, 40-321, 40-322, 40-331, 40-332, 40-334, 40-365, 40-366, 40-367 and 40-401.

4.4. APS' subsidiaries and affiliates (including APS' parent) may take advantage of competitive business opportunities in both energy and non-energy related businesses by establishing such unregulated affiliates as they deem appropriate, which will be free to operate in such places as they may determine. The APS affiliate or affiliates acquiring APS' generating assets may be a participant in the energy supply market within and outside of Arizona. Approval of this Agreement by the Commission shall be deemed to include the following specific determinations required under Sections 32(c) and (k)(2) of the Public Utility Holding Company Act of 1935:

> APS or an affiliate is authorized to establish a subsidiary company, which will seek exempt wholesale generator ("EWG") status from the Federal Energy Regulatory Commission, for the purposes of acquiring and owning Generation Assets.
>
> The Commission has determined that allowing the Generation Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

The Commission has sufficient regulatory authority, resources and access to the books and records of APS and any relevant associate, affiliate, or subsidiary company to exercise its duties under Section 32(k) of PUHCA.

APS will purchase any electric energy from its EWG affiliate at market based rates. This Commission has determined that (1) the proposed transaction will benefit consumers and does not violate Arizona law; (2) the proposed transaction will not provide APS' EWG affiliate an unfair competitive advantage by virtue of its affiliation with APS; (3) the proposed transaction is in the public interest.

The APS affiliate or affiliates acquiring APS' generating assets will be subject to regulation by the Commission, to the extent otherwise permitted by law, to no greater manner or extent than that manner and extent of Commission regulation imposed upon other owners or operators of generating facilities.

4.5. The Commission's approval of this Agreement will constitute certain waivers to APS and its affiliates (including its parent) of the Commission's existing affiliate interest rules (A.A.C. R14-2-801, *et seq.*), and the rescission of all or portions of certain prior Commission decisions, all as set forth on Exhibit D attached hereto.

4.6. The Parties reserve their rights under Sections 205 and 206 of the Federal Power Act with respect to the rates of any APS affiliate formed under the provisions of this Article IV.

ARTICLE V
WITHDRAWAL OF LITIGATION

5.1. Upon receipt of a final order of the Commission approving this Agreement that is no longer subject to judicial review, APS and the Parties shall withdraw with prejudice all of their various court appeals of the Commission's competition orders.

ARTICLE VI
APPROVAL BY THE COMMISSION

6.1. This Agreement shall not become effective until the issuance of a final Commission order approving this Agreement without modification on or before August 1, 1999. In the event that the Commission fails to approve this Agreement without modification according to its terms on or before August 1, 1999, any Party to this Agreement may withdraw from this Agreement and shall thereafter not be bound by its provisions; provided, however, that if APS withdraws from this Agreement, the Agreement shall be null and void and of no further force and effect. In any event, the rate reduction provisions of this Agreement shall not take effect until this Agreement is approved. Parties so withdrawing shall be free to pursue

their respective positions without prejudice. Approval of this Agreement by the Commission shall make the Commission a Party to this Agreement and fully bound by its provisions.

6.2. The Parties agree that they shall make all reasonable and good faith efforts necessary to (1) obtain final approval of this Agreement by the Commission, and (2) ensure full implementation and enforcement of all the terms and conditions set forth in this Agreement. Neither the Parties nor the Commission shall take or propose any action which would be inconsistent with the provisions of this Agreement. All Parties shall actively defend this Agreement in the event of any challenge to its validity or implementation.

ARTICLE VII
MISCELLANEOUS MATTERS

7.1. To the extent any provision of this Agreement is inconsistent with any existing or future Commission order, rule or regulation or is inconsistent with the Electric Competition Rules as now existing or as may be amended in the future, the provisions of this Agreement shall control and the approval of this Agreement by the Commission shall be deemed to constitute a Commission-approved variation or exemption to any conflicting provision of the Electric Competition Rules.

7.2. The provisions of this Agreement shall be implemented and enforceable notwithstanding the pendency of a legal challenge to the Commission's approval of this Agreement, unless such implementation and enforcement is stayed or enjoined by a court having jurisdiction over the matter. If any portion of the Commission order approving this Agreement or any provision of this Agreement is declared by a court to be invalid or unlawful in any respect, then (1) APS shall have no further obligations or liability under this Agreement, including, but not limited to, any obligation to implement any future rate reductions under Article II not then in effect, and (2) the modifications to APS' certificates of convenience and necessity referred to in Section 1.4 shall be automatically revoked, in which event APS shall use its best efforts to continue to provide noncompetitive services (as defined in the proposed Electric Competition Rules) at then current rates with respect to customer contracts then in effect for competitive generation (for the remainder of their term) to the extent not prohibited by law and subject to applicable regulatory requirements.

7.3. The terms and provisions of this Agreement apply solely to and are binding only in the context of the purposes and results of this Agreement and none of the positions taken herein by any Party may be referred to, cited or relied upon by any other Party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose except in furtherance of the purposes and results of this Agreement.

7.4. This Agreement represents an attempt to compromise and settle disputed claims regarding the prospective just and reasonable rate levels, and the terms and conditions

of competitive retail access, for APS in a manner consistent with the public interest and applicable legal requirements. Nothing contained in this Agreement is an admission by APS that its current rate levels or rate design are unjust or unreasonable.

7.5. As part of this Agreement, APS commits that it will continue the APS Community Action Partnership (which includes weatherization, facility repair and replacement, bill assistance, health and safety programs and energy education) in an annual amount of at least $500,000 through July 1, 2004. Additionally, the Company will, subject to Commission approval, continue low income rates E-3 and E-4 under their current terms and conditions.

7.6. APS shall actively support the Arizona Independent Scheduling Administrator ("AISA") and the formation of the Desert Star Independent System Operator. APS agrees to modify its OATT to be consistent with any FERC approved AISA protocols. The Parties reserve their rights with respect to any AISA protocols, including the right to challenge or seek modifications to, or waivers from, such protocols. APS shall file changes to its existing OATT consistent with this section within ten (10) days of Commission approval of this Agreement pursuant to Section 6.1.

7.7. Within thirty (30) days of Commission approval of this Agreement pursuant to Section 6.1, APS shall serve on the Parties an Interim Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company. APS shall voluntarily comply with this Interim Code of Conduct until the Commission approves a code of conduct for APS in accordance with the Electric Competition Rules that is concurrently effective with codes of conduct for all other Affected Utilities (as defined in the Electric Competition Rules). APS shall meet and confer with the Parties prior to serving its Interim Code of Conduct.

7.8. In the event of any disagreement over the interpretation of this Agreement or the implementation of any of the provisions of this Agreement, the Parties shall promptly convene a conference and in good faith shall attempt to resolve such disagreement.

7.9. The obligations under this Agreement that apply for a specific term set forth herein shall expire automatically in accordance with the term specified and shall require no further action for their expiration.

7.10. The Parties agree and recommend that the Commission schedule public meetings and hearings for consideration of this Agreement. The filing of this Agreement with the Commission shall be deemed to be the filing of a formal request for the expeditious issuance of a procedural schedule that establishes such formal hearings and public meetings as may be necessary for the Commission to approve this Agreement in accordance with

Exhibit A
5/10/99
DA-R1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-R1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

DECISION NO. 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$1.30 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/10/99
DA-GS1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$ month	$12.50			
Per kW over 5		$0.721		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

DECISION NO. 61973

A. RATE (continued)

November – May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$0.30 per month
Billing	$0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 – 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

Section 6.1 and that afford interested parties adequate opportunity to comment and be heard on the terms of this Agreement consistent with applicable legal requirements.

DATED at Phoenix, Arizona, as of this 14th day of May, 1999.

RESIDENTIAL UTILITY CONSUMER OFFICE

By Greg Patterson

Title Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Delivery & Sales

ARIZONA COMMUNITY ACTION ASSOCIATION

By Janet R. Regan

Title Executive Director

(Party) _____

By _____

Title _____

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,* a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, [redacted], Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, [redacted], Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, [redacted], and Arizona Retailers Association. **

By Peter A. Woog

Title CHAIRMAN

(Party) _____

By _____

Title _____

(Party) _____

By _____

Title _____

Enron is NOT a signatory to this Agreement

Also [illegible]

DECISION NO. 61973

Exhibit A
5/10/99
DA-GS10

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

NTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.
b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS11

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

1 1072

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS12

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
5/13/99
DA-GS13

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

A.C.C. No. XXXX
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: XXX XX, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$55.00 per month
Meter Reading	$ 0.30 per month
Billing	$ 0.30 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

ARIZONA PUBLIC SERVICE COMPANY

5/10/99
Schedule A

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of 1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

DOCKET NO. E-01345A-98-0473 ET AL.

1 of 2

ARIZONA PUBLIC SERVICE [illegible]ANY

Exhibit
5/13/
Schedule [illegible]

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004✓
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.3%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00732	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (BHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

✓ Transmission voltage customers will not pay Distribution Charges after June 30, 2004

DOCKET NO. E-01345A-98-0473 ET AL.

DECISION NO. 61973

Exhibit A
5/14/99
Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1]	Total [2]
164	158	145	115	86	18	686

[1] Amortization ends 6/30/2004

[2] Includes the disallowance from Section 3.3

DECISION NO. 61973

DOCKET NO. E-01345A-98-0473 ET AL.

5/7/99

EXHIBIT C

Generation assets include, but are not limited to, APS' interest in the following generating stations:

Palo Verde
Four Corners
Navajo
Cholla
Saguaro
Ocotillo
West Phoenix
Yucca
Douglas
Childs
Irving

including allocated common and general plant, support assets, associated land, fuel supplies and contracts, etc. Generation assets will not include facilities included in APS' FERC transmission rates.

Exhibit B

	Annual ACC Jurisdictional Sales of Delivered kWh or kW[1]	x % then Eligible for Access	x Applicable CTC (¢/kWh or $/kW[2])	= Annual Recovery[3]
1999	Residential	20	.93	
	General Service less than 3MW	20	2.43	
	General Service greater than 3MW	20	2.82	
	BHP Copper	20	1.54	
	Cyprus Copper	20	1.34	
	Ralston Purina	20	1.86	
2000	Residential	20	.84	
	General Service less than 3MW	20	2.20	
	General Service greater than 3MW	20	2.55	
	BHP Copper	20	1.53	
	Cyprus Copper	20	1.46	
	Ralston Purina	20	1.98	
2001	Residential	100	.63	
	General Service less than 3MW	100	1.66	
	General Service greater than 3MW	100	1.89	
	BHP Copper	100	1.06	
	Cyprus Copper	100	1.05	
	Ralston Purina	100	1.50	
2002	Residential	100	.56	
	General Service less than 3MW	100	1.46	
	General Service greater than 3MW	100	1.72	
	BHP Copper	100	.95	
	Cyprus Copper	100	.94	
	Ralston Purina	100	1.34	
2003	Residential	100	.50	
	General Service less than 3MW	100	1.30	
	General Service greater than 3MW	100	1.51	
	BHP Copper	100	.83	
	Cyprus Copper	100	.82	
	Ralston Purina	100	1.18	
2004	Residential	100	.36	
	General Service less than 3MW	100	.94	
	General Service greater than 3MW	100	1.09	
	BHP Copper	100	.61	
	Cyprus Copper	100	.61	
	Ralston Purina	100	.87	

[1] This formula assumes no change in APS' distribution service territory. In the event of any material change (e.g. by purchase, sale, expansion, condemnation, etc.) the formula will be adjusted such that APS receives the same opportunity to recover the agreed upon level of costs.
[2] General Service unmetered loads will have a demand calculated for CTC purposes based on contract energy.
[3] At the en[illegible] 2004 the net present value will be calculated to compare to the $350 millio[illegible]

EXHIBIT D

Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-804(A)

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

659323.01

ARIZONA PUBLIC SERVICE COMPANY

Informational Unbundling for Standard Offer
Proposed Standard Offer Bill

Sample Summer Bill on Rate E-12 at the Proposed 7/1/99 Rate Level
1.5% Overall Residential Class Decrease (1.68% decrease in energy charges from 9/1/98 Rate Level)

The following information is proposed to be shown on the customer's monthly bill:

Page 1, Standard Offer Bill Calculation:

Your total energy usage this month is: 991 kWh

Basic Service Charge	$ 7.50
Charge for kWh used	100.09
Regulatory Assessment	0.20
Sales Tax	7.06
TOTAL	$ 114.85

Page 2, Informational Unbundling:

Your total energy usage for this month is: 991 kWh
You Standard Offer Bill is (see page 1): $ 114.85

If you choose to receive competitive services from an Electric Service Provider, your APS bill on Rate DA-R1 for delivery service would include:

Metering Service:	$ 1.30	
Meter Reading Service:	0.30	
Billing Service:	0.30	
Distribution Service:	49.30	
System Benefits:	1.14	
Competitive Transition Charge:	9.22	
Regulatory Assessment:	0.12	
Sales Tax:	4.04	
Total Charges for APS Delivery Service Only:		$ 65.72
Transmission and Ancillary Services billed to your Electric Service Provider:		$ 5.09
Generation Services:		$ 44.04
Shopping Credit to purchase competitively supplied Generation and Transmission Service, including any applicable taxes and regulatory assessments		$ 49.13 or, 4.96 ¢/kWh

ATTACHMENT 2

DOCKET NO. E-01345A-98-0473 ET AL.

1 1072

Jana Van Ness
Manager
Regulatory Affairs

Tel 602/250-2310
Fax 602/250-3399
e-mail:jvanness@apsc.com
http://www.apsc.com

Mail Station 9909
P.O. Box 53999
Phoenix, AZ 85072-3999

RECEIVED
1999 DEC -1 P 3:48
AZ CORP COMMISSION
DOCUMENT CONTROL

December 1, 1999

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

RE: APS Settlement Proceeding
ACC Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165

Dear Sir or Madam:

Pursuant to the Opinion and Order, Decision No. 61973 in the above referenced Dockets, Arizona Public Service is filing an Addendum to the Settlement Agreement incorporating the modifications required by that Decision. This Addendum has been reviewed and executed by all signatories to the original APS Settlement Agreement.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness
Manager
State Regulations

Attachment

Cc: Docket Control (18 copies plus original)
Parties of Record

Addendum to Settlement Agreement

This Addendum is to the Settlement Agreement dated May 14, 1999 (hereafter "Agreement") between Arizona Public Service Company ("APS" or "Company") and the various signatories to the Agreement (collectively with APS, the "Parties"). By signing this Addendum to Settlement Agreement ("Addendum"), the Parties intend to revise certain provisions of the Agreement as directed by the Arizona Corporation Commission ("Commission") in Decision No. 61973 (October 6, 1999) ("Decision"). The Decision adopted and approved the Agreement subject to certain modifications.

I.
Introduction and Recitals

1. On May 14, 1999, the Parties entered into the Agreement;

2. On May 17, 1999, APS filed with the Commission a Notice of Filing Application for Approval of Settlement Agreement and Request for Procedural Order.

3. Commencing on July 14, 1999, and pursuant to a Procedural Order issued by the Hearing Division of the Commission, a full public evidentiary hearing on the Agreement was conducted.

4. On October 6, 1999, the Commission issued its Decision No. 61973 adopting and approving the Agreement as modified in the Decision.

5. The Parties now wish to enter into this Addendum to revise the Agreement as directed in the Decision.

II.
Addendum Agreement

1. <u>Metering, Meter Reading, and Billing Credits</u>

A. The Company's revised unbundled rates and charges reflecting the metering, meter reading, and billing credits required by the Decision are attached hereto as Revised Exhibit A.

B. The revised unbundled rates and charges in Revised Exhibit A to this Addendum are substituted for the corresponding tariffs in Exhibit A to the Agreement.

C. Schedules A through C of Exhibit A to the Agreement are not affected by this Addendum and were adopted and approved by the Commission in the Decision as originally proposed in the Agreement.

2. Advanced Notice for Large Customers. Section 2.3 of the Agreement is replaced with and superceded by the following provision:

> 2.3. Customers greater than 3 MW who choose a direct access supplier must either (a) give APS one year's advance notice before being eligible to return to Standard Offer service, or (b) pay APS for all additional costs incurred as a result of the customer returning to Standard Offer service without providing APS at least one year's advance notice.

3. Deferral of Transfer Costs. Section 2.6(3) of the Agreement is replaced with and superceded by the following provision:

> (3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS, provided however, that no more than sixty-seven percent (67%) of the costs to transfer generation assets to an affiliate or affiliates shall be allowed to be deferred for future collection under this provision; and

4. Rate Matters. Section 2.8 of the Agreement is replaced with and superceded by the following provision:

> 2.8. Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

5. Generation Affiliate. Section 4.1 of the Agreement is replaced with and superceded by the following provisions:

4.1. Affiliates.

(1) The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services and assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

(2) The affiliate or affiliates formed under this Section 4.1 shall be direct subsidiaries of Pinnacle West Capital Corporation, and not APS.

(3) After the extensions granted in this Section 4.1 have expired, APS shall procure generation for Standard Offer customers from the competitive market as provided for in the Electric Competition Rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS.

6. Statutory Waivers. Section 4.3 of the Agreement is deleted in its entirety.

7. Waivers of Affiliate Interest Rules. The Revised Exhibit D to this Addendum setting forth the Affiliate Rules Waivers is substituted for the corresponding Exhibit D to the Agreement so that the proposed waiver of R14-2-804(A) in the Agreement is deleted.

8. Conflicts with Electric Competition Rules. In reliance upon the Commission's directive in Decision No. 61973 (page 9) that "We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for," Section 7.1 is replaced with and superseded by the following provision:

> 7.1. Approval of this Agreement by the Commission shall constitute a waiver of any existing Commission order, rule or regulation to the extent necessary to permit performance of the Agreement, as approved by the Commission. Any future Commission order, rule or regulation shall be construed and administered, insofar as possible, in a manner so as not to conflict with the specific provisions of this Agreement, as approved by the Commission. In the event any of the Parties deems a future Commission order, rule or regulation to be inconsistent with the specific provisions of this Agreement, a waiver of the new Commission order, rule or regulation shall be sought.
>
> Nothing in this Agreement is intended to otherwise interfere with the Commission's ability to exercise its regulatory authority by the issuance of orders, rules or regulations. The requirements of this Agreement shall be performed in accordance with the Commission's Electric Competition Rules including any specific waivers granted by the Commission's order approving this Agreement, except where a specific provision of this Agreement would excuse compliance.

9. Interim Code of Conduct. Section 7.7 of the Agreement is replaced with and superceded by the following provision:

> 7.7. Within thirty (30) days of the date of the Commission decision approving this Agreement pursuant to Section 6.1, APS shall file an initial proposed Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company as required by the Electric Competition Rules and which includes provisions to govern the supply of generation during the two-year extension provided for by Section 4.1 of this Agreement. Interested parties may provide APS with comments on the initial proposed Code of Conduct within sixty (60) days of the date of the Commission decision approving this Agreement. APS will file a final proposed Code of Conduct for Commission approval within ninety (90) days of the date of the Commission decision approving this Agreement. Until the Commission approves a Code of Conduct for APS, APS will voluntarily comply with the initial proposed Code of Conduct or, once filed, the final proposed Code of Conduct.

10. Effect of Addendum. Other than as specifically modified by this Addendum, all provisions of the Agreement remain in full force and effect.

AGREED TO AS OF December 21, **1999:**

RESIDENTIAL UTILITY CONSUMER OFFICE

By Barbara Wytaske

Title Acting Director

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Title President Distribution Services

ARIZONA COMMUNITY ACTION ASSOCIATION

By Betty K Pruitt

Title Acting Executive Director

(Party)

By _____

Title _____

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs and Raytheon.

By _____

Title President

Stan Barnes

(Party)

By _____

Title _____

(Party)

By _____

Title _____

Revised
EXHIBIT D
Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

Recision of Prior Commission Orders

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

A. RATE (continued)

November - May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.
3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$7.62 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)

APPROVED AS TO FORM
DECISION NO. 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5351
Tariff or Schedule No. DA-GS1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June - October Billing Cycles (Summer)

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.7[illegible]		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		
Per kWh for the next 42,000 kWh		$0.02901		
Per kWh for all additional kWh		$0.01811		
Per all kWh			$0.00115	
Per all kW				$2.43

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 - 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING

DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5350
Tariff or Schedule No. DA-R1
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May – October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November – April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $10.00 per month

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61923

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION # 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5352
Tariff or Schedule No. DA-GS10
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.
2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.
3. Pursuant to A.A.C. R14-2-1612 K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.
b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

DECISION: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5395
Tariff or Schedule No. DA-GS11
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED [illegible]
DECISION # 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5396
Tariff or Schedule No. DA-GS12
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

Pursuant to A.A.C. R14-2-1612 K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DECISION #: 61973

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director, Pricing and Regulation

ORIGINAL

A.C.C. No. 5397
Tariff or Schedule No. DA-GS13
Original Tariff
Effective: October 1, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

(CONTINUED ON REVERSE SIDE)

APPROVED FOR FILING
DECISION #: 61973

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

APPROVED FOR FILING
DEC 2 [illegible] 61973

ARIZONA PUB[illegible] [illegible]VICE COMPANY

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of 1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$ 0.0093	$ 0.0084	$ 0.0063	$ 0.0056	$ 0.0050	$ 0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$ 0.0067	$ 0.0061	$ 0.0054	$ 0.0048	$ 0.0043	$ 0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases

ARIZONA PU[illegible] [illegible]CE COMPANY

...nibit A
5/13/99
Schedule B

Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004*
	Residential, DA-R1						
1	Summer per kWh	$ 0.04158	$ 0.04041	$ 0.03934	$ 0.03837	$ 0.03748	$ 0.03689
2	Winter per kWh	$ 0.03518	$ 0.03419	$ 0.03329	$ 0.03247	$ 0.03172	$ 0.03122
	DA-GS1 (Under 3 mW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
5	per kWh for the next 100 kWh per kW over 5	$ 0.04255	$ 0.04075	$ 0.03912	$ 0.03763	$ 0.03627	$ 0.03537
6	per kWh for the next 42,000 kWh	$ 0.02901	$ 0.02779	$ 0.02667	$ 0.02565	$ 0.02473	$ 0.02411
7	per kWh for all additional kWh	$ 0.01811	$ 0.01735	$ 0.01665	$ 0.01602	$ 0.01544	$ 0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
10	per kWh for the next 100 kWh per kW over 5	$ 0.03827	$ 0.03666	$ 0.03519	$ 0.03385	$ 0.03263	$ 0.03182
11	per kWh for the next 42,000 kWh	$ 0.02600	$ 0.02490	$ 0.02390	$ 0.02299	$ 0.02216	$ 0.02161
12	per kWh for all additional kWh	$ 0.01614	$ 0.01546	$ 0.01484	$ 0.01427	$ 0.01376	$ 0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 mW and Above)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$ 0.00999	$ 0.00943	$ 0.00892	$ 0.00845	$ 0.00802	$ 0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.4%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (Ralston Purina)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$ 0.00732	$ 0.00767	$ 0.00727	$ 0.00691	$ 0.00657	$ 0.00635
	DA-GS12 (BHP Copper)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$ 0.00665	$ 0.00651	$ 0.00611	$ 0.00585	$ 0.00561	$ 0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$ 0.00346	$ 0.00332	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227
	DA-GS13 (Cyprus Bagdad)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$ 0.00297	$ 0.00343	$ 0.00292	$ 0.00266	$ 0.00242	$ 0.00227

* Transmission voltage customers will not pay Distribution Charges after June 30, 2004

Exhibit A
5/14/99
Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004 [1/]	Total [2/]
164	158	145	115	86	18	686

[1/] Amortization ends 6/30/2004

[2/] Includes the disallowance from Section 3.3

Arizona Corporation Commission
DOCKETED
OCT 19 1999
DOCKETED BY

Commissioner Jim Irvin

Arizona Corporation Commission
Dissenting Opinion
Decision No. 61973
October 19, 1999

PRICING, REGULATION & RATE DESIGN
OCT 22
ARIZONA REGULATORY AGENCIES

Have you ever been promised a present, given a different one, and then asked to pay for it yourself? Well, that's what has happened to Arizona residential consumers and small businesses with the Commission's approval of the Arizona Public Service ("APS") settlement agreement/contract. In sum, Arizona consumers were promised robust competition, given a modest rate cut (actually, 6.83%), and then asked to pay for that rate cut to the tune of an additional *minimum* of $350 million dollars in stranded cost recovery for APS (plus an undetermined amount for "transition" costs associated with creating affiliates to handle competitive ventures). The parties to this settlement agreement are APS, AECC (a representative of industrial and commercial interests), the Residential Utility Consumer Office[1] (RUCO – a state utility "watchdog") and Arizona Community Action Association. Excluded from participating in the negotiations was the Arizona Corporation Commission, the Arizona Consumers Council and potential competitors of APS, like PG& E Energy Services, Commonwealth Energy and others. Such exclusions – as well as a lack of adequate representation for residential consumers – testify to the fact that this settlement agreement does not encompass the wide spectrum of interests it holds itself out to represent.

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[1] In the recent Auditor General's performance audit of RUCO, it states, "According to the act establishing RUCO, the agency is intended to represent the interests of residential consumers, critically analyze proposals made by public service corporations to the Commission, and formulate and present recommendations to the Commission." According to Greg Patterson – then Director – RUCO did not perform any type of critical analysis to determine whether the benefits to residential consumers are fair and

Consumers Promised Competition

When the Commission embarked on deregulation over five years ago, the primary purpose was to restructure the electric industry by introducing the generation portion of utility service to the wonders of the free marketplace – where robust competition would spark innovative technologies, and consumer choice would improve quality of service and drive rates downward. Incumbent monopolies such as APS fought hard and challenged the Commission's authority to change the regulatory paradigm, but so far these legal challenges have been unsuccessful.

On September 21, 1999 – as I promised voters in 1996 to help bring about competition in Arizona – I voted for a second time in favor of the Electric Competition Rules ("Rules") for the purpose of beginning the deregulation process; one that had been stalled earlier this year. While the Rules are not perfect, and while future Commissions will need to make adjustments to the Rules to assure a 'fair' competitive market, I believe they provide a framework where consumer and free-market interests enjoy some safeguards. However, only *two days* after these Rules were adopted, the Commission has now approved a settlement which, among other things, gives many "exemptions" and "waivers" from provisions in the Rules which conflict with the APS settlement contract.

When potential competitor after competitor testifies that the APS settlement agreement will not provide an appropriate atmosphere for competition within APS' service territory, it is our role as regulators to at least consider their arguments. Unfortunately, at least one Commissioner indicated he was unwilling to consider any amendment unless it was proposed by a party to the agreement. However, many

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reasonable in light of APS' stranded cost recovery figure, or whether the figures supplied by APS and AECC are accurate.

potential competitors – which are not parties to the settlement -- argue that the shopping credits provided for in the settlement are too low, a view supported by Commission Staff.

Staff opined that it had, "demonstrated that the proposed shopping credits were inadequate when considered in reference to each entire class of customers. The fact that one particular customer may experience an adequate shopping credit does not justify the Commission's approval when the referenced customer's usage characteristics are different than those of the class as a whole."[2] In fact, Staff argued that making a modification to the shopping credit would make it more likely that a competitive market can develop without increasing rate levels, and still allow the company to collect all its stranded costs. Not surprisingly, APS counsel stated during Open Meeting that any increase in the shopping credits would be a "dealbreaker." My proposed amendment was then subsequently voted down, as was the opportunity to develop a more competitive market in Arizona.

Consumers Given Modest Rate Cuts

One provision of the APS settlement agreement hailed by consumer groups such as RUCO is the modest 6.83% rate cut to residential Standard Offer customers. How RUCO came to this conclusion is unclear; its Director admitted during testimony that no critical financial analysis of *any portion* of the agreement was conducted by its staff. Timothy Hogan, who represents the Arizona Consumers Council (which is opposed to the settlement) asked the appropriate question; "Is it enough?" APS has not been through a full rate case since 1988, and this Commission has not undertaken the

[2] Staff's Exceptions to Recommended Order

process to determine if the company has been – or is currently – overearning profits. The population in the Phoenix metropolitan area has exploded since 1988, and one can ascertain that customer growth has mirrored that number as well. If the goal of this Commission was to get rate cuts for all consumers, a rate case certainly would have been less onerous and less expensive to all parties than the monumental effort to deregulate the generation portion of the electric industry.

More disturbing is the fact that these "guaranteed" rate cuts are not guaranteed at all. Of the 7.5% rate cut APS proposed, about one-tenth of that number was already ordered by this Commission in 1996. In addition, the company reserves the right to come back and seek changes to its rates prior to July 1, 2004 (the year the "guarantee" expires) in the event of an unforeseen event or an emergency. APS claims that these rate cuts will save all consumers close to $475 million dollars in savings during this transition period. However, Commission staff estimates that the savings are closer to $329 million dollars, with about $173 million going to residential consumers. Unfortunately, RUCO and ACAA conducted no analysis at all.

Customers Pay through Stranded Costs

"Stranded Cost Recovery" is a term artfully used by incumbent utilities to explain why consumers should have to pay them to change the system. Under the original Stranded Cost Order, incumbent utilities such as APS would have had to divest themselves of generation assets – a process which would give a clear indication to all parties of their value. However, the Rules were changed in April, 1999 to allow incumbent utilities to utilize *any* method outside divestiture to recover its stranded costs. In an article appearing in Forbes earlier this year entitled "Poor me," Christopher Palmeri

writes, "Not every state legislature or utility commission has the political will to force divestiture, however." After explaining how incumbent utilities often litigate the matter of stranded cost recovery as a tactic of delay, he writes, "For this reason, legislators and regulators sometimes feel like they need to cut some deal, any deal, just to get a competitive market moving forward." It is a tactic that has worked brilliantly for APS.

The argument advanced by APS is that in changing the regulatory paradigm from one of a monopoly system to a competitive marketplace, certain investments (such as generation plants) lose value. If anything, the market has shown throughout many states (CA, MA, NY, CN) that generation assets can be sold at nearly twice the book value of the plant.[3] Although APS contends that its generation assets are at least $533 million dollars over market value, how can the market value be determined when nothing has been offered for sale in Arizona?

The Commission has had a long standing practice (and one which I support) of allowing utilities' shareholders to keep fifty percent (50%) of any net profit of assets divested. The other fifty percent (50%) is returned to ratepayers who paid for those assets. So how does a utility get around this concept of "stranded benefit"? Instead of divesting themselves of the asset through the open market, they transfer it to an affiliate at "book value," thus bypassing any need to account for a net profit. Meanwhile, the asset still retains it higher "market value" and, if then sold by the generation affiliate, may fetch a hefty price. Only with divestiture can the open market determine whether a utility is left with "stranded costs" or "stranded benefits."

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[3] Palmeri writes, "According to data collected by Cambridge Energy Research Associates, the average nonnuclear power plant put up for sale last year sold for nearly twice its book value." Forbes

Another justification APS advances for the recovery of stranded costs is that "lost revenues" will result by losing current customers to new market entrants. If this is true, why did Pinnacle West Energy Corporation (an APS energy affiliate) announce plans to build and upgrade new generating facilities to meet the demands set by customer growth?[4] In its recent application to the Commission, Pinnacle West Energy Corporation writes:

> "The growth rate in electricity use has exceeded six percent a year for Arizona Public Service Company (APS) customers in Arizona. Growth in the metro-Phoenix area is expected to increase peak customer demand for power from 7,000 MW in 1999 to over 9,000 MW in 2005. In order to meet that need, new generating plants and transmission lines will be needed to import more power into the Valley."

And I thought consumers in Arizona were being asked to pay for "stranded costs" because of lower valued plants, in addition to APS' estimates on how many customers it stands to lose to new market entrants. APS Energy Services (an APS marketing affiliate) already markets power in other states such as California. So, while Arizona consumers are being asked to foot the bill for APS' stranded cost recovery, California consumers are being marketed "competitive" cost power by its affiliate.

Conclusions

1. The APS settlement contract does not promote competition. Rather, it protects the status quo, making Standard Offer Service more attractive to the average consumer and tougher for competitors to effectively compete within APS' service territory. Also, the shopping credits provided for in the agreement are too low.

[4] In 1988, APS' customer based was 582,003. In 1996, it was 717,614. In 1998, it had grown to 798,697. These figures are based on APS filed annual reports.

2. The aggregate 6.83% rate cut over the next four years is a modest figure considering that APS has not been through a rate case since 1988. Is it enough, given APS' rapid growth in its customer base since that time? And what about the so-called "guarantee," even though APS reserves the right to change its rates in the case of an emergency?

3. Parties to the agreement like RUCO did not perform a critical financial analysis of the proposal, either with regards to the consumer rate cuts or the stranded cost recovery for APS. Furthermore, they accepted the information provided by APS and AECC without analyzing its veracity.

4. APS has not proved it is entitled to its stranded cost recovery figure. Commission staff estimates that under the APS methodology, stranded cost recovery should be approximately $110 million dollars, far below the estimated figure of $533 million calculated by APS. Additionally, Arizona's Court of Appeals has ruled that utilities do not have a "regulatory compact" with the Commission, a concept advance by utilities to justify their reasons for stranded cost recovery.

5. The agreement provides for exemptions to APS to the recently passed Competition Rules; rules which attempt to bring about a level playing field to foster a competitive market in Arizona. Such exemptions render the protections for fair competition in the Rules meaningless.

6. Attempting to bind future Commissions to the "benefits" bargained for by the parties has been challenged as unconstitutional, and -- contrary to APS' assertions made in the settlement agreement – its adoption by this Commission will create *more* litigation rather than less litigation.

In my opinion, the APS agreement/contract passed today represents an affirmation of the status quo, does not promote competition through a leveled playing field, and contains rate cuts which could likely have been more if obtained through a rate case. Because the provisions contained therein are not in the public interest, I cannot vote in favor of the agreement, and must therefore dissent.

Jim Irvin, Commissioner
Arizona Corporation Commission

EXHIBIT
APS-2
admitted

REBUTTAL TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, *et al.*

June 11, 2002

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REBUTTAL TESTIMONY OF JACK E. DAVIS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, *et al.*)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jack E. Davis. My business address is 400 North Fifth Street, Phoenix, Arizona 85072. I am President of Energy Delivery and Sales for Arizona Public Service Company ("APS" or "Company"). I am also President of Pinnacle West Capital Corporation ("PWCC").

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS GENERIC PROCEEDING?

A. Yes. I submitted written testimony to the Arizona Corporation Commission ("Commission") on "Track A" issues in Docket No. E-00000A-02-0051 ("Generic Docket") on May 29, 2002. I have also filed both Direct and Rebuttal Testimony in Docket No. E-01345A-01-0822 ("Variance Docket"), which had previously been consolidated with the Generic Docket.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS GENERIC PROCEEDING?

A. My primary purpose is to relate to the Commission the potentially devastating impact of Utility Division Staff's ("Staff") recommendations as set forth in its May 29th testimony – devastating to the Company, to its customers and to the hopes for a competitive retail and wholesale market in Arizona. I also address the efforts of the merchant generator intervenors ("Merchant Intervenors") to both interject "Track B" issues into this "Track A" phase of the proceedings and to at the same time hobble their most formidable competition – the generation

comprising the "Dedicated Units" under the proposed purchase power agreement ("Proposed PPA"), which PPA is currently pending Commission consideration in the Variance Docket.[1] Finally, I will respond to specific contentions made by Staff and Intervenor witnesses.

Q. WILL APS PRESENT OTHER REBUTTAL WITNESSES IN THIS GENERIC PROCEEDING?

A. Yes. Dr. William Hieronymus will address the analyses of market power presented by Staff and Intervenor witnesses as well as the economic and policy flaws in Staff's recommendations. Dr. Charles Cicchetti will also address the latter, but from the special perspective of a former regulator. Finally, Mr. Cary Deise will rebut certain allegations against the Company's transmission system planning and operation made in Staff witness Jerry Smith's May 29th testimony and respond to allegations of "transmission market power" made by both Staff and Intervenor witnesses.

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. Procedurally, the adoption of Staff's recommendations will prevent the Commission from resolving any of the threshold issues identified by the Company in its Motion of April 19th prior to year's end, let alone within the time established by both the Commissioners themselves at the April 25, 2002 Special Open Meeting and by the Chief Administrative Law Judge's Procedural Order dated May 2, 2002. Many of the recommendations could not even be

[1] These consist of APS' present generation plus those Pinnacle West Energy Corporation ("PWEC") units constructed or being constructed to serve APS customers.

implemented in this docket because they would necessitate separate rulemaking proceedings.

Substantively, Staff would have this Commission undo virtually every provision and reverse virtually every finding from the 1999 APS Settlement Agreement ("1999 APS Settlement" or "Settlement"), excepting, of course, the rate reductions, the $234 million write-off and other concessions made by the Company in the course of such Settlement. Indeed, the very existence of the 1999 APS Settlement is barely acknowledged. As noted in my Rebuttal Testimony in the Variance Docket, this Settlement involved the Commission itself as a party and has been characterized as a binding contract with the Commission by the Arizona Court of Appeals. And in the place of the very Settlement that has allowed Arizona to move forward towards a restructured and competitive electric industry without the sort of economic disruptions that have erupted almost everywhere else in the Western United States, Staff proposes a bizarre and oppressive form of "regulated competition" that is neither competition nor traditional regulation and which will utterly fail to provide consumers the benefits of either regime. It is premised on a "lower of cost or market" philosophy that this Commission and others have repeatedly rejected and which is inherently unreasonable, inequitable and unsustainable.

Taken in combination with the suggestions of the Merchant Intervenors, Staff's recommendations are more likely to lead to a repeat of California than to the reliable service at just and reasonable rates that Staff professes to be its objective. This is because Staff's position represents a complete failure to recognize the essentials of a competitive market or to acknowledge the regulatory bargain inherent in traditional cost-of-service regulation.

Furthermore, Staff has ignored the practical aspects of efficiently and reliably planning and operating an electrical system, as is discussed at length in Mr. Deise's Rebuttal Testimony.

Staff's testimony is all the more puzzling to the Company because the very Proposed PPA that Staff has spent so much effort opposing would, in fact, answer many if not most of Staff's stated concerns. And although I am aware that the Commission has stayed proceedings in the Variance Docket, I would be doing the Company's customers a great disservice if I did not point this paradox out to the Commission in my Rebuttal Testimony.

While Staff's testimony was, to put it mildly, greatly disturbing, that of the Merchant Intervenors was, for the most part predictable, self-interested and procedurally inappropriate. The "Track A" issues about which they originally expressed no opinion back in December of 2001 now become a new source of leverage in "Track B." The PWEC that they bravely challenged to open competition in December 2001 now becomes some form of market "superpower" that must be restrained from meaningful competition with the Merchant Intervenors. Rather than support the Company's original request to resolve "Track A" and "Track B" issues in a single proceeding or acquiesce to the Commission's decision to address them separately, the Merchant Intervenors apparently want two turns at bat, once in this proceeding and another in the "Track B" proceeding. What is new is the Merchant Intervenors new-found interest in delay, since many of their proposals are so radically different than anything heretofore proposed in this jurisdiction that they could likely not be in place even by the summer of 2003. This is in stark contrast to a group that as

recently as April of this year urged the Commission to immediately order APS to begin competitive bidding.

Staff's continued disregard for the 1999 APS Settlement is obviously contagious. Residential Utility Consumer Office ("RUCO") witness Dr. Richard Rosen would have the Commission abandon competition and return to traditional regulation if the Commission is unwilling to consider a long-term buyback from the Dedicated Assets similar to that already before the Commission in the form of the Proposed PPA. Although a principled position in the abstract, it ignores that fact that Dr. Rosen's client is bound by the 1999 APS Settlement, which itself imposed no requirement for a PPA of any sort, let alone one as favorable to consumers as the Proposed PPA. Dr. Rosen also expresses concern that PWEC or Pinnacle West Marketing & Trading ("PWM&T") might engage in "capacity withholding" or "bid gaming" if unrestrained by a long-term PPA with APS. Although the Proposed PPA is in the interests of APS customers, a fact recognized by Dr. Rosen, even in its absence there is no reason to believe that APS affiliates would engage in such activities or that regulators, state and federal, would tolerate them.

Arizonans for Electric Choice and Competition ("AECC") witness Kevin Higgins generally presents a balanced recommendation that both recognizes AECC's responsibility to uphold the 1999 APS Settlement and urges appropriate vigilance regarding the wholesale electric market. While APS and the AECC will apparently continue to have disagreements over the particulars of the proposed PPA, we do not appear to have major disagreements in this phase of the Generic Docket, and thus I will not further address in any detail the AECC's testimony in the body of my Rebuttal Testimony. (Dr. Hiernoymus will,

however, discuss the new market power test proposed in Mr. Higgins' testimony.)

III. THE STAFF RECOMMENDATIONS

1. Lower of Cost or Market

Q. WHY DID YOU STATE IN YOUR SUMMARY THAT THE STAFF'S POSITION WAS PREMISED ON A "LOWER OF COST OR MARKET" PHILOSOPHY?

A. Staff's testimony is full of statements and recommendations that can only be characterized as promoting a rate-making philosophy that limits APS' recovery of power supply costs to the lower of (an undefined) cost-of-service or (an equally undefined) market price, regardless of the prudence of the Company's power supply acquisition policies. For example, in Staff witness Matthew Rowell's testimony at page 4, lines 6-7, Mr. Rowell states:

> Staff believes it is important to ensure that consumers are no worse off under the restructured environment than they were under traditional cost-of-service regulation. [Emphasis supplied.]

Of course, such assurance is impossible under a regulatory regime based on market pricing. Indeed, the most ardent supporter of competitive electric markets would not predict and could not promise that competitively-based electric prices would at all times and under all circumstances be below prices based on traditional utility cost-of-service principles.

Staff witness Barbara Keene is even more direct. She urges the Commission to adopt an expanded Code of Conduct that would require:

> for ratemaking purposes, sales or transfers from an affiliate should be priced at the lower of cost or market [emphasis supplied]."

See Testimony of Barbara Keene at page 8, lines 17-19. Ms. Keene would apparently include sales of power under this restriction because she criticizes the

FERC code of conduct for not encompassing such transactions. *Id.* at page 5, lines 21-23.

Q. WOULD STAFF LIMIT THIS APPLICATION OF A "LOWER OF COST OR MARKET" TO PURCHASES OF POWER FROM AN AFFILIATE SUCH AS PWM&T OR PWEC?

A. No. Mr. Rowell expands on the application of Staff's "lower of cost or market" philosophy at page 6, line 26 through page 7, line 13:

> Regardless of the provisions of rule 1606(B) the Commission Should consider measures that ensure that consumers are no worse off because of competitive procurement than they would have been under cost of service regulation. Specifically, during this transition period, the established cost of service should be used as both a standard for UDC [cost] recovery and as the price to beat for any competitive solicitation process. Staff recommends that prudence reviews of purchases by UDCs from their affiliates or others should use the already established cost of service of the assets the utility has chosen to transfer as the baseline for the prudence evaluation. Also, the established cost of service for the utilities' existing generation units should be used as the price to beat during competitive solicitations whether the utility has transferred its generation assets or not. Generally, Staff does not believe it appropriate for a UDC to procure power at a higher price than its own cost of service before transfer or its affiliate's cost of service after transfer. [Emphasis supplied.]

This passage appears to indicate that whether APS transfers its existing generation to PWEC or not, it will be limited to recovering the lower of those generating assets' "already established cost of service" (whatever that means) or the cost of procuring an equivalent amount of power in the market. In the divestiture case, this means that APS would not recover all its purchase power costs even if the latter was prudently acquired in conformance with Rule 1606(B) and fairly represented the then market price of power. Were APS to

retain its existing generation, this means that APS would not recover its cost-of-service unless market prices were continually above such cost-of-service for the entire remaining life of these generation assets.

Q. HOW LONG WOULD THESE COMMISSION-IMPOSED PRICE CAPS ON WHOLESALE POWER PRICES BE IN PLACE?

A. At page 7, lines 1-2, Mr. Rowell appears to limit the duration of these caps to some sort of unspecified "transition period," the length of which the Commission will determine through some unspecified process using some unspecified criteria. *Id.* at page 5, lines 17-20. However, Ms. Keene's testimony uses no such temporal limitation, and thus it would appear that affiliates of APS such as PWM&T and PWEC could be under permanent price caps as regards their sales to APS, or for so long as the current APS generation is in service.

Q. DOES STAFF PROVIDE ANY INSIGHT INTO HOW THIS "MARKET TO COST" COMPARISON WOULD BE MADE IN ACTUAL PRACTICE?

A. No. In fact, it looks like the comparison will be somewhat of a moving target. No guidance is given as to the time frame of the comparison, how disparate products will be compared, or how (in the generation asset retention case) market prices will be discovered. With the present lack of a consistent and developed market structure in the West, including Arizona, these questions, along with the determination of the "already established cost of service" (of the existing APS generating assets post-divestiture) will be - constant sources of debate and controversy.

Q. ARE SUCH PRICE CAPS CONSISTENT WITH A COMPETITIVE WHOLESALE MARKET?

A. No. Under a competitive price regime, the individual seller is entitled to the market price irrespective of its or any of its competitor's cost-of-service. There are neither price caps nor price floors. When market prices are high, producers (especially low-cost producers) earn higher profits. When market prices are low, earnings suffer and in the case of individual producers, may disappear altogether. It is precisely that earnings volatility that makes the cost-of-capital higher for competitive firms in competitive industries.

Q. DOES STAFF'S POSITION REPRESENT THE TRADITIONAL COST-OF-SERVICE REGULATION THAT ELECTRIC CONSUMERS AND UTILITIES HAVE OPERATED UNDER FOR THE PAST 90 YEARS?

A. No. Under such traditional regulation, utility producers are entitled to receive cost-of-service irrespective of market prices. Even when the market price is high, producers earn only their cost-of-capital. On the other hand, producers are protected from losses otherwise attributable to low market prices. In other words, regulation provides both a price floor and a price cap based on prudently incurred costs.

Q. DIDN'T FERC IMPOSE OR APPROVE PRICE CAPS ON MARKET-BASED RATES TO PROTECT CONSUMERS AGAINST PRICE VOLATILITY AND MARKET FAILURE?

A. Yes, and the wisdom of those decisions is a matter of considerable debate. All price caps in a competitive market are likely to disincent new investment and encourage uneconomic consumption. However, short to intermediate-term price caps for peak periods or when transmission is constrained and which are set well above the production costs of most market participants, which is what FERC has endorsed, are a far cry from what Staff is proposing, even assuming the Commission had the authority to impose wholesale price caps of any sort. Moreover, these FERC "price caps" do not apply to wholesale sellers under

traditional cost-of-service pricing, another important distinction from Staff's seeming position in this proceeding.

Q. ISN'T WHAT STAFF PROPOSES THE SAME AS THE OLD LEAST COST PLANNING REGULATION OF THE 80'S AND EARLY 90'S?

A. No, far from it. Least cost planning or integrated resource planning ("IRP") as it was sometimes called, was merely a regulatory tool for implementing traditional cost-of-service regulation. It was prospective rather than retrospective. IRP gave the regulator before-the-fact input, sometimes even final decision-making authority in the planning for new supply or demand-side resources. It also allowed regulators to require that such decisions be made in a specified fashion or that it incorporate specific types of resources (e.g., renewable generation, demand-side programs, etc.). IRP required the utility and the regulator to evaluate resource alternatives in terms of their expected present-value costs over the entire the planning horizon, usually 10-20 years. It was not a year-by-year after-the-fact comparison. Under IRP, once a specific resource decision was made, whether it be to build a new power plant of a certain type, or construct new transmission, or implement a demand management program, the prudent costs of that decision were recovered in rates even if the decision turned out to be more costly than some alternative course of action. IRP never guaranteed outcomes to electric customers, i.e., that the agreed upon resource decisions would be in fact least cost, only that the process by which such resource decisions were made was prudent and rational.

Q. DOES STAFF CITE ANY AUTHORITY OR PRECEDENT FOR THE LIMITATION OF RATE RECOVERY TO THE "LOWER OF COST OR MARKET?"

A. No. I am not aware of any jurisdiction in the United States, or for that matter, anywhere else that would suggest such a patently unfair and destructive form of confiscatory regulation. It would destroy the incentive for the new investment necessary to provide safe and reliable service under either a competitive or traditional regulation price regime. Since all power procurement decisions will result in a penalty to the UDC if anything at any time goes wrong for any reason ("wrong" being defined as being at a cost above some after-the-fact determination of "market"), decision-making itself will be paralyzed. Because retail prices under the "lower of cost or market" philosophy will, on average, always be below cost, uneconomic consumption of electricity will be inevitable and systemic. Just as certain is the ultimate destruction of the UDC's financial viability, unless of course, it abandons Standard Offer service altogether.

Q. HOW WILL SUCH A PRICING PHILOSOPHY DESTROY THE UDC'S FINANCIAL VIABILITY?

A. That should be obvious. If you go to Las Vegas and make a series of bets with only the prospect of getting your bet back when you win, but absorbing all losses when you lose, you will eventually go broke no matter what game you play or what betting strategy you employ. The only way to even beak even or cut your losses is to not play, which in the context of Staff's recommendation means to not offer Standard Offer service.

Let me give you a specific hypothetical example. APS enters into a PPA either with an affiliate or with one of the Merchant Intervenors for a five-year period. In four of the five years, PPA costs are anticipated to be below the "benchmark" cost of the Company's existing generation. (I have put aside for purposes of this hypothetical the difficulty in making such a comparison unless the products

being acquired through competitive bidding are comparable to the products to be provided from the existing generation portfolio.) The anticipated PPA costs are also lower on average for the entire five-year period. I interpret Mr. Rowell's testimony to mean that APS could only recover the actual cost of the PPA during the four years it was below the cost of the existing generation, but would be penalized during the fifth year. Worse yet, even when the PPA was anticipated to be below the cost of the existing generation for every year of this hypothetical five-year period, if (on an after-the-fact basis) the PPA ever turned out to be above such "benchmark" cost for any period of time, the Company would be likewise penalized. The same penalties would seemingly apply if the Company determined that it would retain its existing generation, and it later turned out that market prices were below the "benchmark" cost-of-service for any period of time during either the "transition period" or the remaining life of the retained generation.[2]

Such a punitive system of regulation would be inappropriate even if applied only prospectively, let alone to APS generating assets that have already been found to be prudent, to be used and useful and to have a "fair value" well in excess of cost. You don't have to be either a lawyer or an economist to label this scheme for what it is – the systematic confiscation of the value of the Company's property.

Q. DOES STAFF PURPORT TO ADDRESS THE POTENTIAL IMPACT OF THIS PROPOSAL ON THE FINANCIAL VIABILITY OF THE UTILITY DISTRIBUTION UTILITY ("UDC")?

[2] I say "seemingly" because Mr. Rowell's responses to the Company's data requests on this issue were somewhat confusing, ambiguous, and contradictory.

A. No. Similar to its later position on the Settlement, there is less than a sentence in all of Staff's testimony concerning the financial health of the UDC, and no analysis of the impact of its proposals on the ability of the Company to attract and retain capital or fund operations in a safe and reliable manner.

Q. HOW WILL STAFF'S "LOWER OF COST OR MARKET" PHILOSOPHY AFFECT THE COMPETITIVE WHOLESALE MARKET?

A. It will impede and most likely prevent the development of such a market for the foreseeable future. Since the "price cap" applies to both affiliates and non-affiliates, there is actually an incentive to keep market prices as high as possible. This will assure a greater likelihood that both affiliated and non-affiliated generators will recover at least their cost-of-service. Because building either new transmission or new generation is likely to have a depressing effect on market price, Staff has now created a disincentive to do anything about transmission constraints. This disincentive not only affects the incumbent UDC and its affiliates, but all other market participants because they are effectively subject to the same price caps. Additionally, such Standard Offer "price caps" would discourage customers from even trying Direct Access service, making Staff's dire predictions about the pace of retail competition something of a self-fulfilling prophecy.

Q. THIS ALL SEEMS SOMEHOW FAMILIAR. HAS ANY OTHER JURISDICTION EXPERIENCED THESE PROBLEMS?

A. Yes. UDCs caught in a regulatory price squeeze, demand responses divorced from market forces, new investment in infrastructure discouraged - these are all reminiscent of California. Although the means of destruction are different, the likely result will be the same.

Q. HAVE THIS COMMISSION AND OTHER REGULATORS PREVIOUSLY CONSIDERED AND REJECTED THE LOWER OF COST OR MARKET PHILOSOPHY EMBODIED IN STAFF'S RECOMMENDATION IN THIS PROCEEDING?

A. Yes. Although nobody in Arizona, or to my knowledge anywhere else, has ever proposed anything of the scope of Staff's recommendations, some aspects of this "heads I win, tails you lose" version of regulation was proposed during an APS fuel and purchase power adjustment proceeding in 1986. At that time, RUCO proposed that APS generating unit performance be measured against some historical measure of performance, with an automatic disallowance if performance fell below the standard but no potential for reward above the units' cost-of-service if performance exceeded the standard. RUCO's scheme was not strictly a "lower of cost or market" proposal. Yet it was one in which cost-of-service was a rate cap but not a rate floor, and one where the prudence of APS' actions would not prevent a disallowance, and thus it had many of the flaws and inequities inherent in Staff's present proposal. The Commission rejected the RUCO proposal as "inherently biased against APS." Decision No. 55118 (July 24, 1986) at Finding of Fact No. 37. The Commission also labeled a companion RUCO suggestion to automatically disallow costs above some specified level (analogous to Staff's suggestion of a *per se* cap of the lower of cost or market) "an unreasonable and draconian position." *Id.* at 13.

In large part the Commission's analysis was similar to the discussion of "economic excess capacity" in Docket No. U-1345-85-367, a seemingly endless rate proceeding filed in 1985 but not finally decided until the Spring of 1988. In that proceeding, Staff proposed to subject Palo Verde to a "market cost" test while at the same time constraining the value of the Company's other generating

plants to original cost. Thus, as in Staff's current proposal, APS cost recovery for generation would be the lower of cost or market. But unlike Staff's present recommendation, Staff was at least willing to compare the present value of Palo Verde's life cycle costs to the present value of the market alternative for a comparable period of time rather than a year to year spot analysis. Then, as in this case, Staff contended that its standard for cost recovery would be "reasonably applied," similar to Mr. Rowell's admonition that "the financial health of the UDCs cannot be forgotten." Testimony of Matthew Rowell at page 4, lines 15-16. At the time, the Company was honored to present as a rebuttal witness Dr. Alfred E. Kahn, former head of the New York Public Service Commission and former Chairman of the Civil Aeronautics Board, and almost literally the father of modern utility regulation. His response to this "lower of cost or market" scheme was eloquent, if somewhat blunt:

> I am honestly uncertain whether this [Staff's] response is properly characterized as disingenuous or meaningless; but at least one of the two or some combination of them seems to me inescapable. It will not do for [Staff witness] Dr. Yokell to set up an admittedly unattainable standard of perfection; recommend that departures from it will be subjected to a substantial penalty; and then assure us that his intention is, however, to have it applied "reasonably." The standard is itself unreasonable; it is a standard for expropriation; and "reasonable expropriation" is an oxymoron.

Rebuttal Testimony of Alfred E. Kahn in Docket No. E-1345-85-367 at 3. After later characterizing Staff's proposal as "pie in the sky" (*Id.* at 4), Dr. Kahn went on to state:

> In other words, just as his [Staff's] basic proposal would have the Commission play "heads we win/tails you lose" by allowing utility companies to recover only the costs (including the cost of capital) associated with their successful plants and something less than that on the unsuccessful ones, even though the associated investments were prudent, so similarly he [Staff] would allow them recovery of costs and only of costs only during the period when the Commission assesses those investments as meeting the standard of perfection, but not during the period of its [the Commission's]

> erroneous and later withdrawn assessment that they fell short of the standard.
>
> In short, under Dr. Yokell's [Staff's] regulatory scheme, the utility company would be penalized not just for its own lapses from omniscience but also those of its regulators!

Id. at 7-8 (emphasis in original). Needless to say, Staff's recommendation was not adopted by the Commission.

In Commission Docket No. U-1345-90-007, the Commission was again faced with the issue of "economic excess capacity." This time it was RUCO that proposed "capping" cost recovery of Palo Verde at some calculation of the market cost of an alternative resource, in those days a coal plant. Once again the concept was utterly repudiated.

Other jurisdictions have also repeatedly rejected the selective use of market value in setting rates, which is essentially what Staff's "lower of cost or market" philosophy embraces. These include New York, Oregon, Illinois and North Carolina.

2. What 1999 APS Settlement?

Q. YOU HAVE REPEATEDLY CRITICIZED STAFF'S FAILURE TO OBSERVE THE TERMS OF THE 1999 APS SETTLEMENT AGREEMENT. DO STAFF'S PROPOSED LIMITATIONS ON BOTH PWM&T AND PWEC VIOLATE THE SETTLEMENT?

A. Yes, and I know some may think I'm a broken record on this topic. But I am continually puzzled and confounded by the fact that the 1999 APS Settlement apparently means so little to Staff. Whether you accept the Court of Appeal's pronouncement about this Settlement being a binding contract or believe it just part of another order of the Commission, the 1999 APS Settlement deserves more consideration and deference than has been repeatedly evidenced by Staff's

recommendations in this proceeding as well as in the Variance Docket. The 1999 APS Settlement specifically found that APS could transfer the power marketing function, which of necessity includes power acquisition. *See* 1999 APS Settlement at Section 4.2. Yet Staff now is recommending that either this function be retained at APS or worse yet, that APS and PWM&T have redundant power marketing functions. *See* Testimony of Matthew Rowell at page 7, lines 15-18. The 1999 APS Settlement specifically held that the Company's new generation affiliate would not be placed under any different regulatory scheme on account of its affiliation with APS:

> The APS affiliate or affiliates acquiring APS' generating assets will be subject to regulation by the Commission, to the extent otherwise permitted by law, <u>to no greater manner or extent than that manner and extent of Commission regulation imposed on other owners or operators of generating facilities</u>.

1999 APS Settlement at Section 4.4 (emphasis supplied). Yet Staff proposes both limiting the ability of APS affiliates to compete for sales of power to APS in a manner not applicable to non-affiliates and requires nonsensical affiliate pricing rules for such sales that would likewise not be applicable to non-affiliates. *See* Testimony of Barbara Keene at page 8 lines 13-20.

Q. WHAT ABOUT STAFF'S RECOMMENDATION THAT RELIABILITY MUST-RUN ("RMR") UNITS BE RETAINED BY APS?

A. This would encompass Ocotillo, Yucca, the non-PWEC units at West Phoenix, and perhaps the Douglas CT. Retention by APS of this small amount of generating capacity would also violate the 1999 APS Settlement, which specifically listed these units as among those to be divested (1999 APS Settlement, Exhibit C), and would be unwise and unnecessary in any event.

It is not economic for APS to retain a small redundant generation infrastructure when the overwhelming majority of its generation will reside at PWEC. I discuss this at pages 29 and 30 of my Rebuttal Testimony in the Variance Docket as well. The Company's Open Access Transmission Tariff ("OATT"), the Arizona Independent Scheduling Administrator ("AISA") protocols, and the WestConnect protocols before the Federal Energy Regulatory Commission ("FERC") address RMR, and Rule 1609(I) requires that there be a contract or other legal assurance of RMR prior to divestiture. A FERC-approved contract or tariff (or both) will suffice in lieu of continued APS ownership of these units, which after all are RMR only a limited number of hours each year. (West Phoenix Units 4 and 5, which are PWEC units, as well as SRP's planned San Tan and Kyrene Units are much more efficient than the Ocotillo and older West Phoenix facilities and will largely if not completely displace them for RMR service.) And once the WestConnect protocols are approved and WestConnect becomes operational, RMR issues will be handled through that organization.

Q. DOES STAFF'S TREATMENT OF THE 1999 APS SETTLEMENT AFFECT YOUR CONSIDERATION OF ITS PRESENT RECOMMENDATIONS IN THIS DOCKET?

A. Absolutely. For example, Staff witness Jerry Smith is suggesting an acceleration of transmission projects and a general substitution of transmission for generation. Both these recommendations will be exceedingly expensive to implement. APS has already spent hundreds of millions to comply with the 1999 Electric Competition Rules and the 1999 APS Settlement, both of which are now being dismantled or ignored by Staff. Staff is recommending a whole new code of conduct when APS has already formally trained over 2000 employees on the existing Code of Conduct that Staff itself helped to draft just

two years ago and concerning which there has not been even one alleged violation. Staff is recommending that APS get back into the generation business when it has already devoted millions of dollars to get out of it in compliance with divestiture provisions in the Electric Competition Rules drafted and promoted by Staff and with the divestiture provisions in the 1999 Settlement Agreement that were supported by Staff and which were indistinguishable from the divestiture provisions insisted upon by Staff in the ill-fated 1998 settlement also discussed in my Rebuttal Testimony in the Variance Docket. Aside from the Company's many and profound substantive disagreements with most of Staff's positions, there is the quite legitimate question whether any or all of Staff's recommendations are likely to be completely changed or abandoned altogether within a few short years, if not sooner.

Q. DOES STAFF OFFER ANY EXCUSE FOR ITS TREATMENT OF THE 1999 APS SETTLEMENT?

A. No Commission employee has a word to say on the subject. Staff outside consultant witness Neil Talbot offers the "change of circumstances" excuse at page 31, line 21 of his testimony. I find it more than curious that these "changed circumstances" justify changing those portions of the 1999 APS Settlement bargained for by the Company but not those portions of the Settlement, such as the guaranteed rate reductions and the write-off of $234 million in prudently-incurred costs, which were bargained for by the various consumers groups that joined in that 1999 APS Settlement and apparently welcomed by the Commission. That aside, the changes in circumstances since 1999 have generally been towards a more competitive wholesale market, especially in Arizona. We have far more merchant generation and merchant generators in Arizona than in 1999 or than were anticipated in 1999 to be in Arizona today.

We are closer to having a working RTO than in 1999. We have a more proactive FERC than in 1999. We have a cost-based PPA on the table, which is again something we did not have in 1999. Rather than being a document that time and events have passed, the 1999 APS Settlement has proven an even better deal for consumers than first anticipated (just ask people in California and Nevada). Moreover, the rationale stated by the Commission for each of its major provisions is more salient than ever before.

3. The Proposed PPA Would Resolve Most of Staff's Stated Concerns

Q. HOW WOULD THE PROPOSED PPA RESPOND TO STAFF'S STATED CONCERNS?

A. As I noted in my Summary, it is ironic that the very Proposed PPA that Staff seemingly rejected out of hand in the Variance Docket would go a long way towards meeting many if not most of Staff's stated concerns. This is especially true given the clarifications and amendments to the Proposed PPA discussed at pages 36-51 of my Rebuttal Testimony in the Variance Docket. Below is a listing of the concerns or issues raised by Staff in this Generic Docket along with the Proposed PPA's treatment or resolution of each such concern or issue:

> ***Market Power*** – The Proposed PPA completely eliminates even the potential exercise of market power by APS affiliates against APS or its customers. And Staff's own analysis demonstrates that neither APS (pre-divestiture) nor PWEC (post-divestiture) can exercise any significant market power on a regional basis.
>
> ***Affiliate Transactions*** – The Proposed PPA gives the Commission prior-approval authority for most of APS' purchases from PWM&T. The balance of the Company's needs would come from a transparent and open competitive bidding process under the direct control of APS. Except as regards its responsibilities under the PPA, PWM&T will undertake no other significant affiliate transactions with APS. The same is true as regards PWEC. As it is, those transactions are already subject to Commission review in both rate proceedings and as a result of the Affiliate Rules (A.A.C. R14-2-801, *et seq.*).
>
> ***Code of Conduct*** – Approval of the PPA moots most potential code

of conduct issues identified in Ms. Keene's testimony. Moreover, the Commission should await final FERC action on this same issue So as to avoid potentially conflicting or duplicative requirements.

Just and Reasonable Rates - The Proposed PPA gives APS customers the greatest possible assurance that they will be no worse off than if restructuring had never taken place. It does so without confiscatory "lower of cost or market" schemes but through incentives to maximize performance from the Dedicated Units and by fixing a return component during today's period of historically low capital costs. Because the PPA imposes no restrictions on customers' ability to chose retail access, such customers can play the "lower of cost or market" game themselves without making the Company's shareholders unwilling and uncompensated participants in that game.

Reliable Service – The Proposed PPA gives APS customers the same reliability benefits of fuel, geographic and operational diversity as heretofore enjoyed.

Long-Term Promotion of Wholesale Competition – The PPA gradually phases in market resources through a combination of mandatory procurements and significant purchases of Supplemental and Replacement Energy Products under the PPA. Although the Merchant Intervenors naturally would be enriched by an acceleration of both, it is clear that the PPA, even as drafted, would not impose the sort of draconian price caps and create the sort of disincentives for open market development as are part and parcel of the Staff's recommendations.

Please note that the above analysis does not purport to "solve" the "jurisdictional issue." If by "solve," it is meant a means by which the Commission can wrest jurisdiction over wholesale power transactions from FERC or by which the Commission can arrest FERC's progressive stranglehold over transmission issues, I can offer no "magic bullet." Only Congressional enactment can serve those purposes. But I can say that the Commission's influence over wholesale market participants such as PWM&T and PWEC, both because of their affiliation to APS and their status as Arizona-centered businesses rather than a collection of Delaware LLCs, is and will remain far greater than the influence it

believes it can exercise through the occasional power plant siting proceeding or even by the Merchant Intervenors' participation in this proceeding.

4. Procedural and Timing Issues

Q. DOES STAFF INDICATE IT WISHES TO DELAY THE DIVESTITURE OF GENERATION ASSETS IN VIOLATION OF THE SCHEDULE AGREED TO IN THE 1999 APS SETTLEMENT?

A. Staff's position is confusing at best, and disingenuous at worst. At page 12, lines 16-19 of his testimony, Mr. Rowell states that Staff's recommendations are not "designed to delay the asset transfers provided in the settlement agreements." Yet at page 9, line 12 of that same testimony, he states "that the timing of the asset transfers is problematic." And at page 10, lines 2-9, Mr. Rowell sets up a gauntlet of prior conditions to any transfer that could not possibly be achieved by year's end. Some of these prior conditions would not even be initiated, let alone resolved, until 90 days after the conclusion of this proceeding, which means a start date of late November at the earliest.

It's not as if Staff has made any specific proposals that could be easily implemented without further controversy. For example, Mr. Rowell states:

> The [required] market power study should consider any and all factors that could adversely impact the ability of new or alternative suppliers to enter the Arizona retail or wholesale markets. The market power study shall examine horizontal and vertical market power, the effect on competition of distribution and transmission pricing, contractual arrangements, and other potential barriers to entry into the Arizona wholesale and retail market. The analysis of horizontal market power should be consistent with the U.S. Department of Justice and Federal Trade Commission's Horizontal Merger Guide-Lines, as revised April 8, 1997 ("DOJFTC Merger Guidelines"). The DOJFTC Merger Guidelines, standards, and methods, which are designed to apply [only] to mergers, should be adapted and modified as necessary to the circumstances specific to the deregulation of generation and the introduction of retail open access. The analysis should also be consistent with current FERC market power tests such as the pivotal supply test and analytical methods such as

> strategic behavioral analysis. The horizontal market power analysis for retail and wholesale products should include analyses of market concentration and barriers to entry for non-affiliated providers for each customer class. The vertical market power analysis should demonstrate that the functional separation, codes of conduct, affiliated transactions, and interconnection and open access policies and tariffs are or will be structured and implemented to assure that all wholesale and retail competitors have access to the competitive markets equal to that of the utility and its ESP affiliates. If the results of the above described analysis reveal areas of concern the Commission may require that additional analysis be conducted such as strategic behavioral analysis. The Arkansas Public Service Commission's Minimum Filing Requirements for Market Power Analysis approved on June 27, 2000, provides additional detail on The content of market power studies.

Testimony of Matthew Rowell at page 11, lines 2-25 (emphasis supplied). This is not a study – it's a lifetime endeavor for a "think tank" full of market power and market structure experts. Or at least it would be if the confusion of retail and wholesale issues in the above-quoted passage and the continuous use of ambiguous qualifiers such as "consistent with," "as necessary," "any and all," "such as," etc., did not make Staff's precise recommendation indecipherable. Mr. Rowell then goes on to prejudge the outcome of his own mandated mega-study by requiring that the utility (APS) submit a "market power mitigation plan for Commission approval." *Id.* at page 10, line 4. I have to assume this prejudgment is a by-product of the so-called "rebuttable presumption" theory espoused by Mr. Talbot at page 17 of his testimony. Mr. Talbot neither provides or cites any proof for this theory nor do the potential concerns of the Arkansas Public Service Commission about multi-state giant Entergy constitute such proof.

The same problem exists with Ms. Keene's recommended "code of conduct" filing. She references a number of other jurisdictions' codes of conduct, most of which are irrelevant to the issue at hand. But Ms. Keene makes no specific

recommendations other than the "lower of cost or market" mantra previously discussed and the suggestion that the code should address in some unspecified manner a host of other issues. For the most part, each of these issues is already addressed in the existing Commission-approved APS Code of Conduct and/or FERC Code/Standards of Conduct or was an issue (e.g., shared office space) already considered and rejected by Staff and the Commission. If Ms. Keene had simply and straightforwardly recommended that the existing Commission-approved APS Code of Conduct needed this or that additional provision, this would be the sort of recommendations to which the Company and others could rationally respond.

Combined with Mr. Rowell's never-ending market power analysis, I am led to the inescapable conclusion that, contrary to Mr. Rowell's assertion, the whole point of Staff's recommendation is to delay the transfer of assets indefinitely. And yet Staff cynically maintains that the decision to divest or not will be, in Mr. Rowell's own words "at the utilities' discretion." Testimony of Matthew Rowell at page 10, line 7.

Q. DID STAFF RAISE THESE ISSUES IN 1999?

A. Vertical market power concerns were one of the stated reasons why Staff proposed divestiture of the Company's generation in the first instance and why, as I noted in my May 29th testimony, the Commission specifically held that such divestiture was "in the public interest." Code of Conduct was also an issue, resulting in the present Commission-approved APS Code of Conduct. Horizontal market power was not raised. In fact, in the ill-fated 1998 settlement agreement between APS, TEP and Staff, Staff agreed to allow APS (and thereafter its affiliate) to acquire even more generation. That never took place,

and since 1999, the generation market share of APS generation has dropped significantly.

In point of fact, APS and its affiliates have already passed every known form of recognized market power test I have ever heard of, and thus no "market power mitigation plan" is either necessary or possible. FERC has repeatedly found that APS and its affiliates have no market power and perhaps more to the point, that the transfer of APS generation to PWEC "will not adversely affect competition." FERC Docket Nos. EC00-118-000 and EC00-118-001 (November 24, 2000) at 5. I must note that the referenced FERC proceeding included this Commission as an intervening party, and that FERC went on to note in its order: "no intervenor disagrees" with the Company's assertion that "the proposed transaction will not have an adverse effect on competition in the generation or transmission markets."

Aside from the amorphous nature of the preconditions (to divestiture) themselves, which require significant further definition before they could possibly be adopted and implemented, Staff also assumes completion of an as of yet uninitiated rulemaking proceeding to amend Rules 1615, 1616 and 1606. This is easier said than done, and once you begin pulling on the essential threads of restructuring, you don't know how much of the cloth will unravel. Even if such a proceeding were begun immediately and conducted concurrently with the market power and code of conduct proceedings contemplated by Staff's recommendations, something Staff has been most reluctant to do, completion prior to December 31, 2002, or any time remotely close to such date, is impossible.

Q. COULD THE COMMISSION JUST PROCEED TO INSTITUTE STAFF'S VARIOUS RECOMMENDATIONS IN THIS PROCEEDING, THUS SHORTENING THE PROCESS?

A. Perhaps if back in January, when this Generic Docket was conceived, Staff had initiated the process of completely reinventing regulation in this state or had opened up a new rulemaking docket, there might be the procedural vehicles in place. However, there would still be no evidentiary basis for any of these Staff proposals, which I believe will inevitably lead to the same sort of chaos that gripped California and other Western states in 2000-2001.

Q. DIDN'T STAFF PROPOSE AND THE COMMISSION AGREE THAT THE DIVESTITURE ISSUE WAS TO BE RESOLVED, YEA OR NAY, BY AUGUST OF THIS YEAR?

A. Yes. I do not understand how Staff can possibly reconcile its current suggestion of some open-ended and ill-defined code of conduct proceeding or an equally ill-defined and unprecedented set of market power analyses with goal of getting this threshold issue resolved by August.

IV. THE MERCHANT INTERVENORS

Q. DOES APS OPPOSE CONSIDERING "TRACK B" ISSUES SUCH AS HAVE BEEN RAISED IN VIRTUALLY ALL OF THE MERCHANT INTERVENORS' TESTIMONY IN A SINGLE PROCEEDING?

A. No. APS does oppose considering them in two proceedings. Both Reliant and Panda/TECO opposed a one-track proceeding. They should not now be allowed two bites at the apple. Nor should they be permitted to use this "Track A" proceeding as additional leverage to further their pecuniary interests in "Track B" at the expense of APS and its customers.

Q. WHAT SPECIFIC RECOMMENDATIONS OF THE MERCHANT INTERVENOR PANDA/TECO DO YOU OPPOSE?

A. Panda/TECO witness Dr. Craig Roach would condition asset transfer on the denial of the Proposed PPA. Although asset transfer is directly linked to the requirement and need for competitive power procurement under Rule 1606(B), the Proposed PPA and asset transfer are largely independent of each other. Although PWM&T could not fulfill the terms of the Proposed PPA without the portfolio of generating assets that PWEC will acquire from APS, APS would effectuate divestiture as called for in Rule 1615 and the 1999 APS Settlement with or without approval of the Proposed PPA.

Dr. Roach also suggests that APS not be permitted to divest its generation in accordance with the 1999 APS Settlement until APS established a short-term energy market in Arizona. Testimony of Dr. Craig Roach at page 4, lines 6-7. While I appreciate the vote of confidence, neither APS nor any other single market participant can establish such a market. In California, it took a concerted effort by all market participants and the state over many months to establish a liquid short-term market, and even it eventually failed.

In point of fact, APS will need significantly less competitively procured power if it is forced to retain its generation than would be acquired under the Proposed PPA, and thus Dr. Roach's suggested denial of the Company's generation asset transfer is hardly in the interests of Panda/TECO and the other Merchant Intervenors. Panda/TECO appears to be raising these issues largely in an effort to use divestiture as a carrot to induce the Company to abandon the Proposed PPA.

I also disagree with Dr. Roach's assertions at page 15, lines 1-5, and thus further disagree that there is anything this Commission can and should do to

"mitigate" alleged APS "transmission market power." The first two assertions made by Dr. Roach to support his recommendation are simply wrong, both factually and legally. The third is partially true in that FERC does regulate APS transmission. It is not true that FERC grants APS any monopoly. The fourth is true in the sense that WestConnect is not fully operational, but the implication that APS is somehow in violation of some FERC order or regulation is completely false. FERC is presently reviewing WestConnect's protocols, and APS expects a positive response from FERC prior to any significant competitive procurement process being implemented in Arizona. Even if they were not, the type of competitive procurement presently favored by the Company, an open and transparent auction-type process, with the winners becoming designated network resources on an equal footing with those covered under the Proposed PPA or any variant of such agreement, when combined with the Company's OATT and the AISA, would satisfy any fair-minded individual that APS ownership of transmission is a non-issue in these proceedings.

Finally, Dr. Roach suggests using an RFP process followed by private negotiations, with PWEC and PWM&T being excluded from this process, as a "mitigation" measure for non-existent market power. Whatever merit there is in Dr. Roach's recommendation, it has nothing to do with mitigation of market power. In fact, as we saw in California, the use of the RFP process and private bilateral negotiations magnified the market power of the merchant generators to the considerable detriment of consumers. To the extent that "Track B" issues are in any way related to market power, this is just another argument in favor of having as open and transparent a competitive procurement process as is feasible. Also, eliminating or handicapping the merchant generators' major competitors

(PWEC and PWM&T), or requiring APS to competitively procure power without the assistance of its most experienced and knowledgeable power traders (PWM&T) is just the ticket for driving up prices to consumers.

Q. ARE YOU SAYING THAT APS WOULD DO AS POOR A JOB AS THE CALIFORNIA DEPARTMENT OF WATER RESOURCES ("CDWR") IN HANDLING AN RFP/BILATERAL NEGOTIATION PROCUREMENT PROCESS?

A. No, and I'm also not in a position to criticize CDWR. For all I know CDWR did the best it could with the weak hand it had been dealt. I do believe, however, that any procurement process that is based on RFPs and private bilateral negotiations will, because of the tremendous degree of subjectivity involved and the lack of proper oversight and accountability, potentially lead to claims of "foul" by the losers (claims that may and have resulted in prolonged litigation), invite "second guessing" by regulators, and result in higher prices to end-users.

Q. WHAT ABOUT RELIANT'S PROPOSAL?

A. Reliant witness Curtis Kebler presents the unusual scenario wherein APS or PWEC generation is first sold to merchant entities and then resold with some undisclosed markup back to APS. Although I don't know how long it would take to set up what would be in effect a second auction, I would agree that this would allow parties without uncommitted generation in Arizona to participate in providing generation for Standard Offer customers, but I fail to understand why this is particularly desirable. One of the things APS, and I believe the Commission, wish to encourage is the construction of new generation in Arizona, not a proliferation of "asset-less" power marketers. From a reliability point of view, the proposal may have some merit since it allows others to

purchase APS' and PWEC's then existing reliable portfolio of generation, but I again struggle to see how essentially adding a "middleman" (and a "middleman's" profit) to the Proposed PPA benefits the Company's customers or enhances Arizona's future energy supplies.

Q. BOTH THE MERCHANT INTERVENOR WITNESSES AND STAFF WITNESSES HAVE SUGGESTED THAT MANY ADDITIONAL STEPS NEED TO TAKE PLACE BEFORE WE CAN HAVE RESTRUCTURING AND REALLY EFFECTIVE WHOLESALE COMPETITION. DO YOU AGREE?

A. I certainly agree that implementation of WestConnect, the creation of a liquid spot market, and the construction of more transmission would each facilitate more efficient wholesale competition. I do not agree that the first steps toward that more efficient wholesale competition, which are divestiture of APS generation in conformance with the 1999 APS Settlement and the Electric Competition Rules and the beginning of a rational competitive procurement process, should be delayed pending the other institutional and infrastructure changes described above. If we wait to move forward until we have perfect conditions in place for wholesale competition, we will be waiting a long time, if not forever.

Q. WHY DO YOU BELIEVE THE MERCHANT INTERVENOR WITNESSES ARE MAKING PROPOSALS THAT WILL SIGNIFICANTLY DELAY, PERHAPS INDEFINITELY, THE BEGINNING OF COMPETITIVE PROCUREMENT OF POWER BY APS?

A. I don't really know. It was just this past April that Panda/TECO was filing a Motion asking an "Order to Show Cause" because the Company was not immediately proceeding to competitive bidding. All the other Merchant Intervenors supported Panda/TECO in this request. The scheduled hearing on the Company's request in the Variance Docket was cancelled so that we could

get on with the bidding. Now, just as suddenly, the Merchant Intervenors are the co-proponents (with Staff) of delay. Maybe they simply are hoping that market conditions will improve before they have to commit any resources to Arizona. Maybe some of them don't believe their plants will be done in time for 2003. Or it may be that getting a competitive edge vis-a-vis APS and its customers by structuring the procurement process in "Track B" to their liking is more important to them than getting the procurement process started on time.

V. RUCO AND AECC

Q. DO YOU HAVE ANY COMMENTS ON THE RECOMMENDATIONS OF EITHER RUCO WITNESS DR. ROSEN OR AECC WITNESS HIGGINS?

A. I indicated in my Summary that APS did not disagree with most of Mr. Higgins observations or recommendations, and I will not belabor that point. As to Dr. Rosen, I agree with his observations about the benefits of the Proposed PPA or some similar buy-back agreement premised on the assets, old and new, constructed by APS and its affiliate to serve APS customers. I do not agree that the absence of this or any other PPA would result in PWEC or PWM&T engaging in the sort of market activities described in Dr. Rosen's testimony. APS did not conduct itself that way in California (and in fact reported to authorities others that did), where market rules actually encouraged that sort of behavior, and it certainly would not do so in its own back yard even if there were not the sort of increased Commission and FERC market monitoring and oversight we are now experiencing. If Arizona goes the way of California, it most likely will not have market manipulators to blame, but only the sort of bad regulatory policies urged by Staff and some of the Merchant Intervenors in this proceeding as well as in the Variance Docket.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS IN REBUTTAL?

A. Yes. It was no pleasure having to be so critical of Commission Staff in these proceedings. But I honestly believe their recommendations, if adopted, could only lead to the financial destruction of the Company and send us down a path that although different in both design and intent, would lead to the same end result as California, Nevada and other Western states. You can have competition and surrender the safety of traditional regulation. You can keep traditional cost-of-service regulation and forego the potential benefits of competition. You can hedge your bet with devices such as the Proposed PPA. But you can not insure that the outcome of any of these choices will always be the best for consumers all of the time. And you cannot reasonably expect the Company to provide such assurance without inviting financial disaster and denying to it the opportunity to make a reasonable return either under competition or regulation. Even insurance companies, and Staff has certainly not proposed paying APS any premium to provide the price insurance Staff is essentially seeking, do not cover every hazard all of the time.

Aside from the substance of Staff's recommendations, I continue to be dismayed by the lack of deference, or even consideration, afforded the 1999 APS Settlement. Reinventing regulation every two to three years is certainly not in the best interests of customers. I see no reason to give Staff's proposals in this Generic Docket any greater consideration since if I wait a year or two, they too will likely be rescinded or significantly modified.

No party has demonstrated why the current provisions on affiliate transactions and code of conduct are not sufficient with perhaps a tweak here or there.

Similarly, APS has already passed every legitimate market power test, and there is no need to attempt to keep coming up with ever more complex and time consuming studies or to prepare mitigation plans to address a non-existent market power.

The Proposed PPA is still in the best interests of our customers. It actually addresses most of Staff's stated concerns and allows for greater development of the wholesale market than would retention of generation by APS.

Q. DOES THAT CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY IN THIS GENERIC PROCEEDING?

A. Yes, it does.

EXHIBIT

APS-3
Admitted

BEFORE THE
ARIZONA CORPORATION COMMISSION

Rebuttal Testimony of

Charles J. Cicchetti, Ph.D.

Docket No. E-00000A-02-0051, et al.

On Behalf of

Arizona Public Service Company

June 11, 2002

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1 **SECTION I. INTRODUCTION AND EXPERIENCE**

2 **Q. PLEASE STATE YOUR NAME, BUSINESS AND ADDRESS.**

3 A. My name is Charles J. Cicchetti. My address is Pacific Economics Group,
4 L.L.C. (PEG) 201 South Lake Avenue, Suite 400, Pasadena, California
5 91101.

6 **Q. WHAT IS YOUR POSITION WITH PACIFIC ECONOMICS GROUP?**

7 A. I am a Co-Founding Member of PEG.

8 **Q. WHAT ARE YOUR DUTIES AS A MEMBER OF PEG?**

9 A. I actively consult with clients on price, costs, environmental, natural gas
10 and electricity market issues and antitrust policies, particularly as those
11 policies relate to regulated industries.

12 **Q. DO YOU HOLD ANY OTHER POSITIONS?**

13 A. I hold the Jeffrey J. Miller Chair in Government, Business and the
14 Economy at the University of Southern California.

15 **Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

16 A. I attended the United States Air Force Academy, and I received a B.A.
17 degree in Economics from Colorado College in 1965 and a Ph.D. degree
18 in Economics from Rutgers University in 1969. From 1969 to 1972, I
19 engaged in post-doctoral research on energy and environmental matters
20 at Resources for the Future.

21 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.**

22 A. I served as chief economist for the Environmental Defense Fund from
23 1972 to 1975, and was a faculty member at the University of Wisconsin

1 from 1972 to 1985, ultimately earning the title of Professor of Economics
2 and Environmental Studies. From 1975 through 1976, I served as the
3 Director of the Wisconsin Energy Office and as Special Energy Counselor
4 for the Governor. In 1977, I was appointed by the Governor as Chairman
5 of the Public Service Commission of Wisconsin and held that position until
6 1979, and served as a Commissioner until 1980. In 1980, I co-founded
7 the Madison Consulting Group, which was sold to Marsh & McLennan
8 Companies in 1984. In 1984, I was named Senior Vice President of
9 National Economic Research Associates and held that position until 1987.
10 From 1987 until 1990, I served as Deputy Director of the Energy and
11 Environmental Policy Center at the John F. Kennedy School of
12 Government at Harvard University, and from 1988 to 1992, I was a
13 Managing Director and ultimately Co-Chairman of the economic and
14 management consulting firm, Putnam, Hayes & Bartlett, Inc. In 1992, I
15 formed Arthur Andersen Economic Consulting, a division of Arthur
16 Andersen, LLP. In late 1996, I left Arthur Andersen to co-found Pacific
17 Economics Group.
18 **Q. HAVE YOU PUBLISHED ANY PAPERS OR ARTICLES?**
19 A. Yes. I have published a number of articles on energy and environmental
20 issues, public utility regulation, competition and antitrust. A complete
21 listing of my publications is included in Attachment 1.
22 **Q. HAVE YOU EVER GIVEN EXPERT TESTIMONY IN A COURT OR**
23 **ADMINISTRATIVE PROCEEDING?**
24

A. Yes. A list of the proceedings in which I have provided expert testimony since 1980 is also included in Attachment 1. Much of my consulting work before and since the time I was the Chairman of the Public Service Commission of Wisconsin has involved regulated industries, specifically, electric, natural gas, telecommunication, and water. I have testified in the U.S. before most of the state public utility commissions, and various federal agencies. In Canada, I have testified before the Alberta and Ontario Energy Boards, as well as before the National Energy Board.

SECTION II. PURPOSE OF TESTIMONY

Q. WHO RETAINED YOU FOR THIS TESTIMONY?

A. I have been retained by Arizona Public Service Company (APS) to provide rebuttal to testimony in response to the Procedural Order dated May 2, 2002 (Procedural Order) entered by the Arizona Corporation Commission (ACC).

Q. WHAT IS YOUR UNDERSTANDING OF THE NATURE OF THIS PROCEEDING?

A. This is a generic proceeding that, as I understand matters, will involve issues related to the transfer of assets and associated market power issues, code of conduct issues, and Affiliate Interest rules. These issues arise from the ACC's Retail Electric Competition Rules that were intended to develop competitive markets for electricity in Arizona.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS GENERIC PROCEEDING?

1 A. I have had significant regulatory and restructuring experience in the
2 electric utility business. APS has asked me to review the proposals set
3 forth by witnesses for the ACC's Utilities Division (Staff) in this proceeding
4 and to provide my perspective on the various staff proposals. This
5 testimony represents my critical review and evaluation of what I find to be
6 the most egregiously misdirected aspects of Staff's proposals in this
7 matter

8 **Q. CAN YOU BE MORE SPECIFIC?**

9 A. Yes. Staff has simply and very surprisingly failed to "learn the lessons" of
10 California's power crises and, most troublesome, the disastrous role that
11 faulty regulatory designs and bad transition plans played in this financial
12 catastrophe. Quite simply, California's failed attempt to manage
13 competition had a lot more to do with a bad combination of regulatory
14 failures and very unfavorable market forces than alleged Enron-style
15 gaming or even, to a lesser extent, as yet unproven but frequently charged
16 market power abuse. Failing to grasp the regulatory and institutional
17 failures and design flaws in California, Staff is apparently making
18 recommendations that will repeat these errors.

19 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

20 A. In Section II, I discuss the testimonies filed by three Staff witnesses. First,
21 I discuss Matthew Rowell's testimony, which I find most troubling. In
22 particular, I focus on Mr. Rowell's testimony with respect to: (1) standard

1 offer service pricing and (2) enhanced prudence reviews of supply
2 acquisition decisions.
3 Second, I explain that Erinn Andreasen's proposed Advisory Group
4 structure and requirements are unnecessary and likely to be grossly
5 ineffective.
6 Third, I explain that Barbara Keene's proposed treatment of utility
7 affiliates virtually ignores the APS restructuring agreement with the ACC.
8 Ms. Keene mostly creates phantom affiliate issues that, if they ever
9 actually arose, could be readily addressed under current regulation. Ms.
10 Keene's proposals effectively shift significant risk to APS and its affiliates
11 without conferring corresponding benefits to APS and its affiliates, or even
12 to APS' customers.
13 Fourth, I review Ms. Keene's code of conduct discussion. While I
14 recognize this is a generic proceeding, I am troubled that Ms. Keene
15 mostly ignores the existing strong regulatory tradition of affiliate and cost
16 of service regulation In Arizona. Ms. Keene also appears to believe that a
17 generic proceeding means that Staff should ignore existing regulatory
18 agreements, affiliate regulation, and codes of conduct. She is quite wrong
19 when she implies that this proceeding should evolve into a broad, full
20 blown proceeding to solve non-existent, very speculative affiliate matters.
21 In my experience, regulation needs to recognize preexisting precedents
22 and principles, and build upon them to address new circumstances and
23 contingencies.

SECTION III. STAFF WITNESSES

Mr. Rowell's Testimony

Q. PLEASE SUMMARIZE YOUR CRITICISM OF MR. ROWELL'S "STANDARD OFFER" PRICING PROPOSAL.

A. Beginning at page 5 of his Direct Testimony, Mr. Rowell seeks to improperly elevate the "Standard Offer" retail customer to an unattainable and counterproductive status under a misdirected guise of "regulatory bargain" protection. Under the traditional "regulatory bargain," Investor owned utilities are granted a service territory franchise in exchange for a "duty to serve." This is coupled with a real "opportunity" to recover reasonable expenses and earn a "fair return" on prudent investments.

Customers expect regulators to review the franchise utility's cost of service, prudence, rate of return, cost allocation, and tariff design. The stated regulatory goal is safe and reliable cost-based service that provides for the recovery of prudent utility investments. In Arizona, as is true throughout the United States, prudence review using twenty-twenty hindsight is eschewed by regulators who recognize that the future is uncertain and that economic and financial risks are unavoidable, although manageable over time through prudent management.

Mr. Rowell believes that new Standard Offer Service (SOS) should represent the "best" combination of "lowest" price and "lowest" consumer risk, significant terms that he leaves largely undefined. Such a standard would effectively cause Standard Offer customers to "have their regulatory

1 cake and eat a free competitive price dessert." This is unnecessary and,
2 as far as I know, it is a proposal that is totally without regulatory
3 precedent. Worse, it would mean that no rational retail consumer would
4 ever forgo such a "standard offer" because it would guarantee that retail
5 consumers pay the "lesser of" cost of service prices (i.e., the regulatory
6 default price) or a competitive market price – whichever turns out "best." I
7 hope this asymmetric result is not what Staff is pushing here. I may be
8 confused, but wish to err on the side of extreme caution because no
9 regulator should seek to impose a "heads I win, tails you lose" retail
10 pricing system.

11 **Q. PLEASE REVIEW IN MORE DETAIL YOUR CRITICISM OF STAFF'S**
12 **PROPOSAL TO CHARGE RETAIL CUSTOMERS THE "LESSER OF**
13 **COST OF SERVICE OR MARKET PRICES?"**

14 A. An example will help to explain what I believe Mr. Rowell is unreasonably
15 seeking to do and why I think that this is a heterodox approach. Suppose
16 a utility has a cost of service generation price of 7 cents per KWh, while
17 market prices generally swing between 5 cents and 10 cents per KWh. As
18 I understand Mr. Rowell's proposal, he would charge retail customers the
19 "lesser of" the cost of service price (7 cents per KWh) or the lower market
20 price (5 cents per KWh). Thus, when the market price was less than the
21 cost of service price, consumers would pay the market price of 5 cents per
22 KWh, even though the actual cost to serve those customers from
23 dedicated generation was 7 cents per KWh. However, when market

1 prices rose to 10 cents per KWh and were, therefore, above the cost of
2 service price, customers would pay the cost of service price of 7 cents per
3 KWh. Retail consumers would never pay 10 cents per KWh, even though
4 wholesale prices in the Commission-desired competitive market would rise
5 to this level. Thus, the regulated utility would systematically fail to recover
6 its actual costs when market prices are low and would lose the opportunity
7 to profit from the competitive market when market prices are high.
8 Mr. Rowell seeks to accomplish the impossible when he tries to
9 resolve the inherent antimony between regulation and competition. Quite
10 simply, consumers that opt for the 7 cent per KWh cost of service price
11 because they eschew competitive risks cannot and should not expect to
12 be able to reap the benefits that sometimes occur under a competitive
13 market outcome when the competitive price dips below the cost of service
14 price. Similarly, consumers that select a retail competitive market
15 outcome cannot and should not expect a safe harbor (i.e., cost of service
16 fixed prices) if and when market prices rise above the cost of service
17 standard.
18 None of this means that energy service providers (ESPs), should
19 be prevented from offering competitively priced retail contracts that permit
20 customers to switch back and forth between a base charge and
21 competitive market swings in prices. Most important, when retail suppliers
22 offer such contracts, they recognize two facts. First, the base prices are
23 established with respect to competitive market expectations, not on cost of

1 service prices. Second, the greater risk of such retail option offerings
2 increases the costs of suppliers and these costs would need to be
3 recovered through an insurance-like surcharge that would be added to the
4 expected value of the competitive market price.
5 Here, Mr. Rowell proposes an unorthodox and unsustainable
6 pricing recommendation that purports to offer retail customers the "best" of
7 these conflicting approaches. This is simply not possible.
8 **Q. WHY DO YOU CONCLUDE THAT SUCH A SCHEME WOULD BE**
9 **UNDESIRABLE? WOULDN'T MR. ROWELL'S PROPOSED "BEST"**
10 **PRICE AND "LEAST RISK" BE GOOD FOR ARIZONA'S**
11 **CONSUMERS?**
12 A. No. Any notion of consumer benefits would be illusory. Mr. Rowell's
13 proposal is hopelessly myopic. The long-run effects would be disastrous
14 and include:
15 1. No one would build new generation or enter into long-term
16 dedicated purchase power contracts if they would receive the
17 "lesser of" cost of service or market prices.
18 2. No competitive retail supplier would be able or willing to enter the
19 retail market in Arizona if Staff's standard offer service pricing
20 requirements were imposed on the incumbent utility companies.
21 3. Retail consumers would not receive appropriate price signals to
22 moderate consumption of electricity, and market prices would,
23 therefore, not be disciplined.

4. The financial effects on the incumbent utilities that would be forced to sell retail electricity at the "lesser or" cost of service or market price would be devastating. At best, stranded costs (i.e., the cumulative difference between cost of service and market prices when market prices are lower) could rise to significant levels. At worst, there would be an unfair (and to my way of thinking, clearly illegal) taking of utility assets that, to be blunt, would amount to systematic confiscation on a scale that has no place under either the doctrines of a capitalistic market driven economy or long-standing American regulatory principles and practices.
5. Bankruptcy of incumbent utilities would inevitably result. One need only look at the PG&E bankruptcy in California to realize that a utility cannot long afford to sell electricity at prices below those at which it must purchase the power. Buying high and selling low is not a practice that can be sustained for long. State regulators who impose such unreasonable constraints would nearly certainly find that they would cede significant jurisdiction to federal bankruptcy courts.

Q. ARE YOU SUGGESTING THAT RETAIL CONSUMERS ARE NOT TO BE GIVEN CHOICES?

A. No. A primary purpose of retail, as opposed to wholesale, electricity competition is consumer choice. Differences in price/risk preferences are what will drive the various retail consumer product choices under retail

1 competition. Mr. Rowell seeks to establish a world in which retail
2 consumers would falsely appear to be perfectly insulated from wholesale
3 price risk, yet pay nothing for this "insurance." Compounding this difficulty,
4 Mr. Rowell would guarantee that the load serving entity would not recover
5 its conventional cost of service because the incumbent utility would also
6 be required to sell electricity at lower competitively based retail prices
7 when market prices beat cost of service based prices. Mr. Rowell's
8 proposal is patently inequitable and does not conform to either reasonable
9 competitive market or traditional regulatory practices. This outcome is
10 unfair, unsustainable, and inefficient.

11 **Q. ISN'T FIXED STANDARD OFFER PRICING OFTEN USED DURING**
12 **TRANSITION PERIODS IN MOVING FROM A REGULATED TO A**
13 **COMPETITIVE ENVIRONMENT?**
14
15 A. Yes. APS has actually reduced its Standard Offer prices each year sine
16 the Electric Competition Rules were first implemented in this jurisdiction in
17 1996, and has further decreases scheduled for 2002 and 2003. However,
18 Mr. Rowell's proposed Standard Offer Service (SOS) is far from typical
19 As I understand Staff's proposal, Staff seeks to guarantee the
20 "best" result to retail consumers that take the "Standard Offer," not one
21 based on a fixed competitively set contract reference price, but one based
22 on a fixed cost of service price. Retail consumers would expect to pay
23 more for a fixed competitive price than the expected value of the
24 competitive price because they could avoid price volatility and, in effect,
25 hedge their retail purchase position. Here, Staff seems to propose that

the base Standard Offer price would be a cost of service price and if, and only if, competitive prices are less than this cost of service price, retail customer would pay less, but never more.

Q. WHAT OTHER PROBLEMS ARISE FROM IMPLEMENTING MR. ROWELL'S PROPOSED "STANDARD OFFER"?

A. There are two problems that arise. First, if Staff wants to encourage a fixed competitive tariff offering for some retail customers that provides for an anchor or base price with options to purchase at lower competitive prices, the base price needs to be set by competitive energy service providers and *not* an historic cost of service approach. Second, power markets have volatility, as do all commodity markets. Some customers may seek to insulate themselves from price volatility in both directions or on the upside. Regardless, avoiding market price risks is a form of insurance, and premiums must be paid.

Staff's approach assigns *all* risk to the utility distribution company and provides the utility with no potential upside as an insurance provider. This means that retail consumers would be so much better off under Staff's best price Standard Offer that no competitive energy service provider (ESP) could ever compete for these customers. In other words, the Staff proposal would set back competition in Arizona.

Worse, Staff's proposal increases APS' costs and risks without any compensation for being forced to assume those costs and risks. Much worse, this approach is precisely one of the principal structural flaws that helped to bring on and worsen California's electricity crisis because

regulators incorrectly believed that retail customers could, in effect, pay cost of service rates after wholesale markets jumped to more than twenty times their preexisting cost of service levels.

Q. WHAT IS WRONG WITH MR. ROWELL'S PROPOSAL FOR ENHANCED PRUDENCE REVIEWS?

A. Mr. Rowell applies the *coup de grace* when, at page 14 of Direct Testimony. Most important, Mr. Rowell seems to ignore the fact that APS' proposed PPA would be reviewed and approved by the ACC. This is a reasonable regulatory prudence review. That said, Mr. Rowell would seem to invite ongoing, *ex post prudence* review through his advocacy of a "lesser of" tariff standard.

This would mean a terrible trifecta and unfair *ex post* combination of: (1) retail consumers paying the "lesser of" cost of service or market prices with no consumer risk or insurance premium payment for such assurances; (2) all asymmetric risks and costs would be shifted to the incumbent utility distribution company; and (3) no competitive ESP could or would attempt to match such a one-sided Standard Offer, and retail competition would fail to materialize in Arizona.

I am advised that under traditional Arizona regulation, prudently incurred costs should be recovered. Arizona Administrative Code, Title 14, Chapter 2 defines "prudently invested" as those:

> "Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in

the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made."

Mr. Rowell's "enhanced prudence" review is consistent with neither this regulation nor general regulatory precedent.

Q. HOW DOES MR. ROWELL FAIL TO GRASP THE "LESSONS" OF THE RECENT CALIFORNIA ELECTRICITY CRISIS?

A. I am the co-author of the California Bureau of State Audits' Report on the causes of the California electricity crisis.[1] A brief review of California, as Arizona moves towards competition, is important in the context of California's recent disastrous experiences. This will help to demonstrate how Staff is falling into some of the same traps that California did when it restructured its markets.

The ACC determined in 1996 to let, to a greater extent, competition regulate electric markets, and rely less on comprehensive cost-of-service regulation. This decision was reviewed in several subsequent proceedings until it was finally affirmed in 1999, both by the passage of the current Electric Competition Rules and by approval of historic settlement agreements with APS and Tucson Electric Power. At the time, Arizona's mammoth economic neighbor (California) had nearly two years of wildly successful competitive wholesale market results and a program for full-blown retail consumer choice. Indeed, in 1998 and 1999, California's average annual competitive wholesale prices were nearly half

[1] Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Forces, March 2001.

their former cost-of-service levels (2.5¢ to 3¢/KWH versus more than 5¢/KWH). I fondly recall a major forum in April of 1999 at the University of Southern California at which all stakeholder groups sang a chorus praising California's great restructuring and electricity deregulation successes.

As we look back, it is now apparent that the western United States in 1999 had an existing excess generation supply with more new power plant construction under way. Crude oil and natural gas prices were very low and, adjusted for inflation real energy prices were at levels that the nation had not seen for decades.

Q. WHAT WENT WRONG IN CALIFORNIA?

A. Unusual climate conditions occurred in the western United States. In the Northwest, the winter was cold and dry, and in the Southwest, the spring and summer were hot. Normally, dry winters mean cool springs. This did not occur in 2000. The unusual weather increased demand, and reduced supply. The last time this happened, the WHOOPS[2] fiasco was foisted upon the Pacific Northwest. Natural gas and crude oil prices also surged in 2000. Indeed, the average U.S. natural gas price in late 2000 was more than five times its 1999 level; and, in California in late 2000, spot natural gas prices jumped thirty times over the previous year, from about $2 per MCF to $60 per MCF.

Q. DID CALIFORNIA'S MARKET HAVE ANY DESIGN FLAWS THAT EXACERBATED THE SUPPLY SHORTAGE?

[2] Washington Public Power Supply System. In the 1970s, the West experienced a similar climate anomaly and the western states embarked on a costly major nuclear construction plan.

1 A. Yes. California's new market design also suffered from structural flaws
2 that combined with supply/demand and fuel related market forces to cause
3 California's wholesale prices in 2000 to average more than three times the
4 levels established under cost-of-service regulation (about $150 per MWH
5 versus $50 per MWH), and more than five times 1999 price levels (about
6 $30 per MWH). Furthermore, in December of 2000, wholesale electric
7 prices jumped in the western region to more than $1,000 per MWH. Soon
8 thereafter, California's state government through the California
9 Department of Water Resources (CDWR) signed long-term contracts
10 (seven to ten years) at prices typically equal to about $ 70 to $80 per
11 MWH. The FERC, after several false starts and much political dancing,
12 began to regulate wholesale prices through western states' market
13 mitigation (soft caps), which remains in effect.
14 On the design flaw side, California made three fundamental
15 mistakes. First, retail prices were totally insulated from competitive price
16 volatility. Thus, when supply fell below demand, there were no retail
17 consumer price signals to encourage demand side responses. Second,
18 California put all its eggs in a "spot market" basket, effectively denying
19 market participants access to long-term forward and futures contracts.
20 (California is virtually alone in the jurisdictions that restructured in this
21 respect.) Third, California had a myriad of markets and products, whose
22 existence encouraged arbitrage. Yet, the California entities (ISO and
23 CPX) failed to grasp the need to participate in and to coordinate their

activities in these much too complex interdependent markets and products.

Q. HOW DOES CALIFORNIA'S EXPERIENCE AFFECT ARIZONA?

A. At present, there is great market and regulatory uncertainty, particularly related to the FERC's current market mitigation rules for western states. Also, current political and regulatory conditions cause much uncertainty related to the future FERC terms, conditions, prices, and structure of a new regional transmission organization (RTO). The lessons learned from California's experience show that it is important to get the new rules, institutions, and regulations right at the start. Fixing problems in the midst of a power crisis is not easy, and is often fraught with political and market peril.

Second, despite California, the ACC can be reasonably assured that it has protected Arizona's electricity consumers, while continuing to move toward competition. This can be done while retaining retail choice in Arizona. In my mind, the key is to encourage APS and other ESPs to enter long-term purchase power contracts for much of their retail needs.

Third, the ACC needs to continue to firmly embrace competition's merits over regulation without, as some have proposed, a strict adherence to an academic "spot market" model that fails to reflect current regional market supply and demand, federal regulatory mitigation, RTO uncertainty, and inside Arizona transmission network constraints and realities. This is simply not how free markets work.

Most assuredly, the "best price" and double dip prudence proposals set forth by Staff have no place in this transitional plan because they are unsustainable, unfair, and inefficient. They would, in my opinion, set APS on the path towards bankruptcy.

The California fiasco and the FERC's regulatory mambo demonstrate that both market conditions and regulatory policy uncertainty combine to mean that retail choice will not take hold voluntarily, at least in the very near term. Incumbent utilities that retain their duty to responsibly serve virtually their entire native retail load, which continues to grow, need to be encouraged by regulators to make the necessary investments and to sign prudent long-term contracts for new supplies. This is not the time to impose unsustainable and costly "best price" requirements and to otherwise undermine the incumbent utility distribution companies.

Q. DO MERCHANT GENERATORS HAVE THE SAME SUPPLY AND LEAST COST (OR PRICE) RESPONSIBILITY THAT APS WOULD CONTINUE TO HAVE? HOW DOES THIS AFFECT THE UNREASONABLE CONSTRAINTS THAT STAFF WOULD IMPOSE?

A. No. Merchant generators sell a wholesale commodity in either a short-term spot market or under some long-term contract. The latter can be "futures" contracts in which an organized market defines specific products in terms of size, location, timing, etc. (e.g., pork bellies or West Texas crude oil barrels) or a "forward" bilateral contract in which the merchant generator (seller) and buyer design a long-term contract that uniquely specifies the product sold.

1 Merchant generators have no duty to serve retail consumers.
2 Indeed, unless bilateral forward contracts are used with direct retail users,
3 merchant generators mostly have no retail customers or contracts. They
4 sell their output in commodity markets that mostly ignore geography and
5 political jurisdictions. Competitively generated and sold MWHs would flow
6 toward higher prices and are constrained, if at all, only by transmission
7 networks.
8 Some generators sell to electricity traders or merchants that
9 translate the physical energy produced (MWHs) to a commodity that is
10 traded as a financial instrument much like common stocks, pork or corn.
11 Under these market-trading conditions, few retail consumers have
12 sufficient scale or scope to become direct buyers. New entrants into the
13 energy service business or the incumbent local distribution utility (here
14 APS) need to assume this necessary market aggregation and portfolio
15 function.
16 Distribution and retail service providers must take steps to obtain
17 adequate supply and hedge against price fluctuations along with designing
18 different retail products. As I understand the facts in Arizona, although
19 retail choice is available and has sometimes been touted, at present there
20 are no retail customers that are willing to bypass APS and seek retail
21 services under either bilateral forward contracts or from new competitive
22 retail energy service companies. These retail market results appear to be
23 directly tied to the recent memories of severe wholesale price spikes in the

West and APS' declining retail prices. Through default and its traditional franchise responsibilities, APS is, for a significant part of the state, the sole electricity entity that has any responsibility for achieving the joint retail consumer objectives of supply reliability and least price in Arizona. As such, Staff's proposals to saddle APS with a higher burden than traditional regulation at a much greater cost through a "best" price offer are totally unnecessary and unwarranted.

Merchant generators produce a commodity that is traded like all commodities. Their sense of reliability is related to unit capacity factors, not a commitment to a specific geographic or regulated jurisdictional entity's need to keep the lights on at just and reasonable prices.

Merchant generators, often to their chagrin, are also highly influenced by political and federal regulatory matters. The FERC's shifting, stuttering, and changing forms of western states' market mitigation regulation are prime examples of how politics and federal regulation can and have affected reliability and prices in the wholesale electricity markets in the western United States. Merchant generators bristle at all of this because they quite reasonably do not think that guaranteeing retail reliability or bundled price stability is their responsibility.

Merchant generators neither owe nor have any geographic or jurisdictional allegiance to Arizona. More significantly, the FERC can exercise considerable sway over merchant generators to react to real and

1 politically manufactured emergencies in California. The ACC cannot
2 accept an academic version of a free, unfettered wholesale electricity
3 market as long as California and the FERC combine to prevent such a
4 market from evolving in the west. I conclude that APS needs to be
5 encouraged to sign prudent long-term purchase power contracts without
6 the risk of future *ex post* prudence reviews or some "best" price, "lesser of"
7 pricing scheme in which APS must pay a higher contract price, while
8 charging retail consumers a lower competitive spot market price.

9 **Q. ARE THERE ANY OTHER RELIABILITY CONCERNS THAT STAFF'S**
10 **PROPOSAL DRAW INTO THIS PROCEEDING?**

11 A. Yes. Reliability is more than balancing generation supply with demand to
12 establish relatively stable prices and avoid blackouts. Reliability also
13 involves transmission, which must maintain voltage balances, frequency,
14 and manage capacity. Congestion management on the electricity network
15 or grid is also necessary to achieve system efficiency and grid protection.
16 Accordingly, a network operating entity must manage the power
17 grid, coordinate transmission line construction and new generation
18 location, serve various load pockets, and sustain system growth.
19 Available transmission capacity may vary periodically and over time. It is
20 also necessary to coordinate or account for generation outages, imports
21 and exports, and more. These are all matters of system reliability that are
22 traditionally the regulated, vertically integrated utility's responsibility.
23 These roles and responsibilities do not disappear under wholesale

1 competition. Indeed, the FERC-led, some might say forced-fed, effort to
2 form large RTOs is based on forming new organizations that will assume
3 these transmission functions plus various scheduling coordinator or
4 dispatch roles.

5 In addition, fuel diversity has been and still is important. Merchant
6 generators mostly build or propose to build new natural gas fired units.
7 There have even been suggestions to convert existing coal generation in
8 the region to natural gas. California's fiasco in the late fall and winter of
9 2000 shows that a single fuel choice is problematic in the western United
10 States.

11 Combining coal and nuclear generation with natural gas fired
12 generation enhances price stability and system reliability. Merchant
13 generators have no such system wide or jurisdictional concerns, although
14 they may be expected to hedge their own narrow single fuel position.

15 When a merchant generator designs a hedging strategy in
16 competitive energy markets, it would likely consider upside electricity
17 prices in conjunction with, or as offsets to, high natural gas or fuel prices.
18 This business tradeoff is not what most retail electricity consumers are
19 prepared to accept or consider. Accordingly, retail service entities, such
20 as APS, need to design supply portfolios with multiple fuels, purchase
21 power contracts, and more to provide the very different and more
22 complete retail hedges. Given what happened in California, most retail
23 consumers will demand and expect such assurances.

Ms. Andreasen's Testimony

Q. WHY DO YOU CONCLUDE THAT MS. ANDREASEN'S ADVISORY GROUP PROPOSAL IS "INEFFECTIVE AND UNNECESSARY"?

A. Ms. Andreasen's proposals are unnecessary and most certainly will be ineffective because the advisory group she proposes has no responsibility or authority. It would become a representative stakeholder debating society. As was demonstrated in California, such stakeholder boards are unwieldy in size and provide a false notion that real market performance will be monitored. There is now widespread recognition that such stakeholder advisory boards provide no information about and no security against real market abuse. In virtually all situations, they are simply more trouble than they are worth.

California's experience is quite relevant here. Stakeholder groups can sometimes help resolve small technical differences in a collaborative manner. However, in a crisis and/or when large sums of stakeholder monies are involved, (i.e., precisely when clear communication, authority, and decisiveness are required) stakeholder groups freeze like "deer in the headlights." They cannot act and they will not or cannot communicate quickly and effectively to people who can take action. As shown conclusively in California, advisory groups like the one recommended by Ms. Andreasen are generally useless. Regulators who establish advisory groups can also expect to both be blamed when things go wrong and the press discovers and critically reports that so-called "special interests" dominate the regulators' advisory board.

Second, the FERC has made it very clear that stakeholder representative groups are not sufficient for most substantive tasks. More important, FERC requires that market monitors must be independent, not representative.

Thus, I conclude and recommend to the ACC that Ms. Andreasen's powerless stakeholder advisory group proposal should be rejected.

Ms. Keene's Testimony

Q. WHY DO YOU FIND FAULT WITH MS. KEENE'S AFFILIATE AND CODE OF CONDUCT PROPOSALS?

A. Ms. Keene engages in a "ready, fire and aim" approach to regulation. She fails to identify (i.e., "aim" at) any real target or problem. She simply asserts that "self-dealing" and "preferential treatment" are inevitable, and that "cross subsidies" surely will follow.

Ignoring the significant ACC regulation, FERC regulation, and SEC/PUHCA regulation, Ms. Keene creates problems after she "fires" her charges at Arizona's energy companies. This is not reasonable. Worse, she fails to assess current regulatory rules and ratemaking practices. Ms. Keene cites a litany of bad things that could ensue (e.g., predatory pricing), and unreasonably assumes that even though the "lights are on, no one is home." I have much more faith in existing ACC regulation, FERC regulation, competitive market disciplinary forces, and the track record of Arizona's incumbent electric utilities in controlling and regulating affiliate transactions than does Ms. Keene. The ACC and others do not condone and will prevent self-dealing and predatory practices, eschew

cross subsidies, and reject unfair competition. Ms. Keene fails to address current responsibilities and facts. Instead, she speculates about potential problems and offers no remedies for these non-existing speculative problems, other than the implication that competitive markets need to be regulated. There is no need for her to conjure up problems and to speculate as she does.

Q. WHY DOES MS. KEENE THINK THAT EXISTING CODES OF CONDUCT ARE INSUFFICIENT?

A. Ms. Keene does not explain why the current rules and existing codes of conduct are inadequate. Ms. Keene uses her speculative allegations of self-dealing, cross subsidies, and predatory pricing as a ruse to suggest that utility misconduct is inevitable. In so doing, she misses the target widely. In my experience, utility companies and their affiliates seldom come even close to these excesses. Here, Ms. Keene's speculation does not justify her call for oppressive regulation.

Q. HOW DO YOU RESPOND TO MS. KEENE'S SURVEY OF WHAT OTHER STATES ARE DOING?

A. Ms. Keene's survey appears to consist of only three states. This review is cursory at best, and not particularly representative.

Q. DOES APS' CODE OF CONDUCT ADDRESS THE ISSUES COVERED IN THESE STATUTES?

A. Yes. Like the Massachusetts statute referenced by Ms. Keene, Sections IV(A)&(B) of APS' Code of Conduct prohibit APS from using or providing confidential customer information to any competitive electric affiliate or other third party. As is apparently required by the Maryland statute, cross

subsidization is also prohibited by Sections VIII(A)&(B) of APS' Code of Conduct; affiliates are treated the same as non-affiliates (Section III); customer information and privacy is protected (Sections IV(A)&(B)); and services must be provided in a non-discriminatory manner (Section VII(D)). Similar to requirements in Kentucky, APS' Code of Conduct covers affiliate pricing rules (Sections VIII(A)&(B)) and separate accounting treatment is required (Section X(C)).

Q. DOES MS. KEENE CONSIDER FERC'S AUTHORITY WITH RESPECT TO WHOLESALE POWER TRANSACTIONS?

A. No. Ms. Keene fails to address federal regulatory authority with respect to wholesale electricity transactions. Her "arms' length" transaction reviews are ill-formed and wrongly based on gathering proprietary information without proposing necessary detail, specifics, and relief. Regulators have sufficient experience, expertise, and authority here. Ms. Keene uses the "code of conduct" and "affiliate interest" issues inappropriately and unnecessarily to force unregulated competitive firms and/or affiliates to disclose proprietary information.

Ms. Keene's "ready, fire and aim" approach and her conclusions should be rejected.

Q. DOES MS. KEENE DISCUSS AFFILIATE PRICING ISSUES?

A. Ms. Keene references Mr. Rowell for the proposition that "sales or transfers from an affiliate should be prices at the lower of cost of market." Earlier in this testimony, I discussed at length why I disagree with Mr.

1 Rowell's "lesser of" pricing recommendations. Those criticisms apply
2 equally to Ms. Keene's adoption of Mr. Rowell's proposals.

3 SECTION IV. CONCLUSIONS AND RECOMMENDATIONS

4 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE ACC.**

5 A. I support competition. I continue to urge the ACC to encourage retail
6 choice if practiced on a level playing field. Staff's "standard offer" or "best
7 price" scheme is foolish. It is also dangerous and not sustainable. It
8 would guarantee that Arizona would have its own electricity crisis. This
9 should not and need not happen.

10 Staff should *not* think it can manage and direct specific "best"
11 competitive outcomes. This is a false "god." Thus, I recommend that the
12 Commission neither attempt to control or to regulate competitive markets
13 nor follow Staff's draconian and misplaced advice. When left to their own
14 devices, competitive markets will send appropriate signals to match supply
15 and demand, obtaining the best price and one that will vary based upon
16 the degree of risk allocation for different consumers in a competitive
17 choice market. Attempts to micromanage competition combine the worst
18 elements of cost of service regulation and competition and are a
19 guaranteed recipe for a disastrous California-like result.

20 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

21 A. Yes.

TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

May 29, 2002

EXHIBIT

APS-4

Admitted

TESTIMONY OF WILLIAM H. HIERONYMUS

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TESTIMONY OF WILLIAM H. HIERONYMUS

INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is William H. Hieronymus. I am a Vice President of the consulting firm Charles River Associates, Inc. Charles River Associates is an economic and management consulting firm with offices in Boston; Washington D.C.; Philadelphia; College Station and Houston, Texas; Salt Lake City and several West Coast cities as well as international offices in Europe and the Pacific. My business address is 200 Clarendon Street T-33, Boston, MA 02116.

Q. What is your occupational background?

A. I have assisted clients on the economic and management issues involving utilities since approximately 1975. Since that time, I have performed numerous engagements for utilities, independent power producers, government agencies and other parties with interests in the industry. Since approximately 1988, I have focused on the restructuring of the electric power industry, initially in Europe and the Far East and, from 1993, in North America. In that context, I have performed engagements concerning utility privatization legislation; the treatment and quantification of stranded cost; the creation of regulatory and market rules; asset valuation and market forecasting; and market power monitoring and mitigation. I have testified well over 100 times before state commissions, the Federal Energy Regulatory Commission (FERC), legislative bodies and federal courts. I also have appeared before the Arizona Corporation Commission (Commission) on

numerous occasions. Most recently I submitted prepared written testimony on behalf of the Arizona Public Service Company (APS) in Docket No. E-01345-01-0822. My resume is attached as Exhibit WHH-1.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by APS to comment on two issues. The first is whether the separation of generation from APS, consistent with the Commission's existing competition rules and the APS Settlement, is in the public interest. The second is whether Pinnacle West Energy Corporation (PWEC), as the future owner of the APS generation, will have market power.

SUMMARY OF CONCLUSIONS

Q. Please summarize your conclusions.

A. Regarding the first question, the separation of APS's generation is in the public interest because the public interest is best served by the creation of a liquid and vibrant competitive wholesale market. Severing the vertical connections between generation and transmission materially facilitates the creation of a competitive wholesale market by reducing concerns about the exercise of vertical market power. Eliminating unitary ratemaking over the various portions of the utility enterprise, especially the full separation of the generation entity from the distribution and customer service entity, eliminates cross-subsidization concerns.

The benefits of a competitive wholesale market flow primarily from three causes. First, the progressive movement from cost of service to market pricing

1 produces powerful efficiency incentives that did not exist previously. Related to
2 this is the improvement in management decision making for competitive services
3 as more profit-oriented managements replace utility monopoly managements and
4 their regulators as decision makers concerning what to build, how to contract for
5 fuels, and how to operate generating facilities. Second, a competitive wholesale
6 market allows customers to benefit as competition among efficient generators
7 drives down prices relative to what they would have been under continued
8 monopoly regulation. Third, a competitive wholesale market is an essential
9 underpinning of retail competition and, with it, the product and pricing
10 innovations that retail competition can produce.

11 Within the context of the WSCC market area, there can be a competitive
12 market even if APS remains an "old fashioned" utility, vertically integrating load
13 and generation. However, APS's customers will not be allowed to benefit from
14 either the wholesale or retail competitive alternatives if this occurs.

15 The experience with gas deregulation taught the lesson that separation of
16 the control of the transmission network from the control of bulk energy supply is
17 an essential element of creating a competitive wholesale market. Beginning with
18 Order No. 888 and continuing on through the current campaign to cause all
19 electric transmission to be controlled by RTOs that are independent of generation-
20 owning entities, this separation of generation from transmission has been the main
21 theme of FERC policies to promote competitive wholesale markets.

22 Because the bulk of existing generation is, or was, owned by vertically
23 integrated utilities, the creation of a vibrant wholesale market also is facilitated by

1 reducing the connection between a utility's existing generation and its load.
2 Separation of competitive generation from remaining regulated monopoly entities
3 is necessary to eliminate potential cross-subsidies that could interfere with both
4 wholesale and retail competition

5 I am aware that recent events in areas near Arizona have tarnished the
6 image of market restructuring. I believe that, allegations of misbehavior
7 notwithstanding, the specific events of 2000-2001 in the WSCC arose from a very
8 unusual combination of events that are unlikely to recur simultaneously and must
9 be understood in that context. It is notable that many other policy decision
10 makers have not been fazed by the California experience. The movement away
11 from the regulated monopoly model to the competitive market model has only
12 marginally slackened its pace. In most of the U.S., in Europe, Asia, South
13 America and parts of Africa, indeed even in a number of formerly communist
14 countries, the belief that competitive wholesale and retail energy markets are
15 superior to regulated monopoly remains unshaken.

16 Turning to the second topic of my testimony, potential market power in a
17 competitive market and the potential market power that a post-divestiture PWEC
18 might be alleged to have, this issue is difficult to summarize easily. As a general
19 matter, PWEC, even if it had full authority to sell power from the entire fleet of its
20 assets (including those to be transferred) would lack market power in relevant
21 regional power markets, since its share of such markets is small and those markets
22 are structurally competitive, and will remain so after divestiture. Moreover, the
23 Pinnacle West companies are not in fact free to sell their power at market rates.

1 Currently, the Pinnacle West companies only have power to sell during off-peak
2 periods. Completion of Red Hawk Units 1 and 2, and West Phoenix Unit 5 will
3 somewhat improve its balance between load and resources. However, load
4 growth in Arizona is so rapid that these units will be absorbed before they are on
5 line, with the result that Pinnacle West still will have insufficient resources owned
6 or under current contract to serve 2003 loads reliably while making sales during
7 most near-peak periods. In off-peak periods, they will have power to sell, but so
8 will many other sellers. Hence, these shoulder and off-peak markets will be
9 vigorously competitive.

10 If APS is granted its requested variance from the Commission's Rule
11 1606(B) and enters into a long term contract with PWCC to serve its standard
12 offer load, its net short position will be maintained. Under the proposed
13 agreement with APS, PWEC would contract away its generation on a long-term
14 basis. Since its ability to sell energy at market prices would be small, it would
15 lack market power. As is the case today, its ability to sell power to the market
16 would be primarily during off-peak periods when competition is especially
17 vigorous.

18 To the extent that the Commission's final resolution of the issues in this
19 and related dockets frees up PWEC capacity or, more generally allows such
20 capacity to be sold into short term markets at market rates, PWEC's share of such
21 markets will increase. Even in this event, PWEC still will lack market power in
22 regional power markets (e.g. the market consisting at a minimum of the Desert
23 Southwest and Southern California). In most respects, it is this larger market that

is appropriately considered in evaluating PWEC's potential market power, since power pricing reflects relatively unconstrained competition across it during most periods.

The potential market power adhering to assets located within load pockets such as Phoenix and Yuma is prospectively constrained by existing APS tariff provisions for "must run" power[1] and will continue to be constrained by RTO tariff conditions once an RTO becomes operational.

Whenever there is a transition from traditional regulation to competitive markets, the issue arises as to whether the generation portion of the previously vertically integrated utility will have locational market power over the customers in the related control area. Pinnacle West has passed FERC's test (the "hub and spoke" test) to determine whether it should be authorized to sell power at market rates, including the right to sell at market rates within the APS control area. Since this authority was granted, FERC has supplanted the test that Pinnacle West passed with a new and more stringent test (the "Supply Margin Assessment"). I have performed this test and find that a post-divestiture PWEC still would qualify for market rates in all areas, including the APS control area.

If the Commission has any remaining concern that PWEC could have locational market power in the APS control area, that concern can be addressed readily. APS's customers are potentially subject to PWEC exercising market power only if their loads are not covered by bilateral contracts. If those loads are

substantially covered by bilateral contracts – whether with PWEC (through PWCC) or some other seller – PWEC will not have market power with respect to them. Since any well-designed resolution of the issues in this docket will assure that the APS Standard Offer Service will be backed to a large degree by bilateral agreements, PWEC will not have locational market power in the APS control area.

THE BENEFITS OF A COMPETITIVE MARKET AND NEED TO TRANSFER FACILILITIES

Q. What is the current status of market deregulation in the U.S.?

A. A pictorial summary created by the U.S. Department of Energy is attached as Exhibit No. WHH-2. The primary focus of the DOE analysis is on retail access. However, underlying retail access in most or all instances is wholesale market restructuring. According to DOE, 24 states plus the District of Columbia have enacted retail access by law or by regulation. These states include most of the Northeast and Mid-Atlantic, and much of the Midwest and Southwest and West Coast areas. The areas without approved retail access include the prairie and mountain states, much of the Southeast and some hydro-based states in the Northwest. Arizona is classified as having approved retail access, as is correct. The states with approved retail access include one, California, where access has

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[1] My understanding is that FERC has accepted the form of the must run protocol as part of APS's tariff but requires that the specific (i.e. price) terms of the tariff be filed before the must run portion of the tariff becomes active.

1 been suspended and seven where it has been delayed since the events of 2000-
2 2001.

3 **Q. What common activities have the states with retail access undergone?**

4 A. The activities relevant to this proceeding include separation of generation,
5 transmission and distribution (and in some case retailing or customer service);
6 specifically the corporate separation of generation either into a separate subsidiary
7 or by divestiture to third parties or a combination of the two; creating regulatory
8 structures for retail competition, including provider of last resort regulations; and
9 the creation of transitional arrangements to ensure price stability and guard
10 against the exercise of market power.

11 **Q. You noted that a common activity in states with retail access is the separation**
12 **of competitive generation from the regulated monopoly activities. Has this**
13 **been done in all such states?**

14 A. Yes, with the exception of Virginia. Notably, Virginia retail access is off to a
15 very slow start.

16 **Q. Why is the separation of the generating assets from the regulated utility a**
17 **nearly universal element of the move to retail access?**

18 A. There are several reasons. First, the creation of a market-driven, competitive
19 market is seen as beneficial in its own right. Indeed, many industry experts
20 believe that wholesale competition, not retail competition, is the primary benefit
21 from utility restructuring. Second, both retail access initiatives and the federal
22 move to pull transmission planning and control out of the vertically integrated

1 utility undermine the basis for maintaining a regulated monopoly source of
2 generation. Third, both retail and wholesale competition require a deep and liquid
3 wholesale market. This is made more difficult if the load-serving utility retains its
4 generation.

5 **Q. Please expand on the desirability of a competitive wholesale market.**

6 A. There are two main "fathers" of the movement to deregulate electricity market.
7 The first was the analogy to other markets that previously were tightly regulated
8 and then deregulated. These include rail and motor freight, telecommunications,
9 airlines and natural gas. These earlier industry deregulations were seen as a
10 success. The causes for the perceived success – reducing the scope for vertical
11 market power and cross-subsidization, more profit driven and innovative
12 managements, and removing politics and regulatory policies to a substantial
13 degree from micro-decision making -- were seen as applying also to the electric
14 utility sector.

15 The second was the then-recent history of the electricity industry itself.
16 Both regulators and utilities had been badly bruised by the experience of over-
17 building expensive baseload generation in the 1970s and early 1980s. As reserve
18 margins narrowed, utilities were reluctant to build, and regulators to approve, new
19 power plants. In some states, regulator or legislatively driven excessive costs for
20 QF power were a cause of high rates. Indeed, the first part of the CPUC's "Blue
21 Book" that kicked off its deregulation initiative reads like a plea for someone to
22 "stop me before I make bad regulatory decisions about new generation again."

On the more positive side, the experience with QF power beginning in the mid-1980s and with Exempt Wholesale Generators in the early 1990s created confidence that non-utility resources could be absorbed into the generating mix without impairing reliability. Confidence in a competitive wholesale market also was enhanced by development of a new and better technology for gas-fired generating equipment that could be built quickly and without a need for high front-loaded revenues. Further, increasing trading volumes among utilities, particularly within the existing "tight pools" in the Northeast, created confidence that a wholesale market that depended on both bilateral contracts and spot trading transactions could be operated reliably and economically.

This then-recent history, both negative and positive, along with introduction of competitive electricity markets in the U.K., continental Europe and elsewhere created the confidence that competitive markets for electricity could work and provide efficiency benefits to the economy and cost benefits to consumers. Moreover, a competitive wholesale electric market could underpin retail competition and with it the innovations that had been seen with the deregulation of other industries. This fit well with the general presumption that pervades the U.S. political system and economy that free competitive markets are preferable to government supervision of markets and companies.

Q. Do regulators and public officials in the states that have deregulated remain committed to deregulation, including the separation of generation from regulation?

1 A. Yes. I asked my staff to do a state-by-state online search for remarks made
2 recently by such officials. These officials remain confident that their markets will
3 work well and provide benefits to consumers. I will cite a representative sample:

4 • Deregulation in Texas took effect on January 1, 2002. Since then, According to
5 Texas Governor Rick Perry, consumer costs have plummeted $1 billion due to
6 residential rate savings.[2] "Texas' success can be attributed to the deregulated
7 market's design, competitor strategy, and the good fortune of low wholesale
8 prices."[3] Texas Public Utility Commissioner Rebecca Klein says that electricity
9 market in Texas is "healthy" and customers that have switched electric suppliers
10 are "already seeing savings of up to 12 percent."[4] Tom Noel, CEO of the Electric
11 Reliability Council of Texas (ERCOT), said that "electric deregulation thus far
12 has been successful," and that, "new electricity suppliers have been chosen by
13 approximately 270,000 of the 5.5 million Texas residents who have gained the
14 right to pick new providers on January 1."[5] For the last three years, the Center
15 for the Advancement of Energy Markets (CAEM) has published the "Red Index"
16 (Retail Electric Deregulation Index) which is, in their words, "a scorecard for
17 measuring progress on energy restructuring."[6] CAEM uses 22 objective

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2 *Hopefuls clash over electricity; Sanchez, Perry cite higher, lower rates*, San Antonio Express-News, Metro/South Texas section; pg. 5B, May 16, 2002

3 Xenergy Vice President Bruce Humphrey (http://www.eren.doe.gov/electricity_restructuring/weekly/apr05_02.html)

4 *Texas Officials and Suppliers Proclaim Electric Deregulation A Success Thus Far,* PR Newswire, Financial Section, February 28, 2002

5 *Texas Deregulation Picking Up Speed,* Energy Daily, Volume 30, Number 28, February 12, 2002

6 Retail Energy Deregulation Index 2002 (Abstract), Center for the Advancement of Energy Markets

1 restructuring criteria to arrive at a state's score based on 100 points. The CAEM
2 criteria are broken up into a competitive framework cluster, a generation cluster, a
3 consumer cluster, a distribution cluster, and a commission cluster. Texas took the
4 top U.S. spot, in the 2002 Index, with 69 points. Ken Malloy, CEO of CAEM,
5 said, "I am confident that Texas customers will enjoy the benefits of electric
6 competition much sooner than customers in other states."[7]

7 • On March 27, 2002, Pennsylvania's Public Utility Commission Chairman Glen R.
8 Thomas and Mark Schwiker, the Governor of Pennsylvania, announced, "the first
9 Pennsylvania customers will see the Competitive Transition Charge eliminated
10 from their bill. Duquesne Light customers will see their rates drop between 16
11 and 20 percent."[8] Pennsylvania's Electric Choice program has, over the last 5
12 years, saved customers more than $4 billion in electricity costs.[9] Pennsylvania
13 ranks second among states in the 2002 RED Index, having recently been
14 overtaken by Texas.[10] On February 7, 2001, in his annual budget address to the
15 General Assembly, then Pennsylvania Governor Tom Ridge said, "We have
16 delivered approximately $3 billion in savings, due to guaranteed rate cuts, savings
17 from shopping, and avoided fuel costs." Then-Pennsylvania Public Utility
18 Commission Chairman John M. Quain added, "Before electricity choice,

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7 *Texas Electric Competition Ranked #1 in U.S.,* (web site)

8 *PUC Chairman Thomas Marks Milestone for Electric Competition: First PA Customers See Lower Rates Thanks to 'Stranded Cost' Coming Off Bills,* March 27, 2002 (http://puc.paonline.com)

9 *PUC Chairman Thomas Marks Milestone for Electric Competition: First PA Customers See Lower Rates Thanks to 'Stranded Cost' Coming Off Bills,* March 27, 2002 (http://puc.paonline.com)

10 Retail Energy Deregulation Index 2002 (Abstract), Center for the Advancement of Energy Markets

Pennsylvania electric rates were 15 percent above the national average, and now our rates are 4.4 percent below the national average."[11]

- "About 46 percent of the total amount of electricity used every day in Maine is purchased from competitive power suppliers", said Maine Public Utilities Commission spokesman Phil Lindley.[12] "For large and midsize commercial customers, Maine has more competition in energy supply than perhaps any state. In Central Maine Power's territory, for instance, 88 percent of all manufacturers and other large power users have signed contracts with energy providers. For medium users such as supermarkets, the figure is 42 percent."[13] Maine has seen success that most states haven't in converting customers to competitive suppliers because they use a system where "the standard offer tracks the wholesale market up or down on a year-to-year basis, with the cost of competitive supplies staying in the same range. In most states, the multi-year standard offers rate remains well below wholesale market rates this year and the number of users choosing alternative suppliers has declined."[14]

- On February 1, 2002, the Michigan Public Service Commission (PSC) released its "Status of Electric Competition in Michigan" report. According to the PSC's findings, competition in Michigan's retail electric choice program grew 30 percent

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[11] *Pennsylvania Again Ranked No. 1 in Nation for Electric Deregulation,* Commonwealth of Pennsylvania Office of the Governor: Commonwealth News Bureau, February 7, 2001

[12] *Power rates to change today; For many customers, prices will decrease,* Bangor Daily News, March 1, 2002

[13] *Restructuring quietly meeting most goals,* Maine Sunday Telegram, BUSINESS; Pg. 1F, January 6, 2002

during 2001.[15] To date, the Commission has licensed 15 alternative electric suppliers to serve its State's customers. "Commissioner Robert Nelson has said that he believes the state would experience a dramatic increase in commercial load going to competition, particularly in Detroit Edison's territory."[16] The commission remains confident of the success of retail access despite a slow start, citing transitional problems including "infrastructure limitations, economic difficulties nationally and statewide and the simple need for participants to learn how to compete effectively."[17]

- Ohio's electric restructuring is in the second year of a five-year market development period. Alan R. Schriber, Chairman of the Public Utilities Commission of Ohio (PUCO), reports that 40 governmental aggregators received certification from the PUCO and subsequently their programs have accounted for 85 percent of the residential switching customers, 50 percent of the commercial switching customers and 25 percent of the industrial switching customers.[18]

These comments focus primarily on retail access, since delivering choice to customers is a primary motive for utility restructuring. However, these policy-

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[14] *Marketers serving more load in Maine as standard offer rate hikes take effect*, Retail Services Report, COMPETITION; Pg. 5, September 28, 2001

[15] *Status of Electric Competition in Michigan,* Michigan Public Service Commission: Department of Consumer & Industry Services, February 1, 2002

[16] *Electric Restructuring Weekly Update,* The United States Department of Energy, February 8, 2002 (http://www.eren.doe.gov/electricity_restructuring/weekly/feb08_02.html#mich)

[17] *Status of Electric Competition in Michigan,* Michigan Public Service Commission: Department of Consumer & Industry Services, February 1, 2002

[18] *The Ohio Retail Electric Choice Programs Report of Market Activity for the Year 2001,* Public Utility Commission of Ohio, April 2002

1 makers would not remain bullish on the success of retail access unless they also
2 were confident that underlying wholesale markets also were competitive.

3 Q. **Your summary indicated that a number of states had not embarked on**
4 **deregulation and that some had backtracked from scheduled deregulation**
5 **after the California experience. Why have some states shown lesser interest**
6 **in restructuring their electricity industries?**

7 A. The reasons vary. Many of the states that have not undertaken restructuring are
8 states with low rates and low variable production costs. Low rates give rise to "if
9 it ain't broke, don't fix it." Low variable costs cause concerns that restructuring
10 would cause power to be shipped to higher cost markets or, more generally, for
11 low in-state prices to be arbitraged against higher prices in nearby areas. Some
12 states are primarily public power and for both tax-related reasons and cultural
13 ones are reluctant to participate in markets. Some states may simply be
14 conservative, not in the political-economic sense of being pro-market and pro-
15 capitalism, but in the sense of reluctant to change. Finally, in some states a short
16 legislative calendar has contributed to failure to take up the issue in preference to
17 other concerns seen as more pressing.

18 What is signal about the motives for not moving to restructure is the
19 relative absence of a defense of the status quo except in the public power states.
20 States that have eschewed restructuring due to low generation costs do so for the
21 pragmatic reason that the current system allows them to circumvent what
22 otherwise would be constitutional barriers to measures that keep in-state power

1 from being sold in multi-state markets. Only Florida might be considered to be
2 affirmatively status quo, relying on vertically integrated utilities for make or buy
3 decisions and prohibiting purely merchant generators.

4 **Q. You alluded earlier to what was going on internationally. Can you**
5 **summarize briefly?**

6 A. Yes. Utility deregulation first started in Chile in the 1980s. In 1988, the U.K.
7 embarked on privatizing its state-owned electricity industry. Privatization was
8 completed in 1990, with separation of generation, transmission and distribution, a
9 partial breakup of generation (into three entities) and limited retail access, since
10 expanded to full retail access, with a retail access program ranked as the most
11 successful in the world. In 1993, the European Union adopted a retail electric
12 competition program with phased access that now stands at about 40 percent.
13 National initiatives in some member states resulted in 100 percent access. Both
14 the EU and its member states have taken steps to create competitive underlying
15 wholesale markets. Restructuring is complete in Australia and New Zealand, well
16 underway in Korea, Singapore and Hong Kong, and beginning in China. Various
17 South American countries have restructured their markets to accommodate new
18 entry and the sale of companies to new owners. Some of the larger former Soviet
19 republics and satellite nations in Eastern Europe have completed or are well on
20 their way to restructuring.

21 **Q. In your summary at the beginning of this section, you indicated that the legal**
22 **and operational separation of utility functions generally was one reason for**
23 **the legal separation of generation. What did you mean?**

A. The alternative to the creation of a competitive wholesale market is the Integrated Resource Planning (IRP) process. IRP recognizes that generation and transmission are built to serve load economically and reliably and are, in a sense, interchangable. Under IRP, demand-side measures, transmission planning and generation planning all must be done interdependently.

Retail access means that no entity can plan its generation for a stable and predictable customer base for the simple reason that the load that it will serve cannot be predicted with the same accuracy as previously. Whereas previously load uncertainty related to the economy and weather of a predetermined region, generation planning can no longer be based on "native load" but must reflect the market opportunities of selling generation not only to a (relatively unknown) base of retail customers but also to the market.

Related to this is a concern with cross-subsidy and preferential self-dealing that can undermine the effectiveness of retail competition. These appear to have been the principal reasons for this Commission's approval of asset transfers on a number of previous occasions, as discussed in Mr. Jack Davis's testimony.

Another break in the vertical chain that underpinned IRP is the separation of transmission planning and operation from both generation and from retail operations. FERC Order 888 required strong codes of conduct restricting communication between transmission providing portions of a utility and those portions with market functions, including expressly those that buy and sell power. It since has broadened the application of those codes. More fundamentally,

1 FERC's RTO initiative, together with its insistence that all essential transmission
2 planning and operation functions occur at the RTO level, have broken the nexus
3 between transmission and generation planning. Whereas previously a utility
4 could trade off between generation siting decisions and transmission investments,
5 that process cannot be integrated, at least not directly, in an RTO world wherein
6 the RTO plans transmission and merchant generators site generation.

7 **Q. The third summary reason why utility generating assets need to be separated**
8 **is the need for a deep and liquid wholesale market. Why is this needed?**

9 A. All markets benefit from many buyers and sellers and from transparency. By
10 transparency, I mean that there exists a market price (rather than several prices for
11 the same product and area) and that this price is visible and knowable to all actors
12 in the market. This inherently requires deep and liquid markets. If all existing
13 utility-owned or controlled generation remained with the utility, then most of the
14 power used by customers (all of it, initially) would be outside of the market and
15 the market correspondingly thinner.

16 **Q. Doesn't this imply that APS's proposed PPA will have a negative effect on**
17 **competitive markets since it will reduce the amount of energy traded in the**
18 **market for its duration?**

19 A. No, not materially. If your question had been, would long term PPAs covering <u>all</u>
20 <u>of the load in the WSCC and all of the existing generation</u> injure competitive
21 markets, my answer would have been yes. However, this is not the case. The
22 large-scale divestitures in California and the substantial amount of new merchant
23 generation being built in the region are sufficient to create a deep and liquid

1 market under foreseeable circumstances. This gives APS and the Commission the
2 luxury of deciding whether it wants the PPA on other grounds, such as price,
3 reliability, fuel diversity and so forth without needing to be concerned about
4 whether wholesale power markets will be deep and liquid.

5 **Q. Your comment about California divestiture prompts me to ask what your**
6 **basis is for the statement that the California experience has not deterred**
7 **other states and was due to causes unlikely to recur. Why is it?**

8 A. What happened in California can be traced to four causes, each of which is
9 unlikely to affect Arizona in the future. Briefly, these are: 1) a supply shortage,
10 amplified by a temporary gas shortage; 2) the absence of long-term contracts; 3)
11 market design flaws; 4) the absence of regulatory safeguards and slowness in
12 regulatory response. The first, a shortage of supply, is the principal cause of the
13 crisis. The remaining three are reasons why the tight supply conditions had such
14 a great effect on customers, the California utilities and markets throughout the
15 WSCC.

16 The reasons for the supply shortage are well known. For years, California
17 said "no" to new power plants. Indeed, I was SCE and PG&E's economics
18 witness in the last CPUC proceeding in which they sought, unsuccessfully, to gain
19 CPUC permission to build a major new power plant. That proceeding took place
20 in 1980! In the late 1990s, California was rapidly sucking up all of the available
21 surpluses in surrounding states. This amplified the effects of demand growth on
22 making supplies available to California disappear. Then, the record shortage of
23 hydro, combined with hot weather, created a need to run essentially all available

1 generation. This created inherently higher marginal costs and a seller's market
2 that was conducive to the exercise of market power or, at a minimum, shortage
3 pricing. Partly as a result of the high demand for gas-fired generation and partly
4 for other reasons, some of which were not specific to California or the West, gas
5 prices surged and availability fell, resulting in the extension of high prices into
6 and through the winter of 2000-2001.

7 While another low rainfall year doubtless will occur in the future, such
8 abnormal hydro conditions will not be the norm. Importantly, even if such
9 conditions recur, the conjunction of low rainfall with regionally inadequate supply
10 and wholly price insensitive demand are conditions that are quite unlikely.

11 The absence of bilateral contracts with terms that would have reflected
12 more normal market expectations meant that the California utilities, and other
13 buyers without sufficient contracts to meet their sales obligations, faced the high
14 market prices for much of their power. If the California utilities and other utilities
15 in the western U.S. had had, for example, 95 percent contract cover, I doubt that
16 we would be talking about California today. The absence of contracts sufficient
17 to cover load obligations had two causes: the decision to not sign transitional
18 PPAs for divested generation and a more general prohibition on the IOUs buying
19 power outside of the PX spot market. That provision, designed to assure market
20 liquidity, was patterned after the U.K. market rules that required that all power be
21 sold through a central spot market. However, while all power flowed through the
22 pool in the U.K., bilateral contracts were still the norm, covering some 90-odd
23 percent of distribution company purchases. A contract form called "contracts for

differences" insulated pricing from the volatile pool price despite that the power was bought and sold through the pool.

The absence of bilateral contracts may have had another effect as well. As I will discuss more thoroughly in connection with market power, a seller's incentive to seek to drive up prices is reduced to the extent that it has pre-sold power. If all of a seller's output is being sold in short term markets, it can profitably withhold a large amount of power in order to raise prices for the remainder. While I am not aware of a definitive demonstration that such withholding occurred in California, the incentive to do so clearly was magnified by the lack of bilateral sales.

Market participants and regulators have learned these lessons. California load is now fully covered, perhaps over-covered, by forward contracts. The California ISO is planning market changes, particularly an installed capacity obligation, to insure that adequate reserves exist, generally covered by forward contracts. Other load serving entities in the region also has taken steps to increase contract cover.

Poor market rules bear some of the blame for the California experience. The "gaming" recently revealed in internal Enron memoranda existed primarily to take advantage of flaws in the rules. Other rules, or the toothlessness of existing rules, contributed to high costs of power in the ISO's market. Rules changes, including market power mitigation procedures since have been made to cure at least some of these problems.

1 The last cause that I cited was a slow regulatory response. The adversely
2 affected California parties and public officials were tardy in making use of
3 available opportunities to seek redress at FERC and initiate a refund-effective
4 date under Section 206 of the Federal Power Act. FERC was, at that time, led by
5 a Chairman who was ideologically indisposed to intervention in markets. Perhaps
6 most fatally, California officials left retail prices unchanged despite the high costs
7 in the wholesale market, with the result that the demand response that would have
8 brought supply and demand better into balance did not occur. Doubtless, these
9 officials were motivated in part by an unconditional rate freeze that was part of
10 the California restructuring legislation that allowed the illusion that the high costs
11 would be absorbed by utility investors. Again, this is a lesson that, having been
12 learned, should not be repeated.

13 Indeed, the change in federal and state vigilance about the exercise of
14 market power, both horizontal and vertical, has been very marked. In particular,
15 FERC's insistence on RTO formation has taken on a new urgency since RTO
16 market power monitoring and mitigation is seen as the principal "front line"
17 defense against both the exercise of market power and gaming of inadequate or
18 inefficient market rules. Notwithstanding this role of the RTOs, the FERC itself
19 has stepped up its market power policing with proposed new rules to eliminate the
20 time gap in which prices are not subject to refund, new market power tests, and a
21 new 100 person investigation and enforcement unit.

22 **Q. What conclusion do you draw about the California experience?**

A. Simply that the Commission should not retreat from its previously expressed belief in a competitive market merely because of the California experience. At FERC and among the market participants and policy makers in WSCC markets, lessons have been learned, perhaps even over-learned, to prevent a recurrence.

This does not mean, however, that the Commission should ignore the experience in California and in other markets that prices can be volatile. Electricity is a commodity and, like all commodities, will be prone to "boom-bust" cycles. Moreover, as the market price of electricity comes increasingly to be dependent on the price of gas, the natural volatility of prices will increase. The reduction in volatility and in dependence on a single fuel source that is forecasted to increase in price more rapidly than competing fuels is a substantial benefit of entering into a long term purchase of energy from a generation fleet utilizing a mixture of fuels and technologies.

MARKET POWER

Q. What is the purpose of this section of your testimony?

A. Among the "Track A" issues set for hearing by the Commission is "the transfer of assets and associated market power issues". The purpose of this testimony is address market power in a post-transfer world.

Q. Please begin by defining market power.

A. Market power is the ability, profitably, to sustain an increase in price above a competitive level. Each element of this statement matters. Manifestly, in order to

1 increase prices, the firm or firms in question must have the ability to do so. In
2 any market with an upward-sloping supply curve,[19] all firms have some such
3 ability, albeit perhaps only to a minimal extent. Hence the next word: the action
4 taken must be profitable. If a market participant withholds capacity, price will
5 increase. However, its own sales will fall. The profitability calculus depends on
6 whether the increase in profits from higher prices outweighs, or not, the decrease
7 in profit resulting from lost sales. Next, the increase must be sustainable. If
8 prices are increased, rivals will react, for example by shifting output to the
9 affected market. Entry also may occur. The Federal antitrust authorities, i.e., the
10 Antitrust Division of the U.S. Department of Justice (DOJ) and the Federal Trade
11 Commission (FTC), and FERC tend to regard entry that can occur within a one to
12 two year period as available to discipline prices. Lastly, price increases are
13 measured relative to a competitive price; in the vague words of the DOJ/FTC
14 Merger Guidelines, the increase of concern can be "small but significant".

15 **Q. How is market power exercised?**

16 A. Exercising market power requires that capacity be withheld from the market. It is
17 basic economics that the price in a market is determined at the intersection of the
18 supply and demand curves. By withholding capacity, a supplier will reduce
19 aggregate market supply, causing price to rise. Generally, the steeper the supply
20 curve, the greater is the increase. Hence, if there are other suppliers with

[19] An upward-sloping supply curve means nothing more than that the price at which an additional amount of output will be provided increases as the amount demanded increases. For example, low loads can be met with coal and nuclear generation, moderate loads with relatively efficient gas-fired generation and high loads will require use of inefficient gas-fired or oil units. With relatively rare exceptions, most supply curves are upward sloping, especially in the short run.

1 significant capacity only slightly more expensive than the firm's competitive bid
2 price (termed an elastic supply condition), the attempt by the firm to raise price
3 significantly will be mostly unsuccessful and almost certainly unprofitable.
4 Generally, the competitive price for electricity supply is flat over broad regions,
5 then jumps between fuel types and technology, and becomes steeply increasing
6 only in the region at the end of the supply curve, where inefficient units with low
7 but diverse efficiency are the only remaining units. This is important in the
8 current context because the substantial amount of combined cycle capacity being
9 built in or near Arizona has quite similar cost characteristics and similar
10 opportunity costs, so that this region of the supply curve is flat. This means that
11 only in very high load period (when all such units are already running) or perhaps
12 very low periods (when prices are below the variable costs of such units), will
13 feasible withholding strategies in spot markets be potentially profitable.

14 Electricity also is believed to have a quite inelastic demand. That is, load
15 does not change materially if wholesale prices rise. This partly is a consequence
16 of the essential nature of some electric services and the fact that it does not
17 consume a large amount of household income or represent a large proportion of
18 most business costs. The other reason, of some policy significance, is tariff
19 design. If the prices charged to consumers do not change as wholesale prices
20 change, there will be no demand response. I discussed this in the context of the
21 California experience. Many experts also believe that real time price signaling,
22 allowing customers to avoid price spikes by reducing consumption (or even
23 paying them to do so) would discipline market power.

1 Market power can be exercised by a single, dominant firm or by the joint
2 action of multiple firms. Overtly collusive behavior (price fixing or bid rigging)
3 among erstwhile competitors is illegal and subject to severe sanction. Tacitly
4 collusive behavior is not illegal, and its prevention is a major focus of merger and
5 acquisition policy.

6 Market power generally is conceived of as involving two types of
7 activities.[20] Horizontal market power is what most people think of as monopoly
8 or oligopoly power. It flows from a dominant share of supply by a single firm or
9 from cooperative behavior among a small group of sellers collectively possessing
10 a dominant share of the supply of a product. While this condition is not itself
11 illegal, abuse of it or some types of efforts to create it are. A second type of
12 market power is called vertical market power. The relevant example would be for
13 an owner of a transmission system, itself a legal monopoly in its area, to use that
14 monopoly over an "essential facility" to exclude or disadvantage competitors in
15 related activities such as generation or serving retail customers.

16 In this discussion, I focus on horizontal market power. That is not because
17 vertical market power is less important. Indeed, in electricity, vertical market
18 power has far greater potential to destroy competitive markets. Rather, it is
19 because the actions of this Commission in approving generation divestiture and of
20 the FERC in its orders and its RTO policy already have focused so strongly on
21 preventing the exercise of vertical market power.

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[20] A third type of market power, monopsony, or power exercised by buyers over sellers, is not relevant to this discussion.

Q. How do FERC and the antitrust authorities analyze horizontal market power?

A. It is necessary to distinguish between enforcement – the detection and punishment of illegal behavior – and prevention. Since the market power issue in this proceeding is whether the divestiture of APS generation to PWEC will give it market power prospectively, I will focus on prevention.

For the past several decades, the main focus of the antitrust authorities has been on market structure. Is a single firm so dominant that it clearly can exercise market power? Is the structure of an industry so concentrated that tacitly collusive behavior is likely? If so, they will guard against measures firms might take to increase concentration or preserve a concentrated structure or a firm's dominant position.

About 20 years ago, the antitrust authorities adopted a particular measure of market concentration, called a Herfindahl-Hirshmann Index (HHI). This test measures market concentration by summing the squares of individual firm's market shares. For example, a market in which there are 5 equal sized firms (i.e. each has a 20 percent share) would have an index value of 2000 (20 percent squared is 400; 5 times 400 equals 2000). A market with a concentration of 1800 is considered to be highly concentrated and subject to anticompetitive behavior, though the standard is not a 'bright line" but rather a test to determine whether further investigation is warranted. Similarly, a single firm possessing a 35 percent share is considered potentially dominant.

1 FERC, in 1996, adopted this methodology for looking at mergers. The
2 FERC methodology focuses on a "delivered price test" that fundamentally counts
3 as "in the market" all capacity that can reach such market using the physical
4 transmission system (i.e. imports are limited by transmission constraints) with
5 costs below or just above the market price. In testimony before this Commission
6 in 1999, in Case No. E-01345A-98-0473 et al., I applied this test to the APS
7 market. I concluded that the APS market area had an HHI of about 1200 and that
8 APS's share was about 23 percent. These are well below the trigger values for
9 FERC and the antitrust authorities. I also noted that a focus on the APS market
10 area likely was not warranted since Arizona participates in a wider market
11 consisting of at least Southern California and the Desert Southwest. Since that
12 time, PWEC has added or nearly completed additional capacity. However,
13 substantially more capacity has been, or is being, added by other firms and
14 transmission is being expanded. Hence, if I were to redo this analysis for
15 Pinnacle West today, the results would show a still smaller market share for
16 PWEC.

17 **Q. In this earlier testimony, didn't you concede that some APS units are must**
18 **run and could exercise market power?**

19 A. Under some circumstances, generally the highest load conditions in the summer,
20 APS and SRP capacity located in the Valley is must run. Capacity in Yuma also
21 is must run at some times. By definition, this means that, absent mitigating
22 conditions, the owners of the capacity could name their own price, with the
23 alternative of rolling blackouts. This condition is not unique to the APS control

1 area. There are many other must run units in the U.S., usually but not always
2 located in or near major cities. There are well-established means of mitigating the
3 potential market power of such units. APS already has created protocols for such
4 mitigation in its FERC-approved tariffs. This, or equally robust mitigation will be
5 carried forward when WestConnect becomes operational.

6 **Q. You stated that your 1999 testimony discussed market definition and**
7 **indicated that an area larger than the APS control area was appropriate.**
8 **Why is this?**

9 A. By way of introduction, an analysis of market power always begins with the
10 definition of relevant product and geographic markets. Here, the product market
11 of greatest interest is electric energy. FERC simply assumes as a starting point
12 that a control area is a relevant geographic market, though it invites evidence of
13 larger or smaller markets and routinely uses geographic market definitions that
14 are larger than control areas. It was simply because it is FERC's default
15 assumption that I used the APS control area as the relevant geographic market.

16 In fact, the power markets of the WSCC are highly interdependent.
17 Unless transmission constraints prevent it, an increase in prices in one area draws
18 power from other areas, raising prices in those areas also. This connection of
19 prices across broad regions is, to one degree or another, common to all
20 interconnected power markets. APS is interconnected with other Desert
21 Southwest utilities and more importantly is strongly interconnected with Southern
22 California. The transmission capacity from Arizona to California is rarely if ever
23 fully utilized. The transmission capacity from California to Arizona is so slack

1 that the WSCC doesn't even quantify its limit. Likewise, there is substantial
2 capacity linking Southern to Northern California and California to the Northwest
3 via the DC interconnection into Southern California and the California-Oregon
4 interconnect into Northern California

5 California is, and is likely to remain, capacity short and shorter still in
6 terms of economic energy. Typical year energy imports into California are about
7 50 billion kWh. As an important power sink, it interconnects prices in the
8 WSCC. I recall a study submitted by the California Attorney General's market
9 power expert in the state proceeding that approved the merger of Southern
10 California Gas and Enova into Sempra that found that the degree of price
11 convergence in western power markets was very high.

12 In the market power analysis that I explain later in this testimony, I have
13 assumed that APS is a relevant geographic market. In fact, in this larger
14 interconnected market in which prices are determined, PWEC's share is quite
15 small and it clearly lacks market power.

16 **Q. Assuming that the asset transfer takes place and that the PPA does not exist,**
17 **would PWEC have market power in these larger markets?**

18 A. No. PWEC's share of either a Desert Southwest-Southern California or WSCC
19 market would be small, a single digit share, even if it were free to sell all of its
20 output at market rates in short to intermediate term markets.

1 Q. **You noted that FERC had adopted the antitrust authorities' method of**
2 **assessing prospective market power in 1996. In what context did that**
3 **adoption take place?**

4 A. It was adopted in the Merger Policy Statement that indicated how FERC would
5 assess the market power implications of mergers and acquisitions.

6 Q. **Are there other contexts in which FERC assesses prospective market power**
7 **using other analysis methods?**

8 A. Yes. Under Section 205 of the Federal Power Act, FERC regulates the pricing of
9 wholesale transactions. Within its Section 205 authority, FERC has devised tests
10 to determine whether sellers will be authorized to sell power at market prices, as
11 opposed, for example, to cost of service prices.

12 Until recently, FERC relied on a simple "hub and spoke" test. On two
13 separate occasions, in 1999 and 2000, FERC granted Pinnacle West affiliates
14 market rate authority based at least in part on Pinnacle West passing the hub and
15 spoke test.

16 The hub and spoke test was criticized by some FERC Commissioners and
17 by others, primarily on the grounds that it ignored transmission constraints. Last
18 autumn, FERC adopted a new method, dubbed the "supply margin assessment" as
19 its standard for testing whether market rate authority was appropriate. As
20 discussed below, Pinnacle West will also pass this new test to demonstrate that it
21 qualifies to sell power at market rates.

Subsequently, FERC has noted that the supply margin assessment test, or SMA, will be applied to market-based rate applications on an interim basis until new analytical methods for analyzing market power are reviewed and adopted. The SMA test was further refined by FERC in *AEP Power Marketing, Inc., et al.*, Docket No. ER96-2495-015, *et al.* 97 FERC ¶ 61,219 (2001) ("AEP Order").

Q. Would PWEC continue to meet FERC's Requirements for market-based rate authority under the SMA test?

A. Yes. I have conducted the SMA test for PWEC using a summer 2003 snapshot and find that the test is easily passed. The results of the SMA test are summarized in Exhibit No. WHH-3.

Q. How is the SMA test conducted?

A. The SMA test measures whether a market's peak demand could be met without the applicant's generation. Each utility control area is deemed to be a separate market. For each market where applicants own or control generating resources, applicants are instructed to compare the applicant's generation capacity in the market to the difference between "Available Supply" and peak demand in the market (termed the "Supply Margin"). Available Supply includes all of the generating capacity located in the market, plus imports, quantified as the uncommitted capacity that can reach the market using available inbound transmission capacity, as measured by the Total Transfer Capability (TTC) value for all transmission lines that enter the control area, irrespective of current use or ownership. If the Supply Margin is greater than applicant's generation, then peak load can be met without the applicant's generation, and the seller is not considered pivotal in the market. Reserves are not taken into account in the test,

either for purposes of determining what capacity is uncommitted or for determining load levels.

Q. Is the SMA test regarded as a stricter test than the test previously used by FERC in determining whether an applicant should have the authority to sell at market rates?

A. Yes, very much so. First, the ability to rely on imports is constrained by physical capacity. This was not true previously, so that the amount of supply in the market is much reduced. Second, while the previous test either compared applicants' total capacity to the total capacity in the market or its uncommitted capacity to the total uncommitted capacity in the market, this test combines applicants total capacity with only the uncommitted capacity that can be imported. When the SMA was first announced, it was widely believed to be a regulatory sledgehammer to force utilities into RTOs, since most utilities would fail the test in their home market, while utilities in RTOs were exempt from the test for sales in the RTO (including in their own market).

Q. What market did you analyze for purposes of conducting the SMA test?

A. FERC's application of the SMA test continues to rely on control areas as the relevant market areas, and I have analyzed APS' control area as the relevant market. While the SMA is not formally applied only to the applicant's own control area, it is most unlikely that an applicant would fail the test in some other market area at present.

1 **Q. How did you calculate Available Supply inside the APS control area?**

2 A. I included all of the generation physically located inside of APS' control area,
3 which includes about 6,571 MW owned by (or under contract at time of summer
4 peak to) PWEC or its affiliates and about 5,783 MW owned by other entities,
5 including new merchant capacity and capacity at jointly-owned units located in
6 APS' control area. PWEC's total includes the new and planned upgrades at Red
7 Hawk and West Phoenix and APS' purchases from PacifiCorp and SRP.[21] The
8 SMA test does not require that capacity within the control area owned by others
9 whose loads are outside the control area be eliminated from the supply margin.
10 Presumably, this is because such owners (e.g. El Paso Electric or Public Service
11 Company of New Mexico) can use substitute generation located outside the
12 control area being analyzed to meet load, and presumably would do so if prices
13 within the control area were to rise to above competitive levels. Thus, the total
14 Available Supply from inside the APS control area is 12,354 MW (6,571 MW
15 owned or controlled by PWEC and 5,783 MW owned by other entities).

16 **Q. How did you calculate the amount of imports to include as part of Available**
17 **Supply in the SMA test?**

18 A. The TTC into the APS control area is expected to be 11,089 MW by summer
19 2003. This total includes the planned transmission upgrades at Palo Verde –
20 Rudd. I have reduced this capacity by 2,146 MW to account for PWEC's share
21 of Palo Verde and for Red Hawk, since importing their power from the SRP

[21] Note that the SMA test is wholly insensitive to the amount of the applicant's capacity since the central issue is whether other sellers could meet the load, not whether the applicant could meet it.

1 switchyard to which they are connected uses up this amount of capacity. Thus,
2 the TTC that I use is 8,943 MW.

3 Next, I determined whether there were sufficient uncommitted generating
4 resources available to potentially serve the APS control area. I conservatively
5 considered only newly constructed units or those planned to come on-line by the
6 summer of 2003, as listed in the California Energy Commission's WSCC
7 Proposed Generating Database (available on its website) as being potentially
8 available to serve the market. The total new capacity in control areas directly
9 interconnected to APS is 23,814 MW by the summer of 2003. Since this greatly
10 exceeds the TTC that I am using, the SMA rules limit imports to the 8,943 MW of
11 TTC as capacity available to the APS market.

12 **Q. Please Describe the results of your analysis.**

13 A. A summary of the results of the SMA test is provided in Exhibit No. WHH-3.
14 As detailed above, the total Available Supply to the APS control area is 21,297
15 MW. This total includes about 12,354 MW inside the control area and 8,943 MW
16 from outside of the control area. Total load in the APS control area by summer
17 2003 is expected to be 6,127 MW, based on APS' forecast in its FERC Form 714
18 filings.

19 The Supply Margin is the difference between Available Supply and load
20 and is 15,170 MW (21,297 MW less 6,127 MW). PWEC's capacity in the market
21 is 6,571 MW. Since the Supply Margin is greater than the capacity of PWEC and
22 its affiliates, the SMA test is passed. That is, PWEC is not a pivotal supplier

under the SMA test. Indeed, capacity controlled by others is more than twice the control area load.

Q. Are there any other potential areas outside of APS' control area where PWEC is a pivotal supplier?

A. No. PWEC and its affiliates own capacity at Palo Verde interconnected to switchyards in the SRP control area, however PWEC is not a pivotal supplier in the SRP control area which has experienced a significant amount of new and planned capacity additions, especially around Palo Verde.

Q. Please summarize your review of the results of FERC-mandated market power tests.

A. Over the past few years, FERC has mandated three market power tests: the hub and spoke test, the merger-related delivered price test, and the new SMA used for determination of market rate authority. Pinnacle West, APS and its affiliates have qualified for market rate authority under each of these tests, based on the demonstration that they lack market power, individually or collectively.

Q. Assuming, notwithstanding your analyses and the results of the FERC-mandated market power tests, that the Commission has remaining concerns that a post-divestiture PWCC might be able to exercise market power with respect to entities serving its jurisdictional customers, can you provide guidance concerning how those concerns could be addressed?

A. The most obvious means of dealing with potential market power is to require that the supplier dedicate a portion of its capacity to a long-term contract.

1 Alternatively (or additionally) the Commission could assure that the entities
2 serving those customers (or at least the Standard Offer supplier) are substantially
3 covered by bilateral contracts.

4 **Q. Why does a long-term contract mitigate potential market power?**

5 A. Recall that in my general discussion of market power I relayed that the exercise of
6 market power requires both the ability and incentive to do so. If a supplier
7 controls sufficient capacity that the "ability" issue is a question, then reducing the
8 incentive is a cure. To the extent that PWEC has sold its energy under a long-
9 term contract, the pricing of which does not float with the market, it has no
10 incentive to raise prices.

11 This can be shown in the following example. Suppose that PWEC
12 controls 6,000 MW of capacity. Assume further that withholding 1,000 MW
13 from the market increases the price by $3 per MWh. Also assume that the
14 withheld capacity would have earned $8 per MWh in contribution to profit and
15 fixed costs. The withholding is profitable; profits increase by 5,000*$3 for the
16 remaining capacity and fall by 1,000* $8 for the withheld capacity, so the net
17 profit is $15,000 minus $8,000. Now assume that, say, 4,000 MW of capacity has
18 been sold in a bilateral contract. The impact of withholding on the market price is
19 unaffected: withholding 1,000 MW still increases the market price by $3 per
20 MWh. However, there now are only 1,000 MW of PWEC capacity receiving the
21 elevated price, since the price received for the 4,000 MW of bilateral sales is not
22 increased. The profit calculus now is 1,000*$3 minus 1,000*$8, so the formerly
23 profitably strategy to raise prices is no longer profitable.

1 **Q. Are PWCC and its affiliates currently subject to this type of market power**
2 **control?**

3 A. Yes. Currently, as a result of the rate plan adopted in the APS Settlement, APS
4 has pre-determined retail rates through at least the first half of 2004. APS, and
5 indeed the Pinnacle West family of companies, do not have enough capacity to
6 supply that load. During high load conditions, when prices are most susceptible
7 to manipulation, the company is a net buyer in the market and hence has a
8 disincentive to increase prices. Even during hours when it has something to sell,
9 the amount of its capacity that it must dedicate to meet APS and wholesale
10 requirements loads leaves it with little to sell into (or withhold from) the market.

11 APS's proposed long term purchased power agreement with PWCC
12 effectively continues the current style of mitigation far into the future. Since APS
13 would have the right to PWEC's total capacity, and would exercise that right with
14 respect to most of it most of the time, PWEC would have little available to sell at
15 market rates and hence no incentive to increase prices.

16 **Q. Is it necessary that all of PWEC's capacity be dedicated to APS and**
17 **requirements load in order to constrain its potential market power?**

18 A. No. As I have shown, PWEC would meet FERC's test for market rate authority
19 even if none of its capacity were dedicated to contracts. If the Commission
20 accords less than full faith to the efficacy of that test, and disbelieves the result
21 that APS would price competitively even if all of its capacity were available to
22 sell at market prices, it still would follow that a less-than-100 percent dedication
23 would mitigate potential market power to satisfactory levels. Moreover, any

capacity that is dedicated to APS, even if less than 100 percent, thereby reduces the incentive to exercise market power. Any PWEC capacity that wins in any competitive bid auction and thereby gains an intermediate to long-term contract similarly reduces the risk of it exercising market power. As a practical matter, I cannot conceive of an implementation of Commission Rule 1606(B) that would not cover APS's Standard Offer load with bilateral contracts, put the majority of PWEC capacity under bilateral contracts, or both.

It is important to ask the question, over whom is PWEC allegedly exercising market power? If the Commission's policy coming out of these proceedings results in APS's customers being covered by intermediate to long term contracts with PWEC and other parties, as I assume it will, then APS Standard Offer customers have little or no exposure to the competitive wholesale short-term market. SRP and TEP are or will be by then essentially self-reliant and not dependent on power from PWEC. APS's wholesale customers are covered by FERC-regulated contracts. Since Arizona loads will be substantially covered, the energy that PWEC would have available to sell would have to compete in a broad regional wholesale market in which its share is small. In that market, there can be no serious concern that PWEC could exercise market power.

CONCLUSIONS

Q. Would you please summarize your conclusions?

A. Yes. The Commission has determined that Arizona customers are best served by the creation of competitive wholesale and retail markets. Events subsequent to that policy determination have not undercut, and to a substantial extent have

1 confirmed, the soundness of that decision. I recommend that the Commission
2 continue with its policies to restructure the Arizona electricity industry that it
3 regulates.

4 In furtherance of creating a competitive market, the Commission
5 determined that the jurisdictional utilities should separate their generating assets
6 from transmission, distribution and customer service functions. This remains
7 sound policy.

8 PWEC will not have market power. In the larger regional market in which
9 it competes, it is a small player. Within Arizona, and in particular within the APS
10 control area, PWEC passes all of the FERC-mandated tests for market power.
11 The potential market power inherent in its must run units will be mitigated by
12 APS's Open Access Tariff provisions and by a future RTO's market power
13 mitigation measures. Any remaining concerns that the Commission might have
14 can be mooted by an intermediate to long-term PPA between PWEC or PWCC
15 and APS and/or by intermediate to long-term bilateral contracts with other
16 suppliers.

17 **Q. Does this complete your written direct testimony in this proceeding?**

18 A. Yes, it does.

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20

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William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last thirteen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his twenty-plus years of consulting to this sector, he also has performed a number of more specific functional tasks, including selecting investments; determining procedures for contracting with independent power producers; and assisting in contract negotiation, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States and United Kingdom. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus advised on the formation of a Transco in response to FERC's Order 2000. His primary role was to advise on the concepts and details of market design.
- Dr. Hieronymus serves as an advisor to the senior executives of an electric utility on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment, he has testified regarding regulatory filings with state agencies, evaluation of potential acquisitions, and aspects of internal restructuring.
- For several utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers where he has testified are Sempra, Xcel, Exelon, AEP-CSW, Dynergy-Illinois Power, Con Edison-Orange and Rockland, Dominion-CNG, Nisource-Consolidated Natural, Eon-LG&E and Nyseg_RG&E.

- For utilities seeking to sell or purchase generating assets, Dr. Hieronymus has provided analyses concerning market power in support of submissions under sections 203 and 205 of the Federal Power Act and analyses required by state regulatory commissions.

- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.

- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.

- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding the U.K. electricity system and, for senior U.S. utility managements, has arranged meetings with executives and regulators in the U.K.

- For an East Coast electricity holding company, Dr. Hieronymus prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand-management programs as alternatives to new plant construction.

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- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

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Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers. Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

WILLIAM H. HIERONYMUS — Vice President

Ph.D.	Economics, University of Michigan
M.A.	Economics, University of Michigan
B.A.	Social Science, University of Iowa

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last thirteen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his twenty-plus years of consulting to this sector, he also has performed a number of more specific functional tasks, including selecting investments; determining procedures for contracting with independent power producers; and assisting in contract negotiation, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States and United Kingdom. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus advised on the formation of a Transco in response to FERC's Order 2000. His primary role was to advise on the concepts and details of market design.
- Dr. Hieronymus serves as an advisor to the senior executives of an electric utility on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment, he has testified regarding regulatory filings with state agencies, evaluation of potential acquisitions, and aspects of internal restructuring.
- For several utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers where he has testified are Sempra, Xcel, Exelon, AEP-CSW, Dynergy-Illinois Power, Con Edison-Orange and Rockland, Dominion-CNG, Nisource-Consolidated Natural , Eon-LG&E and Nyseg_RG&E.
- For utilities seeking to sell or purchase generating assets, Dr. Hieronymus has provided analyses concerning market power in support of submissions under sections 203 and 205 of the Federal Power Act and analyses required by state regulatory commissions.
- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.
- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.
- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.
- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

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- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers. Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

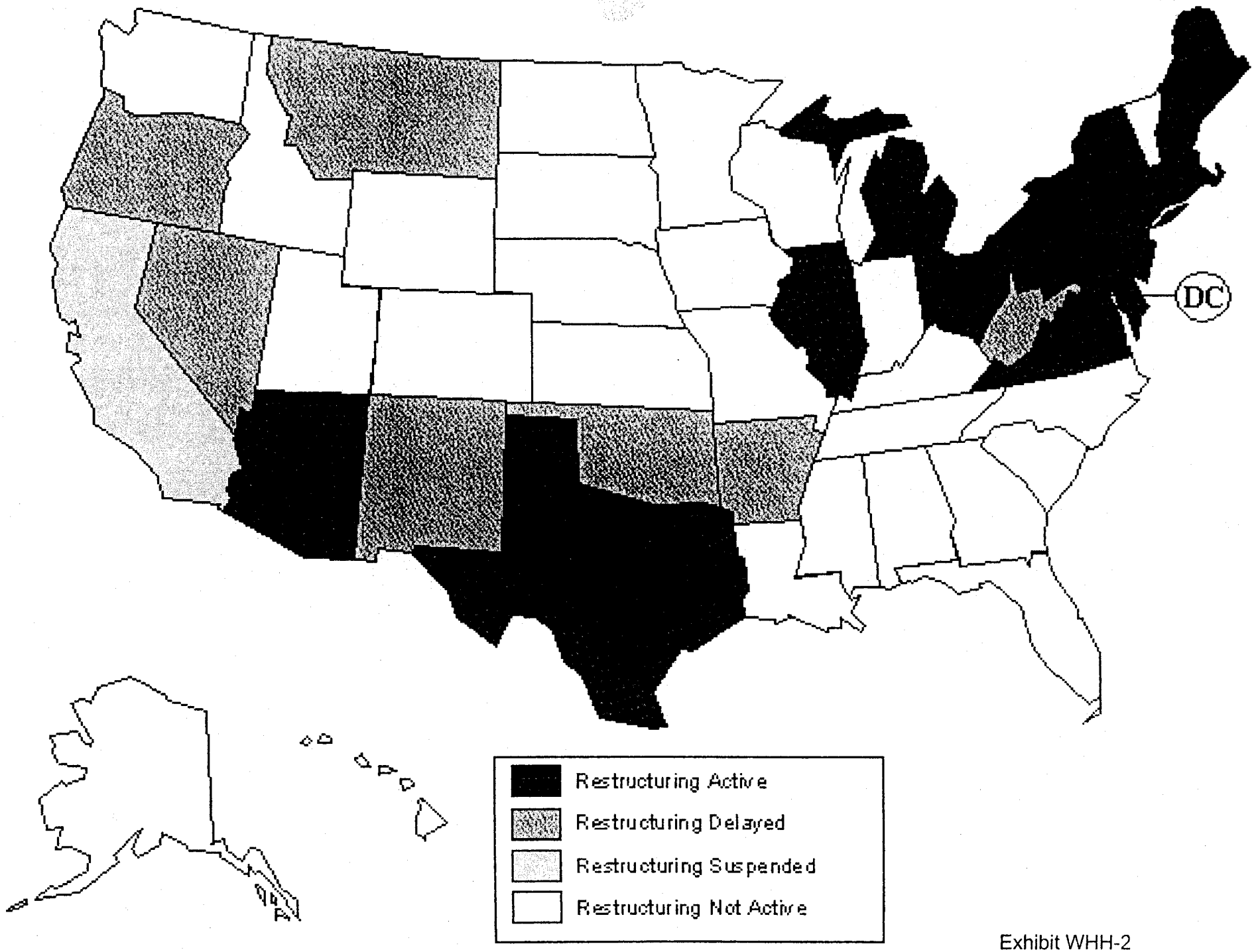

Exhibit WHH-2

Exhibit No. WHH-3
SMA Screen for APS Control Area
Summer 2003

Inside Generation	MW	Key
PWEC and Affiliated Generation		
PWEC (owned) [1]	5,751	
PWEC (contracts) [2]	820	
Subtotal: PWCC	6,571	*[A]*
Merchant Capacity (owner)		
Gila River 1-4 (Panda/TECO)	2,080	
Desert Basin (Reliant)	510	
Subtotal: Merchant Capacity	2,590	
Existing Capacity (excludes PWEC afffiliated capacity)		
Four Corners	1,258	
Navajo	1,935	
Subtotal: Existing Capacity at Jointly-Owned Units	3,193	
Subtotal: Non-PWEC Internal Generation	5,783	*[B]*
Total Local Generation:	12,354	*[C] = [A] + [B]*
Imports [3]	8,943	*[D]*
Available Supply	21,297	*[E] = [C] + [D]*
Peak Control Area (APS) Load	6,127	*[F]*
Supply Margin	**15,170**	*[G] = [E] - [F]*
Can Load be Met without PWEC Capacity?	**Yes**	*Is [A] < [G] ?*
Non-PWEC Affiliated Generation in Excess of Load	**8,599**	*[E] -[A] - [F]* *(or, [G] - [A])*

Potential Imports	TTC [5]	New Capacity [6]	Minimum (TTC or New Capacity)
TTC into APS	8,943		
Arizona		5,110	
California		15,483	
Colorado		2,059	
New Mexico		1,162	
Total:	8,943	23,814	8,943

Notes:
[1] Includes PWEC affiliated capacity at Palo Verde and Redhawk.
[2] Includes 480 MW PacifiCorp purchase and 340 MW purchase from SRP.
[3] Import TTC into APS system was reduced by APS' share of Palo Verde and Redhawk.
[4] APS peak load forecasts is for 2003 (from 2000 FERC Form 714 filings).
[5] TTC value consists of 11,089 MW of TTC, less 2,146 MW to account for APS' share of Palo Verde and Redhawk.
[6] New Capacity estimates from WSCC Proposed Generation Database (http://www.energy.ca.gov/electricity/wscc_proposed_generation.html.) and http://www.cc.state.az.us/utility/electric/Gen020051/jds1606.pdf
Only units categorized as Operational, Under construction, or Regulatory approval received and with on-line dates prior to summer 2003 are included in totals from WSCC Database.

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, *et al.*

June 11, 2002

EXHIBIT

APS-5

Admitted

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REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

INTRODUCTION

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My address is Charles River Associates Inc., 200 Clarendon Street T-33, Boston, MA 02166.

Q. Have you testified previously in this proceeding?

A. Yes. I filed direct testimony on May 29, 2002. My credentials are attached as Exhibit WHH-1 of that testimony.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. APS has asked me to comment on the testimony of various intervener and ACC Staff witnesses, primarily on the subject of market power associated with the transfer of generating assets.

Q. Can you summarize your rebuttal testimony in this proceeding?

A. Yes. While a number of witnesses talk about market power, none demonstrates, or even makes a serious attempt to demonstrate, that PWEC would have unmitigated market power after transfer of the assets. Moreover, these witnesses studiously ignore the fact that the intermediate to long term contracts that are a near certain outcome of this group of proceedings will (to the extent that customers are served under contracts priced independently of future market prices) protect Standard Offer customers from the exercise of market power by PWEC or anyone else. Similarly, to the extent that a substantial proportion of PWEC's energy is sold under long-term contracts, any plausible concern that it could exercise market power with respect to any customer will be mooted.

1 Staff proposes a "lower of cost or market" means of pricing the wholesale
2 component of Standard Offer service that is certain to trap costs within APS no
3 matter what purchasing strategy it employs. If it buys from the market, including
4 by competitive bidding for long-term contracts, it will face disallowance if the
5 market price exceeds what would have been a cost of service price for PWEC or
6 APS. If it buys on a cost of service-type contract, it will face disallowance if the
7 market price is lower. This proposal would replicate, and in some respects be still
8 worse than, some of the bad regulatory policies that led directly to the California
9 fiasco with bankrupt and near-bankrupt utilities unable to buy power for their
10 customers and the state having to take over procurement. Further, Staff's
11 procedural proposals, including in particular its proposal for a smorgasbord of
12 market power studies, inevitably and needlessly will delay Arizona moving forward
13 along the path of restructuring that has been the Commission's firm policy for the
14 past several years.
15
16 **REBUTTAL TO PANDA WITNESS ROACH**
17
18 Q. **At page 5, Dr. Roach is asked whether his "concern about market power**
19 **[would] persist even if the transfer entailed a contract to sell back at cost-plus**
20 **rates." He responds, "Yes, absolutely." Do you agree?**
21 A. No, absolutely not. His response makes no sense whatsoever. The purported basis
22 for this conclusion is his assertion in the variance proceeding that Standard Offer
23 customers would pay higher prices, face higher risks and have lower reliability than

if served by competing suppliers. In my rebuttal in that proceeding I explained the total invalidity of his conclusions, to the extent that they had any basis beyond bald assertion. However, that is not the point I wish to make here. The point that is relevant to my testimony in this proceeding is that the PPA of which he complains is not, and could not be, the result of "market power".

Market power is the ability to profitably sustain an above-competitive price in the marketplace. APS never has contended that the PPA is a contract arrived at in the market, although it does believe that the contract is at least as favorable as a contract originated in the market would be. Moreover, since the contract is cost-based it is just and reasonable and will only allow a reasonable return on investment. PWEC cannot use "market power" to impose this contract on its affiliate, APS. APS is before this Commission to seek its approval for the PPA. The PPA also would be subject to FERC jurisdiction, since it is a wholesale contract. If this Commission believes that the contract is not in the best interests of APS's Standard Offer customers, it presumably will reject it. FERC similarly can act in appropriate circumstances to reject the contract. Nothing in this approval process suggests that the contract can possibly be the product of market power, either arising from the transfer of assets or from other causes.

Q. Dr. Roach argues that APS's supposed market power requires mitigation and asserts that the asset transfer should be approved only if APS acquires 100 percent of its standard offer requirements from a competitive market prior to asset transfer. Do you agree?

1 A. No. Setting aside, for the present, the question of whether APS might have market
2 power in some circumstances, it is manifestly untrue that any such market power
3 requires procurement of 100 percent of Standard Offer requirements from the
4 competitive market. I do agree that were I to assume that PWEC would have
5 market power over APS it would be good policy to insulate APS's customers from
6 the potential abuse of that market power. However, I very much doubt that 100
7 percent contract cover would be necessary. Any market power that PWEC might
8 have would arise from the fact that, at least at present, competitors likely could not
9 meet 100 percent of APS's customers' loads. However, there clearly is or soon will
10 be sufficient competition available to discipline prices for a substantial portion of
11 such loads.[1]

12 The main point, however, is that <u>any</u> intermediate to long term contract
13 covering a substantial proportion of APS's customers' loads would insulate them
14 from PWEC exercising market power against them under even the most pessimistic
15 scenario. The key attribute of such a contract is that its pricing terms are not
16 affected by the market price that PWEC allegedly could increase using its
17 hypothetical market power. The PPA that APS has proposed in the variance
18 proceeding clearly meets that objective, as would a range of alternative contractual
19 arrangements, assuming that they are feasible (and, hopefully, reliable and
20 economic). Certain types of contracts entered into in the "competitive market"
21 would meet this objective. Others would not. So, the key point about insulating
22 customers from any market power PWEC might have, or indeed, that any other

[1] Customers are insulated from the market though at least mid-2004 by the rate plan agreed as part of the

1 provider might have in the future, is to cover a substantial portion of the customers'
2 load with contracts that insulate them from it.

3 Q. **Dr. Roach presents an SMA analysis, as did you. Have you reviewed his**
4 **analysis?**

5 A. Yes. While there are material differences between his analysis and mine, these
6 appear to relate primarily to what capacity is considered to be inside or outside of
7 the control area, not to the total amount of competing capacity. Both Dr. Roach and
8 I find that APS (and PWEC post-transfer) pass the SMA test by a wide margin.

9 Q. **Did Dr. Roach construct a test similar in form to the SMA that APS fails?**

10 A. Yes. However, he does so by assuming away the competing capacity that FERC
11 would count and that disciplines prices.[2] There are three categories of competing
12 capacity that FERC counts in the SMA: in-area merchant generation, in-area shares
13 of power plants that are owned by utilities other than APS, and imports. In Dr.
14 Roach's Table Two, in which APS fails the test, he assumes both in-area merchant
15 generation and the joint units away in their entirety. Unsurprisingly, by changing
16 the FERC test to eliminate the competition, he is able to construct a version of the
17 test that PWEC will fail.

18 Q. **Do you agree with his basis for zeroing out in-area merchant capacity and the**
19 **shares of other utilities in jointly owned facilities?**

APS Settlement. Between now and mid-2004, substantial additional merchant generation is scheduled to come on line.

[2] *AEP Power Marketing, Inc., AEP Service Corporation, CSW Power Marketing, Ind., and Central and Southwest Services, Inc.; Entergy Services, Inc.; Southern Company Energy Marketing L.P.,* Order on Triennial Market Power Updates and Announcing New, Interim Generation Market power Screen and Mitigation Policy, 97 FERC ¶ 61,219 (2001).

A. No. His sole argument appears to be that the proposed PPA denies the merchants an opportunity to compete. This misses the point entirely. The SMA test inquires whether a seller is pivotal over the control area load. A traditional vertically integrated utility may be pivotal and hence fail the SMA test despite the fact that the load to which its capacity is dedicated is, in fact, served under state-regulated rates. The fact that the load is not served from the market is not deemed to be relevant for the SMA. Even if the bulk of APS's load were served under contracts with other sellers that insulate it from market prices, PWEC still could be pivotal and fail the test. The two concepts (the PPA and the SMA test), therefore, are wholly unrelated. As noted below, this lack of relationship is a flaw in the SMA test. However, correcting the flaw to take the PPA into account would support rather than attack the PPA. In fact, the PPA would fully moot any conceivable concern that PWEC could possess market power.

The SMA test is designed to determine whether a supplier faces sufficient competition that it cannot be pivotal with respect to the control area load, irrespective of that load's contractual arrangements. This has been criticized by utilities that fail the test despite the fact that most of their capacity is dedicated to native load.[3] However, the fact that competitors' capacity is not, in fact, serving the native load of the control area utility hardly means that it should be ignored, as Dr. Roach proposes. If anything, the presumed fact that their capacity is not dedicated

[3] Note that if the supplier's capacity were contracted away to another wholesale supplier who in turn served the load (or sold its output off-system), the capacity would be counted as competing rather than owned capacity. Hence, the SMA test's failure to take native load responsibility into account treats serving native load as a less "real" responsibility than meeting wholesale contracts.

to APS's standard offer load means that it is fully available to compete for any sales in the competitive market with delivery points in APS's control area.

Q. What basis does Dr. Roach offer for zeroing out the capacity owned by non-APS owners of jointly owned plants in its control area?

A. Dr. Roach suggests two reasons. The first is identical to his argument about the merchants, i.e., the PPA means that the capacity somehow goes away. The argument is wrong for identical reasons. His second argument, that the owner is a load-serving utility means that the capacity should be ignored, also lacks merit. It depends on very unusual factual circumstances, which simply do not exist.

Q. What do you mean by "very unusual" facts??

A. The key fact question is whether the joint owners must use their capacity to serve their native loads or whether such capacity could be sold in competitive markets to serve load at delivery points in the APS control area. I emphasize the point of delivery, because the SMA treats the control area as transmission constrained. It almost certainly is true that the jointly-owned capacity can be sold within the APS control area. For example, El Paso Electric owns a portion of the Palo Verde nuclear plant, a plant that is included by Dr. Roach in the control area. However, if APS/PWEC were to seek to exercise locational market power in the APS control area, El Paso could sell its Palo Verde output into the hypothetically high-priced market and buy power elsewhere at prices not affected by this local market power. So the mere fact that an owner whose load is outside the control area also has native load, or even that its native load requirements equal or exceed its capacity, does not

1 mean that its capacity in the APS control area does not and would not discipline
2 APS/PWEC's hypothetical market power.

3 Q. **Doesn't Dr. Roach also cast doubts that 3,900 MW of imports could compete?**

4 A. Yes, though this appears to be a throwaway argument made solely for
5 completeness. He points to market conditions in 2000 for the proposition that there
6 is no uncommitted capacity that could be made available. However, this clearly is
7 not relevant. Indeed, if Panda truly believed that 2000 market conditions would
8 prevail in 2003 and beyond, they would not be in this proceeding fighting so
9 vigorously.

10 Q. **Beginning at Page 13 Dr. Roach performs an SMA-type analysis for the**
11 **Phoenix area (the "Valley Market"), and finds that APS fails the test. Does**
12 **this result surprise you?**

13 A. No. All that Dr. Roach is seeking to demonstrate is that the valley is a load pocket
14 and that generation inside the valley (all of which are owned by SRP, PWEC or
15 APS) is needed during the peak hour. APS has never denied that the valley is a
16 load pocket and that, in consequence, the prices charged by in-valley generators
17 must be mitigated for a few hours per year. As I noted in my Direct Testimony in
18 this proceeding, APS has filed mitigation protocols, as have AISA and
19 WestConnect that doubtless will be in effect when the latter becomes operational.

20 Q. **What mitigation does Dr. Roach propose?**

21 A. He suggests, first, that competitors should be given full access to the transmission
22 capability into the valley market. Second, he suggests that APS should have a
23 competitive procurement for new capacity inside the valley interface.

1 **Q. Do you agree with his first mitigation?**

2 A. No. First of all, it is inherent in the definition of a load pocket that imports cannot
3 fully discipline prices because they cannot be delivered into the load pocket in
4 sufficient quantity to meet load. So the proposal cannot be effective in replacing
5 the usual forms of mitigating prices in a load pocket. Beyond this obvious failing,
6 it is not entirely clear what he is proposing. On page 18, lines 7-11, he appears to
7 argue that all merchant generation that "competes in the APS Market" should be
8 designated as network resources. It simply is not feasible for all such capacity to be
9 network resources In support for this proposal, he cites a FERC order requiring
10 that all new interconnections have the right to be studied as if they were network
11 resources. This order is only germane for utilities that fail the SMA test (which
12 APS and PWEC do not) and only for new connections (which Panda is not).
13 Moreover, if I understand the proposal, it means that transactions through the valley
14 to external destination points, or to SRP destination points would have access to the
15 transmission system on a par with the use of the system to serve APS's native load.
16 This could reduce reliability to, and/or increase the cost of, serving APS's
17 customers, both Standard Offer and Direct Access.

18 On the other hand, at page 18, lines 13-15 he recommends that APS be
19 required to designate as network resources all winners of any competitive
20 procurement. This is not the same thing as he appears to have said in the
21 immediately previous answer. This latter recommendation is, at least in concept,
22 reasonable. I understand APS's proposal to be that any resource contracted to it to
23 meet Standard Offer load would be treated as a network resource.

1

2 **Q. Do you agree that APS should be required to issue a competitive RFP for new**
3 **facilities to be built in the Valley?**

4 A. No. It sometimes, indeed often, is cheaper to rely on must run facilities than either
5 relieve transmission constraints or buy power from new facilities. APS's existing
6 must run units at Ocotillo and West Phoenix are old units. While they are less
7 efficient that modern peaking facilities, they also are heavily depreciated from a
8 relatively low historic book value. Dr. Roach has not even attempted a showing
9 that replacing these units with new capacity, whether owned or purchased
10 competitively, is cost effective, and there is no particular reason to believe it would
11 be. Further, there are absolutely no legal or other prohibitions against merchant
12 generators building new generation in the valley to compete against the must run in-
13 valley generation – they simply have chosen not to do so. Dr. Roach's proposal
14 would require that APS contract for, and subsidize, generation that his client and
15 other merchant generators have not found to be commercially feasible.

16 **Q. Dr. Roach also proposes that APS's must run price should be set based on the**
17 **operating and capital costs of a new peaker. Would this benefit ratepayers?**

18 A. I very much doubt it, though I have not analyzed the matter. Since West Phoenix
19 and Ocotillo have such low rate base costs, such a pricing scheme almost certainly
20 would increase costs to APS and its ratepayers.

21 **Q. At Page 18, Dr. Roach seeks to rebut portions of your rebuttal of Dr. Ruff in**
22 **the variance proceeding. Do you agree with his "clarifying points"?**

1 A. While I am not sure of whether this portion of Dr. Roach's testimony is
2 procedurally proper, I will respond. His first point is that market power is not just a
3 spot market issue, but also can affect longer-term markets. I agree. However, this
4 is not valid rebuttal since I made no statement to the contrary. His second point is
5 that a long-term contract mitigates market power only if the contract itself was
6 arrived at through a competitive process. He is not correct, at least in the context in
7 which I address the role of long-term contracts. If a seller contracts away its output
8 at rates that do not vary with the market price, its incentive and ability to exercise
9 market power is essentially eliminated. Similarly, a buyer covered by a long-term
10 contract that does not float with the market is subsequently insulated from the
11 market (to the extent that it has contracted), including both the exercise of market
12 power and any other source of price changes. Dr. Roach makes the point that
13 contract terms may themselves be affected by the seller's market power. I agree
14 that this could be so. However, it does not follow that any contract not arrived at
15 through a competitive solicitation is infused with market power. Nor, for all that, is
16 a contract arrived at through a competitive solicitation necessarily free of market
17 power. While I am not opining on their merits, the regulatory filings whereby the
18 California Department of Water Resources and other buyers of power in the
19 Western power markets are seeking to overturn the contracts that they entered into
20 in competitive RFP procurements allege that these contracts are not "competitive."
21 In any event, as I have stated earlier, this Commission is in the midst of a process of
22 determining whether the PPA is in the interests of customers. Presumably it would

1 not accept a contract that it believes is over-priced as a result of PWEC exercising
2 market power.

3 His third point is that the exercise of market power is not necessarily
4 confined to withholding supply. He asserts that market power also can be exercised
5 by APS "pushing competitors away" to sign the PPA. I have two responses. First,
6 the "market power" that he asserts is not PWEC's post-transfer market power that is
7 docketed here, but rather the power inherent in the agency role that APS plays as
8 the buyer of power for Standard Offer service. This agency function is inherently
9 exclusive, hence "monopoly", even if the agent wholly lacks power in the energy
10 market which, parenthetically, would be monopsony power, not monopoly power.
11 In any event, a Standard Offer provider's decision to contract with one supplier
12 inherently excludes other suppliers. The question in the relevant docket (not here)
13 is whether APS is justified in signing this particular agreement – an issue this
14 Commission already has been asked to address.

15 Finally, he objects to my statement that whether PWEC might or might not
16 be in a position to exercise market power over APS is frankly irrelevant, contending
17 that this is the key issue in Track A. While I do not presume to tell the Commission
18 what it deems to be the key issue in Track A, I can explain my statement. The PPA
19 is not a contract arrived at in the market. Hence, whether APS might have had
20 market power in a market for such contracts is irrelevant. The Commission can,
21 and presumably will, determine the merits of the proposed contract based on its
22 content, not the means by which it was negotiated. The full sentence in my
23 testimony from which Dr. Roach abstracts his quotation is, "APS does not contend

1 that this is an arms-length transaction, so that the issue of whether PWEC might or
2 might not be in a position to exercise market power over sales to APS is frankly
3 irrelevant." This statement was and is true.

4 **Q. What do you conclude concerning Dr. Roach's testimony?**

5 A. Dr. Roach's key conclusion is that PWEC possesses, or would possess, market
6 power and that, hence, the asset transfer should be approved only if 100 percent of
7 APS's Standard Offer load is contracted. However, he fails to demonstrate that
8 PWEC would have market power. He fails to demonstrate that allowing APS to
9 contract with PWEC for all or a substantial portion of its load outside of the
10 competitive procurement that he advocates would expose APS's customers to any
11 PWEC market power. He fails even to demonstrate that a competitive procurement
12 would insulate such customers from market power. In fact, a substantial long-term
13 contract between APS and PWEC would serve to insulate APS's Standard Offer
14 customers from market power in the post-transfer market, irrespective of by whom
15 such hypothesized market power is exercised. It also moots any conceivable
16 concern that PWEC would exercise market power over any wholesale power buyer
17 after the assets are transferred.

18

19 **REBUTTAL TO ACC STAFF**

20

21 **Q. How have you organized your rebuttal to ACC Staff witnesses?**

22 A. Because Staff's testimony is inter-related and cross-referenced, rebuttal is
23 somewhat hard to organize. Since Mr. Rowell summarizes Staff's positions, I will

1 begin with him and deal with other Staff witnesses relevant to the issues I am
2 addressing in turn, to the extent that relevant testimony has not been covered in my
3 rebuttal to Mr. Rowell.

4 Q. **Mr. Rowell begins by discussing retail competition and its role in Staff's**
5 **recommendations concerning the wholesale market. He asserts that UDC**
6 **customers have no alternative to buying from the UDCs, so that the**
7 **Commission must scrutinize the UDC's procurement practices. Do you have**
8 **any comment on this?**

9 I agree that since Standard Offer Service is a retail tariff service, the
10 Commission has a valid interest in the prudence and reasonableness of the costs
11 included in it. I would, however, point out one oddity of Mr. Rowell's position. It
12 simply is not true that customers have no alternatives. It is true that few retail
13 providers are actively trying to sell to APS's customers and that few customers
14 have switched. This does not mean that customers have no alternatives, merely that
15 retailers cannot successfully compete against APS's retail rates. There is a simple
16 reason for this: retailers buying power in the competitive market and adding their
17 costs of operation cannot sell profitably at prices that attract consumers. This does
18 not mean that competition fails to discipline the prices charged by APS, but rather
19 that APS's current prices are below a competitive level. If APS's prices were to
20 rise above the competitive level, I have little doubt that retail service providers
21 would flock to Arizona. So long as retail choice remains an option for consumers,
22 APS's prices, and hence the amount that it can pass through from its wholesale
23 purchases, will be disciplined by competition.

1 Q. **Mr. Rowell states that the goal of Staff's recommendations is to ensure that**
2 **Standard Offer consumers will receive reliable electric service at just and**
3 **reasonable rates. He goes on to state that, "Staff believes it is important to**
4 **ensure that consumers are no worse off under the restructuring environment**
5 **than they were under traditional cost-of-service regulation." Are these goals**
6 **achievable?**
7 A. The first goal is. Mr. Rowell concludes that cost of service rates are just and
8 reasonable. My understanding of the PPA is that it is intended to deliver power at
9 prices wholly consistent with cost of service ratemaking. Therefore, this goal can
10 be achieved via the PPA.
11 The second goal is inherently unachievable. Once one embarks on a
12 market-based procurement of wholesale power, there is no feasible way to assure
13 that prices will be no higher than under regulation. Indeed, market prices on an
14 hour-by-hour, day-by-day or even year-by-year basis will sometimes be above, and
15 sometimes below regulated prices. Staff surely cannot truly believe that customers
16 are entitled to, or could get, the "lower of cost or market" on this pick-and-choose
17 basis.
18 Even on a wholly *ex ante* basis, evaluating the PPA relative to hypothetical
19 or even real competitive market offers can be difficult and will necessarily be based
20 on projections of costs and contract terms that are inherently uncertain. This
21 comparison seems to be what he has in mind in saying, at Page 5, that the
22 Commission can use cost of service rates as a benchmark for evaluating
23 competitive rates.

At page 7 Mr. Rowell puts a little more flesh on the bones of Staff's proposal. He says that the established cost of service should be used as both the standard for UDC cost recovery and the price to beat for any competitive solicitation. With respect to an affiliate PPA, he states Staff's position that the UDC should pay no more than its pre-transfer cost of service or the affiliate's post-transfer cost. He notes, that this does not apply to load growth beyond the capability of the utilities' current capacity.

First of all, a critical caveat is that this standard must be applied prospectively in approving the prudence of contracts, including affiliate contracts that APS enters into before they are signed. This is especially true if the Commission rejects the PPA in whole or in part in favor of APS buying from the merchant market. If the Commission requires that APS turn down a cost-based contract, one based on its affiliates cost of service, and requires that it buy instead from the market, it cannot ethically or in all likelihood legally, subsequently disallow resulting costs as "imprudent".

However, Staff does not appear to be thinking only in terms of an *ex ante* determination that APS is pursuing a strategy that will result in just and reasonable rates. What Staff appears to have in mind is absolutely inappropriate. While the language used by Staff is a bit imprecise, I am especially concerned by the question and answer on Page 14 of Mr. Rowell's testimony. The question asked is, "After a utility transfers its generating assets to an affiliate, how should the UDCs recover the cost of power purchased from that affiliate?" He assets that the prudence of purchases from any of "its affiliates or for any other wholesale provider should be

1 evaluated based on (1) the costs of other competitive alternatives and (2) the costs
2 the UDC would have borne had the transfer of assets not happened" [emphasis
3 supplied]. This smacks of the worst sort of after-the-fact, lesser of cost or market
4 regulation. Purchases from an affiliate made on a cost of service basis would be
5 judged based on costs of competitive alternatives. When lower, they are
6 recoverable. When higher, they are not. Similarly, the cost of purchases from the
7 competitive market is recoverable only if they are less than the cost of service
8 alternative. Indeed, the comparison of competitive purchases to cost of service
9 does not exhaust risk. The Nevada Commission recently disallowed nearly half a
10 billion dollars of the power purchase costs of Nevada Power Company, enough to
11 put the company on the verge of bankruptcy, on the theory that it should have
12 entered into a different market contract at an earlier time.

13 Mr. Rowell professes concern for the financial health of UDCs. His
14 proposal assures that the UDCs would not be credit-worthy and poses a high risk of
15 bankruptcy even if their procurement decisions are uniformly reasonable and
16 prudent. At a minimum, lenders would impose a substantial risk premium on APS,
17 as would equity investors. Vendors, including merchant sellers of wholesale
18 electricity, would sell to APS, if at all, only at prices that reflected the substantial
19 risk of default.

20 If this indeed is Staff's proposal, it is repeating the worst of the policy errors
21 committed by the state of California. When the power shortage developed and
22 prices went sky-high, there was no impact on Edison's and PG&E's retail prices.
23 They remained at levels based on historic cost of service, a ceiling that Staff

1 proposes here. With no pass through of cost and hence no demand response, the
2 California shortage persisted. Once a material increase in retail prices was allowed
3 to occur, demand fell substantially. This substantially eased the supply-demand
4 imbalance eliminating the shortage wherein any major supplier was "pivotal".
5 And, of course, this ill-conceived policy bankrupted a utility with far deeper
6 pockets than the Arizona UDCs and nearly bankrupted another. An end result was
7 that a state agency ended up having to contract for power to meet Standard Offer
8 loads and, having paid what is believed (with hindsight) to be too much, retail
9 access had to be suspended so that these above market contract costs could be
10 imposed on all consumers, including Direct Access.

11 If I understand Staff's proposal correctly, were energy prices to spike again,
12 rates would be held at a fictitious "cost of service" level. I find it astounding that
13 Staff would propose repeating this crucial California policy error. Conversely, if
14 Staff were to support the PPA it could have cost-of-service level prices (themselves
15 locking in a cost of capital at historically low levels), irrespective of the market
16 price, without embarking on an inherently unworkable attempt to trap unrecovered
17 power costs in APS.

18 The imprecision of Staff's proposal with regard to which costs serve as a
19 benchmark also gives me pause. Staff references both the UDC's cost of service
20 and the affiliates' post-transfer cost of service. At least for APS, these are not the
21 same, but Staff does not indicate which of the two benchmarks it would support.
22 Since PWEC's cost of service includes the new plants required to meet load
23 growth, and Staff explicitly exempts purchases to meet load growth from the

1 benchmark tests, the distinction should not matter, but Staff's language suggests
2 otherwise.
3 If, as I hope (but doubt) the prudence test that Staff has in mind is an *ex ante*
4 test, conducted prior to APS signing contracts, the proposed benchmark still is
5 difficult.[4] The APS PPA has many of the same cost of service provisions as
6 traditional ratemaking, for example, the pass-though of fuel and purchased power
7 costs. It also is a requirements contract shaped to APS's load. Competitive
8 offerings will, if some of the merchants have their way, have quite different forms.
9 Intermediate and long-term merchant contracts typically are gas price and inflation
10 indexed. Several of the merchants likely would offer power that is not load shaped,
11 but in 7X24 or 6X16 blocks, either firm or unit contingent. It is, of course, possible
12 to gerrymander both the PPA and competitive offerings to be directly comparable.
13 For example, each could be required to be for a slice of load (as Reliant
14 recommends) and fixed price over identical time periods. However, this is
15 standardization would come at a price, quite possibly a high one. Moreover, it is
16 quite inconsistent with Staff's insistence that the UDC should be given full latitude
17 to procure power in whatever matter it deems appropriate.
18 **Q. At page 6, Mr. Rowell relates Staff's recommendation that UDCs be allowed to**
19 **not transfer their assets if they so choose but that they would still need to**

[4] This interpretation of what Staff is proposing is consistent with Mr. Rowell's statement that "As part of their ongoing procurement planning process, the UDCs should be required to perform an assessment or analysis that demonstrates that they are obtaining and/or producing reliable power for Standard Offer customers at the best price." He earlier had defined best price in terms of a combination of price and risk. Since risk is *ex ante* (after the fact outcomes are no longer risky) this suggests that the prudence review is before the fact. Unfortunately, he may mean that prudence must be demonstrated before the fact, and then confirmed based on after-the-fact outcomes.

comply with Section 1606(B) or seek a variance. What is your view of these positions?

A. Regarding the transfer issue, I think that there are valid reasons for many state legislatures and commissions to have required such transfer. However, the issue is moot for APS, as it intends to transfer its generating assets.

Regarding 1606(B), Staff's position is confusing. Staff accepts that UDCs that do not transfer assets would be unlikely to be able to comply with these competitive procurement provisions. This surely is correct. Since non-transferred assets remain in rate base, procuring 50 percent of power from an auction and the balance from a competitive market are not consistent with retention of assets in the regulated UDC. However Staff also says that a variance from 1606(B) should be backed by a demonstration that the UDC tried to comply but could not procure the requisite power at just and reasonable rates. For the non-transferring utility, this makes little sense, since even a partially successful procurement would result in a combination of retained and contracted capacity far in excess of load requirements. For transferring utilities, Staff is silent on what demonstration is required. Staff appears to be suggesting that the utilities should proceed with the competitive bid auction, but stand ready to supply power to the extent to which the auction does not match the "price to beat". I already have discussed the difficulty of such comparison. Moreover, Staff's proposal smacks of yet another form of the "lower of cost or market" theme that permeates Staff's recommendations. Further, the whole variance process raises serious questions about timeliness, in view of Staff's response to the variance requests made earlier this year by APS and TEP.

1 **Q. Beginning at page 7, Mr. Rowell addresses Staff's market power concerns**
2 **regarding the transfer of assets. Please comment.**
3 A. Much of what Mr. Rowell says is derivative from other Staff witnesses and I will
4 address it in that context. However, I will make a few comments. Staff begins by
5 simply assuming that the UDC's have market power – with no analysis whatsoever.
6 Mr. Rowell focuses primarily on the possibility of affiliate abuse – PWEC inflating
7 costs then passing them on to ratepayers. This "strategy" has nothing to do with
8 market power. It arises from unbundling a utility into a regulated entity and a
9 competitive entity. This decision, I had thought, was settled in Arizona.
10 In any event, Mr. Rowell's stated concern, arising from the loss of
11 jurisdiction over wholesale rates, ignores two key facts. The first is that any
12 affiliate sales will be by contract. APS is before this Commission for approval of
13 the contract. The Commission has power to accept or reject its terms. Second,
14 FERC is particularly vigilant concerning affiliate dealing. It too will have
15 jurisdiction over the contract. While the prudence and reasonableness of APS's
16 purchase costs now are subject only to ACC oversight, any affiliate contract will be
17 subject to challenge in both State and Federal venues after the assets are transferred.
18 Second, any local market power that PWEC might have hypothetically will
19 be constrained by contract provisions, market oversight and, in the future, RTO
20 monitoring. Moreover, as I have discussed at length, PWEC will not be in a
21 position to exercise market power with respect to APS's customers to the extent
22 that their needs are covered by contracts or with respect to anyone to the extent that

its power is sold into the larger regional market or that its sales are under contracts that pre-exist the period of alleged concern.

Q. Beginning at page 10, Mr. Rowell discussed the market power studies that he proposes that UDC's be required to file. Do you have any comment on these recommendations?

A. Yes. Mr. Rowell proposes a laundry list of every imaginable and unimaginable type of market power study. This includes the DOJ/FTC Merger Guidelines analysis, presumably as adapted by the FERC, the FERC Supply Margin Assessment Test, and an amorphous category that he terms a strategic behavior analysis. He also proposes a vertical market power analysis and an analysis of entry barriers.

Let me begin by noting that much of this already has been done. Both Dr. Roach and I have provided SMA analyses in this proceeding, and APS passes. In 1999, I provided the Commission with an analysis based on the Merger Guidelines; APS also passed. Market changes since then have been clearly pro-competitive. The vertical issue is not new and is not exacerbate by the transfer of assets. Indeed, the greater remoteness from transmission that is a consequence of the transfer should reduce market power concerns. APS already has a regulation-imposed code of conduct governing affiliate dealings, and FERC has imposed restrictions intended to eliminate the potential use of vertical market power. I am unaware of any allegations that APS has exercised such power. An analysis of entry barriers seems an empty exercise in view of the very substantial entry that has occurred in Arizona.

1 I would not recommend the "strategic behavior analysis" that Mr. Rowell
2 asserts should be done. I have reviewed a number of such analyses, all of which
3 assume forms of tacit collusion among market participants. I have yet to see one in
4 any electric market that did not conclude that the market structure would not
5 support competition. Indeed, some of Mr. Talbot's colleagues performed a study of
6 the PJM market that concluded that 30 firms, each of whom owned identical plants,
7 were required before the market would be acceptably competitive. Thus, a market
8 with concentration index of 300 (30 times 3.33 squared) is necessary to achieve
9 workable competition, according to their analysis. In contrast, the DOJ/FTC
10 Merger Guidelines that Mr. Rowell also proposes regard a concentration index of
11 1,000 (ten identical firms) as so competitive that the effects of a merger do not
12 matter, and an index of 1,800 as only moderately concentrated and presumptively
13 still workably competitive.

14 Q. **Does Mr. Rowell provide any guidance on how the Commission should use**
15 **these analytical tools?**

16 A. No. This is unfortunate, because the tools themselves, having been written for
17 general application, ignore facts that are knowable in the Arizona context. The two
18 FERC tests – merger guidelines and SMA, have been used often and have well-
19 known limitations. I have performed, or had performed under my direction, more
20 such tests than anyone else in the country. I am very familiar with them and how
21 they operate. A major problem with both tests is that they are presumptive of what
22 the relevant geographic market is and of what share of the capacity that the utility
23 owns is available to sell at market prices in the relevant market. The core

1 presumption of both SMA and the Merger Guidelines-related delivered price test is
2 that all of the load in a control area is uncontracted and must buy in the competitive
3 market and that none of the local utility's capacity is sold under regulated tariffs.
4 Both assumptions are patently false for APS today, for APS if the PPA is signed, or
5 under any other plausible outcome of these proceedings.

6 As I have stated in my Direct Testimony and in other testimony before the
7 Commission, any assessment of market power must take into account the contracts
8 that will result from this series of proceedings. A good example is the PPA. If it is
9 in place, all of PWEC's capacity will be under contract and it will have nothing that
10 it could sell to APS that is not covered by the contract. Under these circumstances,
11 it is silly to even attempt to analyze PWEC's post-transfer market power over
12 customers in the APS control area. Manifestly, it will have none.

13 The portfolio of market power studies that Mr. Rowell proposes be required
14 as a post-transfer condition will take a very long time to prepare and considerably
15 more time for Staff and others to comment on and for the Commission to review
16 and accept. Given that the Commission has the opportunity to mandate the
17 existence of contracts that insulate APS customers from the exercise of market
18 power, including but not restricted to accepting the PPA, this is a waste of time.
19 Moreover, the fact that the Staff cannot even agree on which market power test to
20 use, but instead wants all tests performed, does not signal that Staff is prepared to
21 play a resolute role in the timely resolution of any market power issues.

22 Q. **On pages 12 and 13, Mr. Rowell discusses Staff's recommendations regarding**
23 **reliability must run generating units. He proposes that they be retained under**

ACC rate regulation (presumably, owned by APS) until they no longer are must run. Is this a good policy?

A. Frankly, it doesn't matter, at least from a market power perspective. Energy from must run units is provided on a cost of service basis today, and would be under the AISA protocols or under the proposed PPA. Moreover, the Commission will not retain jurisdiction over must run pricing for long, no matter who owns the units. Once there is an RTO, Must Run power is provided pursuant to a contract between the owner and the RTO. This is a FERC jurisdictional contract, whether PWEC owns the units or APS.

Thus, the only real issue about the must run units is which ownership is likely to minimize costs. If the expertise for running generating units resides primarily in PWEC, my presumption is that costs would be minimized if the units were transferred. Finally, I should note that with the completion of West Phoenix 4 and 5, the largest portion of costs, and the bulk of must run power, likely will come from units that are not ACC jurisdictional.

Q. Please turn now to Mr. Schlissel's testimony. At pages 4-8 he discusses an SMA analysis of APS, focusing on the load pockets in the valley and Yuma. Please comment.

A. My only substantive comment is that APS can properly resent his discussion of various APS "admissions" concerning market power. This terminology suggests an inadvertent disclosure of something that APS is seeking to hide. APS always has voluntarily acknowledged the need to regulate the pricing of units that are must run as a result of these constraints. FERC policy similarly insists that such prices be

1 mitigated. There is no dispute that when these areas are constrained for a few hours
2 each year, market power mitigation is warranted.

3 Q. **At page 9, Mr. Schlissel disputes your statement that FERC would assure that**
4 **must run units could not exercise market power, pointing to FERC's supposed**
5 **dilatory mitigation of market power in California. Can you respond?**

6 A. Yes. FERC has been quite active in controlling prices for reliability must run
7 (RMR) units in California and elsewhere. In pointing a finger at FERC lapses in
8 proactively solving the California mess, he does not provide any evidence
9 whatsoever that the failings had anything to do with the pricing of output supplied
10 by must run units under RMR conditions.

11 Q. **Please turn now to Mr. Talbot's testimony. What in his testimony do you**
12 **choose to comment upon?**

13 A. There is little to comment upon. Mr. Talbot primarily summarizes Staff's
14 recommendations, effectively duplicating Mr. Rowell's testimony. In terms of
15 what is new, there is a commentary on the western regional market and on market
16 power supposedly exercised in them. The discussion is backward looking, and his
17 market power conclusions are wholly unsupported in his testimony. Frankly, there
18 is nothing there to aid the Commission in determining whether the market in which
19 Arizona will buy power after the rate freeze ends will be competitive. There also is
20 a discussion of local market power that duplicates several other discussions of load
21 pockets in Arizona. The existence of load pockets and need to discipline pricing of
22 RMR units are not in dispute.

1 Next, there is a discussion of the "rebuttable presumption" that the
2 traditional utilities have market power. I will leave to lawyers the import of the
3 term "rebuttable presumption" but will note that if it has the meaning that I believe
4 it has, it puts the utilities in the position of proving the negative. This is a generally
5 insurmountable burden of proof, since interveners always can hypothesize a case
6 that has not been examined.

7 He also quotes at length from a New York Public Service Commission
8 Order in 1998 relating its vertical market power concerns. I will note simply that,
9 as a consultant to a party participating in that proceeding, I know that the NYPSC
10 had decided to order the divestiture of generation and the hypothetical vertical
11 abuses that are in the cited section of the order were designed to justify that
12 conclusion. In any event, those concerns did not arise from a transfer of assets such
13 as is contemplated by this Commission's competition rules, but from the retention
14 of generation by a vertically integrated regulated utility.

15 He next discusses the motive for doing analyses of "strategic behavior"
16 noting that such analyses "reveal opportunities for market manipulation by large
17 sellers" even when market concentration is low. As I have discussed earlier in this
18 testimony, it is this ability to find such "opportunities" by assuming collusive
19 behavior that is the most serious flaw in such studies. I can state categorically that
20 the methodology he is discussing would not find that any U.S. power market is
21 competitive.

22 He then discusses jurisdictional issues, noting that the ACC would lose
23 authority over wholesale pricing. He accepts that a buyback agreement or PPA

could overcome this problem. He notes that APS has proposed such a PPA but also notes that Staff opposes it. He provides no information, useful or otherwise, concerning the basis for that opposition.

Lastly, in his "Concluding Remarks", he begins by expressing his concern with the competitiveness of the wholesale market in the context of the asset transfer. He asserts that this concern can be assuaged if the UDCs file market power studies. Of course, filing studies does not in and of itself resolve anything, and Mr. Talbot and Staff witnesses generally provide precious little insight as to what the Commission should do on the basis of those studies. In general, the whole tone of this section is an apologia for Staff's "go slow, if at all and take no substantive positions" stance. This, frankly, is disappointing. One would hope that Staff and its consultants would provide the Commission with a basis for action rather than non-action. Arizona is now some six years into restructuring. Policy makers need to make policy decisions and move on.

Q. Please turn now to Mr. Peterson's testimony. What is the first point on which you would like to comment?

A. In his summary, he urges caution in view of the recent problems in the industry and the in-progress status of various regulatory initiatives concerning the wholesale market. He concludes by supporting Staff's recommendation that "if APS is confident that the transfer of its assts is in best course of action at this time, then it is appropriate to assign to APS the financial risks associated with such a decision." This statement of Staff's position is an egregious distortion. Staff is not merely asking that APS take on the risks of the asset transfer. Indeed, the proposed PPA

1 fundamentally eliminates those risks by putting all jurisdictional assets under a
2 long-term contract. Staff's "lower of cost or market" proposal demands that APS
3 take on a wholly new risk that it did not have pre-transfer; the risk that cost of
4 service will be, from time to time, above market.

5 Indeed, the more of Staff's testimony one reads, the more one is convinced
6 that Staff doesn't know what it wants. Mr. Rowell appears to be saying that the
7 1606(B) auctions must go forward and that utilities should be free to transfer assets.
8 Mr. Peterson comes quite close to saying that the time is not right for asset transfer
9 and the utilities should bear the consequences of any costs incurred on other than a
10 cost of service basis – including any purchases from the competitive market.

11 Q. **Mr. Peterson has an extensive discussion of Market Rule 17 of the New**
12 **England ISO and recommends the adoption of something like in Arizona. Do**
13 **you have any comment?**

14 A. I was the primary author of Market Rule 17 and the witness that sponsored it. I
15 therefore am unlikely to oppose its adoption elsewhere under appropriate
16 circumstances. However, Market Rule 17 depends on certain institutional
17 conditions that do not exist in Arizona, notably the existence of an explicit, hour-
18 by-hour unconstrained price for the region. Market Rule 17 cannot exist without an
19 ISO or RTO, at least as it is written.

20 Mr. Peterson also describes the level of congestion that has occurred in New
21 England and surmises about the causes. While not particularly relevant to this
22 proceeding, I disagree with his diagnosis. The main reason why congestion
23 increased in New England after the ISO was formed was that the formerly-

1 integrated utilities had dispatched around congestion. The Arizona analog to the
2 congestion that did not exist previously but that has occurred in Connecticut and
3 greater Boston after ISO formation would concern the Arizona load pockets. I am
4 confident that, historically, the Tucson and Valley transmission is rarely congested
5 (i.e. loaded to their limits). What is unsaid is that it is not congested because RMR
6 units are run, despite costs that exceed those of external units, before the inbound
7 transmission is exhausted fully. APS does not pretend, as did some NEPOOL
8 utilities, that these areas are not load pockets within which generation must be run
9 even when their costs exceed external units' costs.

10 Lastly, Mr. Peterson discusses, generally positively, recent developments in
11 FERC RTO policy and initiatives being undertaken by the California ISO.
12 However, he remains cautious about the ability to "game" the market despite these
13 initiatives and points to studies indicating that markets other than California have
14 not had fully competitive prices. This, and other references to studies showing
15 above-competitive prices in non-California markets, motivates a comment about
16 standards for determining whether markets behave competitively.

17 Economists, of which I am one, tend to hold to a short run marginal cost
18 concept of competitive prices. However useful this is as an analytical device, it is
19 not a good description of competitive market behavior. My local grocery store does
20 not sell me milk at its marginal cost. If I buy a car, I do not expect to get it at the
21 dealer's actual cost of buying one more car from the factory. Moreover, it is well
22 established that marginal cost energy pricing is not compensatory of the full cost of
23 new facilities, what economists call long-run marginal costs. Studies, such as those

that Mr. Peterson cites, purport to demonstrate that market prices are above short run marginal costs. In itself, this does not demonstrate that prices are not competitive.

REBUTTAL TO RELIANT RESOURCES' WITNESS KEBLER

Q. What is the focus of Mr. Kebler's testimony?

A. Mr. Kebler has a quite specific proposal that PWEC be required to auction off entitlements to approximately one-third of its capacity to other bidders in a competitive auction. The successful bidders would be required to bid the capacity into a Section 1606(B) auction. The auction price would determine the competitive price that also would serve as a benchmark price for any PPA.

Q. Mr. Kebler begins by asking himself what market power issues are raised by the transfer of assets and answers that the main issue is the concentration of assets in a single entity. Is this in fact an issue arising from the transfer?

A. No. Pinnacle West companies own the same amount of assets pre- and post-transfer. The asset concentration and purported problems that it creates for allowing multiple bidders to access the market are not at all related to the transfer. Indeed, absent the transfer, the auction of 50 percent of load requirements under 1060(B) clearly would not occur.

Q. What purpose, then, is served by the auction of output from PWEC's capacity?

1 A. From Reliant's perspective, it serves the purpose of creating the possibility that it
2 would have something to sell to APS. My understanding is that Reliant's Arizona
3 generation is fully pre-sold to SRP. If PWEC were required to auction one-third of
4 its capacity, Reliant would be better positioned to compete.
5 Such an auction also would make the form of competitive purchase auction
6 that Reliant is proposing more feasible. Reliant proposes a load-slice auction.
7 Serving a load slice economically requires access (by contract or otherwise) to
8 baseload, cycling and peaking resources. Mr. Kebler's proposal would compel
9 APS to sell its capacity to PWEC competitors in order to enhance such competitor's
10 ability to compete for the type of load auction product that Reliant is supporting in
11 Track B.
12 **Q. What risks does this proposal imply for PWEC?**
13 A. Reliant proposes that PWEC be compelled to auction one-third of the output of the
14 transferred facilities. It is silent on the term (time-length) of the auction. Pinnacle
15 West companies would not be allowed to participate in the auction. From this, I
16 infer that PWEC would not be allowed to set a reservation price. PWEC would be
17 at risk that the resulting price would be below both its opportunity cost and its cost
18 of service.
19 **Q. If the auction proceeds are below cost of service, what happens to the**
20 **shortfall?**
21 A. Mr. Kebler does not say. These costs would be "stranded". Whether he would
22 support stranded cost recovery is not clear.
23 **Q. Do you believe that auction proceeds would be below cost of service?**

1 A. I don't know. Entitlement to the transferred capacity would be valuable,
2 particularly since it could be packaged with the available merchant combined cycle
3 capacity. Indeed, a buyer such as Reliant might be able to strike a very attractive
4 deal to buy merchant combined cycle output that otherwise would have difficulty
5 competing in a load slice auction if it acquired a major share of the APS capacity.
6 Competition for this favorable position could cause the price for the PWEC
7 capacity to be bid up, perhaps to above cost of service.

8 **Q. If you were certain that the capacity auction would cover at least PWEC's**
9 **embedded cost for the sold capacity entitlements, would you support the**
10 **proposal?**

11 A. This depends on what hat I am wearing. Clearly PWEC would like a high price for
12 its capacity. However, the successful bidder would be unlikely to offer the capacity
13 into the Section 1606(B) auction at less than its acquisition cost. Hence APS could
14 end up paying more for the capacity than it would under the PPA. Note that this
15 also could be true if the successful bidders paid less than cost of service for PWEC
16 capacity.

17 **Q. Mr. Kebler proposes that the successful bidder would be required to bid the**
18 **capacity into the Section 1606(B) auction. Does this moot your concern about**
19 **the effects on APS and its customers?**

20 A. No. Mr. Kebler doesn't say that the capacity would have to be offered at the price
21 that the successful bidder paid for it. Indeed, such a requirement would not be
22 enforceable since the purchased capacity would be commingled with other capacity
23 for which no cost basis is established or jurisdictionally enforceable.

1

2 **REBUTTAL TO AECC WITNESS HIGGINS**

3

4 **Q. What is the subject matter of Mr. Higgins testimony?**

5 A. Mr. Higgins discusses market power. Primarily, his testimony does two things.
6 First, it cites approvingly the various market power mitigation measures that have
7 been included in existing AISA and WestConnect protocols and in more general
8 FERC policies. These include, in particular, measures to mitigate market power in
9 load pockets. He urges the Commission to take notice of what has been
10 accomplished so as not to "reinvent the wheel". He also offers his opinion that
11 FERC is strongly focused on vertical market power and that, in a post-California
12 environment, horizontal market power is also on the "front burner" at FERC.
13 Second he proposes using the California ISO's Residual Supply Index (RSI) in lieu
14 of the FERC SMA test as a measure of market power. It is on this latter issue that I
15 would like to focus.

16 **Q. What is the RSI?**

17 A. The RSI is a measure developed by the California ISO to look at whether there are
18 pivotal suppliers in the real time market. The test looks at the amount of capacity
19 offered into the market in a particular hour. In looking at whether a large supplier
20 is pivotal, it then compares 110 percent[5] of load offered into the real time market to
21 the capacity offered into the market by participants other than the supplier being
22 studied. If the competing supply exceeds 110 percent of load, the supplier being
23 analyzed is not pivotal and "passes" for that hour.

1 Q. **Is the RSI as originally formulated applicable to the prospective analysis of**
2 **market power in a manner similar to the SMA?**
3 A. No. Not as originally formulated. Since the RSI deals only with the real time
4 market and supplies offered into the real time balancing market, it cannot be used
5 prospectively since the amount of supply and demand that will be bid into the real
6 time market is not knowable. Moreover, the SMA is not merely concerned with the
7 real time balancing market, but power markets more broadly.
8 In the April 24, 2002 filing that Mr. Higgins cites, the California ISO has
9 proposed a form that can be used prospectively. In concept, this could be used for
10 the same purposes as the SMA.
11 Q. **What does the California ISO propose?**
12 A. The RSI still would be applied on an hour-by-hour basis. However, it would utilize
13 total load and total capacity (both on a prospective basis), not just capacity and load
14 in the real time balancing market.
15 Q. **What are the key differences between RSI and SMA as proposed as a**
16 **prospective test?**
17 A. In addition to the hour-by-hour provision, one difference is use of 110 percent of
18 load. However, this distinction is more apparent that real. The RSI permits a
19 failure of the test in 5 percent of hours. Given the needle peaks in desert region
20 loads, the tolerance of failure in 5 percent of hours using 110 percent of load is
21 roughly equivalent to the SMA's 100 use percent of peak load with no tolerance of
22 failure. I note also that except under quite atypical conditions, modeling markets

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[5] I.e., load plus a 10 percent allowance for operating reserves.

1 hour-by-hour on a prospective basis will not uncover "pivotal suppliers" that are
2 not also found with the SMA.[6]
3 The other and more important difference is that the RSI excludes from the
4 capacity of the supplier being analyzed any capacity used to serve native load or
5 that is under long term contract to other parties. This is an important difference.
6 The SMA makes no native load allowance; the applicant supplier's total capacity is
7 counted even though it may be wholly dedicated to native load. In this respect, I
8 agree with Mr. Higgins that the RSI is superior. It recognizes that what can be sold
9 into the market does not include that which has been presold or is dedicated to
10 native load. Failure to make that adjustment has been a major criticism of SMA.
11 This having been said, the SMA is FERC's test until it is changed. Nothing
12 that happens in this proceeding will change this.
13 Q. **If the Commission were to adopt the RSI and require that APS demonstrate**
14 **compliance with it, would a post-transfer PWEC pass?**
15 A. Yes. Since PWEC passes the SMA test by a wide margin, it also would pass RSI.
16 Further, under any reasonable expectation of the outcome of these proceedings, a
17 substantial proportion of PWEC's capacity will be under long or intermediate term
18 contracts. I have testified repeatedly that contracts mitigate market power. This is
19 recognized explicitly by the RSI. Since the RSI takes native load responsibility or
20 equivalent contract responsibility into account, PWEC would pass the RSI by
21 amounts still greater than the amount by which it passes the SMA. The amount of

[6] Since load is less in non-peak hours, but competing capacity is more or less the same, a supplier that passes the RSI for the peak hour almost certainly will pass in other hours. The possible exception that I have in mind relates to systems in which competing capacity is predominantly hydroelectric, with sufficiently severe energy limits that such capacity does not discipline off-peak prices. This does not apply to Arizona.

PWEC's capacity covered by contracts will determine the margin by which it will pass the RSI, but it will pass in any event.

Q. Does this complete your prepared rebuttal testimony?

A. Yes, it does.

RESPONSE:
Ms. Keene has been involved in several evaluations of bids for professional consulting services including consulting services for the following cases: APS Variance Request in 2002, Arizona Solar Energy Study in 1999, and the Tucson Electric Power rate case in 1993.

Q.2-11 (Page 8, line 26) Once the "other parties" have filed their comments on APS' proposed competitive bidding plan, would APS be free to implement such plan without further regulatory review or approval? If not, what further action(s) by the Commission or Staff would be required? What would be the timetable for completion of such further action(s)?

RESPONSE:
On page 8, line 22, my testimony indicates that Staff recommends that the plan will require Commission approval. Staff has not recommended a timetable for completion of that proceeding at this time. Furthermore, Staff cannot always control or predict the amount of time that it may take to complete a proceeding. However, Staff will work diligently to ensure that Staff's evaluation of APS' proposed plan is completed within a reasonable time.

Matthew Rowell

Q.2-12 Regarding Mr. Rowell's recommendations beginning at page 2 of his testimony, if the Proposed PPA were amended to address all of the concerns raised by Mr. Schlissel concerning the pricing of Dedicated Energy Products under the PPA, would Staff recommend approval of the PPA and a corresponding variance to Rule 1606(B)? If not, please explain.

RESPONSE:
No. Mr. Schlissel's testimony raises many concerns other than the pricing of Dedicated Energy Products. Each of these concerns would need to be addressed by APS before Staff could reconsider the appropriateness of the PPA. Additionally, alterations to the PPA are unlikely to affect Staff's view of APS' proposed variance to Rule 1606(B). Staff's evaluation of the proposed variance has been, and will be, based on conditions in the wholesale market, not on the appropriateness of the PPA.

Q.2-13 With regard to the competitive bidding proposal summarized on page 3 of Mr. Rowell's testimony and described at page 5, line 14 through page 7, line 21 of that same testimony, it this Mr. Rowell's proposal or Mr. Smith's proposal?

RESPONSE:
Some parts of my competitive bidding proposal refer to and build on Mr. Smith's testimony; to the extent that I have relied upon his testimony to form my recommendations, we share the competitive bidding proposal.

Q.2-14 How many MW and MWH of APS Standard Offer requirements for 2003 would have to competitively-bid under this proposal? 2004? Please differentiate your answer as between load outside transmission constrained zones of the APS service area and load within such zones.

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[Code of Federal Regulations]
[Title 18, Volume 1]
[Revised as of April 1, 2001]
From the U.S. Government Printing Office via GPO Access
[**CITE: 18CFR37.4**]

[Page 273-275]

TITLE 18--CONSERVATION OF POWER AND WATER RESOURCES

CHAPTER I--FEDERAL ENERGY REGULATORY COMMISSION, DEPARTMENT OF ENERGY

PART 37--OPEN ACCESS SAME-TIME INFORMATION SYSTEMS AND STANDARDS OF CONDUCT FOR PUBL

Sec. 37.**4** Standards of conduct.

A Transmission Provider must conduct its business to conform with the following standards:

(a) General rules. (1) Except as provided in paragraph (a)(2) of this section, the employees of the Transmission Provider engaged in transmission system operations must function independently of its employees, or the employees of any of its affiliates, who engage in Wholesale Merchant Functions.

(2) Notwithstanding any other provisions in this section, in emergency circumstances affecting system reliability, Transmission Providers may take whatever steps are necessary to keep the system in operation. Transmission Providers must report to the Commission and on the OASIS each emergency that resulted in any deviation from the standards of conduct, within 24 hours of such deviation.

(b) Rules governing employee conduct. (1) Prohibitions. Any employee of the Transmission Provider, or any employee of an affiliate, engaged in wholesale merchant functions is prohibited from:

(i) Conducting transmission system operations or reliability functions; and

(ii) Having access to the system control center or similar facilities used for transmission operations or reliability functions that differs in any way from the access available to other open access Transmission Customers.

(2) Transfers. Employees engaged in either wholesale merchant functions or transmission system operations or reliability functions are not precluded from transferring between such functions as long as such transfer is not used as a means to circumvent the standards of conduct of this section. Notices of any employee transfer to or from transmission system operations or reliability functions must be posted on the OASIS as provided in Sec. 37.6(g)(3).

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The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e., on behalf of the Transmission Provider and wholesale merchant or affiliate), and the effective date of the transfer. The information posted under this section must remain on the OASIS for 90 days.

(3) Information access. Any employee of the Transmission Provider, or of any of its affiliates, engaged in wholesale merchant functions:

(i) Shall have access to only that information available to the Transmission Provider's open access transmission customers (i.e., the information posted on an OASIS), and must not have preferential access to any information about the Transmission Provider's transmission system that is not available to all users of an OASIS; and

EXHIBIT
APS-8
Admitted

(ii) Is prohibited from obtaining information about the Transmission Provider's transmission system (including information about available transmission capability, price, curtailments, ancillary services, and the like) through access to information not posted on the OASIS that is not otherwise also available to the general public without restriction, or through information through the OASIS that is not also publicly available to all OASIS users.

(**4**) Disclosure. A Transmission Provider is responsible for ensuring compliance with the following provisions:

(i) Any employee of the Transmission Provider, or any employee of an affiliate, engaged in transmission system operations or reliability functions may not disclose to employees of the Transmission Provider, or any of its affiliates, engaged in wholesale merchant functions any information concerning the transmission system of the Transmission Provider or the transmission system of another (including information received from non-affiliates or information about available transmission capability, price, curtailments, ancillary services, etc.) through non-public communications conducted off the OASIS, through access to information not posted on the OASIS that is not at the same time available to the general public without restriction, or through information on the OASIS that is not at the same time publicly available to all OASIS users (such as E-mail).

(ii) If an employee of the Transmission Provider engaged in transmission system operations or reliability functions discloses information not posted on the OASIS in a manner contrary to the requirements of the standards of conduct, the Transmission Provider must immediately post such information on the OASIS.

(iii) A Transmission Provider may not share any market information, acquired from nonaffiliated Transmission Customers or potential nonaffiliated Transmission Customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS, with its own employees (or those of an affiliate) engaged in merchant functions, except to the limited extent information is required to be posted on the OASIS in response to a request for transmission service or ancillary services.

(5) Implementing tariffs. (i) Employees of the Transmission Provider engaged in transmission system operations or reliability functions must strictly enforce all tariff provisions relating to the sale or purchase of open access transmission service, if these provisions do not provide for the use of discretion.

(ii) Employees of the Transmission Provider engaged in transmission system operations must apply all tariff provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all customers (including the public utility and any affiliate) in a non-discriminatory manner, if these provisions involve discretion.

(iii) The Transmission Provider must keep a log, available for Commission audit, detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff. The information contained in this log is to be posted on the OASIS as provided in Sec. 37.6(g)(**4**).

(iv) The Transmission Provider may not, through its tariffs or otherwise, give preference to sales for resale by the wholesale merchant function or by any affiliate, over the interests of any other wholesale customer in matters

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relating to the sale or purchase of transmission service (including issues of price, curtailments, scheduling, priority, ancillary services,

etc.).

(6) Books and records. A Transmission Provider must maintain its books of account and records (as prescribed under parts 101 and 125 of this chapter) separately from those of its affiliates and these must be available for Commission inspection.

(c) Maintenance of written procedures. The Transmission Provider must maintain in a public place, and file with the Commission, current written procedures implementing the standards of conduct in such detail as will enable customers and the Commission to determine that the Transmission Provider is in compliance with the requirements of this section.

[Order 889, 61 FR 21764, May 10, 1996, as amended by Order 889-A, 62 FR 12503, Mar. 14, 1997]

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1 & 2

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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	DOCKET NO. E-00000A-01-0630

NOTICE OF FILING

The Arizona Utility Investors Association hereby provides notice of filing the Direct Testimony of Walter W. Meek as required by the Commission's procedural order in the above-captioned matter, dated February 8, 2002..

DATED THIS 29TH DAY OF MARCH, 2002.

Walter W. Meek

WALTER W. MEEK, PRESIDENT

CERTIFICATE OF SERVICE

Original and eighteen (18) copies of the referenced Testimony were filed this 29th day of March, 2002, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Copies of the referenced Testimony were hand-delivered this 29th day of March, 2002, to:

EXHIBIT
AUIA 1
admitted

William A. Mundell, Chairman
Hercules Dellas, Esq.
James M. Irvin, Commissioner
Patrick Black, Esq.
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Copies of the referenced Testimony
Were faxed or mailed this 29th day of
March, 2002, to:

Appropriate parties of record

DIRECT TESTIMONY

OF

WALTER W. MEEK

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Walter W. Meek. My business address is 2100 North Central Avenue, Suite 210, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the president of the Arizona Utility Investors Association ("AUIA" or "Association"), a non-profit organization formed to represent the interests of shareholders and bondholders who are invested in utility companies that are based in or do business in the state of Arizona.

Q. ARE SOME AUIA MEMBERS SHAREHOLDERS OF PINNACLE WEST CAPITAL CORPORATION?

A. Yes. AUIA has approximately 6,000 members and a substantial percentage are common shareholders of Pinnacle West Capital Corporation ("PWCC"), the corporate parent of Arizona Public Service Company ("APS").

Q. WHAT IS YOUR BACKGROUND IN REPRESENTING SHAREHOLDER CONCERNS AND INTERESTS?

A. I have been president of AUIA for nearly eight years. Prior to that, my consulting firm managed the affairs of the Pinnacle West Shareholders Association for 13 years. During this time we have represented shareholders in numerous rate cases and other regulatory matters and have published many position papers, newsletters and other documents in support of shareholder interests.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am here to represent the views of the equity owners of PWCC regarding the issues raised by the APS request for a variance from the Commission's electric competition rules.

Q. WHAT IS AUIA'S POSITION?

A. We urge the Commission to grant APS a variance from the requirement contained in R14-2-1606(B) that the company subject 50 percent of its load to competitive bid beginning in 2003. We are convinced that a variance would be in the public interest.

Q. DO YOU SUPPORT THE PROPOSED PURCHASED POWER AGREEMENT?

A. We are more ambivalent about the proposed PPA, although we believe it is far superior to the bid requirement. The competition rules require APS to transfer its generation assets to a separate affiliate. If the Commission is concerned about keeping the company's generation assets committed to serving the APS load, the PPA is a good solution. AUIA has no firm positions on the contractual elements of the PPA.

I. The Competition Rules Were Based on False Assumptions.

Q. WAS AUIA INVOLVED IN THE COMPETITION RULEMAKING?

A. Yes. We were involved from the opening of the retail competition docket until the current rules were adopted. We were involved in hundreds of hours of workshops and we intervened in the generic stranded cost proceeding and four separate stranded cost dockets. All of this took nearly six years of effort.

Q. ARE THERE PROBLEMS WITH THE RULES?

A. Yes, there are several, beginning with the fact that the entire rulemaking product was based on false assumptions.

Q. WHAT WERE SOME OF THESE ASSUMPTIONS?

A. First, that the western grid harbored significant excess generating capacity. Second, that low-cost supplies of natural gas would be plentiful. Third, that open access would spur a robust wholesale market. And, that the advent of retail competition would be accompanied by rapid price decreases. Proponents of deregulating generation told this Commission that they could expect cost savings of up to 40 percent resulting from competition.

Q. WHAT WAS THE FATE OF THESE ASSUMPTIONS?

A. All of them melted down in the summer of 2000. Supplies throughout the west proved to be deficient, sending wholesale prices to unheard of levels. Natural gas supplies were constrained and prices reached record levels. The non-municipal portion of California's electric industry experienced financial disaster and the state government is now underwriting the system. Finally, non-municipal electric customers received huge rate increases in 2001.

Q. WHAT HAPPENED TO RETAIL COMPETITION?

A. In California, it died an ugly death. The California Public Utilities Commission officially pulled the plug on retail competition last September. In other western states, competition is dead or on hold.

Q. WHAT WAS THE ARIZONA EXPERIENCE?

A. Arizona was largely shielded from the worst effects, including the price spikes that were experienced throughout the west, but the net effect was that competition never happened here.

Q. WHAT SHIELDED ARIZONA FROM PRICE SPIKES?

A. A few things. Arizona's approach to deregulation didn't replicate some of the provisions that proved to be disastrous in California, such as forced purchases through a central power exchange. Also, the terms of

stranded cost settlements that were reached here prohibited retail price increases. And finally, Arizona utilities were better equipped than most western utilities to meet load requirements with their own resources and were less at the mercy of the volatile wholesale market.

Q. WERE THERE SOME EXCEPTIONS?

A. Yes. Severe price hikes were experienced by two Arizona tribal entities and by Citizens Communications in serving its 75,000 customers in Mohave and Santa Cruz counties.

Q. WHY DID THESE EXCEPTIONS OCCUR?

A. Each of these entities lacks generation capability and has to rely on purchased power to serve its load. Citizens, for example, has an all requirements contract with APS. Unfortunately, the terms of that contract exposed Citizens to some of the market chaos that erupted in 2000 and 2001, to the extent that Citizens has paid more than $100 million in excess power costs that it can't collect from its customers.

Q. WHAT KEPT COMPETITION FROM OCCURRING IN ARIZONA?

A. Simply put, wholesale prices were too high and there was too much risk for large users and aggregators to venture into the market, especially when Arizona was an island of tranquility where prices were stable or going down.

II. The Bidding Requirement Places Shareholders and Ratepayers At Risk.

Q. WHY DOES AUIA OPPOSE THE BIDDING REQUIREMENT?

A. In general, because it is bad public policy that has not been subjected to any scrutiny or market analysis, but we have several specific reasons:

- In the circumstances, it is patently unfair to the company and it places its shareholders at significant financial risk.

- In the long run, APS ratepayers will also be at risk for price fluctuations and reliability failures.
- There is no guidance in the rules about how to conduct the bidding, but APS will be held liable by the Commission if it goes badly.
- The bid requirement does nothing to advance retail competition and may inhibit it.
- Instead, it is a potentially imprudent foray by the Commission into the wholesale electric markets.
- The Commission should consider that the resulting contract(s) would fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC).
- The Commission should also realize that in order to participate in the bidding specified in the rules, APS must divest its generation.

Q. WHY IS IT UNFAIR TO THE COMPANY AND ITS SHAREHOLDERS?

A. Under the rules, APS is the provider of last resort for all of its Standard Offer customers. That means that it must deliver electric service to every customer that is not served by a competitive provider. As we noted earlier, there is no competition in Arizona and every electric utility, including APS, has had to plan and act as if it will continue to have full responsibility for supplying power to its entire customer base.

Q. WHAT IS THE PRACTICAL EFFECT OF THAT RESPONSIBILITY?

A. In APS's case, it has had to invest or commit to investments totalling approximately $1 billion to keep even with load growth. If APS is required to bid out 50 percent of its load, that investment will be at significant risk.

Q. HOW DOES IT BECOME AT RISK?

A. APS's loads and resources are essentially at equilibrium. If some portion of its load is underbid by merchant generators, an equivalent amount of

its generation will be relegated to the wholesale market where there may or may not be a viable market for its output.

Q. IS THIS OF CONCERN TO THE FINANCIAL MARKETS?

A. Yes. I have had conversations with analysts, institutional shareholders and hedge fund managers who are very concerned about these investments as PWCC approaches 2003.

Q. IN WHAT WAY IS THE BIDDING REQUIREMENT DIFFERENT FROM THE REST OF THE COMPETITION RULES?

A. It is one thing to require a utility to open its service territory to retail competition with ground rules that allow consumers and utilities to make reasoned decisions based on economic choices. It is quite another to set up a situation in which the utility may be forced to gamble in the wholesale market with generation it has built to serve customers.

Q. HOW WOULD THE BIDDING REQUIREMENT EXPOSE RATEPAYERS TO PRICE RISKS?

A. In the first place, there is no guarantee that bid prices for generation would be lower than APS is experiencing now. Once the bidding process is underway, APS will simply have to accept what it gets. If the bids are higher than APS's current cost of generation, the customers will have to pay the difference. Under the rule, there would be no opportunity to go back to the APS portofolio.

Q. HOW ELSE WOULD BIDDING CREATE PRICE RISKS?

A. If any significant portion of APS's generation was displaced through bidding, APS would immediately seek to sell the displaced generation in the wholesale market, perhaps on long-term contracts. In two or three years, when the competitive bidding contracts were due to expire, market prices could be higher and the displaced APS generation would

no longer be available. As a result, APS customers would have to pay whatever the market required.

Q. COULD WE REPEAT THE EXPERIENCE OF CITIZENS COMMUNICATIONS ON A LARGER SCALE?

A. That would seem to be an extreme scenario, but the western energy markets are still in serious flux and the future could be very dangerous.

Q. HOW WOULD RATEPAYERS BE EXPOSED TO RELIABILITY RISKS?

A. In the example I just gave, it is possible that when the contracts that resulted from bidding expired, tight market conditions might prevail and the suppliers would be motivated to move to greener pastures. If APS had no generation available to plug the gap, it might not be able to keep the lights on. Clearly, if bidding goes forward, APS or PWCC can't keep building capacity to protect against that contingency.

Q. ARE THERE RISKS IN THE BIDDING PROCESS?

A. The competition rules contain no guidance on how the bidding should be structured and there have been no workshops on the subject. This Commission has workshopped everything from meter reading to gas procurement, yet the state's largest utility is expected to auction off half of its load with no guidance at all.

Q WHAT ARE SOME ISSUES THAT ARE UNCLEAR?

A. For example, it's not clear in the rules whether APS is required to bid out half of its peak load or half of its annual load. I think we can assume that APS will seek bids for firm power with adequate reserves, but they are on their own with regard to terms and conditions and there is no assurance that they will be acceptable to potential bidders or the Commission.

Q. ARE THERE RISKS OF DEFAULT?

A. Enron has proved that in spades. The Enron lesson is that you can have a contract with very favorable terms that is no better than the financial resources that stand behind it. If there is a default, you may have to execute your claim for damages against a pile of shredded paper.

Q. ARE THERE NO PROTECTIONS IN THE COMPETITION RULES?

A. The rules are designed for retail competition, so there are provisions dealing with Standard Offer service and the departure and return of customer loads on the distribution system. However, there are no protections against defaulting wholesale suppliers. After all, the Commission has no jurisdiction over wholesale contracts.

III. Enforced Bidding Will Not Encourage Retail Competition.

Q. WILL THE BID REQUIREMENT FACILITATE COMPETITION?

A. Ironically, the Commission competition rules were designed to enable retail competition and they do that. But the bidding requirement has nothing to do with retail competition and may help to stifle it.

Q. WHERE DID THE IDEA ORIGINATE?

A. That is another irony. It was offered at the last minute in the competition rulemaking by Enron, which later crashed into oblivion owing APS some $15 million.

Q. HOW WILL THE BID REQUIREMENT AFFECT COMPETITION?

A. If it is successful to any degree in displacing APS generation, the bid requirement will benefit only a few merchant generators who have the ability to reach the Phoenix load pocket. These generators will be able to sell into the Phoenix market with APS as their wholesale customer. Any minimal contribution this makes to competition will be at the wholesale level. They will completely avoid any of the transaction costs

that would normally be associated with retail sales. In that respect, it would be a phony brand of competition.

Q. HOW WOULD THIS INHIBIT RETAIL COMPETITION?

A. Assuming for the sake of argument that marginally lower costs can be achieved in the short term through wholesale bidding, why would consumers or suppliers want to take on the additional hassles and transaction costs associated with retail competition?

Q. WHY WOULD THE COMMISSION PROMOTE WHOLESALE TRANSACTIONS?

A. It shouldn't. The merchant plants would like the Commission to believe that it is responsible for their well-being, but that is absurd. The Commission's responsibility is to Arizona consumers and the companies that it regulates. It has no responsibility whatsoever for the fortunes of merchant generators.

Q. BUT WEREN'T MERCHANT PLANTS BUILT ON THE EXPECTATION THAT THE BIDDING REQUIREMENT WOULD BE CARRIED OUT?

A. Some of them make that claim today, but it would have been a very bad business decision to have built one of these plants on that basis. Most of these plants were built to serve California and other western markets and most of them are constrained by lack of transmission into Phoenix. If metropolitan Phoenix was their target, they should have built inside the load pocket as APS and Salt River Project are doing.

Q. WHO WOULD HAVE JURISDICTION OVER THE TRANSACTIONS?

A. The merchant plants are exempt wholesale generators under the jurisdiction of FERC. The contracts resulting from the bidding would also be under FERC jurisdiction.

Q. WOULD APS HAVE TO DIVEST ITS GENERATION?

A. The competition rules anticipate that the existing generating plants that serve APS customers would participate in the competitive bidding, but to assure an arms' length bidding process, APS would have to divest its generation into a Pinnacle West affiliate.

IV. The Variance Is Appropriate and in the Public Interest.

Q. WHY IS THE PROPOSED VARIANCE IN THE PUBLIC INTEREST?

A. The bidding process would subject APS customers to unknown risks, exposing them to the vagaries of an immature and unpredictable wholesale market which failed badly to serve the public interest during the past two years. The market continues to be unpredictable, but once the bidding process has been unleashed, there would be no turning back. Action to prevent this leap into the unknown is clearly in the public interest.

Q. IS THE VARIANCE PERMITTED BY THE ELECTRIC COMPETITION RULES?

A. Absolutely. A.A.C. R14-2-1816(C) authorizes the Commission to grant "variances or exemptions" to the rules.

Q. IS THE BIDDING REQUIREMENT A "CORNERSTONE" OF THE COMPETITION RULES, AS SOME HAVE SAID?

A. No. In the rulemaking, it was an afterthought, a last-minute amendment promoted by a company that is now irrelevant. Understandably, the merchant generators are now trying to use it to their advantage. Under the requirements of the Administrative Procedures Act, if the addition of the bidding requirement had been deemed a major amendment, it would have to have been noticed as such prior to its consideration. It was not.

Q. DOES THE VARIANCE VIOLATE THE APS STRANDED COST SETTLEMENT AGREEMENT, AS SOME HAVE ALLEGED?

A. No. The settlement agreement does not require APS to engage in competitive bidding or acquire any particular percentage of its load requirements in the competitive market. The agreement simply requires APS to follow the Commission's rules in procuring energy for its Standard Offer customers. Obviously, the agreement could not have foreclosed the Commission from amending the rules or granting variances and exemptions, as requested here.

Q. WHO WOULD BE HURT BY THE PROPOSED VARIANCE?

A. No one. Merchant plants were built specifically to operate in the western wholesale markets and they have no right to expect the Arizona Corporation Commission to create a customer base for them.

Q. WOULD YOU CLARIFY AUIA'S POSITION ON THE PROPOSED PURCHASED POWER AGREEMENT?

A. AUIA is not well positioned to analyze the specific elements – particularly the pricing and longevity – of the PPA. However, we believe the concept is infinitely superior to the bidding requirement in 1606(B). The PPA would add stability and lower risk for shareholders and customers alike, while advancing competition at a measured pace.

Q. PLEASE COMMENT ON THE SUGGESTION THAT APS SHOULD SOLICIT BIDS WHICH COULD BE COMPARED WITH THE PPA PRICE.

A. It can't be done. There is no valid comparison between them. The PPA is a long-term power supply agreement, which would supply 6,000 megawatts from a balanced portfolio of generation resources, with protection against market contingencies. The bids would cover two or three years, in increments of a few hundred megawatts from a single fuel source. Besides, there are considerations other than price.

Q. IS RELIABILITY ONE OF THOSE CONSIDERATIONS?

A. Yes. The reliability inherent in the PPA's fuel diversity is one of its most attractive features. Potential bidders would have to rely exclusively on generation from natural gas, which has shown itself to be extremely volatile, both as to price and availability. Pipeline capacity is at a premium and gas supplies can be curtailed.

Q. HOW WOULD APS PARTICIPATE IN COMPETITIVE BIDDING?

A. It couldn't. It would be running the bid process. In order to have a neutral process (not tainted by conflict of interest), APS would have to divest its generation assets to a separate PWCC affiliate which could then participate at arms length.

Q. WOULD A PWCC OFFER LOOK DIFFERENT FROM THE PPA?

A Yes. First, it would have to conform to the bid requirements and would undoubtedly cover a much shorter time frame than the PPA. In addition, PWCC would offer a mix of resources that would fit its view of the short-term energy markets. Like the other bids, the PWCC package probably would offer less stability and certainty than the PPA.

V. Conclusion

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Imagine that it is May of 2000 and APS has just dumped one-half of its customer load onto the open market for competitive bidding. It has divested its generation and PWCC expects to be one of the bidders. But just to be safe, PWCC is diligently pursuing other buyers. Suddenly, unexpected market forces converge and prices surge. APS receives outrageous bids and PWCC is rapidly disposing of its capacity. It's Citizens Communications times ten.

Is this a far-fetched scenario? We don't know. What we do know is that price volatility continued through much of 2001; the gas and electric supply scenarios in the west are still in play; and the wholesale market failed its last serious test.

The bidding requirement in 1606(B) is a three-year-old provision that received no analysis or in-depth consideration when it was proposed by Enron. There has been no Commission analysis to date of market conditions that would bear on this requirement. Absent such an analysis, this is arguably the worst time possible to shoot craps in the wholesale market with half of APS's customer load.

The Commission should grant the APS request for a variance.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	)	DOCKET NO. E-01345A-01-0822
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IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	)	DOCKET NO. E-00000A-01-0630

NOTICE OF FILING

The Arizona Utility Investors Association hereby provides notice of filing Responsive Testimony by Walter W. Meek as provided by the Commission's procedural order in the above-captioned matter, dated May 3, 2002..

DATED THIS 11TH DAY OF JUNE, 2002.

Walter W. Meek

WALTER W. MEEK, PRESIDENT

CERTIFICATE OF SERVICE

Original and eighteen (18) copies of the referenced Testimony were filed this 11th day of June, 2002, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Copies of the referenced Testimony were hand-delivered this 11th day of June, 2002, to:

EXHIBIT
AUIA 2
admitted

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Marc Spitzer, Commissioner
Paul Walker, Esq.
Christopher Kempley, Esq., Legal Division
Ernest Johnson, Esq., Utilities Division
Lyn Farmer, Esq., Hearing Division
Arizona Corporation Commission
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Phoenix, AZ 85007

Copies of the referenced Testimony
Were faxed or mailed this 11th day of
June, 2002, to:

Appropriate parties of record

RESPONSIVE TESTIMONY OF WALTER W. MEEK

ON BEHALF OF THE

ARIZONA UTILITY INVESTORS ASSOCIATION

Docket No.. E-00000A-02-0051, et al.

PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

My name is Walter W. Meek. My business address is 2100 North Central Avenue, Suite 210, Phoenix, Arizona 85004.

BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

I am the president of the Arizona Utility Investors Association ("AUIA" or "Association"), a non-profit organization formed to represent the interests of shareholders and bondholders who are invested in utility companies that are based in or do business in the state of Arizona.

ARE SOME AUIA MEMBERS SHAREHOLDERS OF PINNACLE WEST CAPITAL CORPORATION?

Yes. AUIA has approximately 6,000 members and a substantial percentage are common shareholders of Pinnacle West Capital Corporation ("PWCC"), the corporate parent of Arizona Public Service Company ("APS"). Our members also include shareholders of UniSource Energy Corporation, the parent of Tucson Electric Power Company ("TEP").

WHAT IS YOUR BACKGROUND IN REPRESENTING SHAREHOLDER CONCERNS AND INTERESTS?

I have been president of AUIA for more than eight years. Prior to that, my consulting firm managed the affairs of the Pinnacle West Shareholders Association for 13 years. During this time we have represented shareholders in numerous rate cases and other regulatory matters and have published many position papers, newsletters and other documents in support of shareholder interests.

WHAT IS THE PURPOSE OF YOUR TESTIMONY?

I am here to represent the views of the equity owners of PWCC and UniSource regarding the issues raised in this consolidated docket.

HAVE YOU FILED TESTIMONY PREVIOUSLY IN THIS CONSOLIDATED DOCKET?

On February 8, 2002, I filed direct testimony in Docket No. E-01345A-01-0822 regarding APS' request for a variance from the electric competition rules. Because that testimony contains comments that are still relevant to this proceeding, I am submitting it by reference herewith.

WHAT WAS THE THRUST OF THAT TESTIMONY?

I cited several reasons why AUIA believes that the competitive bidding provision of A.A.C. R14-2-1606 (B) is inappropriate and not in the public interest at this time because it would expose ratepayers and shareholders to significant risk.

IS THAT STILL AUIA'S POSITION?

Yes, but this proceeding has been turned upside-down and bifurcated and the terms of engagement have changed drastically. APS' request for a variance has been trashed and we are now dealing with the Commission Staff's attempts to rewrite the electric competition rules.

WHAT ARE YOUR CONCERNS ABOUT THIS PROCEEDING?

The first is procedural fairness. When APS and TEP requested variances, which are authorized by the rules, they were required to submit expert testimony and exhibits and respond to extensive discovery, including depositions. But when the Staff imposed its new list of issues on this proceeding, they weren't required to put their cards on the table. The parties were forced to respond contemporaneously to issues that were vague and without any evidentiary basis.

The second is the soundness of any decisions that can result from this bifurcated process. We are racing down one track (Track B) as if it has been ordained that there will be competitive bidding when, in fact, the discussion of bidding was aborted. At the same time, the issue of APS' transfer of its assets has been diverted onto a second track (Track A) as if it is an isolated issue unrelated to bidding.

The fact is that these two issues have been married as long as both have been part of the competition rules, and they cannot be separated except at great peril to the shareholders of PWCC. Yet this proceeding has been structured to prevent any dialogue about what happens to UDC assets if bidding goes forward and divestiture does not.

WHAT IS AUIA ADVOCATING IN THIS PROCEEDING?

AUIA insists that full and open consideration of the disposition of APS' generating assets must precede the commencement of any bidding process. In the context of the existing competition rules, APS must be allowed to transfer its generating assets to an affiliate if the Commission is determined to go ahead with competitive bidding for part of APS' load.

WHAT IS THE COMMISSION STAFF'S POSITION?

Generally, the Staff's position is that APS should not be allowed to transfer its assets until it has addressed a perceived condition of market power through a study and, presumably, mitigation measures. The way the Staff has framed its perception of market power, it is unlikely that mitigation could be achieved in the foreseeable future and certainly not before a 2003 bidding procedure. For example, the market power study required by Staff would have to address statewide transmission constraints and how they would be cured by the utilities.

WHAT IS THE STAFF'S POSITION ON BIDDING?

Their testimony is inconclusive at best. Staff witness Matthew Rowell asserts that "If a utility were to choose not to divest, the provisions of Rule 1606(B) likely would not be achievable." (Rowell P. 6) He also asserts that consumers should pay no more than they are paying today, regardless of the results of any bidding process. (Rowell, P. 7)

WHY IS THIS ISSUE IMPORTANT TO EQUITY OWNERS?

Assume for the sake of argument that APS could lose 20 percent of its load to other suppliers in a competitive bidding process. When the process is completed, that amount of APS' generation would no longer be used and useful and would be disallowed from rate base, assuming that it is in a regulated regime. That would be a 20 percent blow to the shareholders' equity.

WHAT WOULD HAPPEN TO THESE ASSETS?

At this time we don't have a clue. We don't know which assets would be affected or in what proportion. If we don't know the answers, the financial community will begin to penalize the company when the bidding process is adopted. The fact is that the rules currently place 50 percent of APS' load and half of its assets at risk through bidding.

WHAT IS AT STAKE FOR THE COMPANY?

Its ability to survive by deploying its assets as market conditions require. PWCC must be able to manage its risk and its portfolio. It can't do that if its assets are frozen in regulation and chopped off intermittently like unwanted fingers and toes. The quasi-regulated regime proposed by the Staff and some other parties ultimately requires the Commission to dictate to APS' how it deploys its assets. AUIA believes that would be an illegal abuse of the Commission's authority and we will urge the company to resist it by every means possible.

DON'T THE RULES REQUIRE ARMS-LENGTH PURCHASES BY APS?

Yes. Beginning in 2003, APS and TEP are required to purchase all of their generation needs through arms-length transactions in the open market, 50 percent by competitive bidding.

CAN APS DO THAT WITHOUT TRANSFERRING ITS ASSETS?

It doesn't seem possible. How can you conduct arms-length negotiations with yourself over the price of your own assets and how do you manage a fair bidding process when your assets will dominate the bidding?

IS AUIA CONCERNED ABOUT MARKET POWER?

AUIA is concerned about anything that distorts a competitive market. Given the peculiar nature of the market for electricity, market power will always be a concern and it should be monitored, analyzed and mitigated or punished where necessary. Market power is also part of the natural course of things and it often gives rise to competition. At the end of the day, the control of market power will largely be vested in the Federal Energy Regulatory Commission (FERC) and the Regional Transmission Organizations (RTOs) that it regulates.

HAVE DIFFERING VIEWS OF MARKET POWER BEEN EXPRESSED?

Yes. Market power is in the eye of the beholder. For example, Staff witnesses postulate that APS and TEP are subject to a" rebut table presumption" of market power because they have operated as vertically integrated utilities serving transmission-constrained load pockets. For another, Craig R. Roach, witness for Panda Gila River, concludes from his own analysis that APS has market power in the Phoenix area. But his concern is transparent. His solution is to postpone the asset transfer until after APS has secured all of its standard offer needs in the competitive market. He claims that the amended Settlement Agreement requires the power purchase to come before divestiture. (Roach, P.4). Contrary to his assertion, the Settlement Agreement does not require the competitive purchase to precede the asset transfer, for obvious reasons. The events are meant to be contemporaneous.

WHAT IS APS' VIEW OF ITS ABILITY TO EXERCISE MARKET POWER?

APS' witness, Dr. William Hieronymus, conducted his own analysis using FERC formulas for measuring market power and concluded that APS passes those tests. His results directly contradict those of Dr. Roach. In other words, APS would argue that it lacks significant market power. What this demonstrates, of course, is that any mandated study of market power, no matter who does it, will be a source of endless disagreement.

HAS AUIA REACHED ANY CONCLUSION ABOUT MARKET POWER?

AUIA has no particular expertise on the subject of market power. It seems intuitive that a formerly vertically integrated utility may be able to exercise some market power. However, apart from Dr. Hieronymus' analysis, I am very dubious about these imaginary applications of market power in the context of Arizona deregulation. While there may be a theoretical basis for postulating the worst case, I'm not convinced that it would happen. It's one thing for a generator or marketer to exercise market power from outside a state like California or Nevada, but it's a different matter for an Arizona company to risk fouling its own nest.

First, as Dr, Hieronymus notes, most of APS' power acquisition will be through contracts and the simplest way to remove the incentive for market power is to tie up most of the incumbents' assets in contracts.

Second, some parties have been dismissive of FERC's alacrity, but where transmission access is concerned it is FERC's primary responsibility is to police equal access through its own rules and the protocols of its RTOs. FERC has the means to enforce equal access.

Third, as Kevin Higgins, the witness for Arizonans for Electric Choice & Competition (AECC) notes, the AISA protocols and the wholesale tariffs approved by FERC provide for mitigation of market power in must-run generation. Mr. Higgins also points out that market power has become a "front burner" issue at FERC. (Higgins, P. 5)

Last, and certainly not least, it is mind-boggling to believe that an Arizona UDC would risk the consequences of exercising market power in order to pay inflated prices to an affiliate while the prudence of its purchases rests with the tender mercies of the Corporation Commission. If anyone thinks that the Commission's rate-setting authority is less than a weapon of mass destruction, just ask Citizens Communications. That company has been trying for two years to collect unrecovered purchased power costs that now total some $120 million. The company has not yet had the first minute of evidentiary hearings on its request.

WHAT IS THE STAFF'S VISION OF COMPETITION?

That is hard to fathom. The Staff's testimony in this docket is both anti-competitive and naïve. On the one hand, they want the competitive environment to be risk-free for the consumer and on the other, they seem to want competition to occur only in a perfect world.

WHAT DO YOU MEAN BY ANTI-COMPETITIVE?

Let my quote from Mr. Rowell's testimony at Page 6: "Regardless of the provisions of rule 1606(B), the Commission should consider measures that ensure that consumers are no worse off because of competitive procurement than they would have been under traditional cost of service regulation."

And on Page 7: "...the established cost of service for the utilities' existing general units should be used as the price to beat during competitive solicitations whether the utility

has transferred its generation assets or not. Generally, Staff does not believe it is appropriate for a UDC to procure power at a higher price than its own cost of service before transfer or its affiliate's cost of service after transfer."

Those are "heads I win, tails you lose" arguments. They are certainly not sentiments in support of a free market and its attendant risks. I thought they could have been authored by Karl Marx.

ARE THERE OTHER PROBLEMS WITH THIS NO-RISK APPROACH?

There are several.

I don't know how you would accurately determine cost of service in time for any bidding process. APS hasn't had a rate case in years and its current rates were actually negotiated in the Settlement Agreement. Also, there are PWEC plants serving APS customers that aren't in the utility's rate base.

Mr. Rowell also implies that the bidding process could be phony. Otherwise, if APS received bids that were higher than its cost of service it would have to eat the difference if consumers are protected from paying more than today's cost of service.

It's also unclear how long this cost-of-service test would be in place: For one bidding round? Two rounds? Forever? If so, would APS have to mothball its power plants just in case prices rose and it had to return to cost of service?

WHAT IS STAFF'S PERFECT WORLD?

Basically, it's a world without transmission constraints for anyone and no reliance on must-run generation. The totality of Staff testimony is that market power and barriers to competition will not disappear until transmission constraints have been eliminated, must-run generation can be bypassed and regional RTOs are planning and policing the grid. Staff doesn't assert directly that asset transfers and competitive procurement can't take place until the perfect world appears, but it's obvious they would prefer it that way. It is clear from the study recommendations that the incumbent utilities are responsible for developing and probably implementing solutions.

WHAT IS STAFF'S VISION FOR TRANSMISSION?

It is subject to interpretation, but one can infer that the Staff's goal is to upgrade the transmission system in Arizona to the point that any conceivable merchant generator

can achieve unconstrained access to the Phoenix and Tucson load centers. In addition, the system should be able to negate the need for reliability must-run generation (RMR). Staff concedes that the transmission problems it identifies can' be resolved until at least the last half of this decade.

IS THAT A REASONABLE GOAL?

On its face, a transmission system with the capacity and the reach to embrace every merchant generator that might want to serve Phoenix and Tucson is absurd. In addition, you would never get it sited and built. The Commission can't really compel anyone to build transmission and about half of the facilities in place today are owned by entities that aren't under Commission jurisdiction.

WHO IS RESPONSIBLE FOR TRANSMISSION IMPROVEMENTS?

In theory, the Staff supports a collaborative process involving all sectors of the industry (Jerry Smith, P. 25), but it is clear that the last line of defense is to compel the incumbent utilities to build the system to accommodate other interests. For example, the staff wants the jurisdictional utilities to perform an economic study of RMR generation and expects the Commission to <u>order</u> the utilities to build facilities to resolve transmission constraints to eliminate RMR if that is in the consumers' best interest (Smith, P. 26).

WHAT ABOUT MERCHANT GENERATORS?

Presumably, they would be included in a collaborative process, but the Commission has little leverage over them and, as Mr. Smith observes, they are currently engaged in a game of "chicken" where transmission adequacy is concerned (Smith, P. 24). The Staff proposes some additional transmission requirements for merchant plants that have not yet received siting approval (Smith, P. 26), but that can be viewed as closing the barn door after most of the horses have left.

WHAT IS YOUR CONCLUSION ON BEHALF OF AUIA?

The Commission's rules and the 1999 Settlement Agreement with APS require the Commission to approve the transfer of APS' generation assets to a corporate affiliate. AUIA believes that the potential for market power is seriously exaggerated in Staff's testimony and that the litany of perceived market faults recited by Staff witnesses

would take years to overcome, if ever. It is clear from their no-risk approach that the Staff is not interested in free market competition that offers both risks and rewards.

If the Commission is persuaded that the risks are too great to allow divestiture, then it must forego competitive acquisition of power supplies. To do otherwise would require APS to deploy the assets of its shareholders according to the Commission's direction while all other generators would be free of regulation. That would be unfair to PWCC shareholders and an abuse of the Commission's authority.

Asset transfer was at the center of the Settlement Agreement, which has not only been upheld by the Arizona Court of Appeals but cast as an enforceable contract. We expect the Commission to live up to its word and abide by the Settlement Agreement and we expect PWCC to employ every legal means to enforce it.

DOES THAT CONCLUDE YOUR TESTIMONY?

Yes, it does.

HGC

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EXHIBIT

HGC-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

NOTICE OF FILING OF REBUTTAL TESTIMONY OF

THOMAS BRODERICK

ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

Harquahala Generating Company, LLC, by and through its attorneys, hereby files the Rebuttal Testimony of Thomas Broderick, Director, External Relations, West Region, PG&E National Energy Group, pertaining to the issues in "Track A" for the above-captioned proceeding.

RESPECTFULLY SUBMITTED this 11th day of June, 2002

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By Sarah Menne

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING.	DOCKET NO. E-00000-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	DOCKET NO. E-01345-01-0822
IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	DOCKET NO. E-00000A-01-0630
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REBUTTAL TESTIMONY OF THOMAS BRODERICK ON BEHALF OF HARQUAHALA GENERATING COMPANY, LLC

June 11, 2002

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REBUTTAL TESTIMONY
OF
THOMAS BRODERICK
HARQUAHALA GENERATING COMPANY, LLC
June 11, 2001

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Thomas M. Broderick. My business address is 1100 Louisiana, Suite 1650, Houston, Texas 77002. I am Director, External Relations, West Region, PG&E National Energy Group ("NEG"). NEG is the owner of Harquahala Generating Company, LLC ("HGC"), the owner of an approximately 1,040 Mw facility under construction.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the Statement of Qualifications attached as Exhibit 1 to this testimony.

Q. HAVE YOU REVIEWED THE TESTIMONY FILED BY THE PARTIES ON THE "TRACK A" ISSUES?

A. I have. Track A concerns one component (asset transfer) of implementing the competitive market structure envisioned under Arizona's Electricity Rules and as embodied in the settlement agreements of Arizona Public Service (APS) and Tucson Electric Power (TEP). For example, under **R14-2-1606(B) of the Arizona Electricity Competition Rules:** "After January 1, 2001, power purchased by an investor owned Utility Distribution Company shall be acquired from the competitive market through prudent, arm's length transactions and with at least 50% through a competitive bid process." And, under the APS settlement, APS agreed that it "[S]hall procure generation for Standard Offer

customers from the competitive market as provided for in the Electric Competition rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS."

These provisions raise questions with regard to the timing of the implementation of the asset transfer from the incumbent utility to its affiliated competitive power supplier as well as to when in this process the bidding for standard offer service should occur. As contemplated, these two actions are linked, with some arguing that they should occur simultaneously. However, there is a question as to what that actually means. HGC's interpretation of these rules is that the competitive procurement of power is to occur prior to the transfer of assets. Further, meeting the competitive procurement requirement of the Rules requires that all or nearly 100% of Standard Offer ("SO") requirements have been successfully contracted for in a valid competitive procurement process; the mere issuance of an RFP or a plan to conduct a process is not satisfactory under the Arizona Rules to permit a transfer of generation assets to affiliates. It is likely that at least some of the existing APS assets will continue to supply native load after its transfer to Pinnacle West. Because this involves an affiliate transaction, it is in the best interest of all parties – and the responsibility of the ACC – to conduct the procurement before a transfer so there is no question that the process is transparent and does not advantage APS' affiliates.

Q. PLEASE ANALYZE FURTHER THE TESTIMONY AND PROVIDE THE REACTION OF HARQUAHALA GENERATING COMPANY TO IT.

A. Yes. The following are our responses to the significant issues raised by the testimony.

1. HGC feels strongly that existing network transmission service rights should **not** be part of the asset transfer from APS and TEP to their generation affiliates. If the generating affiliates received the transmission rights, they would be the only parties who could supply a delivered product in the utility auction. This would presuppose the winner of the competitive procurement for standard offer service, which is antithetical to the objective of the Electricity Competition Rules. In short, the generation affiliate would possess market power because, in the absence of a functioning RTO/ISO, they would be the only entity to have sufficient transmission to deliver their product. Instead, these rights should be designated for use by APS and TEP in securing power from the successful bidders for SO service for the duration of their contracts . As Mr. Kebler states in his testimony, if some of a UDC's generation assets that are transferred to affiliates are not successful in competition to provide SO service, that transmission should be available to others.

2. HGC agrees with the recommendation contained in the testimony of Craig R. Roach that to successfully implement Arizona's Rules, competitive procurement of nearly 100% of SO requirements must occur **prior** to any asset transfers. This recommendation is valid even if the selected procurement design results in several rounds of RFP's and/or auctions over a defined period to competitively procure nearly 100% of SO. Hence, divestiture can occur en masse following successful contracting with the winning bidders, which will, no doubt, include affiliates of APS and TEP. As a result, Arizona retail customers will benefit due to compliance with the Rules.

3. Alternatively, if the Commission waits until after the asset transfer to conduct competition procurement of generation, it will immediately face the need to approve or accept the

price, terms and conditions for the purchase of thousands of Mw from the UDCs' affiliates on an interim basis without knowing what the competitive market could achieve were it allowed to operate. It is HGC's opinion that this does not support the ultimate objectives of the Electricity Competition Rules and the utility settlements – that customers have access to the benefits that market competition can bring. This scenario is also akin to what APS proposed as part of its variance last October, and what the Commission stayed.

4. The role of must run generation in this process is discussed in detail in the testimony of Matt Rowell, Jerry Smith and Craig Roach. HGC is generally supportive of their testimony and believes the RFP-based competition process described by Craig Roach for must run generation should occur as early in the competitive procurement process as possible and the market power issues associated with must run generation need to be addressed. Furthermore, the contracted providers of must run generation should **not** be permitted to use these contracts to create an advantage when bids are submitted utilizing other resources they own or otherwise control. The must run generation is readily identifiable for APS and TEP – it is located inside metropolitan Phoenix, Tucson and Yuma.

5. Ideally, the must run RFP would be a component of a comprehensive RFP for all SO service. This will allow bids for generation inside load pockets to be compared to bids from outside the load pocket. The latter bids will, in many instances, include the allocated incremental cost of transmission to bring power into the inside load pockets. Under this approach, a system-wide, least cost criterion should be applied as the basis for bid selection

6. As a practical example of the workability of the procedure I have described, HGC's owner, National Energy Group ("NEG"), responded to a large RFP from Public Service

Company of Colorado ("PSCO") in 1999 that sought generation bids from a variety of locations both in the Denver load pocket and from remote delivery locations. After literally hundreds, if not thousands, of computer-modeled scenarios (run overnight) of alternative generation portfolios, PSCO awarded 12 contracts. NEG was a successful bidder and our newly constructed 111 Mw Plains End peaking facility, which is located inside suburban Denver, achieved commercial operation last month (May 2002). This was only 28 months after the issuance of the RFP. I note that other PSCO contracts provide peaking, intermediate and base load power from various locations inside and outside the load pocket and, in some instances, required significant transmission infrastructure additions, which were and are still being undertaken by PSCO. In the case of Plains End, PSCO constructed the necessary transmission infrastructure on time and NEG is now delivering to PSCO's retail customers as a network designated resource as specified in PSCO's transmission tariff. In Colorado, PSCO is the control area operator for NEG's facility. This is a service that APS has refused to provide HGC in Arizona. In other words, through normal utility resource planning processes, PSCO was able to successfully weigh the advantages and disadvantages of a large proposed portfolio of potential new generation resources of many types and locations, both inside and outside load pockets. In some instances, some amount of existing transmission was available. In other cases, varying amounts of new transmission infrastructure were identified as cost effective and were or still are being constructed in a timely manner.

7. Mr. Kebler has proposed a thoughtful and creative means to enhance the market prior to the competitive solicitation process for SO. Unfortunately, the lack of a functioning RTO or ISO for APS and TEP leads HGC to conclude that Mr. Kebler's proposal may be premature

and the Arizona market structure needs to evolve further first. For similar reasons, the concept of procuring a "slice of system" product is also premature. HGC would enthusiastically support revisiting both of these concepts after an RTO or ISO in the area is functioning with features conductive to a slice of system auction. However, prior to an RTO/ISO, APS and TEP can use their proprietary knowledge of the transmission system and their market power over the provision of ancillary services to stifle slice of system competition. Only a very small subset of competitors has a generation portfolio adequate to offer a slice of system This would generally limit the pool of able bidders.

8. As an idea to evolve towards, Mr. Kebler's competitive auction proposal would significantly assist in the establishment of a competitive market structure and thereby improve market liquidity, reduce incumbent market power and provide the Commission with additional market benchmark information that would be helpful in evaluating the fairness of contracts between APS, TEP and their affiliates. NEG and many other generation providers successfully participated in the Texas capacity auction in 2001. The capacity NEG obtained from this auction plus the additional ancillary services available daily from the ERCOT ISO augments the single power plant NEG owns in Texas, thus allowing the company to meet long-term 100% full requirements of the City of Denton, Texas and other retail customers. In Texas, the services NEG obtains daily from the ERCOT ISO are critical to establishing a level playing field for the economics of transactions, especially the cost of energy imbalances. In the case of Arizona, Craig Roach and Curtis Kebler have recommended the establishment of a short-term energy market including a real time energy balancing market. This step would be helpful to both wholesale and retail competition.

9. Unfortunately, absent a fully-functioning RTO/ISO as is the case in Texas, we believe the market structure is insufficient to support a slice of system auction even with a capacity auction. While it is possible today for some merchants to provide a slice of service at a single or a few delivery points, absent an RTO/ISO, it is nearly impossible for a merchant to provide a true slice of system which covers all major delivery points for all hours of the year.

10. Therefore, HGC recommends APS and TEP utilize an RFP process for soliciting standard wholesale products – baseload, intermediate, peaking, and ancillary services at multiple delivery points such as Palo Verde, Mead, Four Corners and other locations where the utilities have transmission rights or physical utility owned capacity to accept power. It would likewise be helpful for APS and TEP to indicate preferred transmission locations. Such a process will be much less complicated, will draw the maximum number of bidders and will result in pricing that is transparent and easily verifiable. HGC is confident that both APS and TEP have the resource planning tools, quantitative models and skilled employees to successfully conduct an RFP process. If an RFP process seeking standard wholesale products is concluded prior to generation asset transfer as we have recommended, it is critical for the Commission to work closely with an independent evaluator to ensure that the RFP process is fairly conducted. Hence, this simpler approach for the time being will enable the retail customers of APS and TEP to reap the benefits of a "buyers" market in a time frame during which new generation assets are coming on line.

11. HGC disagrees with the statement of Mr. Jack Davis on page 14 of his testimony that "Divestiture is also the basis for the competitive bidding provision of Rule 1606, which makes absolutely no sense in its absence." While HGC does not oppose divestiture per se and understands that certain details of the competitive bidding process need to be altered in the

absence of divestiture, competitive bidding continues to make significant sense even without divestiture.

12. Using APS as an example, the anticipated level of bidding without divestiture would be significant. Rather than contract with its affiliate, APS would need to bid out approximately 1,700 Mw before being allowed to contract with either Red Hawk or West Phoenix 5. This is approximately 28% of APS' current peak load. Additionally, APS would need to bid out load growth, load served under existing wholesale contracts upon their expiration, load served by generation that is soon to retire, and existing generation identified as having market power. Load growth alone would increase the total bid by approximately 3% per year. Hence, only 4 years into such a program at least 40% of APS' SO service would be subject to competitive procurement.

13. In fact, each of the categories listed above formed the basis for the Colorado competitive bidding program. Hence, the Colorado program is much more significant than simply covering incremental load growth as some have suggested. In Colorado, in more than 3 rounds of RFP bidding, approximately 42% of the SO load of PSCO was contracted with suppliers , the vast majority to suppliers other than PSCO or its affiliate. Furthermore, PSCO has not divested and Colorado is not open to retail competition.

14. Not only does bidding makes significant sense without divestiture, but the methods, practices and procedures developed in other states for bidding absent divestiture are informative and successful.

15. ACC Staff testimony recommends a price to beat be established for generation and, perhaps, for each generation asset, using existing tariffs. The apparent goal of this proposal

is to ensure that competitive bidding and the asset transfer do not increase tariffs, including the PPFAC component, over the next rate cycle. HGC notes that costs of specific generation facilities, whatever company owns them, will vary significantly around the system average. Baseload facilities such as the HGC plant are below the system average, whereas peaking facilities such as NEG's Plains End facility in Denver have costs above the system average. However, each of these facilities contribute to a least supply portfolio. Hence, an RFP that covers all or essentially all of APS' and TEP's SO load is the best way for the Commission to ensure that offers are evaluated on a system-wide and integrated portfolio basis. This approach also allows the Commission to obtain insights into the overall system revenue requirements for the preferred portfolio even in comparison to the existing portfolio. The system planning tools that utilities such as APS and TEP utilize will determine, in fact, the minimum revenue requirement and rate levels of integrated groups of standard wholesale products. Thus, the Commission can be confident that this modeling process will identify the least cost alternative without a separate cumbersome exercise to match and directly compare each selected asset with existing assets and their component of tariffs. Of course, at some more distant point in the future, tariffs may increase, but this approach provides the Commission with the comfort that no other portfolio will result in lower costs. At present, the wholesale market is highly favorable to buyers. For this reason, the near term price concerns are misplaced. A slice of system product, on the other hand, forces each bid to assemble all the components of service. In absence of an RTO/ISO, this would be a more costly scenario. Also note that an RFP solicitation will result in bids from both in-state and out-of-state generating companies.

16. It should also be noted that there is no reasonably current cost of service study by either APS or TEP, which reconciles the cost components for generation, transmission and distribution to existing retail tariff levels, let alone one specific to individual power plants. If the Commission intends to establish a price to beat either by total generation or by asset based on existing tariffs, we suggest that the Commission ask the utilities to begin preparing this study immediately. Given APS and TEP rate settlements which are both cost and incentive based, an attempt to match costs with tariffs is a quagmire best left for consideration until the next rate case.

17. Staff witness Barbara Keene has provided some excellent testimony on affiliate relationships. However, HGC wonders if one of Ms. Keene's suggestions might create a loophole that would allow Red Hawk to be transferred to APS without first obtaining Commission approval of a code of conduct or otherwise be subject to Commission scrutiny. Specifically, she recommends the code of conduct covers arms length transactions (page 8, line 7, Keene testimony) and includes as an arms length transaction, the sale or transfer of assets from an affiliate to the utility (page 8, line 18). Therefore, HGC's concern is that none of the four actions in Barbara Keene's testimony on page 7, lines 12 through 25, which trigger Commission approval of a new code of conduct, covers a situation in which APS purchases power from Red Hawk but only after Red Hawk has been transferred back to APS. Previously, APS/Pinnacle West has discussed the possibility of transferring Red Hawk to APS. To close the loophole, the Commission would need to add a fifth "trigger" action covering transfers from an affiliate back to a UDC.

18. HGC supports Erinn Andreasen's recommendation to form an Electric Competition Advisory Group and HGC would actively participate in such a group. HGC

recommends the Group's scope be expanded to support market/regulation/implementation monitoring.

19. The TEP proposal to close the retail market for customers under 3 Mw is entirely unnecessary given the current circumstances. Indeed, it is a solution in search of a problem. Moreover, HGC believes it would be difficult, time-consuming, costly, and repetitive to re-open the market for these customers at a future date.

Q. DOES THE COMMISSION HAVE A ROAD MAP FOR IMPLEMENTING YOUR NEAR-TERM COMPETITIVE SOLICITATION RECOMMENDATIONS?

A. Yes. It was filed on March 29, 2002 in the testimony of Mr. Alan Taylor sponsored by HGC.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit 1

STATEMENT OF QUALIFICATIONS

2001 PG&E NATIONAL ENERGY GROUP, Houston, Texas

Thomas Broderick is Director External Relations, West Region for PG&E National Energy Group. He is responsible for regulatory, legislative and community relations. His current efforts are concentrated in Arizona, Colorado, and Louisiana where the Company has power plant projects or competitive bidding is planned or underway.

1999 - 2000 U.S. STATE DEPARTMENT /USAID, Kiev, Ukraine and Washington, D.C.

- Senior Energy Advisor

1997 - 1998 PG&E ENERGY SERVICES CORPORATION, Scottsdale, Arizona

- Energy Consultant

1984 - 1996 ARIZONA PUBLIC SERVICE COMPANY

- Planning Manager
- Supervisor, Forecasts
- Supervisor, Regulatory Affairs
- Economist, Regulatory Affairs

1982 - 1984 MILLER BREWING COMPANY, Milwaukee

- Analyst, Marketing Research

1981 ILLINOIS HEALTH FINANCE REGULATORY AUTHORITY, State of Illinois, Chicago

- Regulatory Economist