BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	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 APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS 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

NOTICE OF FILING

The Attorney General, a party in the above-captioned consolidated docket acting on behalf of the citizens of the State of Arizona and pursuant to Rule R14-3-109(Q) of the Arizona Corporation Commission rules of procedure, hereby files the original and ten (10) copies of the direct testimony of Mark W. Frankena, Ph.D., on the matter of the proposed Settlement Agreement between the Staff of the Arizona Corporation Commission and Tucson Electric Power Company and Arizona Public Service Company. Copies of this testimony have been faxed and mailed to the attached Service List.

RESPECTFULLY SUBMITTED this 30th day of November, 1998.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF MARK W. FRANKENA, Ph.D.

On Behalf of

Arizona Attorney General's Office

Docket No. E-01345A-98-0473, et al.

2copies

November 30, 1998

AN ORIGINAL AND TEN COPIES
of the foregoing filed this 30th day of
November, 1998 with:

Docket Control
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Phoenix, Arizona 85007

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Dated this 30th day of November, 1998.

By N. Hernandez

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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

NOV 30 1998

DOCKETED BY

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RENZ D. JENNINGS
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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471
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PREPARED DIRECT TESTIMONY OF MARK W. FRANKENA
ON BEHALF OF
STATE OF ARIZONA OFFICE OF THE ATTORNEY GENERAL

November 30, 1998

I. QUALIFICATIONS

Q. Please state your name, position and company affiliation.

A. My name is Mark William Frankena. I am a Senior Vice President at Economists Incorporated, an economic consulting firm located at 1200 New Hampshire Avenue, N.W., Washington, D.C. 20036.

Q. Please summarize your educational and employment background.

A. I received a Ph.D. in economics from the Massachusetts Institute of Technology in 1971. Between 1971 and 1982, I was an assistant professor and then a tenured associate professor of economics at the University of Western Ontario. Between 1982 and 1988, I held several senior positions in the Bureau of Economics of the Federal Trade Commission, one of the two federal agencies responsible for enforcing the antitrust laws. As Deputy Director for Antitrust, I was responsible for supervising about thirty-five economists who analyzed matters involving market power. In 1988, I joined Economists Incorporated, where I have worked on antitrust and regulatory matters involving the electric power, natural gas and other industries.

Q. Please describe your experience analyzing market power for proceedings in the electric power industry, and identify the parties on whose behalf you carried out your analyses.

A. I have worked extensively on analyses of market power in the electric power industry in connection with mergers, restructuring and antitrust litigation. In the area of mergers, in 1989 I testified in U.S. Bankruptcy Court on the merger between Northeast Utilities and Public Service Company of New Hampshire on behalf of the latter. During 1989-90, I worked on an analysis of the proposed merger between Southern California

Edison and San Diego Gas & Electric on behalf of the City of San Diego. In 1992, my affidavit on the merger between Entergy and Gulf States Utilities was submitted to the Federal Energy Regulatory Commission (FERC) by Occidental Chemical. During 1995, I analyzed PECO Energy's proposed takeover of Pennsylvania Power & Light on behalf of the latter. During 1995-97, I analyzed the proposed merger of Northern States Power and Wisconsin Electric on behalf of Wisconsin Public Power System Inc., Madison Gas & Electric, Minnesota Power, Otter Tail Power, Wisconsin Public Service, the Minnesota and Wisconsin Attorneys General, the U.S. Department of Justice, and others, and I testified on this merger at FERC and at the Public Service Commission of Wisconsin. During 1997, my prepared testimony on the merger between LG&E Energy and KU Energy was submitted to FERC by the merging companies, and my prepared testimony on the merger of Western Resources and Kansas City Power & Light was submitted to FERC by UtiliCorp United. During 1998, my prepared testimony on the merger of Wisconsin Public Service and Upper Peninsula Power Company was submitted to FERC by the merging parties. Also during 1998 I analyzed the proposed merger of four Dutch electric utilities on behalf of the Dutch Competition Authority. In addition, I have worked on competitive analyses of several mergers between electric and gas companies. During 1998, I wrote two papers on methodologies for evaluating competitive effects of electric utility mergers that were submitted to FERC by the Edison Electric Institute in response to a notice of proposed rulemaking on merger policy (Docket No. RM98-4).

I have also analyzed market power in the electric power industry in connection with numerous matters other than mergers. In 1997, I submitted testimony prepared for the staff of the Public Service Commission of Nevada (PSCN) on market power in a restructured electric industry in Nevada, and in 1998 my affidavit on remedies for market power in Northern Nevada was submitted to the PSCN by two gold mining companies. In 1998, my prepared testimony on the New England Power Pool's proposed market power surveillance plan was submitted to FERC by the Maine Attorney General. In 1997, I analyzed market power in connection with restructuring of the electric power industry in New York on behalf of an energy services company and in Spain on behalf of the Spanish National Electric Regulatory Commission. I have also analyzed market-based pricing for electric power in several regions, FERC's Order 888 rules on transmission, and private Sherman Act monopolization suits involving electric utilities, non-utility generators, district heating and cooling companies, and steam hosts.

Q. Please identify your publications on market power analysis in connection with electric power industry restructuring, deregulation and mergers.

A. I am the author or co-author of a book and a number of articles on the analysis of market power in the electric power industry. These publications are listed on my curriculum vitae, which is attached as Exhibit A.

II. Scope of Testimony

Q. On whose behalf was your present testimony prepared?

A. I prepared this testimony on behalf of the State of Arizona Office of the Attorney General.

Q. How many days did you have to carry out your analysis and prepare your testimony on market power in the electric power industry in Nevada, which was submitted in the PSCN's restructuring proceeding on January 31, 1997?

A. I worked on that testimony from December 1, 1996, until January 30, 1997, a total of 61 days.

Q. How much time do intervenors typically have to prepare and submit market power analyses in connection with important and complex FERC proceedings?

A. Typically, in important and complex matters, such as electric power merger proceedings, intervenors have 60 days after applicants file their applications and their own market power analyses.

Q. How much time have you had to analyze market power issues affecting Arizona in the present proceeding?

A. I was contacted by the Office of the Attorney General on November 12, 1998, and was asked to begin work on November 13, 1998. Therefore, I have had only 17 days—of which eight days, including the last four, were during weekends or the Thanksgiving holiday—to obtain information, analyze issues and prepare testimony.

Q. Why did you have so little time to carry out your analysis?

A. The procedural orders in this case provided only that amount of time.

Q. Which issues did the Office of the Attorney General ask you to analyze and address in this testimony?

A. The Office of the Attorney General asked me to analyze and testify on the following issues:

- Is the present structure of the electric power industry in Arizona conducive to competition, or should steps be taken through Arizona's restructuring process to prevent market power problems?

- Do the proposed Settlement Agreements (Agreements) between Arizona Public Service Company (APS) and the Arizona Corporation Commission (ACC) Staff and between Tucson Electric Power Company (TEP) and the ACC Staff, including the provisions for exchange of TEP's interests in the Navajo and Four Corners generating plants for APS's transmission facilities rated 345 kV and above, adequately mitigate any existing horizontal or vertical market power problems in Arizona, and do the Agreements exacerbate or create new market power problems?

Q. If companies that participate in electric power markets in Arizona carry out different activities--such as generation, transmission, and marketing--through separate affiliates whose interactions are subject to code of conduct restrictions, is it appropriate to treat those affiliates as separate entities for purposes of market power analysis?

A. No. While code of conduct restrictions are useful for certain purposes, they do not change incentives or eliminate market power. For example, suppose that a company has separate subsidiaries for generation, transmission, and marketing. In that case, the transmission subsidiary still has incentives to operate the transmission system in a way that will benefit its generation and marketing affiliates, because such actions would benefit their common parent and shareholders. For this reason, in my testimony references to Arizona utilities generally include the affiliates of those utilities.

III. SUMMARY OF FINDINGS

Q. Have you reached final conclusions regarding the market power issues that you were asked to analyze and address in your testimony?

A. I have been able to identify some significant market power problems that would survive implementation of the proposed Agreements. However, I have carried out my analysis under a severe time constraint and based on incomplete information. The incompleteness of the information is explained by the time constraint and by the incompleteness of the TEP and APS responses to discovery requests. As a result, a number of my findings are preliminary and incomplete.

Q. Please summarize your principal findings to date regarding market power.

A. I have reached four principal conclusions:

- First, there are load pockets in the Tucson, Phoenix and Yuma areas. During a large portion of the year, the Tucson area is a relevant geographic market for capacity and energy because loads in TEP's service area exceed the import capability of the transmission system. TEP plans to auction its 12 generating units in the Tucson area load pocket in two packages, both of which could be purchased by the same bidder. TEP's proposal could result in unnecessarily high concentration and market power in the Tucson area load pocket. Rather than relying solely on a regulatory or behavioral remedy—must run contracts—for this market power, a preferable solution would be to rely insofar as possible on structural measures. The ACC could order that TEP divest its plants or separate units within plants so that ownership of generation in the Tucson area load pocket would not be highly concentrated. It is my understanding that Sierra Pacific Power proposes to divest all its generating capacity in the Northern Nevada load pocket to a number of independent parties to mitigate vertical and horizontal market power concerns.

Similarly, the Phoenix area is a load pocket and a relevant geographic market during high load periods. APS and Salt River Project (SRP) have ownership shares of about 35% and 65%, respectively, for generating capacity in this load pocket. As a result, market power is a serious problem. Yet, APS is not proposing to divest any of its generating capacity. The ACC could order that APS divest its generating capacity in the Phoenix area load pocket to a number of independent parties to reduce concentration.

- Second, further investigation may show that there are additional relevant geographic markets for capacity and energy larger than the load pockets just discussed but still small enough so that APS and TEP (prior to divestiture) would have substantial shares and concentration would be high. (A potential example would be a South Arizona market that includes the Phoenix and Tucson areas.) I am not aware of any analysis of whether such geographic markets exist, and I have not had sufficient time and information to resolve this question. If such a geographic market does exist, APS, TEP, and SRP may have significant shares and the market may be highly concentrated. In that case, market power exercised by these utilities is likely to be a problem unless some combination of divestitures by APS, TEP, and SRP brings about a sufficient reduction in shares and concentration. Also, if such a market exists, acquisition by APS or SRP of any of the generating units that TEP proposes to auction would increase generation market power problems. At a minimum, absent an analysis of this issue, the ACC should order that TEP not divest any of the generating plants subject to auction to APS, SRP or their affiliates. If the ACC does not issue such an order and APS, SRP or one of their affiliates is the highest bidder for a TEP generating plant, then TEP's divestiture could be delayed by reviews by FERC and antitrust agencies and TEP may claim that it is unable to divest the plant in question in time to meet its schedule for securitization of stranded costs.

- Third, further investigation may show that TEP's acquisition of APS's transmission facilities rated 345 kV and above may increase horizontal market power in markets for transmission service from remote baseload generators to principal Arizona load centers.

- Fourth, the ACC, among others, has expressed concern over the potential for vertical market power to act as a barrier to retail electric competition in Arizona. The Agreements would not eliminate the vertical market power concerns that have been raised. TEP (including its affiliates) would own and operate a substantial portion of transmission assets in Arizona. At the same time, under several potential scenarios TEP will continue to own generating plants in Arizona. Also, TEP or an affiliate, such as its marketing affiliate New Energy Ventures, Inc., may enter into longer term contracts to purchase capacity and energy on terms that would give TEP the same incentives to raise electric power prices that it would have if it owned generating capacity.

In short, further restrictions on TEP would be necessary to eliminate the vertical market power concerns that have been raised in Arizona. The ACC could order that TEP in fact sell all its generating capacity, with no loopholes, and that TEP not engage in wholesale or retail marketing of electric power in Arizona. The ACC could also order that TEP's and APS's transmission assets be turned over to an *independent* system operator (ISO) with an appropriate governance structure, powers, rules and incentives.

Vertical market power concerns do not end here. Even with the Agreements, APS would own and control not only a substantial amount of generating capacity in Arizona but also transmission and distribution facilities rated 230 kV and below. In particular, APS would continue to own 35% of generating capacity in the Phoenix area load pocket, which results from constraints on 230 kV transmission facilities that APS would continue to own and control. Further restrictions on APS would be necessary to eliminate the vertical market power concerns that have been raised in Arizona. The ACC could order APS to divest either its 230 kV and higher transmission system or pertinent generating plants.

IV. Background on Market Power

Q. Please define market power.

A. Market power is the ability of a seller or group of sellers profitably to maintain prices above competitive levels by restricting output below competitive levels. I discuss market power further in Chapter 4 of Exhibit B.

Q. Your definition of market power indicates that a single seller or a group of sellers may have market power. Would you explain this?

A. A single seller may have market power if it has a substantial market share and there are barriers to entry into a market. In addition, if two or more sellers each has a substantial market share, so that market concentration is high, they may exercise market power simultaneously without any form of coordination. Finally, if two or more sellers each have substantial market shares, they may collude by reaching a tacit understanding or an explicit agreement aimed at raising prices. I discuss unilateral market power and collusion further in the chapter entitled "What is Market Power?" in Exhibit B.

Q. What are the consequences of exercise of market power?

A. When market power is exercised, typical results are higher prices for buyers, higher costs of production for society (because higher cost sources of supply replace lower cost ones from which output is curtailed), and reduced consumption. Companies exercising market power earn higher profits than they would if they behaved competitively. See the discussion of why market power matters" in the chapter entitled "What is Market Power?" in Exhibit B.

Q. How is market power exercised in markets for electric power?

A. Market power may be exercised in a number of ways, two of which are particularly relevant here. First, one or more sellers may reduce their own output or raise the prices at which they offer power. This behavior involves an exercise of *horizontal* market power. Two types of horizontal market power are relevant to the present proceeding: market power over generation (or *generation* market power) and market power over transmission service. Second, one or more vertically integrated sellers may reduce supplies to the market from their competitors, for example, by reducing the availability or reliability of transmission service or increasing its price. This behavior involves an exercise of *transmission* market power. Transmission market power is one type of *vertical* market power. For a further discussion, see the chapter entitled "How Market Power May be Exercised in Electric Power Markets" in Exhibit B.

Q. Could two electric power companies collude to exercise market power if one (Genco) is a large generating company and the other (Transco) is a large transmission-distribution company providing access to the destination area in which Genco's generators are located?

A. This would be possible. Genco and Transco might reach an agreement that Genco would reduce its output in the destination area. This would tend to raise not only electric power prices in the destination area but also demand for Transco's services. This would benefit Transco. At the same time, under the agreement, Transco could raise prices or reduce the availability of transmission service to the destination area. This would benefit Genco by tending to exclude competitors. To facilitate such an agreement, a side payment might be necessary to achieve a mutually acceptable sharing of the profits generated by the anticompetitive behavior. One way that colluding companies may be able to reallocate monopoly profits is by entering into a power purchase agreement with each other at prices that deviate from market prices. If the power is underpriced, profits are transferred from the seller to the buyer. If the power is overpriced, profits are transferred from the buyer to the seller.

Q. Would it therefore be possible for companies such as APS and TEP to collude in the future even if they have different asset bases, as is the case for Genco and Transco in the preceding hypothetical?

A. Yes, that would be possible.

Q. Other things being equal, would companies be likely to find it easier to collude if they also engaged in various transactions with each other, such as power sales, that would permit them to engage in negotiations and to reallocate between them the additional profits obtained by exercising market power?

A. Yes, other things being equal.

V. RELEVANT PRODUCT MARKETS

Q. How does one delineate relevant antitrust markets in which to analyze market power?

A. One delineates relevant antitrust markets using the hypothetical monopolist test. The hypothetical monopolist test is explained in the U.S. Department of Justice and Federal Trade Commission *Horizontal Merger Guidelines* ((1992, rev'd 1997), reprinted in 4 Trade Reg. Rep. (CCH) ¶13,104).[1] A relevant antitrust market is a product or group of products and a geographic area within which a hypothetical monopolist would profitably increase prices by at least a small but significant amount (say, 5 percent) above a pertinent baseline level.

When one is analyzing whether a change in ownership of assets would bring about an increase in market power, the baseline price is the *price that would prevail absent that change*. However, when one is analyzing whether a utility or group of utilities has market power, the baseline price is the *competitive price*. (See Frankena, "Geographic Market Delineation for Electric Utility Mergers," Appendix A to Comments of Edison Electric Institute, FERC Docket No. RM98-4-000, August 28, 1998.)

The product dimension of a relevant antitrust market is often called the relevant product market, and the geographic dimension of a relevant market is often called the relevant geographic market. Delineation of relevant markets is addressed further in the chapter entitled "Assessing Market Power" in Exhibit B.

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1 Similar guidelines are used by the National Association of Attorneys General and its members.

Q. What are the relevant product markets for analysis of the issues about which you have been asked to testify?

A. The relevant product markets are likely to include electric capacity, electric energy, transmission service, ancillary services, and retail marketing services.

- *Capacity and Energy*. There are relevant product markets for electric capacity and (separately) electric energy. Because there is little substitutability in either demand or supply between electric capacity at different times, and little storage, there are separate antitrust markets for summer capacity and winter capacity. Similarly, there are separate antitrust markets for energy during different hours of the year. For both capacity and energy, there are also separate antitrust markets in different years. Thus, there are separate markets for energy during summer 1999 peak hours, summer 1999 off-peak hours, summer 2000 peak hours, etc. In principle at least, in analyzing market power one considers capacity and energy markets during each year until the future date(s) after which entry into each of these markets is "easy," as that term is used in antitrust parlance.

- *Transmission Service*. When one is analyzing seller market power in the electric power industry, the focus is often on electric power delivered to destination markets. Typically, when analyzing a destination market for electric power, one includes in the market generating capacity that is located in the destination area. In some cases, however, a hypothetical monopolist that has competitively significant control over transmission between an origin market (Area O) and a destination market (Area D) would raise prices in the destination market by at least 5 percent because generators in the destination market (and elsewhere other than Area O) would not significantly expand sales in Area D in response to a 5 percent price increase. In that case, transmission from Area O to Area D may be treated as a relevant antitrust market.

  FERC defined transmission service in particular corridors as relevant antitrust markets in connection with several mergers, including PacifiCorp/Utah Power & Light and Northeast Utilities/Public Service of New Hampshire, and the U.S. Department of Justice and the California

Public Utilities Commission did the same in connection with the Southern California Edison/San Diego Gas & Electric merger proposal. (See Frankena and Owen, *Electric Utility Mergers: Principles of Antitrust Analysis*, Praeger, 1994, pp. 75-78, 114-15.)

In Arizona, the load centers in the Phoenix and Tucson areas are remote from many of the principal baseload generating plants. As a result, it may be appropriate to treat transmission service from those baseload plants to the Phoenix and Tucson areas as a relevant antitrust market during some time periods.

- *Ancillary Services*. In addition to the product markets discussed above, there may be product markets for a number of ancillary services, such as voltage control or reactive power.

- *Retail Marketing*. There are relevant product markets for retail energy marketing services, which may include the supply and marketing to retail customers of services such as procurement of power supplies from the wholesale market or generators, procurement of wires services from transmission and distribution utilities, metering and billing services, demand-side management services, and risk management services.

Q. In which of these relevant product markets are APS and TEP sellers?

A. At present, given their generation resources (including long-term contracts), transmission resources and native loads, APS and TEP are presumably sellers in most of these markets during at least some time periods. Other things being equal, the introduction of retail customer choice will reduce native loads and cause APS and TEP to become more important sellers to wholesale and retail customers that are free to choose among suppliers.

VI. Relevant Geographic Markets

A. Delineation of Geographic Markets

Q. In the case of capacity and energy product markets, what geographic markets should one delineate for analysis of the issues about which you were asked to testify?

A. To analyze "pure" generation market power over capacity and energy, that is, market power arising from ownership and control over generation resources, one assumes--for the sake of argument--that no entity or entities exercise transmission market power. For each relevant product (for example, 1999 summer peak electric energy) one delineates the geographic market in which each generating unit in Arizona and each generating unit owned or controlled in whole or in part by an Arizona utility is located. Geographic markets are likely to differ between summer and winter and between peak and off-peak hours. For some periods all Arizona generating units with variable costs below a certain level may be in a single geographic market that extends beyond Arizona, while for other periods there are narrower geographic markets, each covering only a portion of Arizona. When one is analyzing "pure" generation market power, market shares are allocated to companies that own or control generation resources (including long-term purchases of capacity and energy) and to companies that have transmission rights on constrained paths or interfaces. Computation of market shares and concentration are discussed further in the section entitled "Market Shares and Concentration" at pages 39-41 of Exhibit B.

Q. How may transmission market power affect delineation of geographic markets for capacity and energy?

A. One effect of transmission market power may be to reduce the size of geographic markets by reducing the competitive role of more distant generating plants. When one is considering both generation and transmission market power over capacity and energy, market shares are assigned to companies that own or control generation resources located in the destination market and to companies that have competitively significant control over transmission service to the market.

Q. Suppose that you take one relevant product market for electric energy, such as energy delivered during representative 1999 summer peak hours. How do you determine the relevant geographic market or markets in which Arizona generators compete in selling this product, assuming no transmission market power?

A. One applies the hypothetical monopolist test, which is used to identify the generating units that significantly constrain prices charged by each generator in Arizona. The scope of the geographic market depends on numerous factors in various areas in the Western Systems Coordinating Council (WSCC), including: (a) thermal, voltage and stability constraints on the transmission system, (b) prices and losses charged for transmission service, (c) generating capacities, availability of water for hydroelectric generation, and variable costs for other types of generation, and (d) loads. As a general matter, the geographic market will be smaller if portions of the transmission system are more congested. Even absent congestion of pertinent portions of the transmission system, the geographic market is likely to be smaller the higher are charges for transmission service and the smaller are differences in variable costs of generation in different regions. Geographic market delineation is discussed further at pages 36-38 of Exhibit B.

Delineation of relevant geographic markets is relatively easy in some portions of the U.S. where transmission capacity into an area is heavily congested during a substantial number of hours of the year. An example is Northern Nevada, which is a load pocket and separate geographic market during most hours of the year. For further discussion of load pockets, see pages 38-39 of Exhibit B.

However, in many areas of the U.S., one cannot delineate geographic markets without consideration of all the factors identified by (a) through (d) earlier in this answer. Economists have begun to use computer simulation models to deal with the large amount of data that are relevant to the analysis. Simulation models are discussed at pages 42-45 of Exhibit B.

Q. In the limited time available to you, have you been able to delineate any relevant geographic markets for use in analyzing generation market power over capacity and energy in the present proceeding?

A. I have concluded that each of three load pockets within Arizona is a separate geographic market during high load hours of the year. The load pockets in question are the Tucson, Phoenix and Yuma areas. The existence of these load pockets is demonstrated by TEP and APS documents.

I have not had enough time to determine whether, for purposes of analyzing generation market power over capacity and energy, there are additional geographic markets that are larger than these load pockets but still small enough so that market shares or concentration would be sufficiently high to warrant concern.

B. Documented Load Pockets in Arizona

Q. What is a load pocket?

A. A load pocket is an area such that loads within the area exceed the import capability into the area. Thus, a load pocket is an area within which at least some generation must operate during at least some (higher load) hours in order to meet local loads.

Q. Please describe the documented load pockets that exist in Arizona.

A. There are three well-documented load pockets in Arizona: (1) the Tucson area load pocket, (2) the Phoenix area load pocket, and (3) the Yuma area load pocket. A map depicting these and other load pockets in the Southwest is provided in Exhibit D. Originally, this was a color map. If it were reproduced in color, it would show that all the identified load pockets are based on import constraints, with the exception of the Northwest New Mexico load pocket, which is based on an export limit.

1. Tucson Area Load Pocket

Q. Where is the Tucson area load pocket?

A. It is my understanding that the Tucson area load pocket coincides with TEP's service territory (TEP response to AG Set 3 No. 18 (Exhibit G)).

Q. How often is the Tucson area a load pocket?

A. Based on unconfirmed data in a DSTAR email document (Exhibit D), the Tucson area import limit is 950 MW to 1,000 MW, during 81% of the days of the year the Tucson area load exceeds 950 MW, and the Tucson area peak load is 1,650 MW. The data in Table A below indicate that the Irvington 4 unit is on as must run during 91% of hours.

Q. Which generating units are inside the Tucson area load pocket?

A. TEP response to AG Set 3 No. 18 (Exhibit G) states that "For TEP, the generating units located within TEP's service territory operate as must run units to meet the local load within the boundaries of TEP's service territory. Effectively, for TEP, there is a single 'load pocket' which is TEP's service territory." TEP responses to AG Set 3 Nos. 14-15 (Exhibit G) provide the information in Table A below on the TEP generating units in the Tucson area load pocket and the percentage of each month that each unit operates to prevent violation of import constraints. I have added data on unit type and summer capability in megawatts (MW) from the Resources Data International (RDI) Basecase database (1998), and I have added units in Pima County that apparently are not required to operate to prevent violation of import constraints but that presumably would be in the relevant geographic market. TEP has proposed installation of an additional must run combustion turbine (CT) for the Tucson area load pocket within the next five years.

Table A

Generating Units in the Tucson Area Load Pocket

Owner	**Unit**	**Unit Type**	**MW**	**% of Month On as Must run**
TEP	Irvington 4	Coal steam	156	91
TEP	Irvington 1	Gas steam	81	23
TEP	Irvington 2	Gas steam	81	26
TEP	Irvington 3	Gas steam	105	11
TEP	Irvington CT1	Gas CT	24	2.1
TEP	Irvington CT2	Gas CT	25	1.6
TEP	Irvington CT3*	Gas CT	25	0
TEP	North Loop CT1	Gas CT	27	0.7
TEP	North Loop CT2	Gas CT	27	0.8
TEP	North Loop CT3	Gas CT	27	0.6
TEP	North Loop CT4*	Gas CT	27	0
TEP	De Moss Petrie*	Gas CT	47	0
Total			652	

* Added to TEP's list of must run units.

Q. In what packages does TEP propose to auction the generating units in the Tucson area load pocket?

A. Evidently, TEP proposes to auction two packages, one containing Irvington units 1-4 and the second containing TEP's eight combustion turbines. I infer this from page 16 of an October 1, 1998, TEP document entitled "Auction Protocols for the Auction of Certain Electric Generating Assets of Tucson Electric Power Company" (TEP response to RUCO No. 4.9 (Exhibit H)).

2. Phoenix Area Load Pocket

Q. Where can a description of the Phoenix area load pocket be found?

A. The Phoenix area (or Valley) load pocket is described in two APS documents: "APS 'Must Run' Generation Report" (November 1997) and "Must Run Generation Requirements" (April 17, 1998), both of which are included in Exhibit C. These documents describe the nature of the import constraints, the level of import capability, the generation located inside the load pocket, the load profile in the area, and the number of hours per year during which the area is a load pocket as of 1998. The same documents describe the Yuma area load pocket. See also APS response to AG Set 3 No. 14 (Exhibit I).

Q. How often is the Phoenix area a load pocket?

A. According to APS documents, currently the Phoenix area is a load pocket between 400 and 460 hours annually during the summer (Exhibits C and I). Presumably the number of hours will increase as loads increase, unless steps are taken to increase the area's import capability.

Q. Which generating units are located in the Phoenix area load pocket?

A. Table B lists the generating units in the Phoenix area load pocket:

Table B

Generating Units in the Phoenix Area Load Pocket

Owner	Unit	Unit Type	Summer MW
APS	W. Phoenix 1	Gas CC	80
APS	W. Phoenix 2	Gas CC	80
APS	W. Phoenix 3	Gas CC	80
APS	Ocotillo 1	Gas Steam	113
APS	Ocotillo 2	Gas Steam	113
APS	W. Phoenix GT1	Gas CT	47
APS	W. Phoenix GT2	Gas CT	47
APS	Ocotillo GT1	Gas CT	54
APS	Ocotillo GT2	Gas CT	49
SRP	Numerous	Steam & CC	820
SRP	Numerous	CT	465
Total			1,948

CC = combined cycle. Sources: Exhibit C and RDI BaseCase1998. APS also has three mothballed units, West Phoenix 4-6, gas steam units with a combined capacity of 96.3 MW. APS SEC Form 10-K, 1995.

3. Market Power in the Tucson and Phoenix Area Load Pockets

Q. Do the utilities that own generating capacity in the Tucson and Phoenix area load pockets have market power?

A. Yes. During the hours in which these areas are load pockets they are also geographic markets for capacity and energy. Since capacity and energy must be supplied by at least one of the TEP generating units during most of the year, TEP has market power given entry conditions. Since capacity and energy must be supplied by a least one APS and/or SRP generating units in the Phoenix load pocket during high load hours, and shares (APS, 35%, SRP, 65%) and concentration in that market are very high, APS and SRP have market power given entry conditions.

Q. What is must run generation?

A. TEP and APS appear to use the term "must run generation" to refer to generating capacity that is within a load pocket, or to the subset of that generating capacity that would operate in merit order during at least some of the time that the import capability of the load pocket would be fully used. Given this usage of the term, during a large share of the hours that a load pocket exists a majority of must run generation may not operate. The amount that must operate in any hour is equal to local load minus the load pocket's import capability.

In the electric power industry, there are also contexts in which "must run generation" refers to generating units that must operate in order to relieve transmission constraints that would restrict efficient transactions. For example, a particular generator may be the only unit that can relieve a voltage constraint by supplying reactive power.

Q. When one defines "must run generation" as TEP and APS appear to do, should one necessarily conclude that pertinent markets cannot be competitive during any hour that a load pocket exists?

A. No. Whether the markets are competitive during any hour will depend on matters such as ownership shares and concentration. If one defines must run generation as generation that would sometimes be run in an area in which loads sometimes exceed import capability into the area, one could say that most generation in the US, or in the WSCC, or in many other areas is must run generation. Obviously, one should not jump from this definition of must run generation to an assumption that the relevant market could not be structured to permit reliance on competition during at least some of the hours that the load pocket exists.

Q. Is there an alternative to reliance on behavioral regulation under must run contracts for dealing with market power in the Tucson and Phoenix area load pockets?

A. Yes, during a reasonable share of the hours that the load pockets exist, it is likely to be possible to rely on competition rather than regulation if generating units are divested to several independent parties. In that case, prices for a greater share of generation in Arizona would be determined by competition rather than regulation of "must run" units. I discuss advantages of structural over behavioral or regulatory remedies at pages 47-56 of Exhibit B.

Even to the extent that Arizona relies on must run contracts to deal with market power in the Tucson and Phoenix area load pockets, separate ownership of generating units is likely to have significant benefits in terms of lower costs and prices. Assuming cost-based price regulation and little competition in the load pockets, owners of generation would have limited incentives to minimize their costs. Higher costs due to inefficient operation could be passed through to consumers through higher regulated prices. Also, if there is separate ownership of generating units, buyers would have an opportunity to induce owners of generating units to compete to enter into must run contracts.

C. Geographic Markets Larger than Documented Load Pockets in Arizona

Q. In your response to an earlier question, you indicated that you had not had adequate time to determine whether, for purposes of analyzing generation market power over capacity and energy, there are additional geographic markets that are larger than the load pockets you have discussed but still small enough so that market shares or concentration would be sufficiently high to warrant concerns over generation market power. What would be the potential basis for delineating such a geographic market for analysis of market power over capacity and energy?

A. There are three potential bases for an area such as South Arizona or Arizona to be a geographic market for purposes of analyzing market power. Two could relate to "pure" generation market power. The third relates to transmission market power.

Q. What is the first potential basis for an area such as South Arizona or Arizona to be a geographic market for purposes of analyzing market power over capacity and energy?

A. In principle, a South Arizona or Arizona market may be based on transmission congestion on paths or interfaces into and out of the area in question. The role of transmission constraints in limiting the scope of geographic markets, regardless of the direction in which transfers are constrained, is discussed at pages 37-38 of Exhibit C. Some of the potential paths or interfaces in or near Arizona that could be congested are identified in Exhibit L, which includes a map from the *WSCC 1998 Path Rating Catalog*. See, for example, paths 21 (Arizona to California), 22 (Southwest to Four Corners), 23 (Four Corners 345/500 Qualified Path), 34 (TOT 2B), 47 (Southern New Mexico (NM1)), 49 (East of the Colorado River (EOR)), 50 (Cholla-Pinnacle Peak), 51 (Southern Navajo), 54 (Coronado-Silver King-Kyrene), 58 (Eldorado-Mead 230 kV Lines), and 63 (Perkins-Mead-Marketplace 500 kV Line). Additional information on congested paths is provided by the documents in Exhibits D through I. Given sufficient congestion, *including congestion induced by responses to the exercise of market power*, a hypothetical monopolist of generation in South Arizona or Arizona may have the ability to raise prices in South Arizona or Arizona by reducing output from generators inside the interfaces in question. In that case, South Arizona or Arizona would be a geographic market.

In the event that transmission into, say, Arizona is congested, or would become congested in response to an exercise of market power, and at the same time transmission into the Tucson, Phoenix, and/or Yuma load pockets is congested, there could be a geographic market resembling a slice of Swiss cheese: Arizona minus the Tucson, Phoenix, and/or Yuma areas.

Q. Have you found any information indicating the presence of or potential for transmission congestion in Arizona, aside from the import limits into Tucson, Phoenix, and Yuma that you have already addressed?

A. The following information is relevant to the likelihood of actual or potential transmission and warrants further investigation:

- Exhibit 5 to the September 1997 DSTAR Planning Work Group's *Final Report* identifies "existing or potential congested transmission paths in the Southwest," a number of which are in Arizona. In addressing transmission pricing zones based on congestion, the May 1998 DSTAR O/I Workgroup *Status Report* indicates that congestion zones identified for the DSTAR region include Tucson, Phoenix, Yuma, and Remaining Arizona. The "Remaining Arizona" congestion zone is similar to what I described earlier as a geographic market resembling a slice of Swiss cheese. See also the DSTAR O/I Workgroup map entitled "Constrained Paths and Congestion Zones for Desert Star." (All documents cited are in Exhibit D.)

- For a number of paths on the APS and SRP transmission systems, firm available transmission capability (ATC) posted on OASIS has been zero in the recent past and is zero for the coming year. Information on these ATCs is available in DSTAR O/I Working Group *Status Report* (Exhibit D), in ATC data supplied by APS from its OASIS site (Exhibit E), and in *Western Interconnection Biennial Transmission Plan*, May 1998, pages 51-52 (Exhibit F). This information suggests limits on the geographic market for capacity and perhaps energy.

- APS reports that line loading relief was used to reduce flows on the Four Corners West transmission path (#22) and on the Four Corners 500/345 kV transformer during 58 and 68 hours, respectively, in 1997-1998 (APS response to AG Set 3 No. 1 (Exhibit I)). While the number of hours involved is not very high, hours during which line loading relief was applied are likely to represent only a fraction of hours during which there was excess demand and congestion on a transmission path. Generally, excess demand and congestion would result in refusal of transmission requests or posting of zero ATC, which would deter requests from being made.

- Arizona is a load pocket. APS reports that as of April 1998 the WSCC reported a non-simultaneous import capability for Arizona of 4,684 MW (APS response to AG Set 3 No. 37 (Exhibit I)), which is approximately equal to APS's summer peak load.

Q. Have you found any information consistent with the view that transmission paths into and out of Arizona may not often be congested at present?

A. Yes. This is one of the reasons I have not been able to reach a conclusion regarding some potential geographic markets in the limited time available to me. Some of the information in the Northwest, Southwest, and Western Regional Transmission Associations' May 1998 *Western Interconnection Biennial Transmission Plan* may be consistent with this view. However, that document does not address intrastate constraints such as the import limits into the Tucson, Phoenix and Yuma areas. Also, a constraint that is not congested at present may become congested when market power is exercised, and incentives to exercise any market power are likely to increase when there is retail customer choice.

Q. What is the second potential basis for an area such as South Arizona or Arizona to be a geographic market for purposes of analyzing market power over capacity and energy?

A. Even absent transmission constraints, geographic markets may be limited by the structure of transmission tariffs. For example, consider a hypothetical region with only two areas, A and B, each with a separate postage-stamp transmission tariff. Suppose that if a buyer located in area A purchases energy from a generator located in area A, that buyer pays a transmission charge of \$2/MWh. Suppose that if the same buyer purchases energy from a generator located in area B, that buyer pays a transmission charge of \$2/MWh for transmission service in area A and a transmission charge of \$4/MWh for transmission service in area B. Suppose further that with competitive behavior the prices of energy in areas A and B would be \$20/MWh, and that as a result no energy would be transferred between the areas. In that case, areas A and B would be separate markets for purposes of analyzing whether generators have market power. A hypothetical monopolist that owned all generators in area A could raise prices in that area by nearly 20% above the competitive level before it would be faced with competition from generators in area B.

To apply this hypothetical to Arizona, where future transmission pricing is uncertain, suppose that a transmission pricing method were adopted in which APS's generators correspond to those in area A and all other generators correspond to those in area B. In that case, pancaked transmission tariffs could cause area A to be a geographic market for purposes of analyzing whether APS is likely to have market power in area A when competitive prices in area A would be close to those in surrounding areas. Alternatively, suppose that a transmission pricing method were adopted in which the generators presently owned by APS and TEP correspond to those in area A, and all other generators correspond to those in area B. In that case, again area A could be a geographic market. In such a market, not only would APS be likely to have market power but APS's acquisition of any of TEP's generating resources would be likely to increase APS's market power.

In the context of Arizona, one factor that may reduce concentration in the potential markets I have just described is joint ownership of plants in which APS and/or TEP have a share. According to TEP's response to AG Set 3 No. 22, transmission costs to any customer are the same for all owners of a jointly owned plant.

Q. What is the third potential basis for an area such as South Arizona or Arizona to be a geographic market for purposes of analyzing market power over capacity and energy?

A. If vertically integrated utilities have competitively significant control over the transmission system, they may use that control to reduce the availability or reliability or increase the price of transmission service available to competitors. The result of such exercise of transmission market power may be to narrow geographic markets in which to analyze market power over capacity and energy. TEP, APS, and SRP may all have competitively significant control over transmission. However, if in fact TEP actually divests all its generating units and does not engage in wholesale or retail marketing in Arizona, then the transfer of APS's transmission assets to TEP would reduce the extent of problematic vertical integration.

D. Unsound Methods of Delineating Geographic Markets

Q. Have you written papers on delineation of geographic markets in the electric power industry?

A. Yes. Most of the publications listed on my curriculum vitae that deal with the electric power industry address geographic market delineation. A paper that addresses this issue exclusively is "Geographic Market Delineation for Electric Utility Mergers." I prepared that paper for the Edison Electric Institute, which submitted the paper to FERC.

Q. Have you reviewed the following two studies?

- "Arizona Public Service Company's Generation Market Power Analysis," which is attached as Exhibit B to the *Application of Arizona Public Service Company for Order Approving Market-Based Rates*, FERC Docket No. ER97-__-000, Feb. 12, 1997 (APS response to AG Set 1 No. 3).

- "Generation Market Power Study," a May 22, 1996, study that was relied upon in TEP's September 5, 1997, *Application for Market-Based Rates* at FERC (TEP response to AG Set 1 No. 3).

A. Yes, I have reviewed both documents.

Q. Do these studies use a sound methodology for delineating relevant geographic markets for purposes of evaluating restructuring of the electric power industry?

A. No, they do not. The APS and TEP analyses use FERC's hub-and-spoke methodology. For each wholesale customer, APS and TEP delineate a geographic market that includes all generating capacity (in the case of energy) or uncommitted capacity (in the case of capacity) located in (a) the control area in which that customer is located, (b) any control area directly interconnected to the latter control area, or (c) any control area that can be accessed by the customer using the APS or TEP open access transmission tariff.

The hub-and-spoke methodology is not a sound method for delineating geographic markets. The methodology ignores virtually all the actual determinants of relevant geographic markets, namely, transmission constraints, transmission costs, generating capacities and costs, and loads. In addition to having no value, to my knowledge the hub-and-spoke methodology is not used for any purpose other than individual utility market-based rate filings at FERC. Even FERC has abandoned the hub-and-spoke methodology for purposes of analyzing market power in connection with mergers and industry restructuring, such as applications for market-based pricing in regional power pools. Indeed, in its December 1996 *Merger Policy Statement* (Order 592), FERC states:

> A drawback of this [hub-and-spoke] method of defining geographic markets is that it does not account for the range of parameters that affect the scope of trade: relative generation prices, transmission prices, losses, and transmission constraints. Taking these factors into account, markets could be broader or narrower than the first- or second-tier entities identified under the hub-and-spoke analysis.

Therefore, the APS and TEP hub-and-spoke analyses shed no light on market power.

Q. Are data on wholesale purchases and sales of electric power that are reported by APS and TEP in FERC Form 1 useful in delineating relevant geographic markets in which to analyze market power in Arizona?

A. No, they are of little value for that purpose, for at least three reasons. First, there are in fact separate product markets for different times within the year. The fact that APS and TEP engaged in energy transactions during 1997 with Utilities A and B arguably might suggest that during some hours of the year the relevant geographic market is likely to include Utility A and during some (but not necessarily the same) hours the relevant market is likely to include Utility B. However, suppose it were true that both Utility A and Utility B were in the relevant market with APS and TEP during 10% of the year, Utility A (but not Utility B) was in the relevant market during an additional 7% of the year, and Utility B (but not Utility A) was in the relevant market during an additional 8% of the year. Even in this case, it would still be true that neither Utility A nor Utility B was in the relevant market during the remaining 75% of the year. Thus, even if annual data indicate a large number of trading partners, relevant markets may be narrow during some or much of the year, for example, when companies with large amounts of hydroelectric generating capacity have no energy to sell.

Second, the fact that APS and TEP were purchasing energy from another region of the WSCC during a particular period would not demonstrate that Arizona and the supplying region were in the same geographic market, because the interface between them may have been congested, in which case there would be separate markets. For example, during the spring run-off, there are large transfers of hydroelectric energy from the Pacific Northwest to the southern WSCC. However, at such times the interface between Oregon and California is typically congested, and hence the Pacific Northwest is not in the same geographic market as Arizona.

Third, a large share of purchase and sales transactions reported by APS and TEP are with power marketers, and data on these transactions are not helpful in identifying competing generating plants.

VII. Markets for Transmission Service

Q. Earlier you explained that under certain circumstances transmission service in a particular corridor or to a particular destination may be treated as a relevant antitrust market, and you explained that FERC and DOJ have delineated markets for transmission service in merger cases. You also indicated that it may be appropriate to treat transmission service from baseload plants to Arizona load centers as a relevant antitrust market during some time periods. What significance would such relevant markets for transmission service have?

A. One aspect of the proposed Agreements is a merger of TEP's transmission system and APS's transmission system with voltages of 345 kV and above. At present, APS and TEP may be competitors in supplying transmission services. In any event, if the present industry ownership structure were continued, APS and TEP are likely to compete in providing transmission service in the future when retail customers can choose their suppliers. For example, in addition to their separately owned lines, they are joint owners of various transmission facilities. TEP's acquisition of APS's transmission assets may therefore reduce competition and increase horizontal market power in the provision transmission service. If a customer can choose between transmission service from APS and TEP, the customer may be able to bargain for a price discount. Also, if an independent APS could offer transmission service in the event that TEP did something to withhold service, TEP's incentive to withhold transmission service would be reduced. Therefore, other things being equal, if TEP controls both the TEP and APS transmission systems rather than only the TEP system, TEP may be more likely to withhold transmission service.

VIII. Vertical Market Power

Q. Have FERC's Order 888 and 889 "open access" transmission rules eliminated concerns over transmission or vertical market power?

A. No. When those rules were proposed, many parties—including the U.S. Department of Justice, the Federal Trade Commission, and myself—warned that they would not prevent the exercise of vertical market power.

Experience has indicated that FERC's initial optimism about Orders 888 and 889 as a cure for transmission market power was not warranted. There have, for example, been numerous complaints about the limits on what utilities post as available transmission capability, and FERC has found that some transmission service providers have discriminated in favor of affiliates. For this reason among others, there is now considerable interest in ISOs.

Q. The ACC, among others, has expressed concern over the potential for vertical market power to act as a barrier to retail electric competition in Arizona (TEP response to RUCO No. 5.3 (Exhibit H)). Insofar as TEP is concerned, would the proposed Agreements eliminate the vertical market power concerns that have been raised?

A. No. TEP (including its affiliates) would own and operate a substantial portion of transmission assets in Arizona. At the same time, under several potential scenarios TEP will continue to own generating plants in Arizona. TEP has represented that neither TEP nor its affiliates will bid in the auction for its generating plants. However, TEP will own generating plants if it opts not to sell generating units through the planned auction (TEP responses to RUCO Nos. 4.10-4.11 (Exhibit H)). TEP will also own generating plants if the ACC declares a failed auction, which it could do based on a determination that bids were below market values or if TEP is unable to obtain all regulatory approvals for the transfer of an asset, for example, because FERC disapproves the highest bidder. TEP will also continue to own generating plants if the Department of Justice, Federal Trade Commission, Arizona Attorney General, or another party challenges a proposed acquisition as anticompetitive under the Clayton Act and TEP then claims that it is unable to sell its generating plants in time to meet its schedule for securitizing stranded costs (TEP responses to AG Set 3 Nos. 23-24 (Exhibit G)). Even if TEP does not continue to own generating plants in Arizona, TEP or an affiliate, such as its marketing affiliate New Energy Ventures, Inc. (Exhibit J), may enter into longer term contracts to purchase capacity and energy on terms that would give TEP the same incentives to raise electric power prices during shorter periods that it would have if it owned generating capacity. Under the Agreements, TEP will purchase 200 MW of capacity and energy with a minimum 80% load factor from APS during 2001-2004.

In short, further restrictions on TEP would be necessary to eliminate the vertical market power concerns that have been raised in Arizona. The ACC could order that TEP in fact sell all its generating capacity, with no loopholes, and that TEP not engage in wholesale or retail marketing of electric power in Arizona. The ACC could also order that TEP's transmission assets be turned over to an *independent* system operator (ISO) with an appropriate governance structure, powers, rules and incentives.

Q. Would the proposed Agreements eliminate the vertical market power concerns that have been raised insofar as APS is concerned?

A. No. Even with the Agreements, APS would own and control not only a substantial amount of generating capacity in Arizona but also transmission and distribution facilities rated 230 kV and below. In general, 230 kV facilities are treated as transmission rather than distribution facilities. The September 1997 Desert Southwest ISO (DSTAR) Planning Work Group *Final Report* called for the ISO to control facilities generally rated 230 kV and above, although APS claimed an exception for its 230 kV facilities (Exhibit D). Appendix G of the October 1997 DSTAR O/I Work Group *Final Report* contains a preliminary designation of transmission facilities for DSTAR control, including facilities owned by AEPCO, NPC, PNM, SRP, and Western. Furthermore, consider the specific case of APS. APS owns about 35% of the generating capacity in the Phoenix area load pocket (see Table B). Phoenix is a load pocket because imports are constrained by thermal and voltage problems on the 230 kV facilities in the Metro Phoenix area (APS Valley "Must Run" Generation Analysis (Exhibit C); APS response to AG Set 3 No. 14 (Exhibit I)). Therefore, even with the Agreements, APS would continue to own 35% of generating capacity in a major load pocket that results from constraints on transmission facilities that APS would continue to own and control.

In short, further restrictions on APS would be necessary to eliminate the vertical market power concerns that have been raised in Arizona. The ACC could order APS to divest either its 230 kV and higher transmission system or pertinent generating plants.

Q. TEP states that APS's "transmission assets will be acquired by a TEP subsidiary, but the assets will be operated by an Independent System Operator" (TEP response to AG Set 1 No. 29 (Exhibit G)). Does this reference to an ISO adequately mitigate concerns over transmission market power?

A. I have no information on what the purported ISO arrangement is. According to its proposed Agreement (Section XI), TEP would merely commit "*to facilitating the development* of an independent system operator (ISO) for Arizona by December 31, 2000" (emphasis added). In addition to requiring that an ISO would exist and that TEP would turn over its transmission system to the ISO, one would need details on matters such as timing, the ISO's governance structure and its powers, rules, and incentives relating to transmission planning and investments, transmission operations, pricing for transmission and ancillary services, other terms and conditions for transmission service, and generation dispatch and redispatch. FERC has guidelines on some of these issues. Moreover, the Federal Trade Commission has argued on a number of occasions that single-system or single-state ISO's are insufficiently large.

IX. ENTRY

Q. Why should an evaluation of market power include an analysis of entry conditions?

A. Notwithstanding high market shares and concentration in relevant markets, market power is unlikely to be a significant problem if entry into those markets in "easy," as that word is used in antitrust parlance. I discuss how to evaluate entry conditions at pages 41-42 of Exhibit B.

Q. Is entry into relevant markets for capacity, energy and transmission service easy in Arizona?

A. No, it is not. This is true both because of time requirements for entry into markets for energy and transmission service and because of excess baseload generating capacity.

As to time requirements, typically three to four years are required to build new combined cycle generating plants while around six years are required for coal plants. The shorter time requirement for combustion turbines is not relevant to energy markets during most time periods, because combustion turbines are used to produce energy during only a small percentage of the hours in the year. Major transmission projects often take several to many years.

Even if it were possible to build new combined cycle and coal plants quickly, most of the available evidence suggests that it will not be profitable to do so at competitive prices in Arizona through at least 2006 because of excess baseload capacity. Recent APS and WSCC documents indicate no utility plans (let alone commitments) to build generating units in Arizona other than combustion turbines prior to 2005-2007. I note, however, that PP&L Global's plans to build a 520 MW gas-fired power plant near Kingman, Arizona, were approved in September 1998 by the ACC's Siting Committee (Exhibit K).

Q. Are there entry barriers into markets for retail marketing services for electric power and related products?

A. I discuss three potential barriers in pages 67-73 of Exhibit B: barriers that arise from vertical integration of the local distribution utility into retail marketing, barriers that arise from imperfect information and inertia when a market is opened to competition, and barriers created by government policies, such as provisions for recovery of stranded costs.

With regard to the last of these barriers, I explain at page 73 of Exhibit B that Enron recently announced that it would no longer compete for residential customers in California. According to *Foster Electric Report* (April 29, 1998, p. 10), "The company found it too difficult to compete in California under a state law requiring a 10 percent rate cut for all consumers and a competitive transition charge (CTC) designed to recoup California's traditional utilities' stranded costs."

A hypothetical will illustrate this real problem. Suppose a state freezes retail prices at 8 cents per kilowatt-hour (kWh) and requires that consumers pay the incumbent utility 3 cents/kWh for use of its wires and 3 cents/kWh as a

CTC if they purchase their electricity from a competing retail marketer. No competing retail marketer is likely to enter the market, because it would not be able to charge more than 2 cents/kWh for unbundled electricity—a price that is not likely to cover its costs. Incumbent utilities do not mind a low unbundled electricity price, since the low price inflates their claimed stranded costs while eliminating competition from retail marketers, and possibly also incentives for competitors to expand generation and transmission capacity.

Q. Would the provisions for stranded cost recovery in the proposed Agreements raise barriers to entry into retail marketing services?

A. As I explained in my preceding response, those provisions could lead to that outcome.

X. EFFICIENCIES

Q. Are you aware of any evidence regarding potential economies of scale or scope or other cost-reducing efficiencies that might result from the generation and transmission ownership arrangements contemplated by the proposed Agreements?

A. No. Moreover, TEP has stated that it is unaware of any studies or other papers that address the advantages and/or disadvantages of TEP's transmission affiliate holding a monopoly on transmission in Arizona (TEP response to RUCO No. 5.3 (Exhibit H)).

XI. CONSUMER WELL-BEING

Q. ACC Staff states that one of the benefits of the proposed Agreements is that the Agreements will guarantee rate reductions for a number of years into the future. For purposes of determining the impact of the proposed Agreements on consumers, is it sufficient to observe that the Agreements include provisions for reductions in regulated retail prices during three and a half years (July 1, 1999, through December 31, 2002)?

A. No. Insofar as prices for consumers in TEP's and APS's service territories are concerned, what one would like to see is a comparison of prices over a longer horizon (e.g., 10-15 years) among four scenarios: (1) the scenario contemplated by the proposed Agreements, (2) the scenario without industry restructuring and stranded cost recovery, (3) the scenario with industry restructuring but without stranded cost recovery, and (4) scenarios differing from (1) in which there is restructuring and provision for stranded cost recovery. As I understand it, the provision for the proposed price reduction merely tells us something about the comparison between scenario (1) and scenario (2) during a relatively short 3.5 years ending December 31, 2002. The APS Agreement states that "APS will be allowed full recovery of any remaining deferrable costs beginning January 1, 2003." In other words, the explanation for any rate reduction through December 31, 2002, is that the companies will simply defer a sufficient amount of stranded cost recover until after January 1, 2003, to achieve this result.

Also, regulated prices for consumers in TEP's and APS's service territories that continue to buy power from TEP and APS are only one part of the picture. If the proposed Agreements increase the extent to which market power is exercised in markets for wholesale power, then wholesale and retail prices would increase for customers that are in the relevant geographic markets but outside the TEP and APS service territories. Also, prices would be higher for former retail customers of TEP and APS that would choose to buy power from suppliers other than TEP and APS.

Furthermore, prices from one supplier are not the only determinant of the well-being of consumers who purchase electricity. Other variables, such as customer service and the options available to consumers from different suppliers, are relevant.

XII. TIMING

Q. ACC Staff state that one of the benefits of the proposed Agreements is that they will give competitors and customers certainty about key issues that must be resolved to ensure the start of competition on January 1, 1999. Based on your experience at the federal level, would you expect necessary federal regulatory reviews of the proposed Agreements to be completed by December 31, 1999?

A. I believe this would be impossible. I presume that APS and TEP will have to apply to FERC to authorize transfer of APS's 345 kV and higher transmission system to TEP, to transfer TEP's shares of the Navajo and Four Corners generating plants to APS, and eventually (when the auctions have taken place) to transfer TEP's other generating plants to auction bidders, assuming these facilities are FERC jurisdictional. Those applications could be made without prior ACC approval. Moreover, those applications would have to be accompanied by market power analyses using the methodology in FERC's Appendix A, preparation of which is a time-consuming process. Because TEP and APS produced no such market power analyses in discovery, I presume they have not yet been undertaken. And to my knowledge, FERC has not approved a merger application in less than five months since Appendix A was issued. In addition, at the federal level the transactions would be subject to review under the Hart-Scott-Rodino process at the U.S. Department of Justice or Federal Trade Commission.

Q. Does this conclude your prepared direct testimony at this time?

A. Yes.