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Transcript Exhibit(s)

Docket #(s): RE-00000C-94-0165

E-01345A-97-0773

E-01345A-98-0473

Exhibit # : Enron 1, Commonwealth 1, Enron 2, APS 1, Commonwealth 2, APS 2, Commonwealth 3, Commonwealth 4,

EXHIBIT
Enron-1
admitted

Before the

Arizona Corporation Commission

Case Nos. E-01345A-98-0473 and E-01345-A-97-0773

ARIZONA PUBLIC SERVICE COMPANY

Direct Testimony of

DR. ALAN ROSENBERG

On Behalf of

Enron Corporation

June 1999
Project 7167

Brubaker & Associates, Inc.
St. Louis, Missouri 63141-2000

Before the
Arizona Corporation Commission
Case Nos. E-01345A-98-0473 and E-01345-A-97-0773

ARIZONA PUBLIC SERVICE COMPANY

Direct Testimony of Dr. Alan Rosenberg

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Alan Rosenberg and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This is summarized in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of Enron Corporation.

Q HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (ACC) ON THE SUBJECT OF ELECTRIC INDUSTRY RESTRUCTING?

A Yes, I have.

1 Q **WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

2 A Enron requested that I review the latest Agreement entered into by Arizona Public
3 Service Company (APS) and render an opinion as to whether it fosters open
4 competition and fairly safeguards customers against unfair or unreasonable practices
5 by APS. Specifically, Enron asked me to focus on the transfer of generation assets
6 from the regulated utility to an unregulated affiliate of APS. Consequently, all other
7 aspects of the Agreement are beyond the scope of my testimony. Thus, my silence
8 on issues such as unbundled rate design and the appropriate stranded cost level
9 should not be construed as necessarily assent on my part.

10

11 Q **WHAT DID YOU REVIEW IN THE COURSE OF THIS ASSIGNMENT?**

12 A I reviewed the Agreement document itself and the supporting testimony of the
13 signatories to that agreement, as well as certain data responses by APS.

14

15 Q **COULD YOU PLEASE SUMMARIZE YOUR GENERAL CONCLUSION?**

16 A I find that there is insufficient evidence to show that the transfer of generation assets
17 to the unnamed unregulated affiliate of APS (which I will term APS Genco) will
18 adequately safeguard customers and promote competition. When an unregulated
19 affiliate and a regulated utility (which I will term APS Disco) are both owned by the
20 same holding company, there always remains a concern that cost shifting is occurring
21 from the unregulated affiliate to the regulated affiliate. This concern is heightened
22 when, as in this case, the unregulated affiliate is entering a field that hitherto has
23 been a monopoly and will have frequent dealings with the regulated affiliate. After all,
24 even if the transfer of assets were flawless, APS Genco would still enjoy advantages
25 such as name recognition, knowledge of the customer base, and possibly vertical
26 market power.

1 Q **WHY IS SHIFTING COSTS BETWEEN REGULATED AND UNREGULATED**
2 **AFFILIATES NORMALLY AN ISSUE?**
3 A As a rule, regulated companies have a greater assurance of recovering their costs as
4 compared to unregulated enterprises. Consequently, there is an understandable, but
5 perverse, incentive by the common owner to either shift costs from the unregulated
6 enterprise to the regulated one, or otherwise favor the unregulated subsidiary with a
7 sweetheart deal. This is unfair to the competitors of the unregulated (i.e., APS Genco
8 in this case) firm who do not have this advantage. It is doubly unfair to the customers
9 of the regulated firm (i.e., APS Disco) who not only see a diminution of competition for
10 the generation aspect of the electric service, but in addition are perhaps saddled with
11 unnecessary costs from the regulated side of the utility.
12
13 Q **COULD YOU GIVE AN EXAMPLE OF HOW SUCH AN IMPROPER ADVANTAGE**
14 **COULD ARISE IN A TRANSFER OF GENERATION RESOURCES SUCH AS THE**
15 **ONE CONTEMPLATED BY THE AGREEMENT?**
16 A Certainly. APS states that it does not have any expensive QF purchased power
17 contracts. However, it could have the opposite of that—a very beneficial purchased
18 power contract at below market prices. Such a contract, if it existed, would be a
19 stranded benefit (not a stranded cost) and could be used to mitigate APS's other
20 stranded costs. However, under the Agreement, the benefits of this contract would
21 ultimately accrue to APS parent and not to the customers.
22 The flip side, so to speak, of a favorable purchased power contract, is a
23 contract to sell power at a relatively high price. Such a lucrative contract would also
24 be a source of mitigation for otherwise "stranded costs". However, if this contract is
25 transferred to APS Genco, all benefits of this contract accrue to Pinnacle West
26 shareholders and not to the customers.

1 Q **DO YOU KNOW WHETHER APS IS A PARTY TO ANY SUCH LUCRATIVE SALE**
2 **OR PURCHASE CONTRACTS?**
3 A APS is transferring its contractual rights as a seller in some wholesale power
4 agreements. I have not analyzed the details of APS contracts or commitments.
5 However, it should not be the job of the intervenors in this case to show that such
6 lucrative contracts exist. The burden of proof should be on APS to show (1) that they
7 do not exist or (2) if such contracts exist, to commit the inherent benefits to the
8 mitigation of its otherwise claimed stranded costs.
9
10 Q **WHAT OTHER PROBLEMS DO YOU SEE WITH THE TRANSFER?**
11 A The first problem is the transfer itself. A much better approach would be for APS to
12 conduct an auction of the plants, thereby divesting itself of its generation assets. If
13 APS wanted to remain in the generation end of the business, it could have had APS
14 Genco be one of the bidders. (In that case the ACC should oversee the auction to
15 assure that APS Genco did not have an undue advantage over the other bidders.)
16
17 Q **WHAT ARE THE ADVANTAGES OF AN AUCTION OVER A TRANSFER?**
18 A I see three primary advantages. First, an auction would elicit the highest possible
19 price for these plants, thus mitigating stranded costs to the maximum possible extent.
20 Second, an auction would most likely lead to multiple owners of APS generation, thus
21 enhancing competition by reducing the potential for market dominance. Third, an
22 auction (as opposed to a paper transfer) would eliminate the necessity of making
23 arbitrary decisions on the capital structure of the remaining regulated utility. Fourth,
24 an auction may create some tax advantages that could accrue to the customers.

Q PLEASE ELABORATE ON THE ADVANTAGES OF AN AUCTION. WHY WOULD MULTIPLE OWNERS OF APS GENERATION ENHANCE COMPETITION?

A According to its 1997 Annual Report, APS is the second largest investor-owned electricity generator in the 11 state Western Systems Coordinating Council area, based on generation owned or operated for others. Even including governement-operated utilities, it is the fourth largest overall in the western United States. Breaking up that market concentration would clearly enhance competition.

Q DOES THE AGREEMENT SPEAK TO POSSIBLE MARKET POWER BY APS?

A No, not explicitly. I could find no demonstration by the supporting witnesses that purports to show APS Genco will not have market power, e.g., by employing an HHI type of analysis. I understand that Enron will be sponsoring another witness that addresses the issue of market power in greater detail.

Q YOU STATED THAT AN AUCTION WOULD DISSIPATE ISSUES RELATED TO CAPITAL STRUCTURE. WHAT IS YOUR CONCERN ABOUT THE CAPITAL STRUCTURE?

A Perhaps the clearest way to explain this concern is to give an illustration. Suppose an integrated utility has the following simplified balance sheet.

ASSETS		LIABILITIES and EQUITY	
Net Plant	$ 900	Debt	$ 600
Cash & Receivable	$ 100	Equity	$ 400
Total	$1,000	Total	$ 1,000

Now suppose that the utility creates a non-regulated affiliate and transfers to it plant with a book value of $500. Assuming no write-ups or write-downs of the plant,

both the regulated utility as well as the non-regulated affiliate will have total assets of $500. Assuming no new financing activity (issuance or redemption of stock or debt) each affiliate will also have $500 in liabilities and equity. The question of import is how much of each. In the above illustration we could have either of the following two capital structures for the two affiliates (and other possibilities as well)

Scenario A

REGULATED UTILITY		UNREGULATED AFF.	
Debt	$200	Debt	$400
Equity	$300	Equity	$100

or

Scenario B

REGULATED UTILITY		UNREGULATED AFF.	
Debt	$400	Debt	$200
Equity	$100	Equity	$300

Q **DOES IT MAKE ANY DIFFERENCE TO CUSTOMERS OF APS WHICH SCENARIO IS USED FOR THE CAPITALIZATION OF THE TWO AFFILIATES?**

A It most certainly does make a difference. There are implications for all customers. Debt financing is much cheaper than equity financing. This is true for two reasons. First, creditors have a higher claim on assets and cash flow than do shareholders, i.e., debt obligations are paid first before dividends are paid. As a result, the cost of debt is almost always less than the cost of equity. (In the parlance of regulation, the cost of equity is known as the authorized rate of return.)

Second, the cost of debt (interest) is tax deductible to a corporation, while the cost of equity (dividends) is not. The net result is that the customers of the utility are much better off with Scenario B, the more highly leveraged capitalization. It would

also be more logical for the regulated affiliate to have the higher leveraged capitalization because regulated enterprises are viewed as less risky and so can sustain that form of capitalization.

Q WHAT ARE THE IMPLICATIONS OF THIS ISSUE?

A The cost of capital is as real a cost as are salaries and depreciation. If the regulated utility gets the high cost capital and the unregulated Genco gets the low cost capital, both customers and potential competitors of APS Genco are disadvantaged by this unlevel playing field.

Q DOES THE AGREEMENT SPECIFY HOW THE REGULATED AND NON-REGULATED AFFILIATES OF APS WILL BE CAPITALIZED AFTER THE ASSET TRANSFER?

A No, it does not.

Q DID ENRON INQUIRE AS TO THIS CAPITALIZATION ISSUE?

A Yes, it did. (First Set of Data Requests from Enron Corporation, Question 6.)

Q HOW DID APS RESPOND TO THIS INQUIRY?

A The response was:

> No determination has been made as to the future funding method for APS Energy Services or the other competitive electric affiliates authorized by Article IV.

I believe this is an inadequate response to a question of this import.

1 Q **WHAT IS YOUR RECOMMENDATION ON THE CAPITALIZATION ISSUE?**

2 A Capitalization decisions could impact both customers and the financial results of APS
3 Genco. Absent divestiture, I recommend that approval of this Agreement be
4 contingent upon an affirmative showing by APS that its decisions on capitalization of
5 its affiliates do not disadvantage customers or unduly advantage its unregulated
6 affiliate. It would also be preferable if the unregulated affiliate could be prevented
7 from piggy-backing on the credit rating of the regulated utility.

8

9 Q **ARE THERE TAX ISSUES AS WELL?**

10 A Yes. APS claims that its generating plants give rise to stranded costs. This implies
11 that the actual or market value of these plants is less than the book value. If the
12 market value is also less than the book value it is possible that some of these plants
13 could be sold at a loss, giving rise to a tax loss. Rightfully, this tax loss should be
14 used to mitigate the stranded cost recovery. Under the Agreement, however, it
15 appears that any future tax loss would benefit Pinnacle West shareholders and not
16 APS customers.

17

18 Q **WHAT IS YOUR RECOMMENDATION ON TAX ISSUES?**

19 A At a minimum, the Commission should explicitly mandate that any tax losses, or
20 credits, arising from a sale of generation assets or via write-offs by the parent or any
21 affiliate of APS, be deferred and captured for the exclusive benefit of APS customers.

22

23 Q **DO YOU SEE ANY OTHER POTENTIAL FOR COST SHIFTING OR UNFAIR**
24 **COMPETITIVE ADVANTAGES?**

25 A Yes. The Agreement calls for APS Disco to be the default provider for customers
26 who either do not or cannot choose to switch. Customers would be better off if the

ACC had energy suppliers bid for that right. Another area of possible concern is the provision that APS will purchase energy from its generation affiliate at "market based" rates. However, it does not define what is meant by "market based". There are many markets—day ahead markets, spot markets, futures, and so forth. APS has the incentive to structure the transactions that will transfer as much money as possible to APS Genco.

Q HOW ELSE CAN APS UNFAIRLY BENEFIT ITS GENCO AFFILIATE AT THE EXPENSE OF ITS CAPTIVE CUSTOMERS AND/OR POTENTIAL COMPETITORS?

A Clearly, any transfer to a Genco should include all plant in service and O&M expenses that are currently classified as production related (Accounts 310 through 346 and 500 through 557). However, there may be other plant and expenses that should be assumed by the Genco, as well.

Q COULD YOU GIVE SOME EXAMPLES OF SUCH ITEMS?

A Yes. Step up generators and switching gear that are dedicated to a specific APS plant should also be transferred. A proportionate amount of Administrative and General expense and other overhead must also be assigned to APS Genco.

Q HAS APS IDENTIFIED WHAT ASSETS OR EXPENSES WILL BE TRANFERRED TO ITS UNREGULAGED AFFILIATES?

A No. (See response to First Set of Data Requests from Enron Corporation, Question 5.)

1 Q **APS WITNESS MR. DAVIS STATES THAT THIS AGREEMENT YIELDS CERTAIN**
2 **BENEFITS TO CUSTOMERS. DO THESE BENEFITS SUFFICE TO OUTWEIGH**
3 **THE PROBLEMS YOU HAVE PREVIOUSLY OUTLINED?**
4 A That is a question that the ACC must decide. However, I believe that Mr. Davis may
5 have exaggerated the benefits to customers. For example, the Agreement does call
6 for small rate reductions stretched out over the next several years for Standard Offer
7 service. However, to the extent that those reductions apply to the generation
8 component of the unbundled rate, these reductions will make it that much more
9 difficult for those customers to achieve competitive savings. Those reductions would
10 better enhance competition if they applied to the wires component of the service.
11 Moreover, even these reductions may be less than meets the eye because APS will
12 be allowed to defer some costs during this period for possible future recovery.
13
14 Q **MR. DAVIS STATES THAT APS HAS DEMONSTRATED THAT ITS**
15 **"ALLOWABLE" STRANDED COSTS, EXCLUSIVE OF REGULATORY ASSETS**
16 **ARE AT LEAST $533 MILLION, BUT THAT IT WILL ONLY HAVE A**
17 **REASONABLE OPPORTUNITY TO RECOVER $350 MILLION. DO YOU AGREE**
18 **THAT THAT IS A SIGNIFICANT BENEFIT TO RATEPAYERS?**
19 A No, I do not.
20
21 Q **PLEASE EXPLAIN WHY YOU DO NOT AGREE WITH MR. DAVIS.**
22 A In the first place, the way I read the Agreement, APS will not have just a reasonable
23 opportunity to collect the $350 million[1], it will have a virtual *guarantee* to collect that

[1]In nominal dollars APS will collect more than $350 million because the latter is a net present value figure. Also, APS will recover $686 million in regulatory assets. Consequently, its stranded cost recovery is well in excess of one billion dollars.

amount. According to Article 3.4 of the Agreement any shortfall from that amount, as calculated at the end of 2004, will be charged against a future adjustment clause. Since this $350 million would be assured by the ACC's irrevocable approval of the Agreement, it should be possible for APS to securitize this future cash flow at a lower cost of capital and retain the savings for itself and not its customers.

In the second place, I view the Agreement as granting APS more than just $350 million in stranded costs. That is because for the years 1999 and 2000, Exhibit B of the Agreement shows that only 20% of the CTC charges, normally applicable across all customers, will count toward the $350 million. Since any uneconomic costs that APS may have already included in current rates, the correct multiplier should be 100% of retail billing units, not 20%. I estimate, consequently, that the $350 million figure is understated by at least $150 million.

Finally, the claim of $533 million in stranded costs should be taken with a grain of salt. Utilities faced with retail access habitually (and understandably) exaggerate their stranded cost claims. For example, when Montana Power Corporation filed its restructuring plan with the Montana Public Service Commission in July, 1997 it claimed $161 million in stranded costs for its generating assets. It calculated its alleged stranded costs utilizing a "lost revenue" approach, similar to the manner in which APS calculated its stranded costs. Subsequently, it sold its generating assets for a sale price which exceeded the book cost of those assets by over $300 million. Thus, instead of stranded costs, it really had stranded benefits. Similarly, PacifiCorp claimed that it had between $1.4 and $2.4 billion in stranded costs relating to its generating assets. Now it has announced to the Oregon Commission that it will forego any claim for stranded costs. In another instance, Delmarva Power and Light Company claimed to have $217 million in stranded costs related to its ownership position in fossil and nuclear generating plants. It "settled" for

1 stranded costs of $50 million and is waiving its claim to collect even all of that figure.
2 I am not aware of a single utility that has seen its stranded cost claim granted in full.
3
4 Q **IS IT POSSIBLE THAT THE AGREEMENT WOULD RESULT IN APS**
5 **RECOVERING MORE THAN ANY ACTUAL STRANDED COSTS THAT IT MAY**
6 **HAVE?**
7 A Yes, that is a possibility if the Agreement is accepted. This is particularly ironic since,
8 according to Decision 60977, APS is not even entitled to 100% of stranded costs
9 absent divestiture.
10
11 Q **THE AGREEMENT ALSO CALLS FOR APS TO WITHDRAW ITS LITIGATION**
12 **OPPOSING COMPETITION. IS THIS AN ADVANTAGE TO CUSTOMERS?**
13 A Possibly, although to the best of my knowledge in only one state, New Hampshire,
14 has a utility been able to delay the mandates of the legislature and the Public Service
15 Commission. In no instance of which I am aware has a utility been able to gain a
16 court decision for an unalienable right to 100% recovery of stranded costs (absent
17 specific enabling legislation). However, regardless of the benefits of this waiver, I do
18 not believe that the threat of litigation should coerce the ACC to rubberstamp what
19 would otherwise be an unwise Agreement.
20
21 Q **DOES THIS CONCLUDE YOUR TESTIMONY IN THIS CASE?**
22 A Yes.

Qualifications of Alan Rosenberg

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Alan Rosenberg. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q **WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and am a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I was awarded a Bachelor of Science Degree from the City College of New York in 1964 and a Doctorate of Philosophy in Mathematics from Brown University in 1969. Subsequently, I held an Assistant Professorship of Mathematics at Wesleyan University in Connecticut. In the summer of 1975, I was a Visiting Fellow at Yale University. From July, 1975 through January, 1981, I was Assistant Controller for a division of National Steel Products Company. My responsibilities there included supervision of management accounting, cost accounting and data processing functions. I was also responsible for internal control, working capital levels, budget preparation, cash flow forecasts and capital expenditure analysis. From February, 1981, through December, 1981, I was Project Manager of the Steel Fabricating and Products Group, National Steel Corporation, responsible for implementing an integrated general ledger system. I have published in major academic journals and am a member of the International Association for Energy Economics.

In January, 1982, I joined the firm of Drazen-Brubaker & Associates, Inc., the

predecessor of Brubaker & Associates. Since that time, I have presented expert testimony on the subjects of industry restructuring, open access transmission, marginal and embedded class cost of service studies, prudence and used and useful issues, electric and gas rate design, revenue requirements, natural gas transportation issues, demand-side management, and forecasting.

I have previously testified before the Federal Energy Regulatory Commission as well as the public service commissions of Arizona, Connecticut, Delaware, Florida, Illinois, Iowa, Massachusetts, Michigan, Montana, New Jersey, New Mexico, New York, Ohio, Rhode Island, Vermont, Virginia and the Provinces of Alberta, British Columbia, Nova Scotia, and Saskatchewan in Canada. I was an invited speaker at the NARUC Introductory Regulatory Training Program and a panelist at a conference on LDC and Pipeline Ratemaking sponsored by the Institute of Gas Technology. I have presented a paper on stranded costs at the 21st Annual International Conference of the International Association for Energy Economics. I have also spoken at several conferences on the topic of competitive sourcing of electricity for industrial users.

In addition to our main office in St. Louis, the firm also has branch offices in Kerrville, Texas; Plano, Texas; Denver, Colorado; Chicago, Illinois; and Washington, DC.

EXHIBIT
Commonwealth
Admitted

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. R14-2-1602 et seq.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF THE 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 THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-00000C-94-165 **DIRECT TESTIMONY OF JOHN G. PATON**

On Behalf of
TUCSON ELECTRIC POWER COMPANY

NOVEMBER 20, 1998

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EXHIBITS

Exhibit A List of Recently Announced Utility Auctions

Exhibit B List of Recently Completed Utility Auctions

1 **I. Introduction And Purpose**

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A. John G. Paton, New Harbor, Inc., 280 Park Avenue, East Tower, 27th Floor, New York, New
4 York, 10017.

5 Q. WHAT IS NEW HARBOR, INC.?

6 A. New Harbor, Inc. ("NHI") is an investment bank that specializes in financial advisory
7 services for the electric, gas and water industries. The firm was founded in June 1993 and is
8 comprised of experienced investment bankers from First Boston, Kidder, Peabody, Lehman
9 Brothers, Merrill Lynch, Morgan Stanley and Salomon Brothers. Its Managing Directors
10 have accumulated over seventy years of experience in the investment banking and financial
11 advisory industry, and have worked with almost every major electric and gas utility in the
12 United States. Their collective work experience includes a broad range of assignments from
13 strategic advisory, divestiture of assets, mergers and acquisitions, bankruptcy and out-of-
14 court restructurings to project finance, equity research, and debt and equity financings.

15 Q. WHAT IS YOUR POSITION WITH NEW HARBOR, INC.?

16 A. I am currently a Managing Director. My responsibilities include directing and overseeing all
17 aspects of investment banking transactions, primarily in the strategic and restructuring areas.
18 These activities include transaction structuring, auction design, valuation, negotiations, etc.

19 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR BUSINESS
20 EXPERIENCE AS THE SAME PERTAIN TO YOUR POSITION.

21 A. I received a Bachelor of Mathematics degree in 1980 from Waterloo University in Kitchener-
22 Waterloo, Ontario, Canada. I am a Chartered Accountant, having been admitted by the
23 Canadian Institute of Chartered Accountants in 1982. I received Masters of Business
24 Administration and Bachelor of Laws degrees in 1986 from the University of Western
25 Ontario in London, Ontario, Canada.

26 I worked as a public accountant in the audit and tax area of a predecessor firm to Peat
27 Marwick Mitchell in Toronto, Ontario, Canada from 1977 through 1982. After completing
28 my graduate degrees in 1986, I joined Salomon Brothers Inc in New York City. While at
29 Salomon Brothers, I was part of the Mergers and Acquisitions Group, specializing in electric
30 . . .

and gas utilities business combination transactions, defense, restructurings and bankruptcy advisory.

I left Salomon Brothers in February of 1992 to join Barr Beatty Devlin and Co., a strategic financial advisory firm specializing in gas and electric utilities. In July 1993, Jay Beatty and I left Barr Beatty Devlin to form NHI.

Q. PLEASE DESCRIBE ANY OTHER BUSINESS EXPERIENCE OR BACKGROUND AS IT RELATES TO THE DIVESTITURE OF THE GENERATING ASSETS OF TUCSON ELECTRIC POWER COMPANY ("COMPANY" OR "TEP").

A. I have been involved in the auctioning of large generating stations on behalf of U.S. electric utilities preparing for the deregulation of the power supply function. I personally directed the auction of approximately ten thousand megawatts of gas-fired generating capacity on behalf of Southern California Edison Company. I am currently conducting the sale of the 1,340 MW Centralia, Washington coal-fired mine-mouth generating station on behalf of the eight investor-owned and municipal utility owners, in addition to several other yet to be publicly announced divestitures.

Q. PLEASE DESCRIBE ANY BUSINESS EXPERIENCE AND BACKGROUND RELATED TO ELECTRIC UTILITY DIVESTITURES.

A. During the course of my career, I have been involved in several major mergers, acquisitions, and restructurings in the utility business, including the Entergy/GSU and San Diego/SCEcorp combinations and the bankruptcy cases of Public Service Company of New Hampshire, Eastern Utilities Associates and its wholly-owned nuclear power subsidiary, and EUA Power Corporation. More recently, I have been involved in representations of El Paso Electric Company, for both its bankruptcy case and proposed merger with Central and Southwest Corporation, as well as the Official Committee of Unsecured Creditors of the Columbia Gas System, Inc., and PacifiCorp in its acquisition of PowerCor in Victoria, Australia.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary purpose of my testimony is to discuss the various methods of divestiture considered by TEP and the rationale behind the selection of sale by auction.

. . .

. . .

II. What is the Preferred Method of Divestiture for Tucson Electric Power Company?

Q. WHAT ALTERNATIVE METHODS OF DIVESTITURE WERE EVALUATED BY NHI AND TEP?

A. NHI, in conjunction with TEP, evaluated a variety of possible means of divesting the generating assets of TEP, with due regard for factors such as certainty of computation of transition costs, maximization of proceeds, fairness, efficiency and rapidity, and impact upon the competitive market. Two fundamental divestiture strategies were considered:

- Asset sale through auction
- Asset sale through negotiated private transaction

Q. WHAT IS AN ASSET SALE THROUGH AUCTION?

A. An asset sale through auction is a method of divestiture that uses a staged bidding process and allows numerous potential purchasers to participate. In general, an auction is the method that will most likely reveal the market value of an asset because it tends to draw out the largest number of potential buyers.

In light of existing uncertainties regarding the operation of the new electricity market, different potential buyers may have widely varying views of future electricity prices and the development of a direct access market. This may lead to a wide range of values attributed to the generation assets by potential purchasers. It is therefore desirable to expand the pool of potential buyers, at least initially, in order to identify buyers who value the assets most highly. By identifying and soliciting buyers who value the assets most highly, TEP will maximize the proceeds received from a sale and minimize stranded costs.

In addition to maximizing price, an auction advances other objectives, such as fairness to ratepayers, shareholders, and potential buyers. Further, an auction provides greater likelihood of convincingly demonstrating to the Commission and to other interested parties the market value of these stations.

Q. WHAT IS AN ASSET SALE THROUGH NEGOTIATED PRIVATE TRANSACTION?

A. In an asset sale through a negotiated private transaction, TEP would contact a limited number of parties for each asset and attempt to negotiate a sale through those contacts. In some contexts, a negotiated sale with one or possibly a few potential buyers may be the only realistic alternative. This may be true, for example, where there are significant restrictions on

the seller's ability to dispose of an asset, or where market circumstances are such that it is highly unlikely that more than one party would even be potentially interested in purchasing the asset. Because fewer potential buyers are involved in a negotiated sale compared to an auction, sometimes the process is easier to manage.

Q. WHAT ARE THE RELATIVE MERITS OF AN AUCTION AND A NEGOTIATED SALE?

A. So long as TEP believes that a pool of buyers exist to purchase its generating assets, the primary advantage of a negotiated sale is the manageability of the process. However, a carefully designed auction process need not preclude incorporating the more beneficial aspects of negotiation. The auction should draw out the largest number of potentially qualified and interested parties thereby ensuring the best sale price. To make the process most efficient, TEP will narrow the field of bidders based on the bidders' preliminary bid submittals. This narrowing will enable TEP to deal with a more manageable number of parties as time-intensive activities, such as on-site due diligence and discussion of contractual language, proceed. An important feature of a staged auction is that it enables multiple rounds of bidding, providing flexibility to respond to bidders' concerns as well as incentivizing bidders to increase their offers. If TEP, as the seller, is prohibited from engaging in such activities as part of the auction, this lack of flexibility might deter potential bidders from participating, and TEP might be prevented from selling the generating assets at the best price and other terms. Based upon these considerations, TEP believes that the auction process should retain considerable flexibility.

Q. WHY WAS THE AUCTION METHOD CHOSEN?

A. Both an auction sale and a negotiated sale are reasonable and justifiable methods of disposing of generating assets. NHI recommends TEP proceed with an auction sale because it is more likely to give TEP and the Commission the greatest measure of assurance regarding the consequences of the divestiture, to ensure the best price for the assets, to attract and satisfy the largest number of potential owners, and is the most consistent with the regulatory process.

. . .

. . .

Q. IS THE TRANSCO PROPOSAL WITH ARIZONA PUBLIC SERVICE ("APS") A VIABLE METHOD FOR REALIZING FAIR MARKET VALUE FOR TEP'S SHARE IN THE NAVAJO AND FOUR CORNERS GENERATING STATIONS?

A. As I have discussed previously, a negotiated sale is a viable means of realizing the fair market value of generating assets. The Transco proposal between TEP and APS has some unique aspects. which make a negotiated sale a particularly appropriate method of divestiture for the Navajo and Four Corners assets. The transmission assets of APS are an integral part of TEP's plans to become the builder and owner of transmission assets in Arizona, and cannot be obtained from a broad market solicitation of bids. Also, divesting the generating assets and acquiring transmission assets in separate transactions would be a more time consuming process than having both parties agree to the Transco proposal at this time.

III. How Will the Auction Process Work?

Q. WHAT ARE THE GOALS OF THE AUCTION?

A. TEP, in consultation with NHI, has designed its auction procedures with a focus on the goals of efficiency and price maximization, as well as fairness to all interested parties. In order to expedite divestiture, TEP has developed a streamlined, staged approach that is intended to ensure a fair auction process while preserving sufficient flexibility to allow for the maximum possible competition among potential and actual bidders for the assets that are to be sold.

Q. WHAT IS THE PROPOSED SCHEDULE FOR THE AUCTION?

A. Although TEP must retain the flexibility to alter its schedule to reflect unanticipated events, an anticipated schedule has been established to auction TEP's generating assets. The Company plans to implement a five-phase auction process, which is summarized in the following timetable (all dates are estimates only):

Phase 1	Pre-auction marketing activities	through March 1999
	Preparation of selling memorandum	
	Preparation of assets for sale	
	Buyer prequalification	
Phase 2	Distribution of selling memorandum	April through June 1999
	Receipt and analysis of indications of interest	

	Selection of short list of bidders	
Phase 3	Due diligence for short list participants	July through September 1999
	Receipt of final bids	
	Selection of winning bidders	
Phase 4	Negotiation and Execution of Documents	October through November 1999
Phase 5	Final regulatory approvals	By January 1, 2001
	Closing	

The timetable set forth above is tentative, and assumes among other things, timely regulatory approvals and the removal of material asset contingencies.

Q. WHAT IS THE COMMISSION'S ROLE DURING THE AUCTION PROCESS?

A. The Commission will be kept informed during every phase. The auction has been designed to be as robust and transparent as possible. While the bids must be kept confidential to ensure the integrity of the auction, TEP and NHI believe that the Commission must be informed of the progress of the auction.

Q. WHAT IS EXPECTED TO TAKE PLACE AT EACH STAGE OF THE AUCTION PROCESS?

A. The auction process has been designed to ensure that all bidders have the same opportunity to evaluate and bid on the generating assets. Phase 1 of the process is ongoing and will continue during the Commission's review period for this filing up until the commencement of the actual auction (Phase 2). Phase 1 activities include gathering all of the information necessary for bidders to conduct their due diligence, which will include operating, financial, environmental, legal and technical information on the generating assets. During Phase 1, NHI will assist TEP in identifying and contacting potential purchasers. TEP will also prepare a press release directing bidders to contact New Harbor in order to be included in the process. Phase 2 is the stage where initial indications of interest are provided by bidders. Potential bidders will receive copies of the Confidentiality and Auction Protocol Agreements as well as be given or have access to due diligence materials. Following the initial review period in Phase 2, bidders will be asked to submit non-binding Indications of Interest. TEP with NHI will evaluate the Indications of Interest and select a "short list" of bidders to invite into Phase 3, to conduct more extensive due diligence on the assets. The Indications of Interest will be

evaluated primarily on price, financing contingencies, financial wherewithal to complete the transaction and any necessary consents or approvals that could significantly delay a closing. Specific bidders will be invited to participate in Phase 3 and will be provided additional due diligence material, site tours, and management presentations in order to make final bids for the assets. Phase 3 will require a high level of resources and commitment from the invited bidders. At the end of Phase 3, the bidders will be required to submit their final bids. Upon receipt of the final bids by NHI and TEP, the auction will enter Phase 4 where the final bids will be evaluated on a similar basis to the Indications of Interest and winning bidders will be selected. Bidders will be required to be available to meet with TEP and NHI for final negotiations and contract execution. Phase 4 will conclude with documents executed between the winning bidders and TEP for the generating assets. In Phase 5, the last phase of the auction process, TEP will submit executed documents to the Commission for approval. The Commission will have the opportunity at this time to review the filings to satisfy itself that the auctions were done in a fair, diligent and professional manner. Any other regulatory approvals, such as FERC and the Federal Trade Commission, will be obtained in this last phase.

Q. WHAT HAPPENS AT THE CONCLUSION OF THE AUCTION?

A. The auction will actually be concluded at the end of Phase 4 when the winning bidders have executed documents for the purchase of the generating assets. At that time, Commission and regulatory approvals of the sales will be obtained. Furthermore, upon completion of the auction process, but prior to the actual sale and transfer of the assets, TEP will file appropriate form of transfer documents and proposed must-run contracts for approval by the Commission.

IV. What Are the Auction Protocols?

Q. WHAT IS THE PURPOSE OF THE AUCTION PROTOCOLS?

A. TEP and NHI have designed an auction process to attract a wide universe of qualified bidders which will result in a market determination of the value of the generation assets in a manner that is fair to the bidders, efficient in terms of time requirements and effective for TEP, its shareholders and ratepayers. The auction protocols provide potential bidders with the details of the auction process including: the auction methodology, tentative timetable, rules of

conduct, bidding restrictions, methods of allowable communication, cost responsibility and the form of bid. The auction protocols will be contained in the Confidentiality and Protocols Agreement, which each potential bidder will be required to execute prior to participating in the auction process.

Q. WHAT IS INCLUDED IN THE CONFIDENTIALITY AND PROTOCOLS AGREEMENT?

A. In addition, to containing the auction protocols, the Confidentiality and Protocols Agreement will obligate the potential bidder, its affiliates and representatives to maintain as confidential, any information, documents, data or any other material provided by TEP ("Due Diligence Material") or analyses performed by the bidder. Any such Due Diligence Material and analyses may be used by the bidder solely for the purpose of evaluating the assets. Potential bidders will be required to treat as confidential any bid or related discussions it has with TEP. Destruction of Due Diligence Material shall be certified by an officer of the bidder. Due Diligence Material provided to participants in the auction will include, among other things, a selling memorandum, any third-party environmental or engineering reviews performed for TEP in conjunction with the auction, as well as environmental, operating and technical information and data. Such information may be made available in a data room or provided directly to the potential bidder.

Q. WHEN WILL THE CONFIDENTIALITY AND PROTOCOL AGREEMENT BE DISTRIBUTED?

A. The Confidentiality and Protocol Agreement will be distributed to potential bidders at the end of Phase 1. No potential bidder will receive a Selling Memorandum on which to base initial indications of interest until the Confidentiality and Protocol Agreement has been signed and returned to TEP.

V. What Are the Current Divestiture Plans of TEP?

Q. WHICH ASSETS ARE BEING DIVESTED?

A. Bidders will have an opportunity to bid on any or all of the following Assets:[1]

[1] TEP has entered into the Settlement Agreement with the Commission Staff which will exchange TEP's interest in the Four Corners and Navajo generating stations for the transmission assets of the Arizona Public Service Company.

(i) Springerville (100% interest)

(ii) Irvington (100% interest)

(iii) San Juan (TEP's 50% interest in each of Units 1 and 2); and

(iv) TEP's combustion turbines

TEP reserves the right to bundle, or to change the bundling of the assets. Bidders will be notified of any changes and appropriate adjustments will be made to the auction timetable, if necessary, to allow for a resubmission of bids reflecting revised bundling, or for any other reason.

The Assets will include Leasehold, as well as ownership interests. The divestiture will include all ancillary agreements, operating permits, real and personal property, inventory and spare parts required to operate the Assets. TEP will retain ownership of and reserve any necessary easements for transmission facilities and associated property and lines from the facilities. In addition, because TEP will retain its transmission and distribution operations, the Company may enter into one or more joint use/management agreements with the purchasers of the Assets relating to systems or facilities necessary for the operations of each party.

Q. WHAT TEP CONTRACTS MAY BE ASSIGNED?

A. The divestiture of Assets will require the assignment or modification of several ancillary agreements. The most significant of those agreements are the coal and transportation agreements relating to Springerville and Irvington, and the project agreements relating to TEP's interests in remote generating facilities operated by other utilities.

Q. WILL TEP BE ALLOWED TO BID ON ANY ASSETS?

A. The auction process has been designed to provide all bidders access to the same information and due diligence materials regarding the generating assets. Should a TEP affiliate decide to bid on any or all of the Assets, appropriate "fire walls" will be established between the bidding affiliate and TEP personnel involved in the auction. The bidding affiliate will be required to enter into the Confidentiality and Auction Protocols Agreements modified to permit the affiliate to communicate only with NHI. The affiliate will have access to the same information and will be required to adhere to the same rules and standards of conduct as all the other bidders. Indications of interest and final bids from the affiliate will be delivered to

NHI as an independent third party, be opened first and evaluated with the other bids prior to disclosure to TEP.

VI. What Is the Current Market for Generating Assets?

Q. WHY HAVE OTHER UTILITIES CHOSEN AN AUCTION SALE?

A. As stated earlier, the most viable options considered for divestiture of utility assets are an auction sale or a negotiated sale. Each has its advantages and disadvantages. NHI recently completed the sale of generating assets for Southern California Edison ("SCE") through an auction process. The reasons SCE chose to do an auction are similar to the reasons that NHI has recommended TEP proceed with an auction: provide the greatest measure of assurance regarding the consequences of divestiture, ensure the best price for the assets, to attract the largest number of potential bidders, and to avoid unnecessary delay. NHI is currently conducting an auction for the 1340 MW Centralia Generating Station, in the State of Washington, for these same reasons.

Q. WHAT ARE SOME OF THE OTHER UTILITY AUCTIONS THAT HAVE BEEN ANNOUNCED?

A. Across the country, the electric utility market is undergoing substantial and fundamental changes. Many states, like Arizona, are strongly encouraging their traditionally integrated electric utilities to separate into non-regulated generating companies and regulated transmission and distribution companies. Most utilities have chosen to date to sell their soon to be non-regulated businesses including generation, and used or plan to use an auction process in almost every case. Fifteen utilities, including TEP, have announced intentions to divest some or all of their generation assets. The total megawatts for sale are approximately 38,000 MW of which 15,000 MW is coal. The two utilities with announced impending auction sales nearest TEP are Nevada Power and PG&E (California). Exhibit A lists the announced, but not completed, utility generation divestiture activity in the U.S.

Q. WHAT IS THE LIKELIHOOD OF A SUCCESSFUL AUCTION BY TEP?

A. Over the past two years, the market has been robust for domestic generating assets. Approximately 15 utilities have sold mostly gas-fired generating assets for prices from less than one to over five times book value. The five coal-fired facility sales included in the above group yielded proceeds in the range of one to over three times book value. A list of

the generating assets that have been sold in the past two years is provided in Exhibit B. There is currently little generation sale activity in the Southwest. That lack of activity should make potential bidders interested in the auction, and the prices recently obtained for generation assets have been attractive. Accordingly, we believe there is a high likelihood the auction process proposed by TEP will result in the realization of the maximum value for its generating assets.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit A

List of Recently Announced Utility Auctions

Seller	Timing	Fuel Type(s)	Total Capacity (MW)	Coal Capacity (MW)
Central Hudson	By Q2.01	Coal, Gas, Oil	972	366
Con Edison	By Q1.99	Gas, Oil	3,665	0
Duquesne	Early 1999	Coal, Nuclear, Oil	3,035	2,138
ENOVA	By Q4.98	Gas, Oil, Nuclear	1,897	0
Nevada Power/ Sierra Pacific Resources	NA	Coal, Gas, Oil, Hydro	2,725	1,343
NIMO	By Q4.98	Coal, Gas, Oil, Hydro	4,217	1,300
Northeast Utilities	By Q4.98	Coal, Gas, Oil, Hydro	3,482	NA
Orange & Rockland	By Q2.99	Coal, Gas, Oil, Hydro	984	460
PacifiCorp (Centralia)	By Q4.98	Coal	1,340	1,340
PG&E	1998	Gas, Oil, Geothermal	4,289	0
Plains Electric G&T Cooperative	1999	Coal, Gas	278	250
Portland General Electric	By 1998	Coal, Gas, Oil, Hydro	3,363	712
Unicom (CWE)	By Q3.99	Coal	5,576	5,576
Unisource (Tucson Electric)	By Q1.01	Coal, Gas	1,992	1,182
Western Massachusetts Electric	By Q1.99	Oil, Gas, Hydro	290	209
			38,150	14,876

Exhibit B

List of Recently Completed Utility Auctions

(Dollars in millions, except price per kW)

Date Ann.	Buyer	Seller	Plant	Type	Net MW	Total Price	Book Value	Price/kW	Price to Book
11/09/98	Sithe Energies	GPU	23 power plants and 18 generation development properties	Various	4,117	$1,680	$791	$408	2.12
11/09/98	FirstEnergy	GPU	20% interest in Seneca hydroelectric generating station	Hydro	87	43	11	494	3.98
11/02/98	PP&L Global	Montana Power	11 Hydroelectric plants, 2 Coal-fired plants	Hydro, Coal	1,556	988	637	635	1.55
11/02/98	PP&L Global	Puget Sound/Portland General	1058-MW interest in Montana Power's 4-unit Colstrip Plant	Coal-fired	1,058	598	464	565	1.29
10/15/98	NRG	Eastern Utilities Associates	Somerset Station (160 MW)	Various	160	55	31	344	1.80
10/02/98	Wisconsin Energy	United Illuminating	Bridgeport Station Harbor Station (590 MW oil & coal), New Haven Harbor Station (466 MW oil & gas)	Various	1,056	272	218	258	1.25
09/28/98	PP&L Global	Bangor Hydro-Electric Company	8 hydro units, and Wyman Unit 4 (52 MW share)	Hydro, Oil	89	89	49	998	1.80
08/03/98	AES Corporation	NYSEG Generation	Kintigh Station (675 MW), Milliken Station (300 MW), Greenidge Station (160 MW), Goudey Station (125 MW), Hickling Station (70 MW), and Jennison Station (70 MW).	Coal-fired	1,400	950	886	679	1.07
08/03/98	Edison Mission	GPU & NYSEG	1,884-MW Homer City Electric Generation Plant	Coal-fired	1,884	1,800	540	955	3.33
07/07/98	WPS Resources	Maine Public Service	Wyman Unit 4 (20.7 MW share), several small diesel and hydro plants.	Various	91.8	37	12	406	3.20
05/27/98	Southern Energy Inc.	Commonwealth Energy System	Canal Unit 1, Canal Unit 2 (50% interest), five diesel generators, Kendall Station, Kendall Jets, 1.4% interst in Wyman Unit 4	Various	984	462	79	470	5.85

03/25/98	Houston Industries	Southern California Edison	(1)	Ormond Beach	Gas-fired	1,500	40	141	27	0.28
02/04/98	NRG/Destec	Southern California Edison	(1)	Long Beach	Gas-fired	530	30	98	56	0.30
01/06/98	FPL Group	Central Maine Power		91 hydro units (373 MW), 31 MW of wood capacity and 781 MW of fossil-fueld (3 plants)	Various	1,185	846	240	714	3.53
12/10/97	Sithe Energies	Boston Edison		Mystic, New Boston, L Street, Edgar Framingham, West Medway, Wyman	Oil & Gas	1,987	536	450	270	1.19
11/24/97	AES	Southern California Edison	(1)	Alamitos, Huntington Beach, Redondo	Gas-fired	3,956	781	228	197	3.42
11/24/97	Houston Industries	Southern California Edison	(1)	Coolwater, Mandalay, Ellwood, Etiwanda	Gas-fired	2,276	237	127	104	1.87
11/24/97	NRG/Destec	Southern California Edison	(1)	El Segundo	Gas-fired	1,020	88	71	86	1.23
11/24/97	Thermo Ecotek	Southern California Edison	(1)	San Bernardino and Highgrove	Gas-fired	280	10	-6	34	NM
11/18/97	Duke Energy	PG&E		Morro Bay, Moss Landing, and Oakland	Gas-fired	2,645	501	380	189	1.32
08/07/97	US Generating	NEES		3 thermal plants, 15 hydro-electric 23 power purchase contracts	Various	5,100	1,590	1,100	312	1.45
10/31/96	Allegheny Power	Duquesne Light & Power		Fort Martin (50% interest of unit one)	Coal-fired	276	170	45	616	3.78

EXHIBIT
Enron-2
admitted

PREPARED DIRECT TESTIMONY OF MARK W. FRANKENA ON BEHALF OF ENRON CORP.

June 30, 1999

I. QUALIFICATIONS

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

A. My name is Mark W. Frankena. I am a Principal at Economists Incorporated, an economics 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. I have worked on the proposed merger of Central and South West and American Electric Power on behalf of counsel for the former. In addition, I have worked on competitive analyses of several mergers between electric and gas companies.

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. Also, 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. 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.

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. My 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 Enron Corp. (Enron).

Q. Which issues did Enron ask you to analyze and address in this testimony?

A. Enron asked me to analyze and testify on the following issues:

- Is it likely that Arizona Public Service Company (APS), alone or with other owners of electric generating capacity, has significant generation market power in Arizona?

- Does the May 1999 proposed Settlement Agreement between APS and certain other parties mitigate whatever generation market power APS is likely to have in Arizona?

Q. Have you previously analyzed and prepared testimony on market power in the electric power industry in Arizona?

A. Yes. During November 1998 I analyzed market power in the electric power industry in Arizona on behalf of the Arizona Office of the Attorney General, and on November 30, 1998, the Office of the Attorney General submitted my prepared testimony in the Arizona Corporation Commission (ACC) proceeding on the then-proposed settlement agreements between APS and Tucson Electric Power Co. (TEP) and the ACC staff, respectively.

Q. What is the relationship between your present testimony and your November 1998 testimony on behalf of the Office of the Attorney General?

A. The facts and analyses are virtually identical. Enron did not ask me to carry out additional empirical studies. The scope of my present testimony is narrower than that of my November 1998 testimony, and I have modified the testimony as appropriate because of the differences between the 1999 APS Settlement Agreement and the 1998 settlement agreements.

III. SUMMARY OF FINDINGS

Q. Please summarize your principal findings regarding generation market power in Arizona.

A. I have reached four principal conclusions based on my preliminary analysis of generation market power in Arizona and my understanding of the May 1999 APS Settlement Agreement:

- First, there are load pockets in the Phoenix and Yuma areas. The Phoenix area is 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. It is likely that prices for electric power in these load pockets will be raised significantly above competitive prices during a significant number of hours of the year as a result of the exercise of market power.

- Second, further investigation may show that there are additional relevant geographic markets for electric capacity and energy larger than the load pockets just discussed but still small enough so that APS, SRP and TEP would have substantial shares and concentration would be high. A potential example would be a Southern 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, SRP and TEP are likely to have market power in it.

- Third, the APS Settlement Agreement has no significant effect on existing generation market power. It leaves the ownership structure of generating capacity in Arizona unchanged, except that APS's generating capacity would be owned by an unregulated affiliate. Market shares and ability and incentives to exercise generation market power will not be affected by this change.

- Fourth, the APS Settlement Agreement does not mitigate APS's unilateral generation market power and does not reduce the likelihood of exercise of generation market power through coordinated behavior by two or more parties in Arizona. This is particularly troubling, because acceptance of the APS Settlement Agreement would foreclose opportunities to mitigate generation market power relating to APS's generating plants. This is true for two reasons. First, the principal leverage that regulators and legislators have over restructuring arises from their ability to influence the extent to which utilities are able to recover alleged stranded costs. Once agreement is reached on stranded costs, that leverage is gone. Second, the Settlement Agreement includes language that would allow the output of the APS generating plants to be sold at market-based prices regardless of generation market power, and would substantially prevent the ACC from taking a wide variety of actions that might otherwise be used to reduce generation market power problems. The ACC should not accept such restrictions on its future ability to act in the public interest in dealing with market power problems that clearly do exist and which for the most part, to the best of my knowledge, have not yet been carefully analyzed. No such analysis is included in the testimony of Dr. John H. Landon on behalf of APS, and its other witnesses do not purport to address the subject.

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 to this testimony, which is incorporated by reference.

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 that market. In addition, if two or more sellers each have 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 because incentives for efficiency are muted), 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, which is attached.

Q. What is generation market power?

A. Generation market power is the ability of one, two, or more sellers profitably to raise prices of electric power by reducing the output from their generators or raising the prices at which they offer power. For a further discussion, see the section entitled "Horizontal Market Power" in Chapter 5 in Exhibit B.

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). 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, forthcoming in *The Antitrust Bulletin*.)

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.

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 and ancillary 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.

- *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. Such markets are susceptible to market power problems.

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 generation market power?

A. For each relevant product (for example, 1999 summer peak electric energy) one delineates the geographic market or markets 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. Typically, when one is analyzing 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 potentially constrained paths or interfaces. However, when imports into an area are constrained, it may be appropriate to allocate market shares based solely on generation resources within the constraints. Computation of market shares and concentration is discussed further in the section entitled "Market Shares and Concentration" at pages 39-41 of Exhibit B.

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 APS generators compete in selling this product?

A. One applies the hypothetical monopolist test, which is used to identify the generating units that significantly constrain prices charged by each ~~generator~~ APS generator. The scope of the geographic market may depend 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~~ is relevant to the analysis. Simulation models are discussed at pages 42-45 of Exhibit B.

Q. In the time available to you, have you been able to delineate 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 two load pockets within Arizona that contain APS generating units is a separate geographic market during high load hours of the year. The load pockets in question are the Phoenix and Yuma areas. The existence of these load pockets is demonstrated by APS documents.

I have not had enough time to determine whether, for purposes of analyzing generation market power over electric 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. This is an issue that requires further investigation.

B. Documented Load Pockets within Arizona that Contain APS Generating Units

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 contain APS generating units.

A. There are two well-documented load pockets in Arizona that contain APS generating units: (1) the Phoenix area load pocket and (2) the Yuma area load pocket. A map depicting these and other load pockets in the Southwest is provided as the first page in Exhibit C. 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, while the Northwest New Mexico generation pocket is based on an export limit.

1. 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 D to this testimony. 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 was a load pocket as of 1997-98. The same documents describe the Yuma area load pocket. See also APS response to AG Set 3 No. 14 (Exhibit E).

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

A. According to the aforesaid APS documents, as of 1998 the Phoenix area was a load pocket between 400 and 460 hours annually during the summer (Exhibits D and E). 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 1 lists the generating units in the Phoenix area load pocket:

Table 1

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 D 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.

Q. Are you aware of any plans to build additional generating capacity in the Phoenix area load pocket?

A. Yes. On April 29, 1999, Pinnacle West Capital Corp., the parent of APS, and Calpine Corp. announced a partnership to develop a 500 MW natural-gas fired combined cycle generating plant at APS's West Phoenix site. According to the press release, "The joint project is the second phase of a potential 750-megawatt expansion at West Phoenix. The first phase of the expansion includes a $60 million repowering of an existing unit to create a 130-megawatt combined cycle unit. The remainder of the expansion involves repowering other existing units at the site....Construction is scheduled to begin in mid-2000 with commercial operation of the 130-

megawatt unit in mid-2001 and the 500-megawatt plant in late 2001." (Exhibit J)

Q. What effect will these plans for additional APS generating capacity in the Phoenix area load pocket have on APS's market share in that load pocket.

A. APS's market share will increase when the projects are completed.

2. Market Power in the Phoenix Area Load Pocket

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

A. Yes. During 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 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.

C. Geographic Markets Larger than the Phoenix and Yuma Area Load Pockets

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 electric capacity and energy?

A. There are two potential bases for an area such as Southern Arizona or Arizona to be a geographic market for purposes of analyzing generation market power.

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

A. In principle, a Southern Arizona or Arizona geographic 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 B. Some of the potential paths or interfaces in or near Arizona that could be congested are identified in Exhibit F, 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 C, E, and G through I. Given sufficient congestion, *including congestion induced by responses to the exercise of market power*, a hypothetical monopolist of generation in Southern Arizona or Arizona may have the ability profitably to raise prices in Southern Arizona or Arizona by reducing output from generators inside the interfaces in question. In that case, Southern Arizona or Arizona would be a relevant geographic market.

The Tucson area is a load pocket (Exhibit I). 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 area load pocket is congested, there could be a geographic market consisting of Arizona minus the Tucson area.

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

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

congestion

- 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*. See also the DSTAR O/I Workgroup map entitled "Constrained Paths and Congestion Zones for Desert Star." (All documents cited are in Exhibit C.)

- For a number of paths on the APS and SRP transmission systems, as of November 1998 firm available transmission capability (ATC) posted on OASIS had been zero in the recent past and was zero for the coming year. Information on these ATCs is available in DSTAR O/I Working Group *Status Report* (Exhibit C), in ATC data supplied by APS from its OASIS site (Exhibit G), and in *Western Interconnection Biennial Transmission Plan*, May 1998, pages 51-52 (Exhibit H). 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 E)). 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 and schedules from being accepted.

- 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 E); Exhibit F), which is approximately equal to the summer peak load of APS alone.

- As of December 1998, the California Power Exchange (CALPX) Internet site (www.calpx.com) included a page entitled "Network Model and

Congestion Zones," which I interpret to be a map showing the geographic zones that presumably CALPX thought might have different day ahead prices for electric energy (Exhibit F). While I have not investigated the extent to which prices actually have been or are likely to be different in the various zones delineated by CALPX, I note that Arizona appears to be divided into six different zones (AZ, AZ3, AZ5, LC1, LC2, and LC3).

Q. Have you found any information consistent with the view that at present transmission paths into and out of Arizona may be congested during a limited number of hours?

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 loads grow or 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 Southern 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 both area A and area 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. This is true because a hypothetical monopolist that owned all generators in area A could raise prices in that area by 20% ($4/MWh) 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 the context of Arizona, one factor that may reduce concentration in the potential markets that I have just described is joint ownership of plants in which APS and/or TEP have a share. According to TEP's 1998 response to AG Set 3 No. 22, transmission costs to any customer are the same for all owners of a jointly owned plant.

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," which has been accepted for publication in *The Antitrust Bulletin*. I prepared that paper for the Edison Electric Institute, which submitted the paper to FERC.

Q. Have you reviewed the following study?

- "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).

A. Yes, I have.

Q. Does this study use a sound methodology for delineating relevant geographic markets for purposes of evaluating restructuring of the electric power industry?

A. No, it does not. It uses FERC's hub-and-spoke methodology. For each wholesale customer, APS delineates 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 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 hub-and-spoke analysis sheds no light on market power.

Q. Are data on wholesale purchases and sales of electric power that are reported by APS 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 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 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 was 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 that 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 in FERC Form 1 are with power marketers, and

data on these transactions are not helpful in identifying competing generating plants.

VII. 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 is "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 and energy likely to be easy in Arizona?

A. No. This is true both because of time requirements for entry into markets for energy 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.

I note, however, that PP&L Global's plans to build the Griffith Energy Project, a 520 MW gas-fired power plant near Kingman, Arizona, about 50 miles south of Lake Mead, were approved in September 1998 by the ACC's Siting Committee. Also, as I have discussed above, Pinnacle West and Calpine have announced plans to expand generating capacity at West Phoenix. (Exhibit J)

VIII. APS's Commitment on Pricing for Standard Offer Service

Q. Would commitments made in the APS Settlement Agreement regarding prices for standard offer retail electric service until mid-2004 prevent the exercise of generation market power by APS?

A. No. For example, such commitments would not prevent APS from raising wholesale prices as well as retail prices for customers that do not take standard offer service. Also, an increase in wholesale prices would be likely to lead to an increase in retail prices for customers that are in relevant geographic markets but outside the APS service territory.

Q. Does this conclude your prepared direct testimony?

A. Yes.

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ADDRESSING MARKET POWER

THE NEXT STEP IN ELECTRIC RESTRUCTURING

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4 WHAT IS MARKET POWER?

As background for the discussion of market power in the electric industry, this chapter introduces the economic principles of competition and market power. This introduction explains how competitive markets benefit consumers, the nature of market power, and why market power matters.

CONSUMER BENEFITS FROM COMPETITIVE MARKETS

In a competitive market, sellers take market prices as given and expand production and sales as long as the cost of producing and delivering an additional unit is less than the market price. Sellers behave in this way because they cannot profitably raise the market price by reducing the output they supply. A market is likely to be competitive if there are many sellers or if entry of new sellers is easy.

In the United States, there is a public policy preference for competitive markets. Competitive markets generally lead to an efficient allocation of resources and the highest possible level of economic well being for society as a whole. The "invisible hand" of the market leads sellers who are pursuing profits to be responsive to consumers and to supply the goods and services that have the greatest value to them, given limited resources. Prices, profits and losses provide sellers with appropriate incentives to enter or exit markets, expand or contract capacity, and increase or reduce output in response to continuing changes in consumer preferences and incomes, technology, and resource costs. The benefits to consumers from competitive markets provide the rationale for restructuring the electric power industry and deregulating segments of the industry that are, or that can be made, competitive.

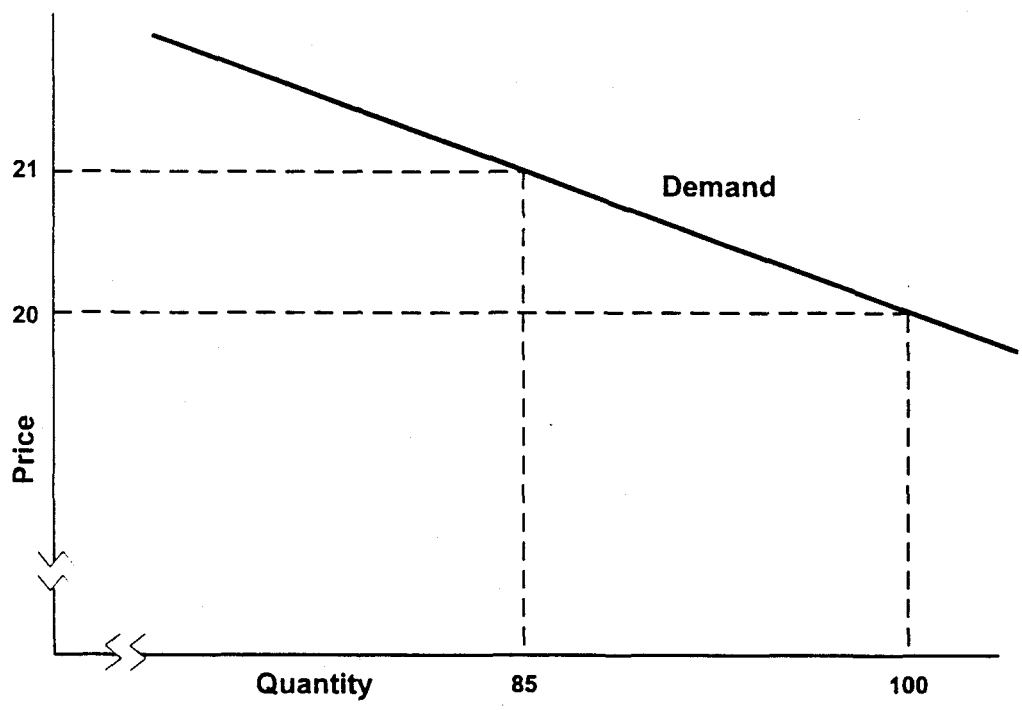
While competitive markets have many virtues, there are situations in which society may not prefer unfettered competitive markets. This may be the case when activities have effects outside markets as they are traditionally defined. For example, competitive markets may not maximize consumer economic well being without government intervention when activities have serious environmental effects. Adverse environmental effects may be brought within the market through appropriate assignment of property rights, such as rights to air quality. Absent action to induce companies to take environmental effects into account, companies in an industry that causes pollution are likely to produce each unit of output in a manner that causes too much pollution and, under competition, to produce too many units of output.

MARKET POWER DEFINED AND ILLUSTRATED

The key feature of competitive markets is that sellers cannot profitably raise prices by reducing the amounts they supply. Market power is defined as the ability of one or more sellers profitably to raise prices above competitive levels for a significant period of time. A market is not competitive when sellers have market power.

The first step in understanding market power is to recognize that a supplier will sell fewer units of output if it charges a higher price, because some buyers will decide to do without the product or switch to substitutes. The demand for a supplier's output can be represented by a Demand curve, such as the one in Figure 1. Referring to the graph in Figure 1, we see that, if the seller offers its output at a price of $20 per unit, it will sell 100 units; at a price of $21, it will sell 85 units.

Figure 1. Illustrative Demand Curve.



This example assumes that the seller starts by quoting a price. However, one could also think of the same seller as starting by delivering some number of units of output to the market and selling them for the highest price at which all would be

purchased. In Figure 1, if the seller delivered 100 units of output to the market, the seller could obtain $20 per unit. If the seller instead delivered only 85 units to the market, the price would be $21.

To determine whether a seller has market power, one can perform the following experiment. Start with the level of output the seller would supply if it behaved competitively. Now suppose the seller began to reduce its output. If it could reduce output to zero without bringing about an increase in the market price, clearly the seller has no market power; this would be the case if the Demand curve were horizontal.

Now suppose a seller faces a demand curve like the curve in Figure 1. In this case, if the seller reduced its output, the market price would increase. But this fact alone is not sufficient to demonstrate that the seller has market power. To conclude that the seller has market power, one must determine that the effort to raise the market price would *increase the seller's profits.* And this depends on whether the profit on sales of fewer units at the higher price exceeds the profit on sales of more units at the lower price.

We can make that calculation in this example. Referring again to Figure 1, suppose the seller would sell 100 units at a price of $20 per unit if the seller behaved competitively. Let's assume that the cost of producing each of these units is $16. To raise the market price by one dollar to $21, the seller would have to reduce its output to 85 units. In this case, the seller would earn an additional $85 on the output it would continue to sell, that is, an extra dollar on each of 85 units. However, it would forego profits of $60 on the output that it would no longer sell, that is, a $4 profit (the competitive price of $20 minus the unit cost of $16) on each of 15 units. Thus, the net effect of the price increase and the output reduction would be to increase the seller's profits by $25, i.e., $85 minus $60.

In this hypothetical example, the seller can *profitably* raise prices above competitive levels, and therefore the seller has market power. However, if the demand curve in the hypothetical were changed so that the seller had to reduce its output to 75 (rather than 85) in order to raise the price by $1, the seller acting alone would not have market power. In this case, the seller's profits would decline by $25 if it tried to raise the market price by withholding twenty-five units, and hence the seller would not have an incentive to raise prices. One conclusion that can be drawn from this discussion is that the existence of market power depends on several factors, including the cost structure of the seller and the demand curve of the buyers.

In order to analyze market power correctly, it is important to understand that companies cannot simply insist upon high prices by virtue of being big. The quantity of a product purchased by consumers depends on the price. Therefore, a company that charges a higher price will sell fewer units of output and may earn lower profits.

In sum, a firm with a large market share that attempts to raise the price of a product may find it profitable to take one of the two following actions, which are equivalent:

- Reduce its output (below the competitive level) in order to raise the price (above the competitive level).
- Raise its price (above the competitive level), even though this involves a reduction in sales (below the competitive level).

If a firm finds such actions profitable, we say it has ***market power***.

UNILATERAL MARKET POWER AND COLLUSION

Market power may be exercised by a single company or by two or more companies acting simultaneously. Companies may exercise market power simultaneously without an agreement to limit competition, or they may reach an agreement to *collude*. Collusion is *tacit* if the agreement is reached without overt communication or sharing of profits. A colluding company forgoes profitable opportunities to increase sales because it understands that, if it were to cheat on the agreement, other colluding companies would punish it by taking steps that would lower its profits.

The following hypothetical illustrates how tacit collusion could operate in a market for electric energy during some hours of the year. Suppose that Utility A and Utility B each have a 500 megawatt (MW) generator with variable costs of $25 per megawatt-hour (MWh), as well as other generators with lower variable costs. Assume that these two 500 MW generators are the only units in the market with variable costs between $25/MWh and $28/MWh.

Even without overt communication, Utility A and Utility B could arrive at a mutually profitable understanding that each would withhold the output of these generators from the market until the market price reached $27.95/MWh. The result of such a tacit agreement would be that, during hours in which these 500 MW generators would be the marginal (highest variable cost) units operating in the market, the market price would be nearly 12% above the competitive level of $25/MWh.

It is worth repeating that this understanding does not require an explicit agreement. If Utility A was a slow learner, or cheated on the understanding, and produced energy from its 500 MW generator when the market price was, say, only $27/MWh, Utility B could teach Utility A a lesson by running its own 500 MW generator at an even lower price, reducing Utility A's profits. Utility A would

quickly conclude that it would achieve higher profits by withholding supply. Acting in this way, Utilities A and B would be tacitly colluding to exercise market power.

WHY MARKET POWER MATTERS

When an electric generating company exercises market power, buyers pay higher prices for electric power. Consumption patterns are distorted — too little electric power is consumed. In addition, costs of generation are increased for society because some efficient generating units belonging to the company exercising market power are not used while less efficient units owned by others are used instead. Also, companies that do not face vigorous competition are apt to be less vigilant about cutting costs and to have lower productivity. Such companies are also less responsive to consumers.

When Firms Have and Exercise Market Power

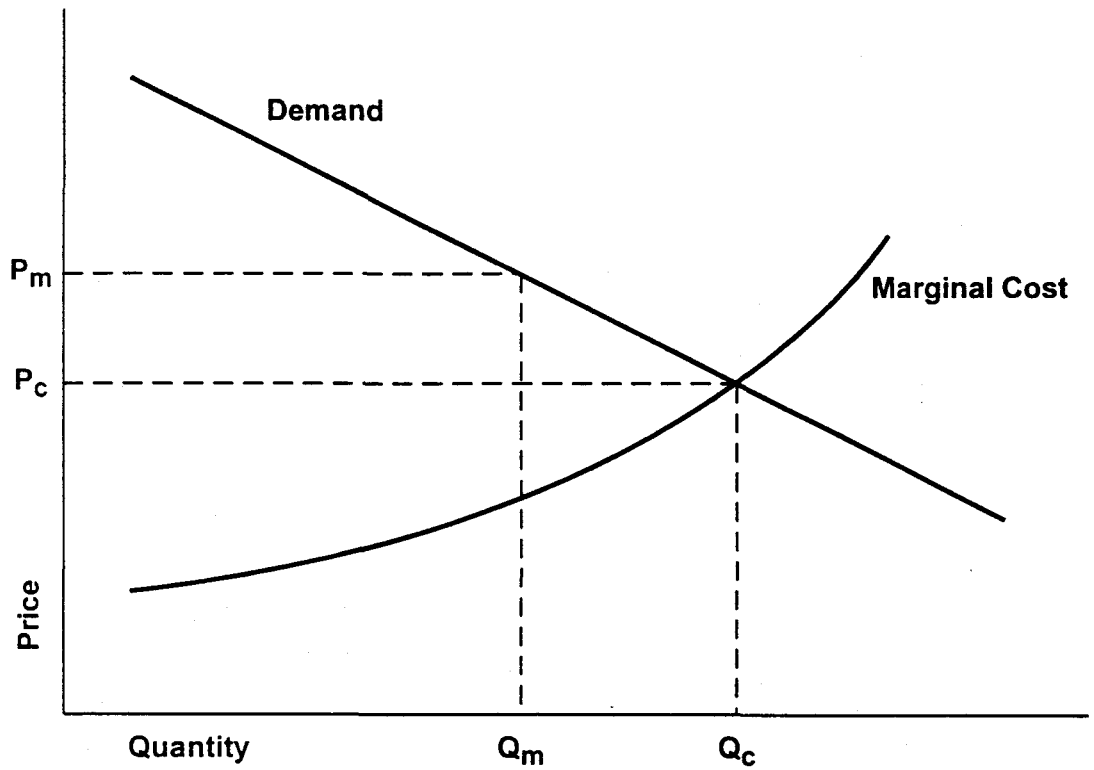
- Prices are too high
- Consumption is distorted
- Firms have lower productivity
- Firms are less responsive to consumers

Market power in the electric power industry is a critical public policy issue because of the role of the industry in the economy. The electricity sector is the nation's most capital intensive industry; the book value of capital investment was nearly $700 billion in 1994. Retail expenditures on electricity amount to $212 billion annually in the United States. (DOE 1998) Purchases of electricity are a major budget item for consumers, businesses, government and others. As a result, market power injures consumers who pay higher electric bills, higher prices for goods and services produced using electricity, and higher taxes to pay for government services.

Figure 2 illustrates the problem of monopoly pricing. The height of the Demand line at any output level expresses how much consumers are willing to pay for an additional unit of service. The height of the Marginal Cost curve represents the incremental cost of producing an additional unit. If the industry were competitive, the price would equal P_C and output would equal Q_C. That is, the price would equal the incremental cost of the last unit of output produced. Because no consumer would be willing to pay enough for another unit of service to cover its costs, the "right" output is produced.

In contrast, a monopolist charges a price of Pm and produces an output of Qm. The units of service between Qm and Qc are not produced by the monopolist even though the amount that consumers are willing to pay for each of these units (the height of the Demand line) is greater than the incremental cost of supplying them (the height of the Marginal Cost curve). In short, the monopolist does not produce enough output and charges too high a price.

Figure 2. Monopoly Pricing.



Electric restructuring should lead to lower costs, better customer service, and lower average prices for electric power. However, the extent of these benefits depends on whether restructuring programs produce competitive markets or tolerate market power.

5 MARKET POWER IN THE ELECTRIC POWER INDUSTRY

Electricity prices — and therefore the benefits that are anticipated from electric restructuring — depend importantly on whether restructured markets for electric power are competitive. Consequently, it is critical for legislators, regulators and antitrust authorities to evaluate market power using sound methodologies. While the basic principles of market power analysis apply to all industries, the application of these principles depends on the individual characteristics of an industry. This chapter discusses characteristics of the electric power industry that make market power analyses complex, and then addresses ways in which market power may be exercised in the electric power supply industry.

WHAT MAKES ELECTRIC POWER MARKETS COMPLEX?

Assessment of competitive conditions in markets for electric power is complicated by a number of characteristics of the industry (Frankena 1996):

- Competitive conditions — including the geographic scope of competition, which types of generating units can compete, and price levels — differ substantially across seasons of the year and hours of the day. As a result, an accurate assessment of market power typically requires separate analyses for several representative periods during the year.

- Electric power is a network industry in which some activities have natural monopoly characteristics and other activities have competitive characteristics. In today's electric power industry, there are substantial amounts of common ownership between these vertically related monopoly and competitive activities.

- Networks that are used to transmit electric power have unique properties. Unlike the telephone network, the electric transmission grid is not a "switched" network; energy cannot be directed from a generator to a buyer along a particular path. Instead, energy flows along multiple paths without regard to ownership or contracts. Also, the capacity of the grid to transmit energy is subject to constraints imposed by system reliability requirements. Attempts to define and measure transmission capacity and to regulate its availability to third parties face great difficulties. In addition, some generating units must operate to maintain voltages on the transmission system to ensure system reliability.

- The ability and incentives of vertically integrated utilities to raise wholesale prices during a "transition" period lasting for at least several years will depend

on the details of state restructuring programs. The effects of higher wholesale prices on a utility's profits will depend on the timing and extent of retail customer choice, provisions for retail rate reductions and freezes, and mechanisms adopted for recovery of stranded costs.

These complicating characteristics of the electric power industry help to explain why methodologies used to assess market power in the industry are constantly being improved.

How Market Power May Be Exercised in Electric Power Markets

In this section we describe the variety of incentives and opportunities electric utilities may have to act in an anticompetitive manner. The purpose of this exploration is not to indict the industry, but rather to suggest the range of market power problems with which legislators, regulators and antitrust authorities must grapple.

Horizontal Market Power

For expository purposes, it is useful to begin the discussion of how market power may be exercised with the assumption that companies in the electric power supply industry are not vertically integrated. (Issues that arise because of vertical integration will be considered below.)

Absent vertical integration, the companies involved at each step of production and delivery — fuel supply, generation, transmission, distribution, and marketing — would be independent. In such an industry, a company would generally exercise any market power it might have by reducing its output below the competitive level (or raising its offer prices above the competitive level) in order to bring about an increase in the market price. The term *horizontal market power* refers to this way of exercising market power.

Of the various stages of production and distribution of electric power, generation receives the greatest attention in assessments of horizontal market power. The Federal Energy Regulatory Commission (FERC) focuses heavily on horizontal market power in generation — also called *generation market power* — in evaluating applications for market-based pricing and for approval of mergers. Generation market power is exercised when a company that owns generating plants brings about an increase in market prices for electric power by reducing the output of its generators or — equivalently — by raising the prices at which it offers to supply wholesale power.

When a company reduces the output of its generators, market prices will increase until other companies with higher-cost generators find it profitable to supply

additional output to replace output withheld by the company exercising market power, or until buyers sufficiently reduce their consumption. A company may achieve the same result by raising the prices at which it offers power — for example, the prices it bids into a power pool. If a company raises its prices, it will sell less, and market prices will increase until other suppliers (with higher costs) find it profitable to supply additional output to replace the power no longer being supplied by the company exercising market power.

Recall that a firm will withhold output in this manner only if doing so increases its profits. The underlying condition for generation market power is this: a company that owns a large share of the generating capacity in a market may have an incentive to reduce the amount it sells in order to raise the prices at which it sells its remaining output.

While evaluation of horizontal market power in generation often receives careful attention in restructuring proceedings and merger evaluations, it is now typical for regulators simply to assume that transmission and distribution companies are natural monopolies and hence have horizontal market power. It is also typical to assume that, absent vertical integration, an adequate way to deal with horizontal market power in transmission and distribution is to regulate prices for wires services. This current approach to horizontal market power represents a change from several years ago. At that time, generation market power was largely ignored and attention was focused on the effects of electric utility mergers — such as the abandoned merger of Southern California Edison (SoCal Edison) and San Diego Gas & Electric (SDG&E) — on competition in transmission (Frankena and Owen 1994, Chap. 4).

A different issue of horizontal market power is raised by mergers between electric and gas distribution utilities with overlapping retail territories, and also when an electric distribution utility proposes to merge with a gas pipeline that can influence the price of gas sold to customers of the electric company. Electricity and natural gas compete for some uses, such as space heating and cooling, water heating, and cooking. By reducing competition between electricity and gas, electric-gas mergers may increase horizontal market power over energy, defined broadly to include both electricity and natural gas (*Id.*, pp. 130-33).

Vertical Market Power

A number of additional potential market power problems arise when a company operates at two or more stages — fuel supply, generation, transmission, distribution, and marketing — in the production and delivery of electric power. These additional problems are termed *vertical market power* because they involve two or more stages in the supply chain. For expository purposes, vertical market power will be discussed in the context of a parent company that owns subsidiaries

that are engaged in different stages of production and delivery. (Other organizational forms, such as unified companies operating at more than one stage, as well as joint ventures, can also give rise to concerns about vertical market power. However, the essential issues can be illustrated with the parent/subsidiaries model used here.)

Vertical market power can arise when one subsidiary has a monopoly (usually a regulated monopoly) at one stage and a second subsidiary is engaged in a competitive (usually unregulated) activity at another stage. Three vertical combinations that may raise concerns are shown in Table 1.

Table 1. Vertical Combinations that May Raise Competitive Problems.

Monopoly Activity	Related Competitive Activity
Electric transmission	Generation, wholesale marketing
Electric distribution	Retail marketing
Natural gas pipelines, coal mines	Electric Generation

These and some other vertical combinations raises concerns about several interrelated forms of potential affiliate abuses, particular the following:

- Discrimination in access to monopoly facilities.
- Other actions to raise costs and reduce availability of inputs used by non-affiliated competitors.
- Improper information sharing.
- Cross-subsidization and self-dealing.

Such abuses may increase market power or the extent to which market power is exercised, in addition to raising other concerns. Some abuses may enable the company to bring about price increases in potentially competitive markets by raising rivals' costs and foreclosing competition. Cross-subsidization and self-dealing raise market power concerns because a firm engaging in such behavior may thereby evade regulations intended to prevent anticompetitive pricing for the monopolized activity, distorting conditions in two markets.

We begin the discussion of market power problems raised by vertical combinations by focusing on discrimination and other actions that adversely affect the price and non-price terms on which inputs are available to competitors. Following this discussion, we examine improper information sharing, cross-subsidization and self-dealing.

Transmission Market Power

When a company owns both (i) generating plants in a market and (ii) transmission facilities required by competitors to reach that market, the company may have an incentive to withhold transmission service from competitors in order to raise the prices at which the output of its generators can be sold. In effect, the company may be able to use its control over transmission to raise its rivals' costs or to exclude them from the market.

Transmission market power is exercised when a company that owns both generating plants and transmission facilities brings about an increase in the market prices at which it sells electric power by reducing the availability of transmission service required by competing generators to reach the market. Transmission market power need not involve ownership of generating plants: a similar problem may arise when a company owns both a wholesale marketer and transmission facilities.

One method of exercising transmission market power is a simple denial of transmission service needed by competing generators to reach a market. In light of FERC's open access requirements for transmission, utilities must, of course, have an explanation for denials, such as their own requirements for transmission capacity to serve native loads or to maintain reliability.

More subtle methods of exercising transmission market power include: (i) restricting the transfer capability of the transmission system by selectively limiting investments in facilities or failing to dispatch generators that supply reactive power; (ii) reducing the reliability of transmission service, for example, by calling for line loading relief that interrupts competitors' deliveries; and (iii) refusing to discount prices of transmission service when circumstances would warrant this. When a transmission system owner that was not vertically integrated might offer discounts to enable a power producer to reach a market, a vertically integrated company might refuse to discount prices, effectively raising prices for transmission service.

Distribution Market Power

A company that has a monopoly over distribution (wires) services and also offers retail supply and energy services is likely to have an incentive to discriminate against non-affiliated marketing companies (or retail customers that purchase from competing companies) in supplying wires services. Regulation is likely to constrain the prices that a distribution company can charge for wires services. Such regulation leaves a distribution company with an incentive to exercise its market power through discriminatory behavior: it can more fully exploit its distribution monopoly if it can force or induce retail customers to purchase power and energy

services from it at inflated prices. This potential problem will be referred to as *distribution market power*.

It is sometimes suggested that a distribution company may impede sales by non-affiliated marketers in ways that are more subtle than expressly denying service to competitors or tying its wire services and power and energy services. Such obvious tactics would, of course, likely run afoul of antitrust laws and regulations when competition is permitted. More subtly, a distribution company might provide superior regulated wires and backup services — for example, more reliable equipment, faster hookups, faster repairs, fewer service curtailments — to industrial customers that also purchase power or other energy services from the distribution company or its affiliates.

Fuel Supply Market Power

When a company owns both (i) generating plants in a market and (ii) fuel supplies used by competing generators, or pipelines used to deliver natural gas to competing generators, then the company may have an incentive to raise the prices of inputs delivered to its competitors. The resulting increase in costs may reduce the ability of these other generators to compete, with the effect that electric power prices are increased. In short, the company may be able to use its control over fuel supplies or delivery to raise its rivals' costs or to exclude them from the market (Frankena 1997b). This form of market power will be referred to as *fuel supply market power*.

In addition to the potential problems described as transmission, distribution, and fuel-supply market power, the vertical combinations described in Table 1 may also lead to abuses related to improper information sharing, cross-subsidization and self-dealing. These are discussed next.

Improper Information Sharing

In the normal course of business, a transmission company, a distribution company or a natural gas pipeline will typically obtain information that is valuable to companies engaged in competitive activities. For example, the profitability of entry by new generators or power marketers may depend in part on the availability of market information that a distribution company would collect. When the information is not confidential, a distribution company that is not vertically integrated would have an incentive to market such information. By contrast, a company that is engaged in both regulated and competitive activities may have an incentive to keep such information from non-affiliated companies — for example, new generators or marketers. Even when the information is confidential and cannot be sold, a regulated company may still have an incentive improperly to share the information with its affiliates.

Regulatory requirements for the handling of such information may be only partially effective in alleviating this problem. For example, if a vertically integrated distribution company is obligated to provide affiliates and nonaffiliates with equal information, it may then have an incentive to impede entry of nonaffiliates by not disclosing such information at all. As the incumbent in the competitive market, it may gain from withholding such information to raise entry barriers.

Here are two examples of potential anticompetitive use of information:

- A distribution company may have detailed information about loads in its service territory that would reduce costs of location selection and risks for new generators. Similarly, a distribution company may have detailed information about specific customers that would reduce costs and risks for energy services companies. A distribution company that is affiliated with a generation or marketing subsidiary would have an incentive to withhold even non-confidential information from entrants with which it is not affiliated.

- If consumers can choose among suppliers of power, the distribution company will obtain information about competitors' sales each time customers change their suppliers of power. The distribution company may also obtain information on the characteristics of the power supplied, including load profiles and interruptions. This information could allow the distribution company or its affiliates to target their retail marketing of power, and to engage in price discrimination among retail customers, in ways that other competitors could not.

Evasion of Regulation

Vertical integration between monopoly activities that are subject to cost-based regulation, on the one hand, and deregulated competitive activities, on the other, may permit a regulated company to evade regulation and increase the exercise of market power in the monopoly activity. A vertically integrated company may have incentives to cross-subsidize its competitive activities by underpricing goods and services supplied by the monopoly units to the competitive affiliates, and overpricing goods and services supplied by the competitive units to the monopoly affiliates. Such abuses would lead to inefficient prices and to transfers of monopoly profits to the unregulated units of the company. Ultimately, these abuses can lead to foreclosure of sales by more efficient competitors in the competitive activities, while raising prices of the monopoly activities.

Cross-Subsidization. Regulation of prices in the electric power industry is intended to constrain the exercise of market power. But cost-based regulation typically permits an increase in regulated prices when costs increase. The combination of cost-based regulation and an affiliation between monopoly and competitive enterprises gives rise to incentives to cross-subsidize competitive activities. Such a combination may allow the monopoly firm to evade the regulatory constraint on its exercise of market power. For example, by inappropriately allocating costs of nonregulated competitive activities to the regulated activity, the firm may obtain regulatory approval for an increase in cost-based prices for the latter, and thereby earn monopoly profits. Furthermore, cross-subsidization of competitive activities may cause more efficient rivals to be displaced. (See insert.)

> A serious cross-subsidization problem can arise even *"when a regulated utility acquires a firm that is not vertically related. The use of common facilities and managers may create an insoluble cost allocation problem and provide the opportunity to charge utility customers for non-utility costs, consequently distorting resource allocation in the adjacent as well as the regulated market."* (DOJ 1984, n.35.)

As one illustration of the problem of cross-subsidization, consider the situation of a distribution utility that enters into various competitive activities. When a competitive activity succeeds, the distribution utility would have an incentive to spin it off to an unregulated affiliate at less than its market value. When the competitive activity fails, the distribution utility would have an incentive to allocate the costs to ratepayers. Such behavior would improperly shift both costs and risks to the monopoly customers and would be possible only because the firm does not face competition in the monopoly enterprise.

Under and Overpricing in Affiliate Transactions. Market power problems relating to underpricing of monopolized goods and services supplied to competitive affiliates of the company, as well as overpricing of goods and services supplied by competitive affiliates to monopoly units, may arise when (i) activities with market power are subject to cost-of-service regulation and (ii) revenues and costs for the activities with market power are computed using affiliate transactions prices that differ from market prices.

When they purchase from their unregulated affiliates, regulated monopoly companies have an incentive to pay their affiliates prices that exceed market prices. For example, a distribution utility with captive retail customers may have an incentive to inflate the prices at which electric power is purchased from a power marketing affiliate. The distribution company may then be able to increase the regulated prices at which it sells to captive customers to recover the inflated prices paid to the affiliate. If so, the distribution company will exercise market power, and

the resulting monopoly profits will appear as income for its affiliate. As a second example, a regulated transmission system operator may have an incentive to pay inflated prices for ancillary services, such as voltage control, purchased from affiliated generating plants.

Similarly, when they sell to their unregulated affiliates, regulated monopoly companies have an incentive to charge their affiliates prices below the market prices of the goods and services in question. For example, regulated monopolies have an incentive to give brand names, customer lists and other market and customer information to their unregulated affiliates free of charge.

Problems also arise in connection with non-price terms of transactions. For example, a regulated monopoly buyer may refrain from enforcing terms in a contract with an unregulated affiliate even though the same buyer would enforce such terms in a contract with a company that is not affiliated.

Regulation can seek to prevent such abuses by careful consideration of cost allocation methods and careful auditing of transactions between monopoly companies and their unregulated competitive affiliates. However, such regulation is costly and time-consuming. And, as a practical matter, regulators have strictly limited resources and cannot be expected to detect many attempts to evade regulation in this way.

DO ELECTRIC COMPANIES EXERCISE MARKET POWER?

Market power is a genuine problem in important parts of the United States electric power supply industry, in part because of the market structures that society has inherited from the past era of regulated vertically integrated utilities shielded from competition. Transmission constraints and costs narrowly limit the geographic scope of competition for electric power in a number of areas of the country. Where relevant geographic markets are narrow, ownership of generating capacity is likely to be highly concentrated in the hands of incumbent utilities. Entry barriers for new generators are often substantial, particularly where there is excess capacity. When high concentration in ownership of generating capacity and entry barriers are combined, generation market power is likely. In addition, various forms of vertical market power are important problems because of vertical integration into potentially competitive activities by firms with monopoly power in transmission and distribution.

Market power abuses in electric power markets are not hypothetical. For example, since its 1990 restructuring, the electric power industry in England and Wales has been plagued by anticompetitive conduct by two generating companies, National Power and PowerGen, according to numerous reports (Kwoka 1997). The market power of these companies has been based on high shares of generating capacity, the

limited amounts of coal-fired generating capacity in the hands of competitors, control of generating units that must run to maintain the reliability of the electric system, and transmission constraints.

Also, there are well-known examples of self-dealing by vertically integrated companies in the electric power and other regulated industries. Such problems led to the breakup of AT&T in the early 1980s, to disallowances for SoCal Edison in the late 1980s, and to customer refunds by NYNEX in the 1990s (see Appendix B).

CONCLUSION

Assessments of market power in the electric power industry are challenging both because of the unusual characteristics of the industry and because of the range of ways in which market power may be exercised. The next chapter of this report provides an explanation of methods used to assess market power in the industry, with particular attention to generation market power.

6 ASSESSING MARKET POWER

Assessing market power in the electric industry is complicated for several reasons, including the inherent characteristics of electric power, the legacy of vertical integration, inherited forms of regulation and the many changes occurring in the industry. Nonetheless, the basic framework that is appropriate to analyze market power in electric power is the same as that used in other industries.

This chapter begins with a discussion of how generation market power is assessed using traditional antitrust principles. Next, we discuss the contributions that simulation models can make to evaluation of generation market power. Finally, we address principles for assessing other types of market power, such as transmission and fuel supply market power.

To analyze horizontal market power using traditional antitrust principles, one identifies the products in a market and the geographic scope of that market. Next, one computes market shares and concentration and evaluates conditions for entry into the market. Finally, based on market shares, concentration, entry barriers and additional information about competitive conditions, one makes inferences about the likelihood that prices would exceed competitive levels.

IDENTIFYING RELEVANT MARKETS

Before one can measure market shares and concentration, one must identify the scope of the market. Suppose the issue at hand is to assess the extent that any market power may affect market-determined prices for electric power in Wyoming. One of the electric power products sold in Wyoming is megawatt hours of electric energy delivered during summer off-peak hours (nights and weekends). To define the market that is appropriate for a market power analysis relating to this product, one must determine whether the pricing of this product is so constrained by competition with other products that those other products should be included in the same market.

Steps in Assessing Horizontal Market Power

- Identify relevant product and geographic markets
- Measure levels of concentration in markets
- Evaluate the difficulty of entry by competitors into markets
- Conclude whether prices are likely to exceed competitive levels

We begin the analysis with a thought experiment. Suppose one company owned all the generating facilities that could be used to supply summer off-peak electric energy. Would that company be able profitably to raise the price of this energy significantly (say, by 5%) above the competitive level for a significant period of time? If so, summer off-peak electric energy would be a relevant product market for a market power analysis. On the other hand, if the company could not profitably raise the price of that energy because many buyers would switch to natural gas, then the relevant product market would include not only summer off-peak electric energy but also natural gas.

As a matter of fact, analyses of consumer behavior demonstrate that no other products sufficiently constrain the pricing of summer off-peak electric energy, and hence summer off-peak electric energy is a relevant product market for assessment of market power. Similarly, electric energy delivered during each of the other major periods of the year (for example, winter peak hours) is a separate relevant product market.

This distinction among product markets during different time periods is important because competitive conditions in energy markets may vary over time. For example, in many regions of the United States, dispatchable gas-fired generating units cannot supply energy at the relatively low prices that prevail under competitive conditions during off-peak hours, and hence these generating units are not included in computing off-peak market shares. By contrast, efficient gas-fired generating units are included in markets for on-peak energy.

In addition to product markets for electric energy, there are markets for certain other electric power products as well. In regions where utilities have obligations to maintain generating capacity reserves, there are markets for generating capacity rights. Also, there may be markets for ancillary services supplied by generators, such as voltage control and spinning reserves.

Geographic Scope of Markets

We now continue with our Wyoming hypothetical. Once relevant product markets have been defined, the next issue is the geographic scope of competition. Would a company that owned all the generating facilities in Wyoming that are able to produce and deliver energy at a competitive price during summer off-peak hours be able to raise prices significantly (say, by 5%) above the competitive level? If yes, only generators located in Wyoming are in the relevant geographic market.

Suppose, on the other hand, that this company could not profitably raise the price of that energy because many buyers would switch to energy generated in Montana. In this case, the relevant geographic market would include not only generators located in Wyoming but also those in Montana. To complicate matters further, the relevant

geographic markets for energy in which generators in Wyoming compete may vary among time periods. While the markets might include states to the north of Wyoming during the summer, they might include states to the south of Wyoming during the winter.

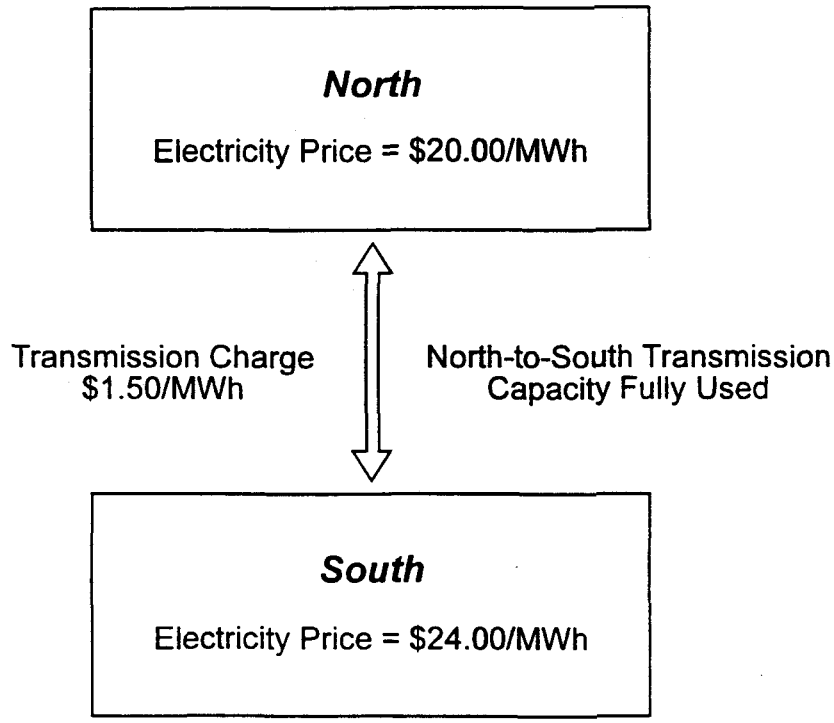
Determining the scope of geographic markets is the most difficult and contentious issue in assessing market power in the electric power industry. FERC's 1996 *Merger Policy Statement* (FERC 1996) adopted the U.S. Department of Justice and Federal Trade Commission *Merger Guidelines* (DOJ/FTC 1992) as the appropriate methodology for use in analyzing the effects of mergers on market power.[1]

Identification of geographic markets for electric energy is difficult because competition depends on numerous factors in the pertinent region. These factors include: (i) capacities and variable costs of generating units; (ii) demands for energy by end-users; (iii) contractual and legal obligations of generators that limit the amounts of energy they can sell at market prices; (iv) transmission charges; (v) limits on transfer capabilities of the transmission system; and (vi) utility practices and regulations regarding access to the transmission system. Because the geographic scope of competition depends on so many factors, economists are beginning to rely on simulation models of the electrical system to assist in the analysis (Frankena 1997a, Frankena and Morris 1997, 1998). These simulation models attempt to reflect the complex interplay of the numerous factors that affect the geographic scope of markets.

Transmission constraints play a particularly important role in defining geographic markets. Consider a hypothetical case in which there are two areas, North and South. Suppose that transmission capacity from North to South is fully utilized, the price of energy in the North is $20/MWh, the charge for transmission service from North to South is $1.50/MWh, and the price in the South is $24/MWh. (See Figure 3.) In this case, North and South would be different geographic markets. For example, a 5% anticompetitive increase in the price of energy in the North (to $21/MWh) would have no effect on energy transfers between North and South, on prices in the South, or on the output levels of generators in the South. As a result, generators located in the South would not be in the geographic market for purposes of evaluation of a merger in the North — even though transmission from the South

[1] However, FERC's detailed methodology for defining geographic markets for use in merger analysis — known as Appendix A — is inconsistent in important respects with the sound economic principles of the *Merger Guidelines* and therefore is of uncertain reliability (Frankena 1998a). Moreover, in evaluating applications from individual utilities for market-based pricing, FERC uses a different, and also unreliable, methodology — known as a hub-and-spoke analysis — to define geographic markets.

Figure 3. Example of Geographic Markets Separated by Transmission Constraints.



to the North would be available. Also, a 5% increase in electric rates in the South would not affect sales from North to South since the existing transmission capacity is fully used.

Load Pockets

In many cases, because of transmission constraints, during much of the year the total amount of energy that can be imported into a region is substantially less than the amount of energy consumed in the region. Such regions are known as *load pockets*. At least some of the generators located inside a load pocket must operate if local demand for energy is to be met. In that case, if a single company owned all generation in the load pocket, it would typically have market power.

Such a company could reduce the output of the generators inside the load pocket until imports filled the transmission capacity into the load pocket. At that point, the company could increase prices to a very high level, and users would have to pay

those prices unless they were prepared to do without energy. Unless there were some regulatory or political constraint on the ability of the company to reduce output or raise prices, the company could raise prices high enough to make such an anticompetitive strategy profitable. In such a case, the load pocket (or possibly a smaller area within the load pocket) would be a geographic market for analysis of the market power over energy of generators in the load pocket.

Load pockets are common. Examples of companies that own generating capacity that must operate in order to meet demands for energy in load pockets are Consolidated Edison of New York, Nevada Power, Pacific Gas & Electric (PG&E), SDG&E, Sierra Pacific Power, and Wisconsin Electric Power.[2]

MARKET SHARES AND CONCENTRATION

In assessing generation market power, market shares are normally based on generating capacity in a relevant product and geographic market. There is no simple rule about the levels of market shares that are likely to confer market power on a single firm acting alone. In various regulatory and antitrust contexts, there is some point between about 30% and 50% at which the potential for a single firm to exercise market power typically receives increased scrutiny. However, a firm with a lower market share may have market power when its competitors are not able to increase their output significantly in response to a price increase. Conversely, a firm with a higher market share may not have market power if entry is easy.

In markets where two or more firms have substantial market shares, inferences about the likelihood that market power will be exercised simultaneously by such firms, either unilaterally or in collusion, are typically based on seller concentration in the market measured by the Herfindahl-Hirschman Index (HHI). The HHI is an *index of concentration* in a market. To determine the HHI for a market, one computes the market shares for the companies in the market and then calculates the sum of the squares of those market shares.

Table 2 illustrates how to calculate an HHI and provides an example in which a market with four sellers has a HHI of 3,000. The federal antitrust agencies and FERC call a market with an HHI greater than 1,800 "highly concentrated." An example of a market with an HHI of 1,800 is a market with five to six equal sized competitors.

[2] Sources: Consolidated Edison, New York Department of Public Service 1996; Nevada Power and Sierra, Frankena 1997a; PG&E, 81 FERC ¶61,122 at 195; SDG&E, Southern California Edison and San Diego Gas & Electric 1996, Chap. 3.

Table 2. Computing an Herfindahl-Hirschman Index (HHI).		
	Market Share	Share Squared
Company A	40%	1,600
Company B	20%	400
Company C	30%	900
Company D	10%	100
HHI		3,000

Now let us consider the effect on the HHI in this illustrative market if there is a merger between two companies. If Company C acquired Company D, the HHI would increase to 3,600. Table 3 illustrates the calculation of the HHI.

Table 3. Effect of a Merger on Example HHI.				
	Pre-merger Market Share	Pre-merger Share Squared	Post-merger Market Share	Post-merger Share Squared
Company A	40%	1,600	40%	1,600
Company B	20%	400	20%	400
Company C	30%	900	40%	1,600
Company D	10%	100		
HHI		3,000		3,600

In markets with an HHI of at least 1,800, mergers that increase the HHI by more than 50 may raise competitive concerns under the DOJ/FTC *Merger Guidelines*. However, in practice the antitrust agencies do not often challenge mergers that would increase the HHI by less than 200 points or that would leave the HHI below 2,000 post-merger. An example of a merger that would increase the HHI by 200 points is one between two companies with market shares of 20% and 5%, respectively.

FERC uses different methodologies for defining geographic markets and computing market shares in merger cases and in market-based pricing applications. Also, while FERC makes inferences based on HHIs in merger cases, in market-based pricing applications FERC looks only at the market share of the firm requesting market-based pricing authority.

As a matter of policy, FERC approves market-based pricing for companies whose shares are under 20%; in practice, FERC also commonly approves market-based

pricing when shares are between 20% and close to 30%. Most utilities are able to pass FERC's structural standards for market-based pricing for electric energy given the way geographic markets are defined, the way shares are measured, and the market share standards used.[3] FERC may grant market-based pricing to an existing generating company in some cases in which the formation of that company as the result of a merger would raise substantial market power concerns.

While FERC's methodology for measuring market power in connection with market-based pricing applications is questionable, the notion that different structural thresholds are appropriate for merger and market-based pricing decisions is widely accepted. DOJ has suggested that in markets with HHIs below 2,500, it is likely to be in the public interest to deregulate prices in order to eliminate costs and distortions caused by regulation. (A market with four competitors, each having a 25% market share, has an HHI of 2,500.) Of course, a finding that the public would be better off without price regulation in a market with an HHI of 2,490 suggests that the public would be *even better off* if prices were deregulated *and* concentration were reduced below 2,490.

Entry Conditions

In antitrust parlance, even if a firm has a large market share or a market is highly concentrated, sellers will not have significant horizontal market power if it is *easy* for new sellers to enter the market. But, for entry to be easy in the antitrust sense, that entry must be not only feasible but also must be both timely and profitable as well.

Frequently, market power analyses incorrectly conclude that entry is easy because it *could* occur. However, the important question is not whether it could occur but whether it *would* occur in a timely manner in response to an attempt to exercise market power. For entry to be sufficiently easy to alleviate concerns about exercise of market power by incumbent sellers, new competitors must be able to enter a market quickly and make a profit doing so.

Feasibility

Obviously, entry cannot constrain the exercise of market power if entry is not feasible. Thus, the first issue in an evaluation of entry conditions is whether entry would be prevented by regulations such as zoning rules, environmental permitting,

[3] The Committee on Electric Utility Regulation (1998, p. 159) reports that, at the end of 1997, 62 investor-owned public utilities and 79 marketers affiliated with a public utility had received market-based pricing authority.

or requirements that an entrant demonstrate a "need" for additional capacity in a market with excess capacity.

Timeliness

Under the standards used by the federal antitrust agencies and FERC, entry is not easy if more than two years would be required from initial planning to significant market impact. Most types of generating units and significant transmission facilities require longer than two years for planning, approval and construction.

Profitability

If a new entrant cannot expect to cover its costs and earn a normal rate of profit by selling its output at competitive prices, then the threat of entry will not prevent an increase in prices above competitive levels. In areas of the United State that have excess generating capacity, entry that would prevent the exercise of significant market power may not be profitable for several years. Several years may be required for load growth to absorb existing excess capacity. Even where excess capacity does not exist at present, entry may not be profitable if the minimum efficient scale for a new generator would represent a substantial share of the market. In such a case, new entry could result in excess capacity that would depress prices below the level required to justify the entry.

Because of conditions relating to timeliness and profitability of entry, in most cases in which entry would take the form of new generating units, wholesale electric power markets do not presently satisfy traditional antitrust standards for easy entry. However, in some areas of the country there is no excess capacity, loads are growing quickly, and merchant gas-fired combined cycle generating plants are being set up with a gestation period of around three years. In such cases, the duration of concerns over generation market power for electric energy during peak periods might not exceed three years. Nevertheless, market power problems might last substantially longer during off-peak periods in areas where gas-fired combined cycle units would not be in the product market (because their variable costs of production would exceed competitive prices by more than 5%) and market power would hinge principally on ownership of nuclear and coal generators.

Simulation Models

The traditional approach to assessing generation market power can be supplemented by analyses based on simulation models. Relevant models use regional data on generation capacity and costs, transmission capacity and costs, and demands for electric power. With these data, models can be used to determine the

geographic scope of markets and whether the existing (or a proposed) ownership pattern for generating plants is likely to lead to energy prices significantly above competitive levels. Simulation models capture market characteristics and interactions that are neglected by simpler traditional analytical methods.

The most difficult issue for analyses of generation market power based on traditional antitrust methods is to determine the geographic scope of competition. It is generally recognized that historic sales data do not provide a reliable basis for measuring the scope of geographic markets in electric energy for several reasons. First, public data on sales are annual aggregates while there are separate markets for energy during different times of the year. The fact that Utilities A and B both sold energy to Utility C during 1997 would not demonstrate that Utilities A and B were competing, since Utility A's sales may have occurred during winter off-peak hours while Utility B's sales occurred during summer peak hours.

A second problem is that sales data often do not allow one to determine ultimate origins or destinations of transactions. A large share of electric energy is sold by generating companies to power marketers or to other utilities that resell to other wholesale buyers. A third problem is that generators that have not supplied a market in the past may yet belong in a relevant market because they could provide supplies in response to a small price increase, and thus play a significant role in constraining prices.

Because one cannot rely on sales data to define the geographic scope of competition for electric energy, one must use data for the underlying determinants of competition — generating capacities and costs, transmission capacities and costs, and demands for energy in different areas. The most satisfactory way to employ such data is to build a model — a simplified representation — of the electrical system over a relatively wide region, such as the eastern half of the United States. Such a model can be used to estimate the geographic scope of competition during each time period, such as summer peak hours.

For example, suppose one is interested in determining the appropriate geographic market in which to evaluate the potential effects on market power of a merger between Illinois Power and Central Illinois Light. One could use a simulation model of the eastern United States to test whether the state of Illinois would be a relevant geographic market.

To illustrate the analysis, we return to the "thought experiment" described earlier in this chapter. The model would be used to determine whether a hypothetical company that owned all generating capacity in Illinois would find it profitable to raise energy prices significantly above competitive levels. If the answer to this question is no, one could determine whether a hypothetical company that owned all generation in, say, Illinois, Missouri, and Indiana would find it profitable to raise energy prices.

To answer this question, the model would bring to bear information about the factors that would constrain an exercise of market power by the hypothetical owner of generation. For example, the model would use information on generating capacity and costs in Kentucky, transmission capacity and costs from Kentucky to Illinois and other potential markets, and demands for energy in Kentucky and other potential markets. Combining all this information, the model would determine whether increased imports from Kentucky and elsewhere would impose a significant constraint on the ability of a hypothetical monopolist of generation in Illinois, Missouri, and Indiana profitably to raise prices.

A simulation model can assist not only in analyzing the geographic scope of competition but also in determining whether companies would be able to increase their profits by taking certain types of anticompetitive actions. In a state restructuring proceeding, for example, a simulation model could be used to determine whether any one of the larger utilities in the market would be able to increase its profits by withholding output or raising the prices that it bids into a power pool.

An analysis of the latter type is a valuable addition to a traditional market power analysis based on shares and HHIs. Suppose a traditional analysis shows that a company has a 35% market share. One still faces the question whether a 35% share is sufficient to give a company market power. The answer to this question depends on two issues that are not addressed by a market share analysis but that are taken into account by a simulation model:

- By how much would this company have to reduce its output to raise energy prices by, say, $1/MWh? The amount of the output reduction depends on (i) the extent to which other generating companies would have the ability and incentive to expand output, and (ii) the extent to which customers would reduce consumption, in response to a $1/MWh increase in energy prices. Other things equal, if competing generating companies would expand output substantially in response to a $1/MWh increase in energy prices, then an attempt to exercise market power would be less profitable.

- How much profit contribution does the company that is raising prices give up on each MWh of sales that it must forego in order to bring about a price increase? The profit contribution is equal to the competitive market price of energy minus the incremental cost at the generating unit where output would be reduced. If the competitive market price were $20/MWh and the incremental cost were $19.90/MWh, the company would give up only $0.10/MWh in profits on sales foregone. On the other hand, if the incremental cost were $12/MWh, the company would give up $8/MWh in profits on sales foregone. Other things equal, if the incremental cost is lower, the company would find an attempt to exercise market power less profitable.

The lesson from this example is that market power depends on matters that are not taken into account by simple market share calculations, and thus market share calculations can usefully be supplemented by analyses using a simulation model.

It is sometimes argued that, since simulation models take account of factors that are omitted from market share and HHI analyses, analyses using simulation models can entirely replace traditional analyses. This is not correct. Simulation models are particularly useful in analyzing *unilateral* exercise of *generation* market power over *electric energy*. However, simulation models appear to have limited ability to analyze issues relating to the likelihood of collusion and market power over capacity and ancillary services.

OTHER TYPES OF MARKET POWER

Both methodologies that are used to evaluate generation market power — the traditional methodology based on market shares and HHIs and simulation models — may be adapted and supplemented to analyze other types of market power. Problems that may arise because of common ownership of generating capacity and transmission systems, or common ownership of generating capacity and natural gas transportation systems, can be analyzed in these ways.

Suppose that Utility A owns 5,000 MW of generating capacity in a market. Suppose further that Utility A can significantly affect the availability of transmission service required to deliver 2,000 MW of energy to the market from generators outside the market that are owned by other companies. Finally, suppose that Utility A can significantly affect the price of natural gas delivered to 1,000 MW of generating capacity in the market that is owned by other companies. Under these assumptions, one way of reflecting Utility A's competitive role in the market would be to base its market share on the 8,000 MW (= 5,000 MW + 2,000 MW + 1,000 MW) of capacity over which it has competitively significant control. One could also use a simulation model to investigate the implications of assuming that Utility A owned the full 8,000 MW of capacity.

One type of market power that plays an important role in restructuring proceedings relates to what is called *reliability must run generation*. Because of properties of electric transmission and distribution systems, under certain conditions a particular generating unit may have to operate to prevent thermal, voltage or stability problems that would threaten system reliability (Jurewitz and Walther 1997). In such cases, there may be a relevant market that contains a single generator that has a 100% market share and substantial market power.

THE DIFFICULT TASK OF ASSESSING MARKET POWER STUDIES

Regulators, legislators and antitrust authorities face a difficult question: which market power studies proffered to them are based on reliable methodologies, assumptions and data? There is no simple answer, and thus no simple way for interested parties to avoid careful scrutiny of any study. The most reliable assessments of market power are likely to be based on a combination of traditional antitrust analysis following the DOJ/FTC *Merger Guidelines* and simulation modeling.[4]

[4] For reasons indicated above, the methodology for evaluation of market power in the competitive analysis screens required by FERC's *Merger Policy Statement* is not reliable (Frankena 1998a). The same is true of FERC's hub-and-spoke methodology. Also, while simulation models can be useful, poorly designed models — such as those offered by applicants in the Primergy merger — obviously are not useful (see FERC's Primergy decision, 79 FERC¶61,158 (1997)).

7 DEALING WITH MARKET POWER

The preceding chapters of this report have discussed the nature of market power in the electric power industry and have described methods used to determine whether market power problems exist. In this chapter, we discuss approaches that may be used to eliminate, reduce and deal with market power problems.

In general, the preferred method for dealing with market power is to bring about changes in market structure that will eliminate the incentives for companies to behave in an anticompetitive fashion. Structural remedies, such as divestiture of generation or transmission facilities, will sometimes achieve this objective. Nonetheless, society cannot rely solely on structural remedies to deal with market power in the electric industry. Some industry activities have natural monopoly characteristics — examples include transmission, distribution and some ancillary services (or reliability must run generation). Where an activity is a natural monopoly, society may have no practical alternative to reliance on regulation of prices and other terms to mitigate market power.

Also, in some cases structural remedies for market power may sacrifice achievement of potential economies of scale and scope. For example, in small markets there may be a trade off between achieving economies of scale in production and having enough sellers for markets to be competitive. Also, it is frequently argued that potential economies of scope would be lost if some forms of vertical integration were prohibited.

STRUCTURAL VERSUS BEHAVIORAL APPROACHES

Approaches to dealing with market power fall into two categories: structural and behavioral. Structural measures change characteristics of a market so that firms no longer have market power. That is, firms no longer find it profitable to reduce their output and take other steps that raise prices. Rather than removing market power, behavioral measures attempt to prevent companies with market power from acting anticompetitively.

Structural Remedies

When generation market power is found to be significant, the obvious structural remedy is for firms with large market shares to sell generating units so that market shares and concentration are reduced. PG&E and SoCal Edison have recently been induced by state regulators to sell generating plants in a manner that will reduce

market shares and concentration. As we discuss later, provisions for incumbent generators to sell generating capacity should typically be included in comprehensive restructuring plans when significant generation market power is found to exist.

Sale of generating units is not the only potential structural measure to alleviate generation market power, however. If generation market power is likely to be temporary, it may be sufficient for companies to enter into long-term contracts to sell capacity or energy for the pertinent period. Another structural approach to dealing with generation market power is to change regional transmission pricing in ways that would broaden geographic markets and lower concentration.[5] Along these lines, in its 1998 order approving the merger of Louisville Gas & Electric and Kentucky Utilities, FERC relied in part on commitments by the merging companies to sell energy for a period of years and to join the proposed Midwest independent system operator (ISO), which plans to provide transmission service under a regional tariff (82 FERC ¶61,308). Other utilities are now offering similar commitments as a *quid pro quo* for merger approval. In their successful merger application at FERC in 1997, Wisconsin Electric Power and Edison Sault Electric committed to make available to others a certain amount of transmission service to the Michigan Upper Peninsula. This commitment reduced their share in an Upper Peninsula market.

In principle, another structural remedy available to reduce generation market power is expansion of transmission capacity. FERC imposed requirements for expansion of transmission capacity to deal with market power issues raised by the FirstEnergy and Alliant mergers. In many cases, however, transmission system investments would take too long to provide a remedy, would be too costly, or would not in fact add significantly to the transfer capability of the grid.

To deal with transmission market power, one structural measure is to separate ownership of generation and transmission facilities. Such separation is clearly the most direct and effective method to prevent utilities from using control over transmission to foreclose competition faced by their generators. A number of foreign countries, including Argentina and Peru, have separated ownership of generation and transmission, and some northeastern states are doing so, at least insofar as non-nuclear generation is concerned.

Independent System Operators. An alternative to separation of ownership of generation and transmission is for a utility that owns generation to turn over to a regional independent system operator (ISO) control over pricing, scheduling, curtailment, operation and maintenance, and expansion of its transmission system.

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[5] Of course, transmission should be priced in a manner that provides the correct signals for use of transmission capacity and for location of new generating plants. Transmission pricing should not be distorted in an attempt artificially to broaden markets. Also, reductions in transmission prices may not broaden markets if increased use of transmission results in congestion on the grid.

ISOs have been set up in several United States regions with the encouragement of the states and FERC.

However, there are some difficulties with ISOs as remedies for transmission market power. First, there are concerns about whether ISO governance structures sufficiently curb the influence of incumbent utilities that continue to own generation and power marketing operations. An ISO may not eliminate the role of incumbent utilities in matters such as transmission expansion decisions.

Second, there are concerns about whether ISOs have sufficient responsibilities and powers. The powers of existing and proposed ISOs vary. For example, the Texas and Midwest ISOs do not serve as control area operators with responsibility for dispatch of generating units.

Third, there is a significant debate about how to provide the correct incentives so that an ISO will manage the transmission system so that its operation, pricing and expansion are efficient. Will ISO committees with representatives of many stakeholders make decisions that allocate resources efficiently? Will the managers and staffs of an ISO be rewarded if they make day-to-day decisions that promote efficient resource allocation, and penalized if they do not? One issue is whether non-profit ISOs can be expected to perform as well as for-profit ISOs. (See insert.)

> *"One potential difficulty with the nonprofit status of ISOs is the lack of profit incentives to operate efficiently and to make economically appropriate investment decisions regarding expansion of the transmission grid to address transmission bottlenecks. ISO governing bodies may be able to design the employment contracts of ISO managers to provide such incentives."* (FTC 1998b).

Finally, there are concerns about the process of establishing regional ISOs. With a few exceptions — for example, California, New York, and Texas — individual states do not have the authority to require ISOs that would qualify as *regional*. While FERC has required that certain merging companies join ISOs, it has not attempted to require establishment of ISOs outside areas of the country that have tight power pools (New England, Pennsylvania-New Jersey-Maryland).

Distribution and fuel supply market power may also be dealt with by divestitures. To deal with distribution market power, utilities and their affiliates could be prohibited from engaging in retail marketing of electricity to customers in the geographic areas in which they own distribution facilities. While this approach has not been used in the electric industry to deal with distribution market power, it has a parallel in the telecommunications industry: the local Bell phone monopolies are not permitted to provide long distance service within their regions, and will not be permitted to do so until they demonstrate that they have sufficiently opened their local networks to competitors.

To deal with fuel supply market power concerns, SDG&E has been required to divest gas-fired generating plants and PacifiCorp was required to divest two of Peabody's coal mines (see Chapter 8 below).

Companies could also be prohibited from owning both regulated monopoly facilities and competitive facilities in order to eliminate the problems of discrimination, improper information sharing, cross-subsidization and self-dealing that sometimes arise when there is common ownership.

Behavioral Remedies

Behavioral remedies allow market power — or anticompetitive incentives — to continue but attempt to prevent companies from behaving in anticompetitive ways that increase their profits. Behavioral remedies are inherently regulatory. Typically, there must be administrative mechanisms for monitoring behavior, adjudicating complaints, imposing sanctions, and overriding company decisions on prices, outputs, services and investments.

Behavioral remedies typically involve regulation or conduct rules. Here are five examples of behavioral remedies:

Dominant firm regulation is sometimes used to limit the prices that can be charged by firms with market power. Typically, the dominant firm in a market will face price regulation even while other suppliers operating in the market are not regulated. This approach was used by the Federal Communications Commission to regulate AT&T's long distance prices until 1996, even as other long distance firms were taking market share. The FCC removed price regulation when it determined that AT&T no longer had market power.

Monitoring and mitigation plans are being put in place to deal with generation and transmission market power in California and other regions with electric power auction markets. Under these plans, ISOs will engage in market surveillance in an attempt to detect and deter anticompetitive behavior. Frankena (1998b) discusses the likely ineffectiveness of these ISO surveillance schemes in detecting and deterring exercises of market power, while Raskin (1998) addresses the high costs these schemes are likely to impose on electric power markets.

Restrictions on a Utility's Use of Transmission Capacity may be used in an effort to prevent foreclosure of other users. Merging companies have agreed to various limits on, and lower priorities for, their own use of their transmission systems.

FERC's Order 888 and 889 transmission open access rules, which are intended to address transmission market power. These rules mandate that public utilities unbundle generation and transmission and provide to others the same types of

transmission services they use themselves — with comparable prices, terms, conditions and information for all.

Codes of conduct governing affiliate relations for companies that own both regulated monopoly and competitive facilities. These codes and related rules may restrict permissible organizational forms in order to separate monopoly and competitive activities; prohibit self-dealing; prescribe transfer pricing and other accounting methodologies to limit cross-subsidies; prohibit sharing of certain types of information; and mandate disclosure, reporting and equal access to information to facilitate oversight and prevent discrimination (Norton and Grabow 1998).

The choice between structural and behavioral remedies is not a pure one. The issue is largely the extent to which reliance is placed on behavioral remedies. Even if primary reliance is placed on structural remedies, there may be little alternative to reliance on behavioral remedies to deal with residual market power, including some problems that arise from monopolies over transmission and distribution.

Differences between Antitrust Agencies and Regulators

The Department of Justice (DOJ) and the Federal Trade Commission (FTC) have traditions of preferring structural to behavioral remedies for market power — particularly for horizontal market power. In dealing with mergers in a wide variety of industries, the federal antitrust agencies commonly require divestitures to settle complaints. The agencies sometimes accept structural remedies that are intended to bring about new entry or lower entry barriers.

In the case of the electric power industry, the antitrust agencies have recommended primary reliance on structural remedies to deal with market power. Both agencies recommended that FERC require ISOs rather than rely on Order 888 to deal with transmission access problems (DOJ 1995, FTC 1995). Recently, the director of the FTC's Bureau of Competition noted that "Although FERC Order No. 888 mandates open access, there remains a concern that incentives and opportunities for discrimination may still be present, through either unilateral or collective action, and rival power generators could be disadvantaged" (Baer 1997).

In comments on the New England Power Pool's application for market-based pricing, the FTC staff as well as the Maine attorney general recommended against substantial reliance on market surveillance plans because of difficulties in detecting anticompetitive behavior and preventing it through behavioral rules (FTC 1998a, Frankena 1998b). Also, the United States assistant attorney general for antitrust cautioned FERC against following "an overly regulatory approach to merger review." (See sidebar.)

> *"While I recognize, of course, that the Commission is a regulatory agency, and that the electric power industry has long been highly regulated, restructuring obviously is intended to move away from that paradigm. We at the Department hope and expect that market forces will become the primary determinants of wholesale electric power rates. And, in that context, mergers that substantially lessen competition should be allowed to proceed only if a court-imposed consent decree, or set of Commission-imposed merger conditions, offers a permanent, preferably structural remedy for the anticompetitive effects of the merger. More specifically, I would urge the Commission to reject rate freezes or rate roll-backs as conditions for approval of mergers creating structural competitive problems in generation. Such remedies typically are short-term, and do not in any way address the real competitive effects of the merger. Even in the short term, there will often be reason to doubt that the frozen rates would be as low as competitive rates. Finally, based on a century of experience, I would further emphasize that the Department is also highly skeptical of any relief that requires judges or regulators to take on the role of constantly policing the industry. Relief generally should eliminate the incentive or the opportunity to act anticompetitively rather than attempt to control conduct directly. We are institutionally skeptical about code-of-conduct remedies. The costs of enforcement are high and, in our experience, the regulatory agency often ends up playing catch-up, while the market forces move forward and the underlying competitive problems escape real detection and remediation."* (Klein 1998, pp. 17-18).

FERC approved the Enova/Pacific Enterprises electric-gas merger subject to prohibitions on inappropriate sharing of information and discrimination, and provisions for separation and transparency of certain transactions. By contrast, DOJ required divestiture of SDG&E's gas-fired generating plants. The director of the FTC's Bureau of Competition observed that FERC's "approach to remedies in this case illustrates the general inclination of regulatory agencies to use conduct remedies rather than structural relief" (Baer 1997, n. 25). However, it should be added that state commissions — notably California's — have imposed structural remedies.

ADVANTAGES OF STRUCTURAL REMEDIES

Several reasons for preferring structural to behavioral remedies have been explained by the director of the FTC's Bureau of Competition:

> *"A behavioral approach...has several drawbacks. First, it does not eliminate the incentive and opportunity to engage in exclusionary behavior. Rules can try to limit the opportunity, but few rules are invulnerable to evasion. Second, detection of violations can be very difficult. For example, discrimination in access could take the form of a subtle reduction in quality of service, whose effects could be difficult to identify and measure. Third, behavioral rules can require long-term monitoring of compliance, which can be a costly process.... Fourth, it*

> *may be difficult to know whether we have selected the right rules. Even a simple cease-and-desist order, which is commonly used in antitrust cases, can be difficult to frame, because we do not want to prohibit too little or too much. More complex orders, especially those that try to guide conduct through affirmative requirements, can be more difficult to frame properly"* (Baer 1997).

The principal economic rationale for relying on behavioral rather than structural remedies is that structural remedies may prevent achievement of economics of scale and scope. The antitrust agencies sometimes rely on behavioral remedies in an attempt to limit potential anticompetitive effects of vertical mergers without sacrificing economies of scope (Baer 1997, n. 12).

INEFFICIENT REGULATION

One obstacle faced by efforts to replace regulation with competition in potentially competitive markets is that society does not always acknowledge the costs and limitations of regulation. While this point applies to many types of regulation, the discussion here will focus on regulation of prices. Price regulation imposes substantial costs.

First, regulated prices are below the efficient level in many circumstances. This is particularly true in the case of electric power, since the value of a MWh of energy may vary by hundreds of percentage points over the course of a day. Regulators lack the resources to determine efficient price levels, and they lack the resources to change regulated prices as cost and demand conditions change. Furthermore, regulators may base regulated prices on incorrect economic analysis. For example, regulators often set prices based on the average historical cost of tangible assets. Prices set on this basis may have little relationship to the determinants of competitive or efficient prices.

Second, price regulation limits the ability of regulated firms to respond to changes in technology, cost and demand conditions, and deters new investments, quality improvements, introduction of new services, and entry by reducing returns on pro-competitive activities. This distortion is likely to be greatest in industries — including the formerly staid electric power industry — that are undergoing important changes and in which future risks will be substantial.

Third, it is also important to remember that government regulations involve substantial administrative costs both for the industries being regulated and for the government.

Fourth, special interests are often over-represented in the regulatory process, compared to the consumer interest, making predictable arguments to protect their

parochial interest in continuing regulation. Consequently, prices and services in regulated industries depart, often considerably, from those that would have prevailed in the markets that regulators displaced (Peltzman 1989).

In addition to its costs, a serious deficiency of price regulation is that regulated prices may well be substantially above competitive prices in some circumstances, even if they are below competitive prices in others. In such cases, utilities selling at regulated prices may actually be exercising significant market power. Such regulatory price gaps may be significant in the case of off-peak services, in regions with excess capacity, and for utilities with high average historical costs.

The limits of regulation, including price regulation, imply that consumers will typically be better off with structural rather than regulatory measures to address market power when structural remedies are an option. It should be recognized, however, that the discomfort of some regulators with reliance on markets to determine prices does not stem solely from concerns about market power. Some regulators are concerned that, without price regulation, consumers may become the victims of price gouging by unscrupulous sellers. We suggest that price regulation is not the best response to potential deceptive and unfair trade practices. Rather than throwing out the benefits of the market, consumer protection concerns are more properly addressed by measures to improve the information received by consumers so that markets can perform efficiently.

Reliance on Antitrust Enforcement

It is not uncommon to hear the argument that market power problems can be dealt with adequately by enforcement of the antitrust laws. This argument is not correct. First, while the Sherman Act makes anticompetitive agreements and exclusionary conduct unlawful, a company with market power does not violate the antitrust laws merely by charging monopoly prices or limiting its output. Also, competitors in a concentrated market may be able to coordinate their pricing, output and other decisions in anticompetitive ways that are not susceptible to challenge under the antitrust laws.

> *"...a company with market power does not violate the antitrust laws merely by charging monopoly prices..."*

Second, illegal behavior is not easily detected, and this would certainly be the case in complex electricity markets. Even when illegal behavior is detected, it is expensive, time consuming, and sometimes perhaps impossible to carry the burden of proving illegality to a court. In the meantime, much injury may have been done to consumers by firms exercising market power. One should also recognize that

antitrust enforcement does not deter all illegal anticompetitive behavior, even of a criminal nature, as revelations of dramatic price fixing conspiracies demonstrate.

> From the United States assistant attorney general for antitrust:
> *"[T]o whatever extent restructured electric power markets are too highly concentrated to yield pricing at or near competitive levels, the antitrust laws provide no remedy."* (Klein 1998, p. 5).

Third, while the antitrust laws permit legal challenges to certain types of anticompetitive conduct, antitrust authorities generally cannot change existing market structures that are not conducive to competition. Issues of market structure in the electric industry must, therefore, be addressed primarily in restructuring legislation or proceedings. (See insert.)

Fourth, certain anticompetitive conduct may be immunized from antitrust challenge by the state action doctrine, which shields anticompetitive behavior that is specifically authorized and actively supervised by a state. For example, the director of the FTC's Bureau of Competition has raised the possibility that the state action doctrine may shield the operations of ISOs (Baer 1997).

Notwithstanding the limits on antitrust enforcement, as greater reliance is placed on markets rather than regulation to determine prices and allocate resources, the importance of protecting competition in electric power markets through enforcement of the antitrust laws will increase. Both federal antitrust agencies are therefore devoting increasing attention to this industry. Aside from mergers, in 1996 DOJ sought to enjoin an Oklahoma city from refusing to extend or connect water and sewer lines to consumers unless they also bought their electric power from the city. DOJ alleged that this conduct constituted *per se* unlawful tying and that it reduced competition between the city and an electric cooperative.

In 1997, DOJ challenged an agreement between Rochester Gas & Electric and a university. DOJ charged that RG&E used financial threats and rewards to induce the university to abandon its plan to build a generating plant that would have competed with RG&E (Klein 1998, pp. 5-6). After a judge ruled that the agreement between RG&E and the university was not protected by the state action doctrine, DOJ's complaint was settled by invalidation of the agreement and a prohibition on RG&E from entering into similar agreements with competitors.

Opportunities for Structural Remedies

As a practical matter, the ability of policy makers today to bring about divestitures is limited to situations in which companies agree to "voluntary" divestitures to obtain approval for something they very much want — such as recovery of stranded costs, approval of mergers, or approval of market-based pricing. The ongoing

divestitures of generation in California and the northeast states are occurring principally because divestiture is the *quid pro quo* for stranded cost recovery.

A lesson that should not be missed is that the states may have only one chance to bring about divestitures in the electric power industry — namely, as a price for whatever stranded cost recovery will be allowed. If a deal for stranded cost recovery has been struck without adequate divestiture provisions, the opportunity will be gone. It should be noted that some state legislatures have even discarded the divestiture option before evaluating market power.[6]

In Chapter 10 we will discuss whether policy makers have adequate authority to deal with market power and how federal legislation might provide additional authority for states or FERC to address market power directly with structural remedies, instead of indirectly as a result of merger reviews or market-based pricing decisions.

CONCLUSIONS

For numerous reasons, policy makers should look first to structural remedies to shape the electric power industry into a competitive marketplace in generation and retail services. Notwithstanding a preference for structural remedies, a number of rationales can be offered for using behavioral remedies as well — mainly to deal with natural monopolies and other situations where structural remedies would cause unacceptable losses in economies of scale and scope. The next two chapters of this report will discuss remedies for market power in the context of mergers and retail restructuring proceedings.

[6] The Pennsylvania Electricity Competition Act specifically precludes divestiture of generation assets as a requirement for restructuring (66 Pa. C. S. §2804(5)).

8 MERGERS AND MARKET POWER

The techniques described earlier for assessing market power are used in a variety of settings — for example, to evaluate proposals for deregulation, divestiture requirements, and mergers. This chapter reviews recent experience with electric utility mergers, discusses how such mergers may increase market power, and finally considers how regulators and antitrust authorities have approached the market power issues raised by these mergers.

RECENT ELECTRIC UTILITY MERGERS

Electric utility mergers are not a new phenomenon, but the number of completed mergers between large electric utilities has increased in recent years. For investor-owned utilities large enough to appear on a standard wall map, one or two mergers were completed in almost every year from 1986 through 1996, with the result that the number of independent utilities on the map declined by 15 (12%). The number of utilities on the map then declined by another 4 during 1997 and will decline by 5 to 10 more by mid-1999, depending on the outcomes of the pending Western Resources/Kansas City Power & Light, Allegheny Power System/DQE, American Electric Power/Central & South West, Sierra Pacific/Nevada Power and Consolidated Edison/Orange & Rockland mergers. Even if all pending mergers are completed, the number of larger independent utilities visible on the map will stand at 92. Thus, we may expect further mergers to be proposed.

But the number of completed mergers is only part of the story. While a majority of announced electric utility mergers have eventually been completed, in the past ten years 14 mergers have been abandoned in the face of opposition and delays by target companies, stockholders, bankruptcy courts, and state and federal regulators. Table 4 lists the mergers and takeovers between investor-owned electric utilities that were proposed from 1994 through May 1998.

A major development on the merger front since 1995 has been the announcement of a dozen "convergence" mergers involving electric utilities and companies engaged in the transportation or retail distribution of natural gas. These are listed in Table 5.

Table 4. Investor-Owned Electric Utility Mergers, 1994 to Present.		
Utilities (Survivor in Bold)	**Year (Announcement to Outcome)**	**Outcome**
MidAmerican Energy Midwest Resources Iowa-Illinois Gas & Electric	1994-95	Merged
New England Electric System Nantucket Electric	1994-96	Merged
Altus Washington Water Power Sierra Pacific Resources	1994-96	Terminated by WWP
Primergy Northern States Power Wisconsin Energy (Wisconsin Electric Power)	1995-97	Rejected by FERC
PECO Energy PPL Resources (Pennsylvania Power & Light)	1995	Rejected by PPL
Ameren Corp. Union Electric CIPSCO (Central Illinois Public Service)	1995-97	Merged
New Century Energies Public Service Co. of Colorado Southwestern Public Service	1995-97	Merged
Constellation Energy Baltimore Gas & Electric Potomac Electric Power	1995-97	Abandoned
Alliant WPL Holdings (Wisconsin Power & Light) IES Industries Interstate Power	1995-98	Merged
MidAmerican Energy IES Industries	1996	Rejected by IES shareholders
Maxim Energies UtiliCorp United Kansas City Power & Light	1996	Rejected by KCPL shareholders
Western Resources Kansas City Power & Light	1996-98	Pending
Conectiv Delmarva Power & Light Atlantic Energy	1996-97	Merged
FirstEnergy Ohio Edison Centerior Energy	1996-97	Merged
Allegheny Energy Allegheny Power System DQE (Duquesne Light)	1997-	Pending
Wisconsin Energy (Wisconsin Electric Power) ESELCO (Edison Sault Electric)	1997-98	Merged
LG&E Energy (Louisville Gas & Electric) KU Energy (Kentucky Utilities)	1997-98	Merged
WPS Resources (Wisconsin Public Service) Upper Peninsula Energy	1997-98	Approved by FERC
American Electric Power Central & South West	1997-	Pending
Sierra Pacific Resources Nevada Power	1998-	Announced
Consolidated Edison (of New York) Orange & Rockland Utilities	1998-	Announced

Table 5. Convergence Mergers.			
Electric Utility	Gas Company	Years (Announcement to Outcome)	Outcome
Puget Sound Power & Light	Washington Energy	1995-97	Merged
Texas Utilities	Enserch	1996-97	Merged
Portland General Electric	Enron	1996-97	Merged
Houston Industries (Houston Lighting & Power)	NorAm Energy	1996-97	Merged
Enova (San Diego Gas & Electric)	Pacific Enterprises (Southern California Gas)	1996-98	Approved
TECO Energy (Tampa Electric)	Lykes Energy (Peoples Gas System)	1996-97	Merged
Duke Power	PanEnergy	1996-97	Merged
Long Island Lighting	Brooklyn Union Gas	1996-	Pending
PG&E (Pacific Gas & Electric)	TECO Pipeline	1996-97	Merged
PacifiCorp	TPC (Tejas Power)	1997	Merged
PG&E	Valero Energy	1997	Merged
NIPSCO (Northern Indiana Public Service)	Bay State Gas	1997-	Pending

HOW MERGERS AFFECT MARKET POWER

Mergers involving electric power companies may increase generation, transmission and fuel supply market power, as well as increase or create opportunities for various affiliate abuses. Mergers between electric and gas companies may raise fuel supply market power issues and retail market power issues. For these reasons, mergers deserve close scrutiny by regulators and antitrust authorities.

Mergers between Electric Utilities

Mergers between electric utilities may increase generation and transmission market power, and in reviewing these mergers antitrust authorities consider effects on both. By contrast, in evaluating the competitive effects of these mergers, FERC now focuses exclusively on generation market power. FERC generally ignores effects of mergers on transmission market power because the agency assumes that such market power is eliminated by its Order 888, which requires open access

nondiscriminatory transmission service, and Order 889, which requires electronic posting of available transmission capacity and standards of conduct.[7]

However, it is obviously one thing to tell companies to behave in a certain way and quite another actually to get them to forgo opportunities to increase their profits. Surfacing complaints relating to how transmission capacity is defined, measured, reported, reserved for native load uses, scheduled and curtailed (*Foster Electric Report*, April 29, 1998, p. 1) suggest that FERC's reliance on the regulatory prescriptions in Order 888 is not warranted.

While ignoring effects of mergers on transmission market power, FERC shows concern for such market power in other contexts. For example, FERC found that Washington Water Power apparently violated numerous rules in providing transmission service to its affiliated power marketer (*Foster Electric Report*, May 13, 1998, pp. 4-6). Also, FERC recognizes that new industry reliability rules and practices could be used to reduce access to transmission, and FERC commissioners and staff are promoting use of ISOs to reduce transmission market power as well as for other reasons.

To appreciate the potential effect of a merger on transmission market power, suppose that GenCo owns a large share of generating capacity in the Peninsula region. Suppose that TransCo has the ability to influence the terms on which competing generators outside Peninsula are able to transmit energy to buyers in Peninsula. As long as TransCo owns no generation in Peninsula, TransCo has an incentive to sell transmission service to generators desiring to sell energy in Peninsula. Now suppose that GenCo and TransCo merge. The merged company may now have both the ability and the incentive to restrict the availability of transmission service to reach Peninsula in order to raise the prices at which it can sell energy from the GenCo generators.

The proposed merger of Northern States Power and Wisconsin Electric Power to form Primergy raised important concerns about both generation and transmission market power. FERC chose to dismiss concerns about transmission market power in light of the assumed efficacy of Orders 888 and 889, but decided that the merger raised serious generation market power problems. Two days after FERC's decision, Primergy was abandoned.

We do not mean to suggest that generation market power should take a back seat to transmission market power concerns at FERC when mergers are examined. As stated earlier, realizing the benefits of a restructured electric market depends

[7] FERC does, however, consider whether a merger would enable the merged firm to reduce the availability of transmission service across congested interfaces for competing suppliers. See Committee on Electric Utility Regulation (1998), pp. 172-73.

> *"Non-horizontal mergers may be used by monopoly public utilities subject to rate regulation as a tool for circumventing that regulation. The clearest example is the acquisition by a regulated utility of a supplier of its fixed or variable inputs. After the merger, the utility would be selling to itself and might be able arbitrarily to inflate the prices of internal transactions. Regulators may have great difficulty in policing these practices, particularly if there is no independent market for the product (or service) purchased from the affiliate. As a result, inflated prices could be passed along to consumers as "legitimate" costs. In extreme cases, the regulated firm may effectively preempt the adjacent market, perhaps for the purpose of suppressing observable market transactions, and may distort resource allocation in that adjacent market as well as in the regulated market. In such cases, however, the Department recognizes that genuine economies of vertical integration may be involved. The Department will consider challenging mergers that create substantial opportunities for such abuses."* (DOJ 1984, Section 4.23, footnote omitted).

critically on the elimination or mitigation of significant market power both in generation and transmission. It is simply the case that FERC should examine both vertical and horizontal market power when considering mergers between electric utilities.

Convergence Mergers

If a single company owns both generators and natural gas pipelines that supply gas to competing generators, it may have the ability and incentive to raise the price of gas delivered to competing generators. DOJ, FERC and the California commission concluded that the proposed merger of Enova (owner of SDG&E's generating plants) and Pacific Enterprises (owner of Southern California Gas's transportation facilities) would result in fuel supply market power. To resolve such problems, DOJ and the California commission required that the merged firm divest SDG&E's gas-fired generators. The California commission also required the merged firm to divest options to purchase two gas pipelines. Both the California commission and FERC also imposed a number of behavioral restrictions.

A fuel supply market power issue arose in 1997 in connection with the proposed merger between PacifiCorp and the corporate parent of Peabody Coal, which supplies coal to large generating plants in the southwestern United States. The FTC reasoned that as a result of the merger PacifiCorp was likely to have the ability and incentive to raise prices of coal from two Peabody mines to competing generators because this action would raise market prices for electric energy during

off-peak hours. The FTC therefore required that PacifiCorp divest the two Peabody mines to avoid an antitrust complaint.[8]

Convergence mergers may raise additional competitive concerns related to information sharing, cross-subsidization and self-dealing (see Insert). The FTC reasoned that PacifiCorp might gain access, through Peabody's coal contracts and coal supply relationships, to highly sensitive data about competitors' costs and to information about the operating conditions of competing generators. The FTC was concerned that such information would enable PacifiCorp to identify situations in which it could raise prices because it did not face competition.

In addition, a horizontal market power issue is raised by mergers between electric and gas distribution utilities that have overlapping retail territories, and also when an electric distribution company proposes to merge with a gas pipeline that can influence the retail price of gas sold to customers of the electric company. In such cases, a merger may increase horizontal market power by reducing competition between electricity and gas.

Some customers can choose between gas and electricity for some of their energy requirements, and a merger between gas and electric utilities with overlapping retail territories is therefore likely to eliminate some price and non-price competition. For example, such a merger might eliminate competition to reduce costs and prices, to provide superior customer service, to provide incentives for developers of all-electric housing, and to provide discounts for customers with gas air conditioners and electric heat pumps. Some studies have concluded that costs are actually lower when electric and gas utilities are separately owned than when there is a combination utility (Frankena and Owen 1994, pp. 130-33). Nonetheless, FERC typically leaves consideration of the effects of mergers on retail competition to state regulators, and the federal antitrust agencies have not challenged electric-gas mergers based on concerns over retail electric-gas competition.

There are a number of possible explanations for why the antitrust agencies may have concluded that they would not prevail in court in a merger challenge based on reduced retail competition between electricity and gas. Merger applicants may have argued:

- At present and forecast prices for electricity and gas in some parts of the country, electricity is not competitive with gas for uses such as space heating.
- The reduction in competition will not be significant if there is open access to the electric or gas distribution system.

[8] Ultimately, PacifiCorp was outbid by Texas Utilities, which had arranged to sell Peabody Coal.

- Requirements for uniform service territory tariffs will prevent a merger involving a partial overlap of customers from having a significant effect.

Also, if state regulators believe they can protect retail ratepayers from the exercise of market power by combination utilities, political considerations may weigh against a federal challenge. Because convergence mergers are likely to continue to be proposed, this heightens the importance of scrutiny of such mergers by state regulators.

EVOLUTION OF FERC'S MERGER POLICY

FERC's concern over the competitive effects of mergers was initially heightened by three large mergers proposed in the late 1980s — PacifiCorp's acquisition of Utah Power & Light, SoCal Edison's attempt to acquire SDG&E, and Northeast Utilities' acquisition of Public Service Company of New Hampshire. Each of these mergers was the subject of FERC and state proceedings that lasted for over two years. The California commission rejected the SoCal Edison/SDG&E merger because of its effects on competition as well as other concerns, while FERC imposed conditions on the PacifiCorp and Northeast Utilities mergers to mitigate transmission market power.

By contrast, during the early 1990s FERC approved all merger proposals — including transactions as large as Entergy's acquisition of Gulf States Utilities — without serious analysis of competitive effects. FERC did not analyze competitive effects when the merging companies agreed to provide open access transmission service, as all did. FERC's reasoning was that the pro-competitive effects of open access under a single-system tariff were sufficient both to prevent an increase in transmission market power and to offset any increase in generation market power.

By 1994, some FERC commissioners were speaking out on the weaknesses of FERC's merger policy in an era in which increasing reliance was being placed on competition. Also, after Order 888 imposed open access on all public utilities in 1996, it was no longer possible for merging companies to avoid scrutiny of competitive effects by offering open access. In 1996, FERC formally changed its approach to merger evaluation by issuing its *Merger Policy Statement*. In 1997, FERC's adverse finding regarding the competitive effects of the proposed Primergy merger was quickly followed by abandonment of the transaction. FERC also found that the Enova/Pacific Enterprises merger raised significant fuel supply market power problems.

More recently, FERC has decided that some merging utilities must provide greater transmission access in order to overcome concerns about market power over municipal and cooperative utilities located in the merging companies' territories. FERC has also required that some merging companies turn control of their

transmission systems over to a regional ISO, typically after the merging companies have offered to do so. By the first half of 1998, as a *quid pro quo* for avoiding hearings on market power, it was becoming routine for applicants to offer commitments to join an ISO and to sell a few hundred megawatts of energy for a few years to offset potential generation market power problems.

FERC has stated that it will leave to states the task of evaluating the effects of mergers on retail competition while FERC focuses on effects on wholesale competition. However, when states open some or all retail sales to competition, utilities have more electric power that they are free to sell — either at wholesale or retail — at market prices. As a result, the introduction of retail competition will change market shares, concentration and market power at the wholesale level. It follows that the effect of a merger on future wholesale competition cannot be evaluated without taking into consideration future changes in retail customer choice. In any case, FERC requires two analyses of the effects of mergers on wholesale competition in electric energy, one based on "available economic capacity," which assumes existing levels of retail competition, and a second based on "economic capacity," which assumes that all native load customers have the ability to choose among energy suppliers.

STATE REGULATORY COMMISSIONS

Regulatory commissions of states in which retail customers are served by a merging utility typically must approve a proposed merger. There are exceptions, for example, when the structure of a merger transaction does not change control over the jurisdictional assets in a state. For a number of mergers, state commissions have considered the same competitive issues that FERC has evaluated, as well as additional issues such as retail competition. This was true of the California commission in the SoCal Edison/SDG&E merger, the Wisconsin commission in the Primergy merger, and the Pennsylvania commission in the Allegheny/DQE merger. The California commission's rejection of the first of these mergers caused that merger to be abandoned. Commission staff in Wisconsin opposed the Primergy merger, which was rejected by FERC before the Wisconsin commission reached a decision. The Pennsylvania commission approved the Allegheny/DQE merger only on condition that the utilities join a functioning ISO, while that merger is still pending at FERC.

ANTITRUST AGENCIES

In addition to requiring approval by FERC and state commissions, utility mergers can be challenged in court by the federal antitrust authorities, state attorneys general, and private parties for violation of the Clayton Act, which prohibits mergers that may substantially lessen competition.

During FERC's evaluation of the proposed SoCal Edison/SDG&E merger, DOJ participated as an intervenor in the FERC proceedings. Since then, rather than participate in regulatory proceedings, the federal antitrust agencies have carried out independent investigations of utility mergers that raised potential concerns. However, with the exceptions of the Enova/Pacific Enterprises and PacifiCorp/Peabody vertical mergers, the antitrust agencies have not issued complaints or obtained remedies.

Antitrust action may in certain cases be deterred by concerns that the agencies will not succeed in carrying their burden of proof to persuade a federal district court to block a merger, particularly if a merger has been approved by FERC. The United States assistant attorney general for antitrust has suggested that even if DOJ concludes internally that a utility merger is likely to be anticompetitive, DOJ may be unable to convince a court to agree given the limited real world market transactions data available to demonstrate key points such as the geographic scope of competition. This concern led the US assistant attorney general to suggest either a moratorium for a few years on mergers between large directly interconnected utilities or a shifting of the burden of proof to the merging companies (Klein 1998, pp. 12-15).

State attorneys general have evaluated the competitive effects of a number of electric utility mergers and either participated in regulatory commission proceedings on those mergers or prepared to challenge them in court. Affected parties may also file antitrust suits in an attempt to convince courts to enjoin mergers. For example, Pittsburgh filed an antitrust suit against the Allegheny/DQE merger.

CONCLUSION

There is no facile "rule-of-thumb" that can be used by policy makers to determine whether a particular merger would be anticompetitive. Some mergers can increase efficiencies without producing undesirable effects on competition. Other mergers can create or increase market power to such a degree that they must be substantially modified or rejected. The lesson is that there is no substitute for careful analysis on the part of policy makers. In a later chapter we examine the implications for merger policy of proposals being considered for federal legislation.

9 RETAIL CUSTOMER CHOICE AND MARKET POWER

This chapter addresses market power problems that may arise at the retail level, rather than wholesale level, of the electric power supply industry. Retail market power is likely to manifest itself in narrower choices among service and pricing options, inferior customer service, and higher prices for retail electric services for any given level of wholesale prices. For the discussion of these issues, the term *retail marketing* will be used to refer to 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. The suppliers of these services are retail marketers, aggregators and energy services companies.

ORIGINS OF RETAIL MARKET POWER PROBLEMS

As discussed earlier, if entry into a market is "easy" in the antitrust sense, market power is unlikely to be a problem even if the market is highly concentrated. As we stressed, though, to be easy, entry by competitors must be more than simply possible. Entry must be feasible, able to occur on a timely basis, and profitable for the new entrant. As a result, in analyzing competition in retail marketing, it is useful to begin by asking what barriers to entry may exist. For the most part, there appear to be three potential types of entry barriers:

- Barriers that arise from vertical integration of the local distribution utility into retail marketing. Vertical integration may lead to exercise of distribution market power (see Chapter 5 above), improper information sharing and cross-subsidization.

- Barriers that arise from imperfect information and inertia when a market is opened to competition. Even though consumers have a choice of suppliers, they may not switch to a new supplier that offers a superior service, or an equivalent service at a lower price, if they lack information about relative services and prices, and because of inertia.

- Barriers created by government policies, such as provisions for recovery of stranded costs.

In order to demonstrate the importance of such entry barriers in explaining any retail market power problems that may exist, suppose that none of these three types of barriers are present but that nonetheless one company has a very large

market share. Suppose further that this company's share can be explained by the fact that its prices are lower than those of its smaller competitors, and that it is able to charge these lower prices because of various cost advantages. Its cost advantages might be a result of its years of experience in the industry, relatively large scale, or superior management. Should policy makers do anything about this situation? What in fact could public policy accomplish?

Public policies might be adopted to "level the playing field," but policies that would eliminate genuine cost advantages or prevent a seller from taking advantage of such cost advantages would not reduce prices to consumers; the opposite effect on prices is more likely. In short, absent entry barriers, public policies aimed at reducing the market share of the largest supplier may help smaller competitors, but such policies may actually hurt consumers. It is, therefore, important to assess entry barriers.

ENTRY BARRIERS ARISING FROM VERTICAL INTEGRATION

Competitive concerns raised by common ownership of monopoly distribution utilities and competitive retail marketing companies operating in the same geographic market are discussed in Chapter 5. Government regulators have followed several approaches to dealing with these concerns, including the following:

- *Prohibition of Common Ownership*: Distribution utilities and their affiliates could be prohibited from engaging in sales of power and energy services to retail customers who are able to choose among suppliers and who are located in the geographic area served by the distribution system. For a time, the New Hampshire commission's restructuring plan required that distribution utilities divest marketing services and prohibited distribution companies from marketing power in their franchise territories. These prohibitions would have barred Northeast Utilities from selling power in over half the state, but they were replaced in 1998 by behavioral regulations. In 1998, an Illinois court affirmed a state commission decision rejecting Commonwealth Edison's proposal for an affiliate that would supply energy support services to jurisdictional customers. The commission ruled that if Commonwealth Edison participated in both the energy and energy services markets, it would have an incentive to drive competitors from the latter.

- *Organizational Separation*: A state could require that regulated and unregulated businesses be conducted in separate subsidiaries of a holding company. For example, the subsidiary operating the distribution utility could be prohibited from engaging in retail marketing, which would have to be handled by a separate subsidiary. More limited forms of separation are unbundling of services, accounting separation, and the creation of firewalls between activities within a company. For example, England/Wales and Norway require that

distribution companies unbundle and keep separate accounts for wires services and retail marketing. However, the industry regulator in Norway reported that a number of problems persisted. (See insert.)

> *Most [distribution] utilities tried to establish barriers to traders entering their service area in the form of network restrictions on wheeling. In most cases these restrictions were discriminatory....*
>
> *Some sort of cross-subsidization seems always to be possible in a vertically integrated company, which also works to the disadvantage of traders....*
>
> *A major problem from a regulatory perspective is cross-subsidization from the wires business to final sales. Without this "extra" margin, the final sales business could be a problem for some utilities....*
>
> *The challenge remaining for the reform and the regulator are to restructure the ownership (the wires and final sales) to avoid cross-subsidization and to lower wheeling costs. A major goal remaining is to split the final sales and wires into separate companies.* (Moen and Hamrin 1996).

- *Prohibitions on Self-Dealing.* In some cases, regulators attempt to deal with competitive problems relating to affiliate abuse and evasion of regulation by prohibiting regulated companies from buying inputs from and selling outputs to unregulated affiliates. For example, a number of states prohibit distribution utilities from purchasing electric power from unregulated affiliated generators, and many states require competitive bidding.

- *Performance-Based Pricing.* Competitive problems relating to cross-subsidization and inappropriate transfer prices in affiliate transactions stem in part from incentives created by traditional cost-based regulation of monopoly activities. These problems may be reduced if regulated prices do not increase when a company's costs increase. A number of states, such as California, have moved away from cost-based regulation to various forms of performance-based regulation. These efforts have parallels in telecommunications, where the Federal Communications Commission and many state regulators are now using "price cap" regulation that breaks the direct link between costs and regulated rates.

- *Regulation of Discriminatory and Other Anticompetitive Behavior*: The default option for attempting to deal with competitive problems raised by common ownership of regulated monopoly and competitive businesses is the proliferation of behavioral regulations, codes of conduct and disclosure requirements aimed at preventing regulated monopolies from behaving anticompetitively toward rivals in competitive markets. Given such regulations, another option is to devote substantial ratepayer and taxpayer resources to monitoring the behavior of vertically integrated companies. An additional option is to subject abuses to

penalties (beyond disallowances) to increase deterrence. Regulatory approaches not only impose costs but offer mitigation that is incomplete. (See insert).

> With regard to SoCal Edison's purchases from its unregulated generation affiliate at inflated prices during the 1980s (see Appendix B), the California attorney general stated:
>
> *"The fact that this proceeding took two years to get to an ALJ decision illustrates the limits of regulation in detecting and correcting abusive self-dealing practices."*
>
> (Opinion No. 90-507. 1990 Cal. AG LEXIS 57; 73 Op. Atty Gen. Cal. 366; 1991-1 Trade Cas. (CCH) P69, 427).

In fact, thus far states have rarely prohibited affiliates of distribution utilities from engaging in retail marketing (see Jaffe 1998). The principal economic rationale that is typically offered for avoiding structural remedies is that there are economies from vertical integration. In any event, as long as vertical integration is permitted, regulators will impose numerous behavioral rules in an attempt to limit potential abuses.

Use of Distribution Company Assets in Retail Marketing

This section addresses one specific situation that arises in connection with vertical integration between distribution and retail marketing, namely: the use by a marketing affiliate of assets acquired by the distribution utility in the course of carrying out its regulated business. The discussion here will focus on use of the distribution company's brand name and logo by affiliated marketers. Another example would be use of the distribution company's databases on customer characteristics and consumption patterns.

As a starting point, it is important to recognize that brands are valuable assets that are recognized in stock market valuations. Companies typically build brand names by supplying products that satisfy consumers and by advertising, often at substantial cost. A brand name is valuable when it enables a company to sell more output, other things equal.

Furthermore, brands have important consumer benefits because they help consumers to overcome imperfections of information. The thrust of the substantial economics literature on the function of brands is that companies build brand names and associated reputations in substantial part to reduce search costs for consumers. Brands also serve as guarantees — or bonds — of product or service quality (Frankena 1992). It does not typically make sense for a company to spend millions of dollars building a brand name if the products the company sells will not satisfy consumers. Company investments in building a brand name are likely to be

worthwhile only if the brand helps in attracting and retaining *satisfied*, repeat buyers. If a company delivers shoddy products, it will not only lose customers but damage its brand — in short, it will forfeit its bond.

Because consumers tend to benefit from the existence of brand names, a policy of restricting the use of brand names has the potential of making consumers worse off. The ability to use the existing brand name of a distribution utility is likely to reduce the costs of an affiliated marketer, and also to increase the incentives of such a marketer to satisfy consumers. Those things will tend to benefit consumers. This is not, however, the entire story. A number of complications should be considered in reaching a conclusion regarding appropriate policies toward brands:

- If an affiliated marketer is allowed to use a distribution utility's brand name and logo, and if the distribution utility is subject to cost-based regulation, then the distribution utility may have an incentive to spend as much money as regulators will permit to build the brand name — even if such expenditures do not benefit its jurisdictional customers. Such expenses may be passed along in higher prices for regulated wires services while benefits will accrue to the affiliated marketer. Thus, regulators may have to decide how much advertising, if any, the distribution utility should do.

- If the distribution utility has been guaranteed recovery of its costs and a regulated rate of return for many years, should the value of its brand in new uses accrue to the jurisdictional customers, rather than to the utility's shareholders? In that case, should jurisdictional customers be paid for use of the brand? Downs (1998) reports that the weight of legal authority is that ratepayers have no property interest in a regulated utility's goodwill assets, including its brand and logo. However, at least in some cases, regulators would seem to have a reasonable case that jurisdictional customers have some claim to the value of a brand name.

- There may be a regulatory concern that an affiliated marketer could conduct its affairs in a manner that would reduce the value of a shared brand name to the distribution utility and its jurisdictional customers. Should jurisdictional customers be compensated for this risk?

- Use by a marketing affiliate of the distribution utility's brand name and logo has the potential to deceive consumers. For example, consumers might infer that the affiliated marketer can offer more reliable delivery because of its affiliation with the distribution company, or that the affiliated company is regulated by the state commission. To deal with potential deception, California has mandated disclosure requirements. A utility affiliate cannot use its parent's brand or logo in advertising unless it plainly reveals that the affiliate is not the same company as the utility, that the affiliate is not regulated by the state commission, and that a customer is not obligated to buy the affiliate's product to receive regulated

services from the utility. This would appear to be a reasonable requirement that achieves consumer protection without an outright ban on the use of the brand name.

In the end, theoretical economic reasoning alone appears to be insufficient to reach a conclusion on efficient policies toward affiliate use of brands. Regulators are put in the familiar position of attempting to protect consumers and provide the right incentives to the regulated companies while maximizing the value of the regulated assets. The correct solution to the brand name issue will likely vary somewhat from case to case, depending on the exact arrangements in the market, regulatory history, style of residual regulation and other factors.

IMPERFECT INFORMATION AS AN ENTRY BARRIER

Imperfect information probably enables former monopolists in deregulated markets to charge prices above those that would prevail if consumers had perfect information about the services and prices offered by competitors and if consumers responded quickly and dramatically to differences in relative prices. This is likely to be true in emerging retail electricity markets. The question is what public policy can usefully do about this situation.

Policy makers cannot in fact easily remove the problems that arise from imperfect information and consumer inertia in electric power or other markets. Two policy approaches may make sense. First, in some cases private parties may not have adequate incentives to provide information to consumers, and there may be a role for government in disseminating information. Some state public utility commissions have made consumer education a main feature of restructuring plans of electric utilities. Second, there is a role for government to pass and enforce consumer protection laws designed to prevent deceptive advertising and marketing.

Once again, the experience in telecommunications is relevant. Telephone consumers experienced a troublesome period as independent deregulated payphones were established. Consumers, many of them "transient" customers who were traveling, were accustomed to dealing with familiar monopoly providers when making collect or credit card long distance calls from payphones. New "operator service providers" (OSPs) found they were able to charge exorbitant rates for long distance calls made from these payphones, even as consumers used calling cards issued by their familiar local exchange company.

Information about the rates of OSPs was very difficult to obtain and billing was often delayed months, making it nearly impossible for consumers to understand the new arrangements and to react to prices. The situation was partially ameliorated only after Congress and many state legislatures passed laws requiring various forms of disclosure and refunds of excessive charges. In reaction to the price

gouging, the FCC and many state regulators adopted regulations for OSPs including disclosure requirements such as the requirement of "branding" announcements during the phone call, refunds of exorbitant charges and limits on commissions paid by OSPs to phone location owners. Some state commissions also undertook consumer education efforts of their own. At a time of significant change in this industry when *more* information was needed, imperfect information resulted in price gouging and poor service.

A second telecommunications example concerns long distance service. Although there are many competitors in the long distance industry, regulators have found it necessary to adopt and enforce regulations about how customers can be solicited by long distance companies. Customer inertia, complicated pricing plans and a poor consumer understanding of the rules in this newly competitive market have led to abuses. One purpose of these regulations is, in part, to stem the practice of *slamming*, the unauthorized switching of a consumer's long distance carrier.

In both cases, less efficient providers displaced more efficient ones, to the detriment of consumers. Regulators and legislators adopted and began to enforce new consumer protection rules even as competition was introduced to this market.

Government Policies as Entry Barriers

Government policies, such as provisions for recovery of stranded costs, may inadvertently erect entry barriers. For example, 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 (see Pierce 1998).

An implication of this example is that policy makers should attempt to remove avoidable entry barriers and avoid adopting new regulations that will impede entry into retail markets.

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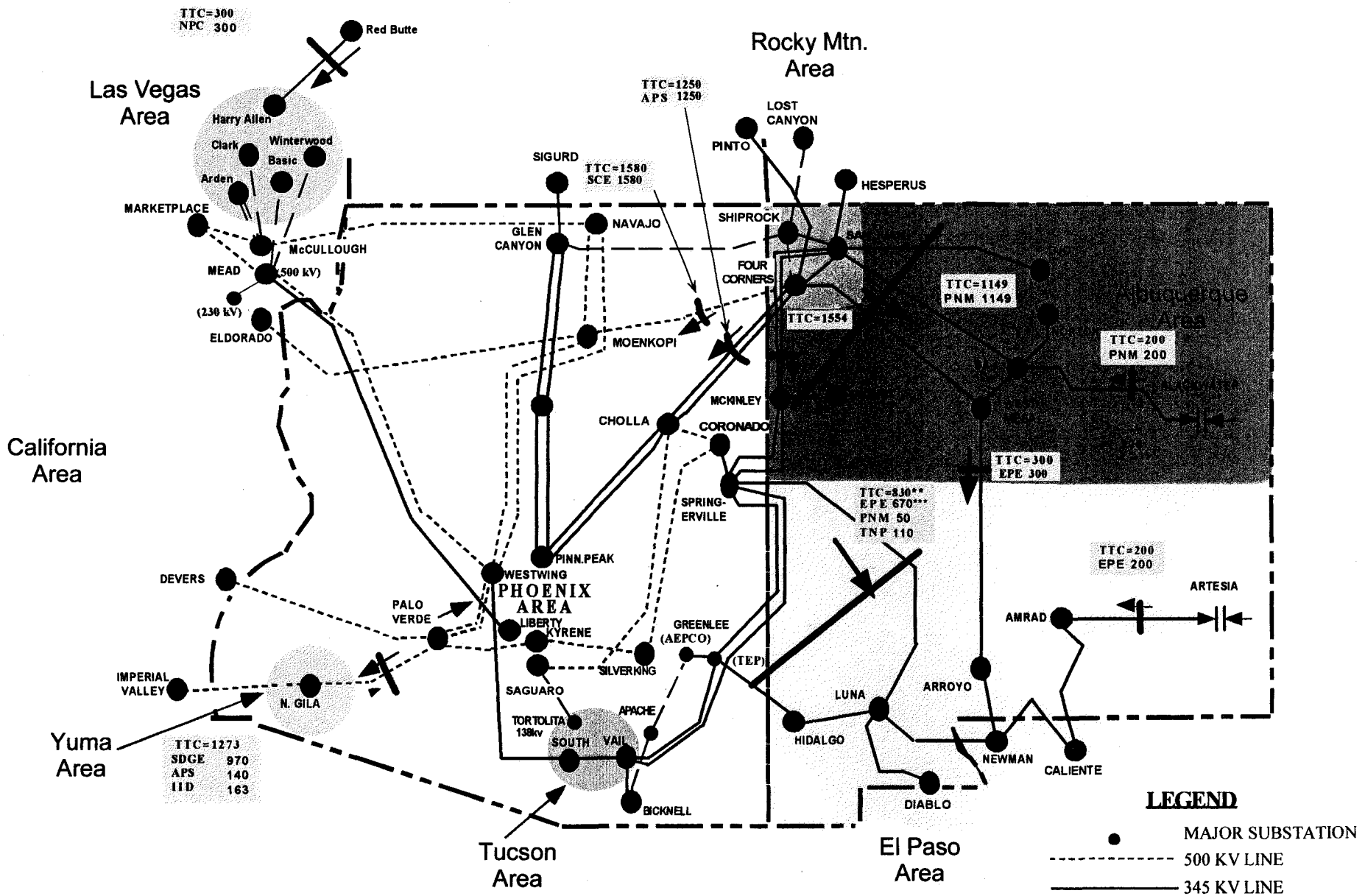

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Planning Work Group Final Report

Desert STAR

Prepared by the Desert Star Planning Work Group

September 12, 1997

The Planning Work Group briefly discussed the need to define the planning and operational seams issues between DSTAR and the distribution entities. The group recommends that a Phase II assignment to the Operations and Planning Work Group should include the development of detailed operating and planning procedures between the distribution entities and DSTAR. To date, the Planning Work Group focused on regional planning requirements of DSTAR, and anticipates addressing local coordination and planning issues in Phase II.

4.3 Seams Issues Associated with Interconnections with Mexico

In addition to the Seams issues currently under discussion, the Planning Work Group identified a number of other coordination efforts that need to be further addressed in Phase II. DSTAR needs to incorporate transmission systems that interconnect the United States and the Mexico transmission grids. These two transmission grids are asynchronous; therefore, transfer of power over those interconnects (either the United States side or the Mexico side of the interconnections) must operate as an island. To safely incorporate this type of interconnection, DSTAR must have sufficient information as to time of day loads.

Currently, the interconnection facilities between the United States and Mexico are under the regulatory control of the U.S. Department of Energy (DOE) while the jurisdiction for open transmission access is under the jurisdiction of FERC. Therefore, the transmission for foreign sales/purchases to and from Mexico is not specifically under the FERC Open Access tariffs, and FERC may not be able to order transmission access for such sales or purchases. This jurisdictional problem is expected to be addressed at both FERC and DOE in the future. Because of the numerous potential interconnections, DSTAR should actively address interconnection issues with Mexico in Phase II and should consider how WRTA and NRTA are addressing this issue with Canada.

5. Transmission Facilities Under DSTAR

This section outlines the transmission facilities that could come under DSTAR=s operational authority depending upon the final ISO requirements and the guidelines developed to select those transmission facilities. The DSTAR planning process and pricing methodology are not necessarily confined to the transmission facilities outlined in this document. For example, the DSTAR pricing methodology may take into account all bulk transmission and sub-transmission assets. The specific details regarding the measure and extent of control that DSTAR maintains over these facilities is covered in the DSTAR Operating Work Group Report. A list entitled APreliminary Designation of Transmission Facilities for DSTAR Control≅ is attached as Exhibit 4.

5.1 Covered Facilities Guidelines

The members of the DSTAR Planning and Operations Work Groups followed the guidelines listed below to identify which member transmission facilities qualify for DSTAR control. The Planning Work Group supports the guidelines developed by the Operations Work Group and expanded those guidelines to include the fifth guideline listed below.

5.1.1 The facilities are critical to maintaining transmission system security.

5.1.2 The facilities have a significant and measurable impact on the transmission system transfer capability (e.g., congested paths).

5.1.3 The facilities are used to maintain, under today=s paradigm, wholesale transactions[1] in the marketplace.

5.1.4 The facilities are generally characterized as 230 kV and above.

5.1.5 The DSTAR transmission facilities as a whole are contiguous.

5.2 Excluded Facilities

To this point, certain transmission facilities which meet one or more of the aforementioned guidelines have been designated as non-DSTAR facilities by the transmission owner. This is a preliminary list, and is subject to change. The rationale used by the transmission owners to exclude these facilities are as follows:

5.2.1 Nevada Power Company
- radial 230 kV transmission lines interconnecting NPC owned generation to the company=s transmission system
- 230 kV lines operate as a network with the company=s sub-transmission system, and as such, the lines do not have specific total transfer capability ratings
- In each case above, the 230 kV transmission lines are nested within NPC=s transmission system.

5.2.2 Arizona Public Service
- 230 kV lines are network lines, and they do not have a specific assigned total transfer capability
- radial 230 kV transmission

5.2.3 Arizona Electric Power Cooperative
- 230 kV line is a non-commercial, radial line

5.2.4 Western Area Power Authority (AWestern≅)
- Western focused on the 500 kV and 345 kV bulk transmission lines between control area.

5.2.5 Salt River Project
- Component of local network providing serving native loads

5.2.6 Tucson Electric Power
- Transformers that connect the Tucson load center to the bulk transmission network.

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[1] A number of wholesale entities receive service at distribution voltage levels. Those wholesale entities recognize the need to separate operational control and authority between the ISO and the distribution entities; however, their concerns related to fair and nondiscriminatory access from generation sources to point(s) of delivery at distribution voltage levels needs to be assured by DSTAR.

The Planning Work Group recognizes that the list of excluded facilities will require detailed analysis in Phase II. Close coordination between the Pricing and Operations Work Groups will be needed. In addition, there are facilities at voltages less than 230 kV that may be appropriately included in DSTAR.

6. Coordination with Pricing/Tariff Group

6.1 Congested Paths

In accordance with a request from the DSTAR Pricing Work Group, the DSTAR Planning Work Group developed a list of existing or potential congested transmission paths in the southwest (attached as Exhibit 5). The discussions centered on two types of congested paths: actual congested paths (labeled by an A) and scheduling congested paths (labeled by an S). Actual congested paths include paths where there are actual flow constraints (i.e, technical limitations related to system reliability and/or equipment limitations); scheduling congested paths include paths where existing contractual obligation limit transactions.

7. Phase II Issues

The members of the Planning Work Group agreed that there are many issues that will need to explored and addressed in greater detail in Phase II.

The Planning Work Group identified some of the issues that will need further exploration and discussion during Phase II of DSTAR. This list is not all inclusive, and may be revised.

7.1 DSTAR=s role in local transmission planning process

7.2 DSTAR=s role in the commercial aspect (Integrated Resource Planning)

7.3 How to ensure compliance with state and local rules and regulations

7.4 DSTAR=s role in siting new facilities

7.5 Accommodating retail access concerns in the DSTAR planning process

7.6 Determine/refine planning process for DSTAR

7.7 Formalize planning process

7.8 Develop/refine regional reliability criteria

7.9 Work out details regarding interactions between DSTAR and other ISOs/control areas

7.10 Work with RTG=s/SWRTA to revise membership of SWRTA to include all DSTAR stakeholders

Springerville to Luna (345)		A

Exhibit 5
to
Planning Work Group Final Report

AList of Existing or Potential Congested Transmission Paths in the Southwest≡

CONGESTED PATHS

	S=Schedule	A=Actual
Arizona		
Northeastern Arizona:		
(2) Glen Canyon to Pinnacle Peak (345)	A/S	
(2) San Juan to Springerville (345)	S	
(2) Four Corners to Cholla (345)	A/S	
Four Corners to Moenkopi (500)	A/S	
Shiprock bidirectional Glen Canyon (230)	A/S	
Southeastern Arizona:		
Springerville to Coronado (345)	S	
Coronado to Silverking (500)	S	
Greenlee into AEPCO=s 230 kV System		A
Springerville to Vail (345)	S	
Springerville to Greenlee (345)	S	
Greenlee to Vail (345)	S	
Vail into AEPCO=s 230 kV System		A
Westwing bidirectional South (345)	S	
Vail into Tucson network		A
South into Tucson network		A
North Loop into Tucson network		A
Central Arizona:		
Moenkopi to Eldorado (500)	S	
(2) Cholla to Pinnacle Peak (345)	A/S	
Westwing (230) into Phoenix network	A/S	
Liberty bidirectional Mead (345)	S	
Liberty to Parker (230)	S	
Pinnacle Peak to Davis (230)	S	
Palo Verde to Kyrene (500)	S	
Palo Verde to Devers (500)	S	
Palo Verde to North Gila (500)	S	

Exhibit 5
to
Planning Work Group Final Report

AList of Existing or Potential Congested Transmission Paths in the Southwest≡

CONGESTED PATHS

	S=Schedule		A=Actual
Colorado			
Southwestern Colorado (Four Corners Area):			
TOT 2A	S		
Rifle to San Juan (345)			
Durango to Shiprock (115)			
Curecanti to Shiprock (230)			
Utah			
Southeastern Utah:			
TOT 2B	S		
Huntington to Four Corners (345)			
Sigurd to Glen Canyon (230)			
Nevada			
Southern Nevada:			
Navajo to McCullough (500)	S		
McMullough into NPC network (230)	S		
Mead into NPC network (230)	S		
TOT 2C	S		
Redbute to Harvey Allen (345)			
New Mexico			
Eastern New Mexico:			
Blackwater bidirectional B-A (345)		A/S	
Eddy County bidirectional Amrad (345)		A/S	
Northern New Mexico:			
Northern New Mexico Imports (NNMI)			A
San Juan to Ojo (345)			
San Juan to BA (345)			
Four Corners to West Mesa (345)			
Four Corners to Gallegos (230)			
Gallegos Transformer (230/115)			
McKinley to YahTaHey (345/115)			
West Mesa to Arroyo (345)			
West Mesa to Belen (115)			
Northeastern New Mexico Imports (NAS)			A
Ojo Transformer (345/115)			
Norton Transformer (345/115)			
Norton to Algodones (115)			
B-A to ETA (115)			
B-A to Zia (115)			
Central New Mexico:			
West Mesa bidirectional Arroyo (345)		A/S	
Greenlee to Hidalgo (345)			A

OPERATIONS/IMPLEMENTATION WORKGROUP STATUS REPORT

DSTAR

MAY 1998

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I. EXECUTIVE SUMMARY

A. CONSTRAINED PATHS/CONGESTED MAP ZONES

Eight zones have been identified for the DSTAR region. The zones are:

1) Northern New Mexico
2) Southern New Mexico/El Paso
3) San Juan/Four Corners/Shiprock
4) Phoenix, AZ
5) Tucson, AZ
6) Las Vegas, NV
7) Yuma, AZ
8) Remaining Arizona

Zones #3 is an "export" congestion zone. Zone #8 is not congested and the remaining zones (to load centers) have "import" constraints.

B. CONSTRAINED PATHS DATA

The constrained path list was developed from a combination of:

1) Known Thermal Line Constraints
2) ATC = 0
3) Must-run Unit Operation

Phoenix, Las Vegas, Tucson and El Paso require local generation due to import limitations into the load centers on transmission circuits internal to their load centers. Albuquerque has voltage limitations for N-1 conditions on the San Juan/Four Corners path.

The San Juan/Four Corners/Shiprock center has export contraints to Albuquerque, Cholla, Moenkopi and Glen Canyon.

C. MUST-RUN GENERATION

Phoenix, Las Vegas, Tucson and El Paso each have units that must be operated to serve load in the high load seasons. Following is the must-run relative magnitude:

Phoenix:	450 Hour/Year
Las Vegas:	Not Verified
Tucson:	81% of the Days
El Paso:	Minimum of 3 Units Must Run All Year

D. IMPLEMENTATION MODELS

Four models are recommended to by analyzed for DSTAR as:

1) a Scheduling Administrator
2) a Security Coordinator
3) a Hybrid-Control Area Operator
4) a Single Control Area Operator.

E. DSTAR CONTROL AREA OPERATIONS

Discussion early in this Stage of Phase II, a poll was taken to obtain a sense as to where the member DSTAR Control Area Operators stood on relinquishing their Control Area Operation to DSTAR.

Following are the results of the poll:

STATUS	MEMBER
Continued CAO's	SRP, WAPA, EPE
Considered Turn-Over of CAO's	APS
Undecided	PNM, NPC, TEP
Evaluating CAO's	PEGT

II. CONSTRAINED PATHS/CONGESTED ZONE MAP

III. CONSTRAINED PATHS DATA

DSTAR O/I WORKING GROUP
Congested/Constrained Interface:

Company:	Path:	Nature of Congestion:
AEPCO	Westwing/Vail 345Kv TTC=161MW	0 ATC all year, committed use.
APS	4-Cnrs/Cholla 345kV TTC=1250MW	0 ATC for 742 hrs/yr, 62 ATC for 1550 hrs/yr
	Palo Verde-Westwing TTC=1318	0 ATC for 318 hrs/yr 66MW ATC for 2294 hrs/yr
	Palo Verde-N. Gila TTC=140MW	0 ATC for 2968 hrs/yr 7MW ATC for 4294 hrs/yr
El Paso	West Mesa-Arroyo 345kV TTC=300MW	0 ATC for 7000 hrs/yr
	Sprvl-Luna 345 kV Greenlee-Hidalgo 345kV TTC=519MW	0 ATC for 5500 hrs/yr
NPC	Red Butte-Harry Allen TTC=300MW	0 ATC for 3384 hrs/yr
	Harry Allen-Mead TTC=300MW	0 ATC for 3384 hrs/yr
	Harry Allen-McCullough TTC=300MW	0 ATC for 3384 hrs/yr
	Namajor-McCullough TTC-360MW	0 ATC for 1248 hrs/yr
PNM	San Juan-Albuquerque	0 ATC all year, committed use.
SRP	4 Cnrs-Coronado TTC=50MW	0 ATC all year, committed use.
	4 Cnrs-4Cnrs TCC-50MW	2MW ATC all year
	NV-Moenkopi- McCullough	0 ATC all year, committed use.

	TTC=344MW	
	Palo Verde-Hayden TTC=95MW	13MW ATC Jul-Sep

DSTAR O/I WORKING GROUP
Congested/Constrained Interface Con't:

	Palo Verde-Pinnacle Peak	13MW ATC Jul-Aug
	SilverKing-Hayden TTC=95MW	21MW ATC May-Aug
TEP	(2) San Juan to McKinley 345kV TTC=1554MW	0 ATC all year, committed use.
	Sprvl-Coronado 345kV TTC=672MW	0 ATC all year, committed use.
	Sprvl-Vail 345kV TTC=666MW	0 ATC all year, committed use.
	Sprvl-Greenlee 345kV TTC=745MW	0 ATC all year, committed use.
	Greenlee-Vail 345kV TTC=896	0 ATC all year, committed use.
	Westwing Bidirectional South 345kV TTC=511MW	0 ATC all year, committed use.
	Vail into Tucson Network TTC=1338MW	0 ATC all year, committed use.
	South into Tucson Network TTC=672MW	0 ATC all year, committed use.
	North Loop into Tucson Network TTC=672MW	0 ATC all year, committed use.
WAPA	Data Not Confirmed	

IV. SUMMARY OF MUST-RUN UNITS

Phoenix, Las Vegas, Tucson and El Paso each have units that must operate to serve load.

The following summarizes the Must-Run relative magnitude:

Company	Description
AEPC	One of the units at Apache must run all year
APS	Metro-Phoenix units must run approximately 447 hrs/yr when valley load exceeds 5800MW Yuma - Douglas - N-1 contingency Douglas - N-1 contingency
El Paso	Minimum of 3 units must run all year Rio Grand Plant must run to maintain import capability which is 100% of the time in the summer months
NPC	Data not confirmed
PNM	No must-run units
SRP	Metro-Phoenix units must run approximately 200-400 hrs/yr when valley load exceeds 5800MW
WAPA	Data not confirmed

V. IMPLEMENTATION MODELS

Four models are recommended to by analyzed for DSTAR implementation consideration: The models were suggested as a result of the Pricing WG's "Economic Analysis" Subgroup efforts.

DSTAR Implementation Options Briefs:

Option 1: ISO as **Independent Scheduling Administrator**

Market Structure:

- WSCC Security Coordinator hosted by WAPA
- Regional OASIS hosted by ISO
- Congestion Management protocols implemented by ISO
- Scheduling Coordinator infrastructure implemented
- Control Area Operators continue to operate the grid.

Characteristics:

The ISO will rely heavily on well defined and well developed Protocols/agreements which would integrate all of the market structure functions listed.

Critical Path Implementation Issue:

- Operation in 12 months
- Regional Transmission Tariff
- Congestion Management Protocols/Agreements.

Option 2: ISO as **WSCC Security Coordinator**

Market Structure:

- WSCC Security Coordinator hosted by ISO
- Regional OASIS hosted by ISO
- Congestion Management hosted by ISO
- Scheduling Coordinator infrastructure implemented
- Control Area Operators continue to operate the grid

Characteristics:

- The ISO would consolidate the OASIS and the Security Coordination functions but would have to develop protocols and agreements such that the ISO, Scheduling Coordinators and Control Area Operators would be integrated.

Critical Path Implementation Issue:

- Operational in 18 months
- Liability Insurance

Option 3: ISO as a **Partial-regional Control Area Operator**

Market Structure:

- WSCC Security Coordinator hosted by ISO
- Regional OASIS hosted by ISO
- Congestion Management hosted by ISO
- Scheduling Coordination infrastructure implemented
- Partial Regional Control Area Services hosted by ISO

Critical Path Implementation Issue:

- Operational in 48 months
- Liability Insurance
- EMS Implementation

Option 4: Independent System Operator

Market Structure

- WSCC Security Coordinator hosed by ISO
- Regional OASIS hosted by ISO
- Congestion Management hosted by ISO
- Scheduling Coordination infrastructure implemented
- Control Area Services hosted by ISO for entire DSTAR Region

Characteristics:

The ISO would meet all of the FERC independence principles with the addition of operating as a single control area. The ISO would require the development of protocols and agreements for the Scheduling Coordinators. The ISO would also facilitate the Ancillary Services Requirements.

Critical Path Implementation Issues:

- Operations in 48 to 60 months
- Liability Insurance
- EMS Implementation

VI. DSTAR CONTOL AREA OPERATIONS

One conclusion that can be inferred from a March 2, 1998 poll, DSTAR will not be a single Control Area Operation in the inception stages.

However, it may be possible the DSTAR would offer Control Area Services for part of the region. This would be described as a Hybrid - Control Area Operation (Option #3, Section V.)

Following is a result of the poll taken on March 2, 1998:

STATUS	MEMBER
Continued CAO's	SRP, WAPA, EPE
Considered Turn-Over of CAO's	APS
Undecided	PNM, NPC, TEP
Evaluating CAO's	PEGT

Subject: DSTAR O/I WG 09Apr98 Meeting Notes, Tucson
Date: Fri, 10 Apr 1998 10:37:19 -0700
From: "David E. Murphy" <demurphy@srp.gov>
Organization: srp
To: <desertstar-operations@listerv.azstarnet.com>, <desertstar-tariff@listserv.azstarnet.com>

DSTAR O/I Meeting Notes of 09Apr98, TEP

Action Items:

- o All: Review/Comment on the 06Mar98 Draft of Congestion Management Outline (for 4/23 Joint Mtg)
- o WAPA: Provide Congested Path Data for WAPA's system
- o WAPA: Provide Must-run data for WAPA's system
- o APS/SRP: Commercial-significance model Metro-Phx must-run
- o SRP: Phase II Implementation Plan update
- o APS: Update Constrained Paths/Congestion Zone Map
- o WAPA: Must-Run Category Strawman

Meeting Information:

- o 23Apr98: Joint Pricing/Operations WG Meeting
  Hosted by El Paso Electric, 123 W Mills, El Paso
  Topic: Congestion Management and Pricing Zones
- o 07May98: Joint Pricing/Operations WG Meeting
  Hosted by APS, Lincoln/3rd Ave, Phoenix
  Topic: Must-Run Generation
- o 21May98: Operations WG Meeting
  Hosted by PNM, (tbd), Alburquerque
  Topic: Finalize Implementation Plan
- o 04Jun98: Operations WG Meeting
  Hosted by SRP, 6504 E. Thomas Road
  Topic: Review Draft of Stage I Operation's Report
- o 21Jul98: Operations WG Meeting
  Hosted by NPC, (tbd), Las Vegas
  Topic: Finalize Stage I Operations's Report

Conclusions:

- o Finalized Pricing Zones based on "physical system constraints"
- o DSTAR functions identified in Phase I Report continue to be valid for requirements for a FERC approved ISO.

Discussion:

- o Implementation Plan Update:

  Steering Committee direction (4/1/98) meeting was to develope a phase-in implementation plan for DSTAR. The discussion concluded with the basic functions identified in Phase I remain valid for implementation strategy of DSTAR to gain FERC approval.

  The Scheduling/OASIS modules should be rolled out together and the Security Coordinator and Congestion Management moules should be rolled out together.

  The FERC ISO conference (next week) may have some impact on how FERC views ISO in the future. DSTAR needs to take into account any changes to FERC's ISO principles as a result of this conference.

  The market place will indicate change towards achieving the ISO priciples. OASIS/Schedulings should be implemented first with Security Coordination and Congestion Management following.

- Must-Run Generation:

There was much discussion/debate regarding Must-Run status. It is recognized that there are at least three categories of must-run generation status and further splits within each of the broad categories. It is also recognized, from a pricing persspective, that must-run units have varing characteristics in the different load centers of the DSTAR region. It is also recognized that there could be pricing variations depending on whether the view is from a Wholesale or Retail open access perspective. Following is a summary, first, of the Must-Run Catagories and Second, the DSTAR load center differing must-run characteristics.

Must-Run Catagories:

- Regulatory
  (para-phrasing from 26Feb98 O/I WG mtg notes)
  -Hydro Units due to water regulatory issues
  -Nuclear due to NRC issues
- System Dynamics
  - Support load-center import capability
  - Increase EHV path TTC
  - Load serving
  - Line loading relief
  - Cover N-1 contingencies
  - Spinning/Non-spinning Reserves
  - Regulation
  - Black start
- Voltage Support
  - Support Voltage profile during at high load periods

WAPA will develope a strawman to futher define "must-run" categories.

Must-Run Load Center Characteristics:

- Albuquerque
  Units increase load serving cpability for Albuquerque.
- El Paso
  - 3 units must run all year to serve load and to "keep the lights on" in El Paso
  - Rio Grand unit must run summer months to maintain the import capability.
- Las Vegas
  - Serve load due to line load limitations on the lower EHV system into Las Vegas
- Phoenix(Metro-region)
  - Serve load due to line load limitations on the lower EHV system into Metro-Phoenix.
  - Voltage Stability at high loads
- Tucson
  - EHV import limitation
  - Voltation Support
  - Contract limitation
- Yuma
  - Import limitation

- Pricing Zones:

Based on a combination of Must-Run data and phisical EHV line loading limitations, the following pricing zones are recommended for analysis for further "Commercial-significance" analysis:

- Las Vegas

Driver: Must-Run Units in Las Vegas to relieve lower voltage EHV ties to the city load.

- o Phoenix
  Dirver: Must-Run Units in Metro-Phoenix to relieve lower voltage EHV ties to the city load. APS/SRP are to get together and follow up on a analysis model that will be used in all of the pricing zones to determin if these zones are "commercially" significant.
- o Tucson
  Driver: Must-Run Units in Tucson to relieve EHV lines to Tuscson.
- o Yuma
  Driver: Must-Run unit in Yuma due to contract limits the tie to Yuma.
- o El Paso
  Driver: a) Must-run to serve load
  b) Must-run to keep increase TTC for NM EHV lines
- o San Juan/Four Corners/ShipRock
  Driver: Identified as an "Export Zone" due to line load limits on the FourCorners-Cholla path.
- o DSTAR Regional (Excluding Specific Zones above):
  The rest of the DSTAR region outside of the zones identified above would be a single pricing zone.

o Congestion Management Modle:

Lots of Discussion/Debate on the proposed congestion management model. All have the assignment to review the doument futher and be prepared to comment at the 4/23/98 Joint Pricing & Operations Meeting in El Paso.

The model on the table now features FTR's (Firm Transmission Rights). There are 3 tiers of market involvement regarding the FTR Model:

1. Annual Aution of FTRs
2. Day-ahead market of unscheduled rights
3. Secondary market FTR trading via an FTR Exchange

It has been suggested that the FTR model is "superior" to the FERC recommended OASIS process of dealing with descriminatory access to the transmission grid.

Please, if I have misrepresented anything in these notes, let me know. Thank you for your participation.

Subject: **DSTAR Regional Congested Transmission Paths**
Date: Mon, 6 Apr 1998 15:54:24 -0700
From: "David E. Murphy" <demurphy@srp.gov>
Organization: srp
To: <desertstar-operations@listserv.azstarnet.com>, <desertstar-tariff@listserv.azstarnet.com>

Summary Operational Data

Re: DSTAR Regional Congested/Constrained Interfaces

Company:	Path:	Nature of Congestion:
AEPCO	Westwing/Vail 345kV TTC=161MW	0 ATC all year, committed use
APS	4-Cnrs/Cholla 345kV TTC=1250MW	0 ATC for 742 hrs/yr 62 ATC for 1550 hrs/yr
	PaloVerde-Westwing TTC=1318MW	0 ATC for 318 hrs/yr 66MW ATC for 2294 hrs/yr
	PaloVerde-N.Gila TTC=140MW	0 ATC for 2968 hrs/yr 7 MW ATC for 4294hrs/yr
El Paso	WestMesa-Arroyo 345 TTC=300MW	0 ATC for 7000 hrs/yr
	Sprvl-Luna 345kV Greenlee-Hidalgo 345 TTC=670MW	0 ATC for 7000 hrs/yr
NPC	Red Butte- Harry Allen TTC=300 MW	0 ATC for 3384 hrs/yr
	Harry Allen-Mead TTC=300 MW	0 ATC for 3384 hrs/yr
	Harry Allen-McCull. TTC=300 MW	0 ATC for 3384 hrs/yr
	Navajo-McCull. TTC=360MW	0 ATC for 1248 hrs/yr
PNM	Not Confirmed with PNM: However, Preliminary conclusions are:	
	SanJuan-4Cnrs to Albuq. voltage limitation for N-1 conditions: 154MW Gas Turbines increase import limitations.	
SRP	Coronado-Kyrene 500kV TTC=1100MW	7MW ATC for all year
	Coronado-PaloVerde TTC=1100MW	7MW ATC for all year
	4Cnrs-Coronado TTC=50MW	0 ATC all year

	4Cnrs-4Cnrs TTC=50MW	2MW ATC all year
	Mead230-Liberty TTC=160MW	8MW ATC all year
	NV-Moen-McCull. TTC=344MW	0 ATC all year
	PaloVerde-Coronado TTC=1100MW	13MW ATC Jul-Sep
	PaloVerde-Hayden TTC=95MW	13MW ATC Jul-Sep
	PaloVerde-PinPeak TTC=554MW	13MW ATC Jul-Aug
	SilverKing-Hayden TTC=95MW	21MW ATC May-Aug
TEP	Data not confirmed, Tucson import limit is 950-1000MW Tucson load is 1650MW 95% of the year, a local unit is on. 81% of the days per year, the load exceeds 950MW	
WAPA	Data not confirmed	

Re: Must-Run Generation

Company:	Description
AEPC	One of the units at Apache must run all year
APS	Metro-Phx units must-run apx 447 hrs/year when valley load exceeds 5800MW Yuma - Douglas - N-1 contingency
El Paso	Minimum of 3 units must run all year Rio Grand Plant must run to maintain import capability which is 100% of the time in the summer months.
NPC	Data not confirmed
PNM	Data not confirmed
SRP	Metro-Phx units must-run apx 200-400hrs/yr when valley load exceeds 5800MW
WAPA	Data not confirmed

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9/9

Attachment 2

APS "MUST RUN" GENERATION

REPORT

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APS "MUST RUN" GENERATION REPORT

Introduction:

Generation is classified as "Must Run" due to constraints on transmission system. The generation is required to maintain transmission line loading within limits. Limits are based on the most limiting factor of the following:

Thermal
Stability
Steady State Voltage
Dynamic or Post Transient Voltage

In many cases "must run" units can exercise market power in the short term since there is no alternative to mitigate the loading constraints.

This report identifies the APS "must run" units, the transmission limitation and number of hours of "must run".

Summary of APS "Must Run" Generation:

Listed below are APS units identified as "Must Run" due to transmission systems constraints in selected areas of Arizona transmission network:

- OCOTILLO STEAM 1, 2

"Must Run" due to transmission import limitation into the Valley. Prevents line overload and provides voltage support into the Valley area. Estimated number of hours of "must rum" during 1988 is 460 Hrs.
(See appendix A.)

- WEST PHOENIX COMBINED CYCLE 1, 2, 3

"Must Run" due to transmission, import limitation into the Valley. Prevents line overload and provides voltage support into the Valley area. Estimated numbers of hours of "must run" during 1988 is 460 Hrs.
(See appendix A.)

- YUCCA COMBUSTION TURBINE 1, 2, 3, 4

"Must Run" due to Yuma 69kV import capability limitation via a nomogram. Prevents transformer and line overload. Estimated number of hours of "must run" during 1988 is 2744 Hrs. (See appendix B.)

- DOUGLAS COMBUSTION TURBINE

"Must Run" due to 115kv transmission outage in the area. Serves the load area during the transmission outage. Load is served radially Thus for a 115 kV line outage, load can only be served by local generation (Douglas CT) . Estimated time for "must run" during 1988 is 48min. (See appendix C.)

Conclusion:

Resource Planning Department should develop the principles for the rates , terms and conditions for APS "Must Run" units under retail direct access on 1/1/99.

P.K., Nov. '97

APPENDIX A

APS Valley "Must Run" Generation Analysis

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APS VALLEY "MUST RUN" GENERATION ANALYSIS

Study Objective

Determine Valley generation "must run" requirements to maintain line flow and voltage profile within Valley import capability.

Conclusion

Valley generation should be classified as "Must Run" due to constraints on the 230KV Valley system.

Study Methodology

This study was performed using two programs: WSCC IPS Power Flow program and GE MAPS cost production model. Most of the simulation was done for 1998 system peak load condition in Arizona and additional scenario cases were run with 2004 transmission system improvement.

Cases with no Valley generation were simulated by importing power from outside of Arizona with 80/20% ratio between California and PacifiCorp respectively.

Valley import capability was calculated by summarizing power entering Phoenix Metro area from four main EHV delivery points. Westwing 500/230KV, Pinnacle Peak 345/230KV, Kyrene 500/230KV and Liberty 345/230KV substations. (see attached map)

Generation Capacity Factor for APS Valley units "must run" was estimated based on hours APS plants (Ocotillo Steam 1,2 and West Phoenix Combined Cycle 1,2,3) needs to be put on-line to alleviate overload or voltage problem on transmission system in the Metro area. Energy output and response factor of each unit was integrated into calculations to determine capacity factor based on summer (3 months) and one year time frame.

Study Criteria

Import capability into the Valley was determined based on the three limiting factors:

- Thermal (Transmission Loading) - no transmission element will be loaded above 100% of its continuous rating under steady state conditions.

  Note: This transmission loading analysis only evaluated all lines in-service loading problems.

- Steady State Voltage - voltages should be maintained within their normal operating range at selected buses (1.018 at Pinnacle Peak 230KV) for steady state conditions.

  In power flow simulation, base case voltage level was maintained within normal range by switching off reactors, adjusting TCUL transformer taps, switching on capacitors, etc. In cases where voltage level was less then desirable, additional shunt compensation was added to maintain steady state voltage limit.

  Note: This voltage analysis only evaluated all lines in-service conditions.

- Post Transient Voltage - reactive margin requirement should be maintained at most critical bus for system condition following major disturbance in the area. This margin is obtained by conducting Q-V analysis for N-1 contingency on selected bus. In our study, 350MVAR of reactive margin was used for Pinnacle 230KV bus.

Study Results

A summary of the power flow, steady state voltage and post-transient studies completed are presented below.

- Results from both MAPS and Power Flow simulation of Valley 230KV transmission system during 1998 without APS/SRP Valley Generation showed that Valley 230KV Import Capacity was 6180MW based on Glendale - Country Club continuous rating. (see table 1, graph 1)

  Also, in order to maintain steady state voltage limit and post-transient margin at 6180MW (thermal import limit), additional 260 MVAR of shunt capacitors needs to be added to transmission system at estimated cost of $2.0 mil. (see table 1, graph 1)

- In order to alleviate the Glendale to Country Club overload, APS Valley generation needs to run for 460 hours during 1998. That translates to a capacity factor of 3.1% a year for West Phoenix Combine Cycle 1,2,3 and 5.3% a year for Ocotillo Steam 1,2. Most of the 460 hours that generation was on line occurred during the summer months that brings up the capacity factor to 12.4% for West Phoenix Combine Cycle 1,2,3 and 21.2% for Ocotillo Steam 1,2. based on total summer hours. (see table 1)

- The need for new generation or transmission in the Valley is estimated to be after 2004. This assumes the current load growth projection, APS/SRP Valley generation, and current import limit into the Valley area. (see graph 1)

- Scenario case analysis without APS/SRP Valley Generation but 230KV transmission reinforcement (at estimated cost $25 million) showed that Valley 230KV Import Capacity was at 7000MW.

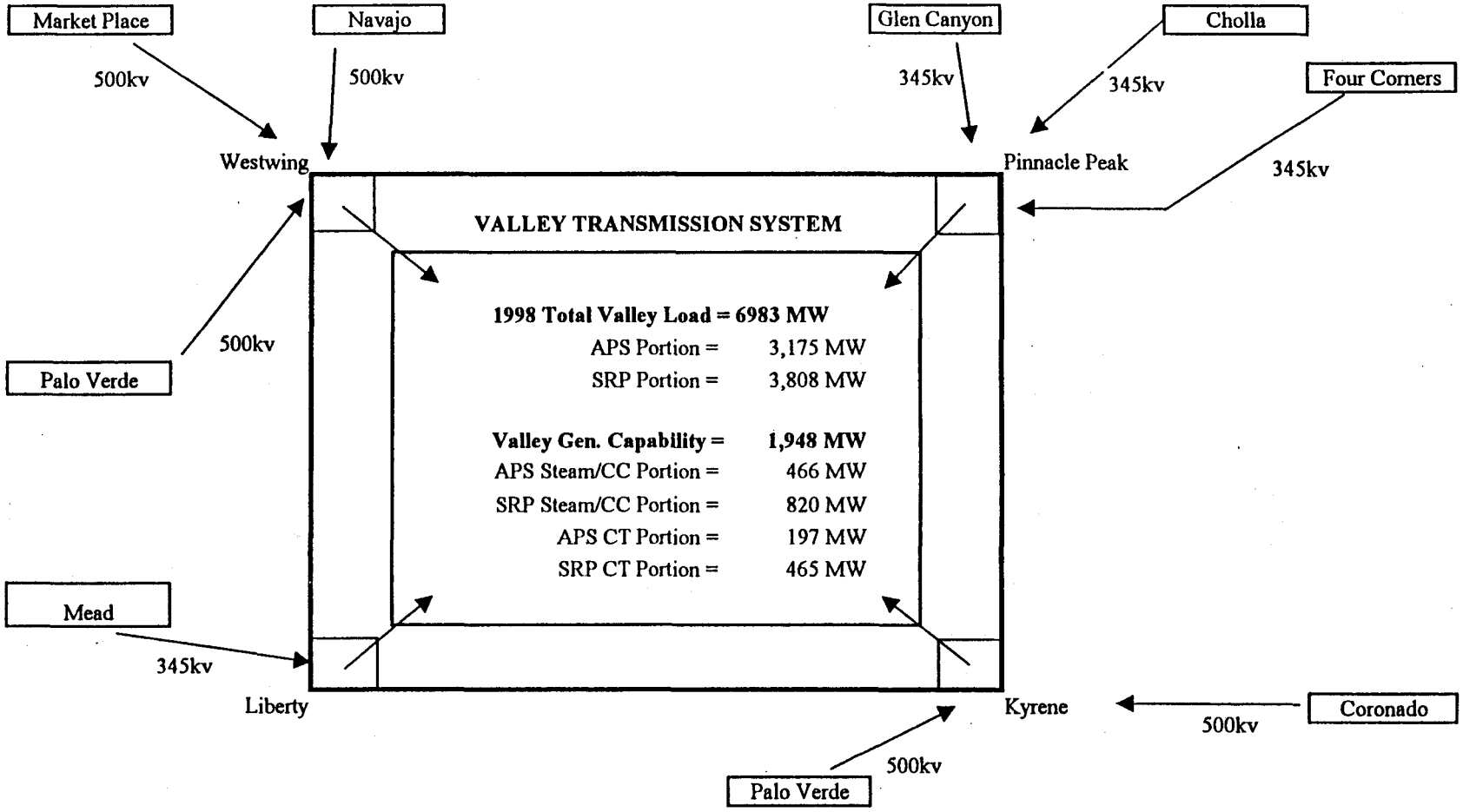
  Transmission reinforcement consists of two 230KV transmission lines Westwing to El-sol and White Tanks to W. Phoenix and 750 MVAR of shunt capacitors in the Phoenix Metro area.

  In this case, the need for new generation or transmission is estimated to be after 2009. (see table 1, graph 2)

P.K. Oct/97

MAP

IMPORT CAPABILITY INTO THE VALLEY



Import Limitations:

- **Thermal**
- **Steady State Voltage**
- **Post Transient Voltage**

MAP

TABLE 1

VALLEY 230 KV IMPORT CAPACITY (MW)
No Valley Generation

OPERATING LIMIT	VALLEY * IMPORT MW	LIMITING ELEMENT PNPK VOLT	PNPK Q-V MARGIN MVAR	THERMAL MW GLND-C.CLUB	HOURS OVER LIMIT	CAPACITY FACTOR WPHX CC1,2,3 YR./SUMMER %	OCT ST 1,2 YR./SUMMER %
THERMAL LIMIT	6184	.993	170	360	460	3.1 / 12.4	5.3 / 21.2
POST TRANSIENT MARGIN	5987	1.007	350	340	550	3.7 / 14.8	6.3 / 25.2
STEADY STATE VOLTAGE	5824	1.018	510	320	650	4.3 / 17.2	7.5 / 30.0

ELEVATE THE LIMITS:

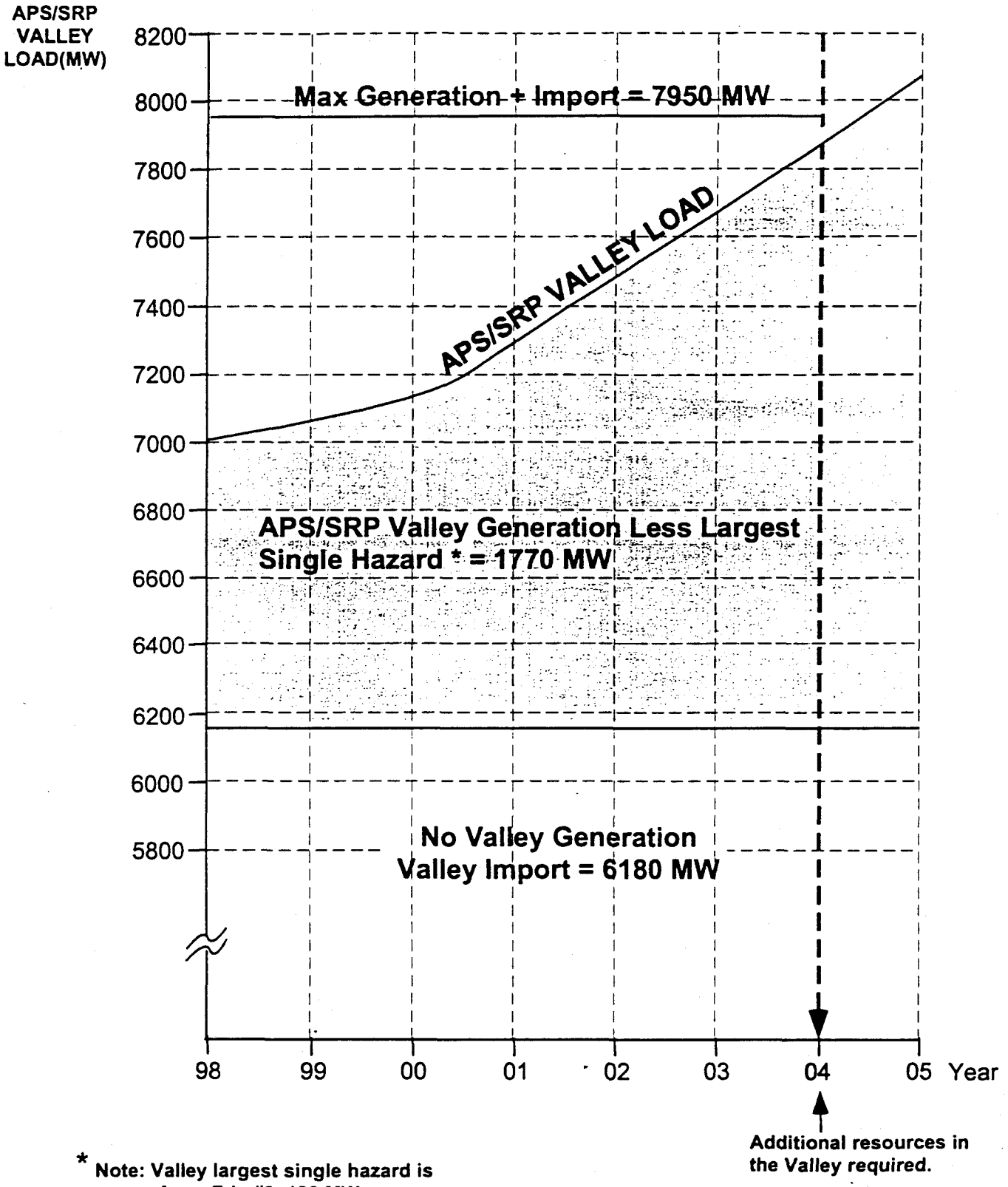
- STEADY STATE = THERMAL LIMIT→ TAKES ADDITIONAL 260 MVAR OF SHUNT CAPACITORS. COST $2.0 MIL
- POST TRANSIENT = THERMAL LIMIT → TAKES ADDITIONAL 200 MVAR OF SHUNT CAPACITORS. COST $1.7 MIL

SCENARIO CASE W/2004 SYSTEM ADDITION WW – EL SOL 230KV WHTX – PHX 230KV EST. COST $20. MIL	6915	1.018	210	294	0	0	0
	♦ FOR STEADY STATE LIMIT TAKES ADDITIONAL 600 MVAR OF SHUNT CAPS. EST. COST $ 4.5 MIL. ♦ FOR POST TRANSIENT LIMIT TAKES ADDITIONAL 750 MVAR OF SHUNT CAPS. EST. COST $5.5 MIL						

* Valley Import Capacity updated by 340MW to accommodate Mesa load.

APS VALLEY "MUST RUN" GENERATION ANALYSIS

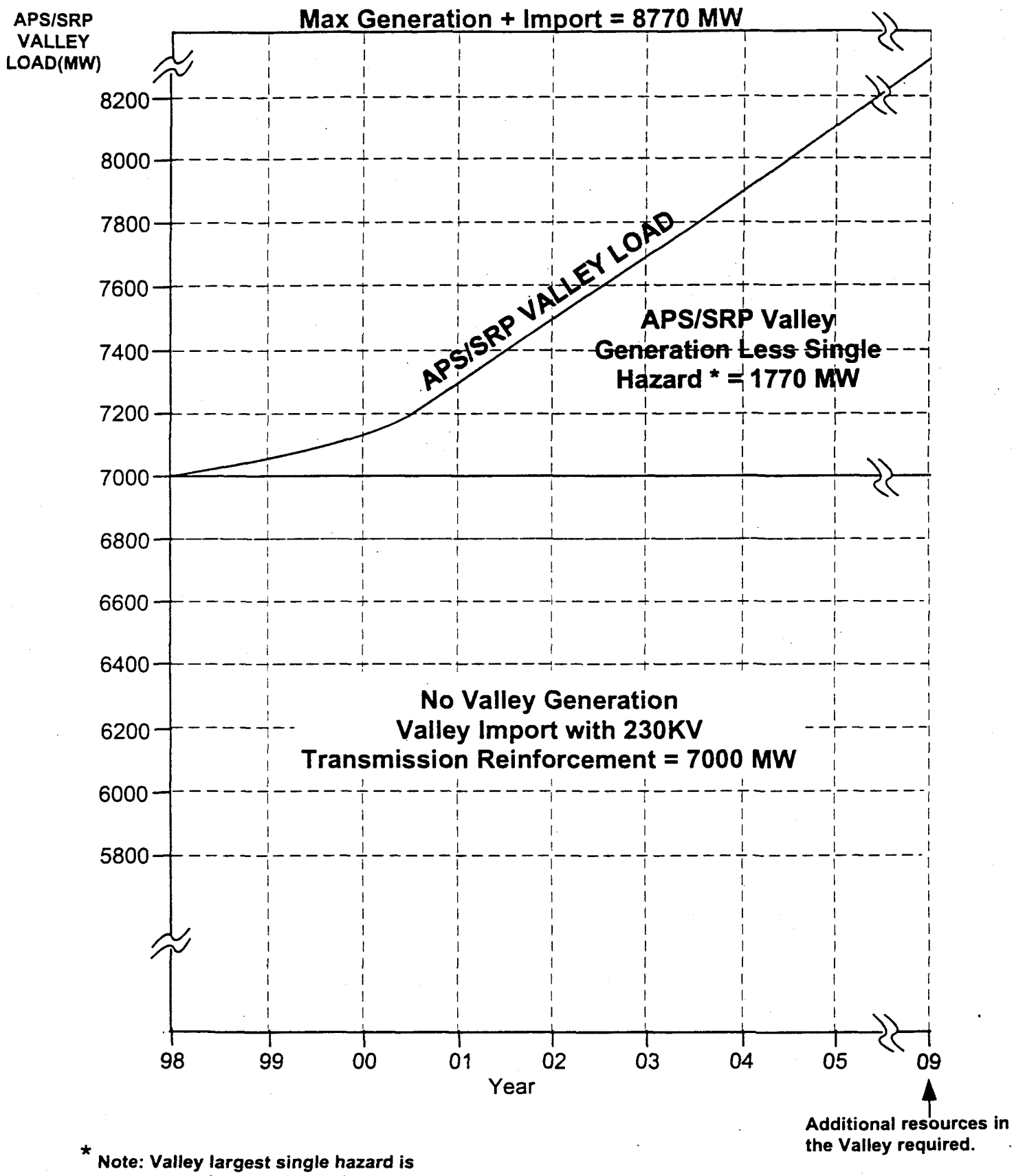
CASE 1 : NO GENERATION OR TRANSMISSION ADDITIONS



* Note: Valley largest single hazard is Agua Fria #3, 180 MW.

APS VALLEY "MUST RUN" GENERATION ANALYSIS

CASE 2 : NO GENERATION BUT 230KV REINFORCEMENT



* Note: Valley largest single hazard is Agua Fria #3, 180 MW.

APPENDIX B

Yuma Area Import Analysis

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Arizona Public Service Company

Yuma Area Import Analysis

Conclusion:

Yucca generation is classify as "Must Run" due to Yuma 69kV import capability limitation.

1. Normal Operating Limits:

In the last decade Yuma area experienced substantial load growth in the range of 4% a year from 180MW in the 1987 to 245 MW in 1997.

Yuma area load is served from three main delivery points; Yucca 161/69kV substation , Gila 161/69kV substation and North Gila 500/69kV substation .

Under Normal operating conditions (all lines in service) Yuma import capability is limited to 175 MW of which 140MW is contractual capacity on North Gila 500 kV line and remaining 35MW is WAPA Wheeling . This 175MW import capability reflects also the fact that Axis steam unit capacity of 25MW was recaptured by IID in september 97. (see nomogram 1)

This substantial load growth expansion combined with import capability limit into Yuma area creates a generation "Must Run" scenario for Yucca CT 1, 2, 3, and 4 units.

GE MAPS cost production simulation was done for 1998 system peak load condition in Yuma area to determine amount of hours of "Must Run"generation for Yucca CT's.

As a result Yucca generation needs to run for 2744 hours during 1998 to serve the Yuma area load above175mw.

2. First Contingency Limits:

Yuma 69kV import capability for first contingency condition is define by Yuma Load vs. Yuma Generation nomogram. (see nomogram 2)

The conditions that determine the boundaries of the nomogram are as follows:

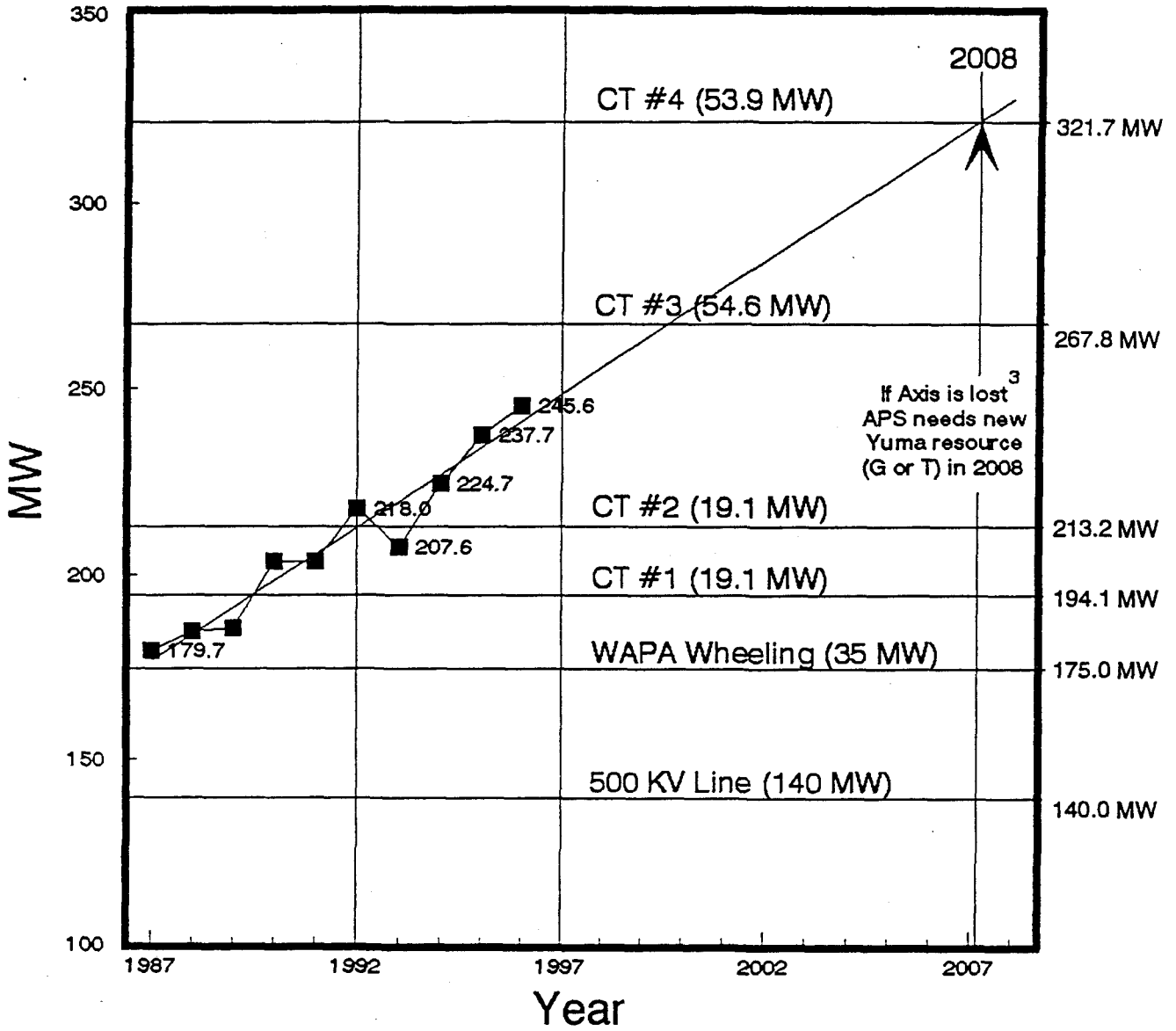
- **Critical outage**
  Loss of N.Gila 69kV Bus or Yucca 69kV to 32nd Street 69kV line.
- **Limiting Element**
  Overload on Yucca 161/69kV Transformer or 20th Street to 32nd Street 69kV line.

2. First Contingency Limits (continued):

It could be seen from the nomogram that Yucca generation is needed to alleviate the Yucca 161/69kV transformer overload for the first contingency (loss of N.Gila 69kV bus) condition . That point on the nomogram corresponds to the Yuma load of 135MW.

NOMOGRAM L

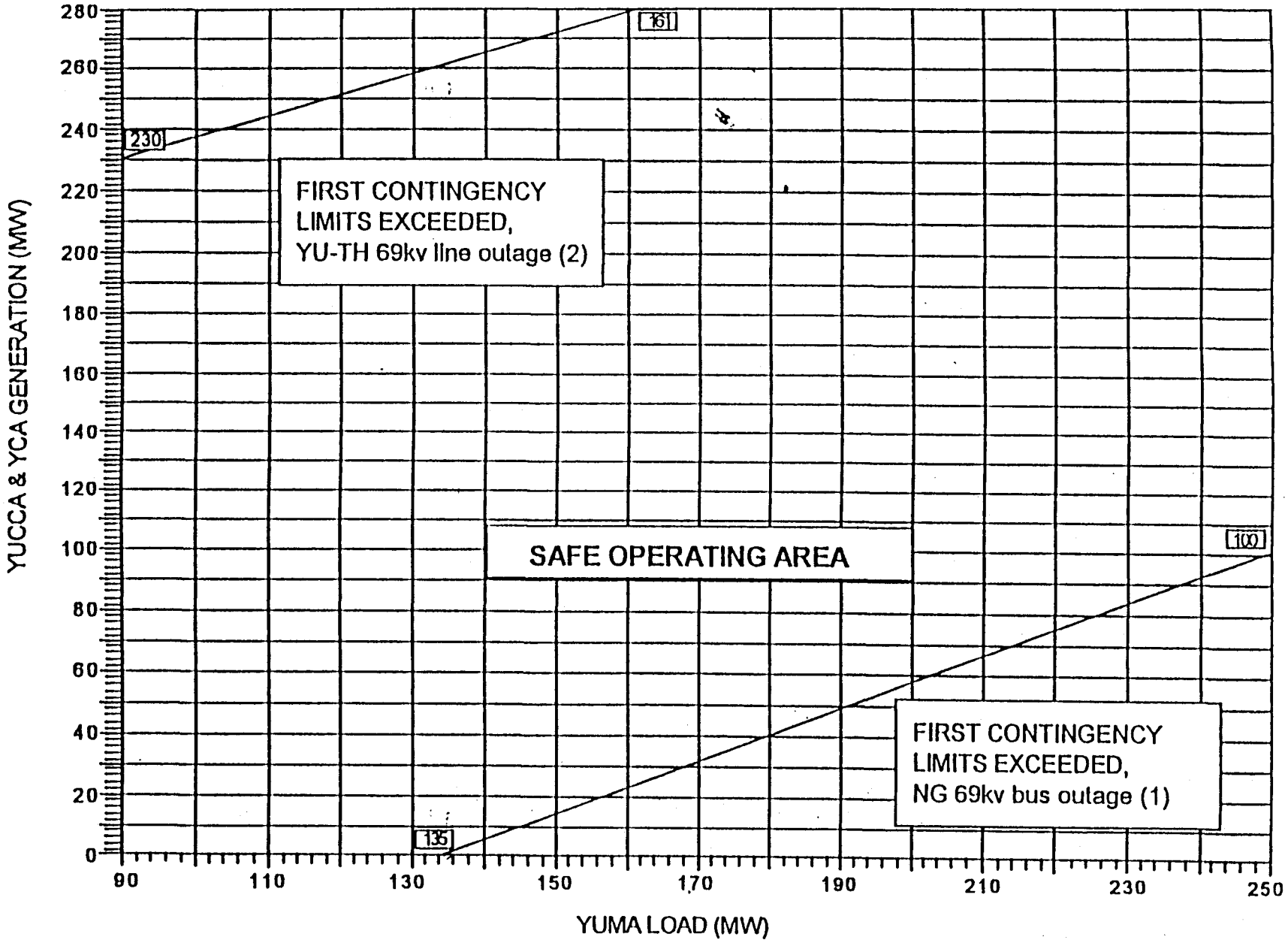
YUMA AREA LOADS[1] & RESOURCES[2]



NOTES:

1. 1987–1996 Yuma Area historic load from Energy Accounting.
2. Resources assumes APS maintains 25–MW Yuma area reserve margin external to Yuma area per Participation Agreement #2 of the APS/IID Power Coordination Agreement (page 6, Section 4.7). Note: total APS/IID reserve margin = 75 MW.
3. Assumes Axis steam (25 MW) is recaptured by IID effective 8/31/97.

YUMA LOAD vs. YUMA GENERATION
FOR LOSS OF
NORTH GILA 69kv BUS OR YU-TH 69kv LINE



(1) Limiting factor: Thermal YU 161/69kv transformer.
(2) TE-TH 69kv line 900A rating. Limiting factor: (A) YU 161/69kv transformer.

T.O.D
JRM 02/13/95

NOMOGRAM 2

APPENDIX C

Douglas Area Analysis

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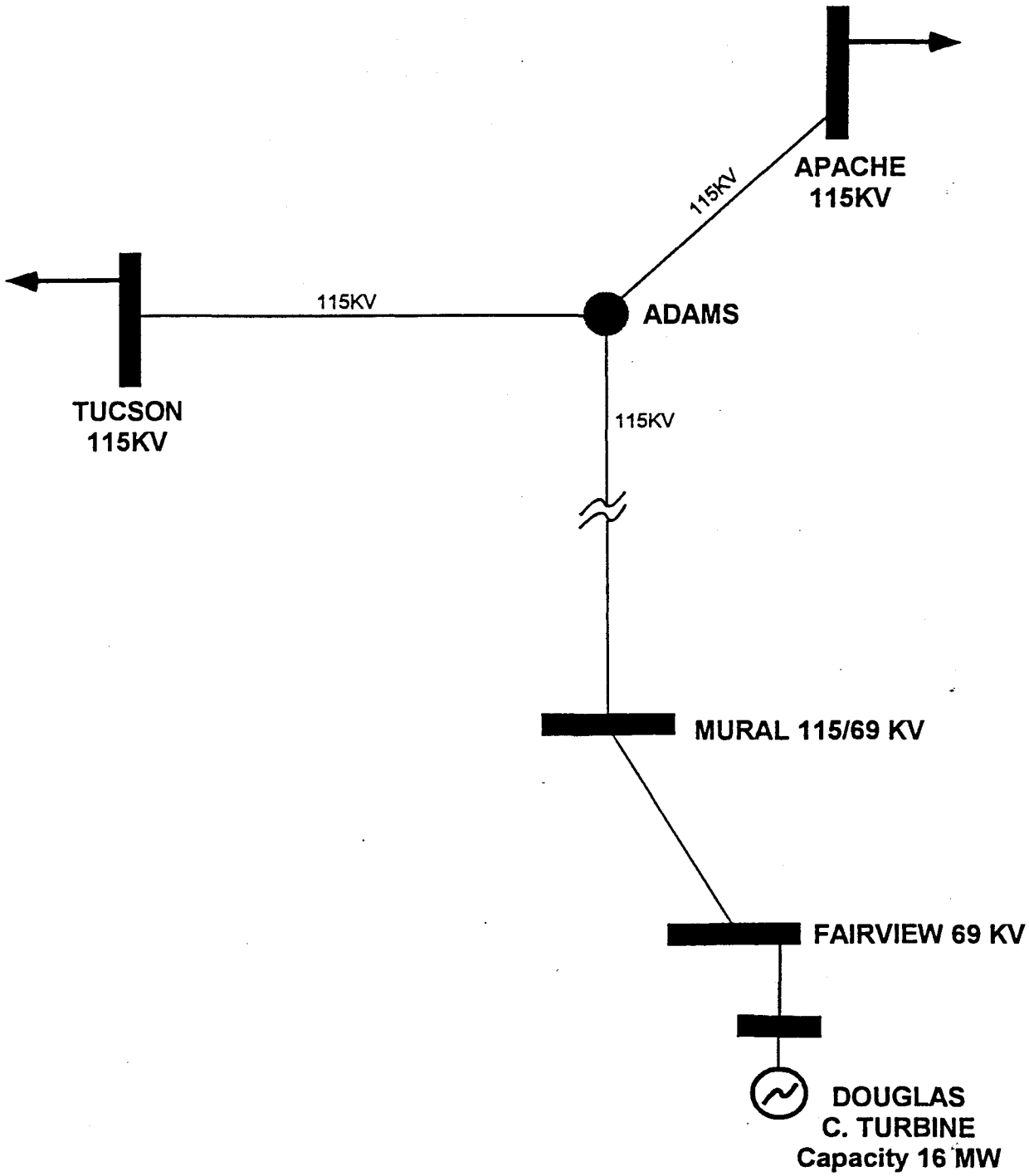
DOUGLAS " MUST RUN " GENERATION

LIMITATION: (OUTAGE OF 115KV LINE AS SHOWN BELOW)



Attachment 3

MUST RUN GENERATION REQUIREMENTS

April 17, 1998

- **Approximate analysis based on load duration curve analysis.**
- **Minimum run times and economic considerations will increase hours.**
- **Most requirements can be met by subset of possible generators.**

Reliability Must Run Generation: Generation required to meet firm load without violating reliability criteria.

Categories:

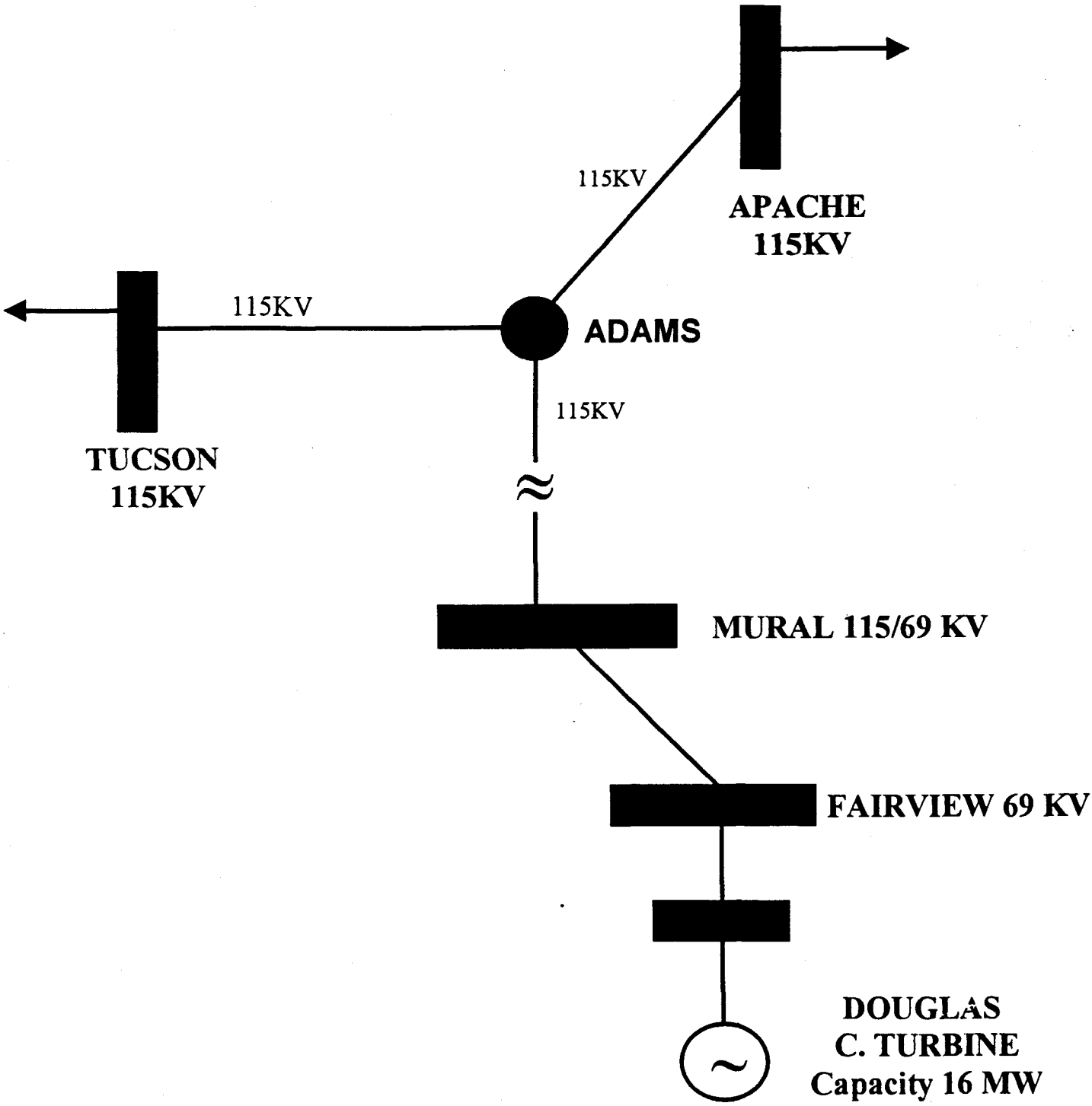
1. **Thermal Overload (may be also considered as necessary to "meet load")**
2. **Voltage Requirement**
3. **System Stability**
4. **Contingency to "meet load"**

Unit Requirements:

Area	Units	Limitation	Hours
Phoenix	West Phoenix (APS) Ocotillo (APS) Agua Fria (SRP) Kyrene (SRP) Santan (SRP) Hydro (SRP)	Voltage/Overload	447
Yuma	Yucca	Voltage/Overload	1295
Douglas	Fairview	Contingency	1

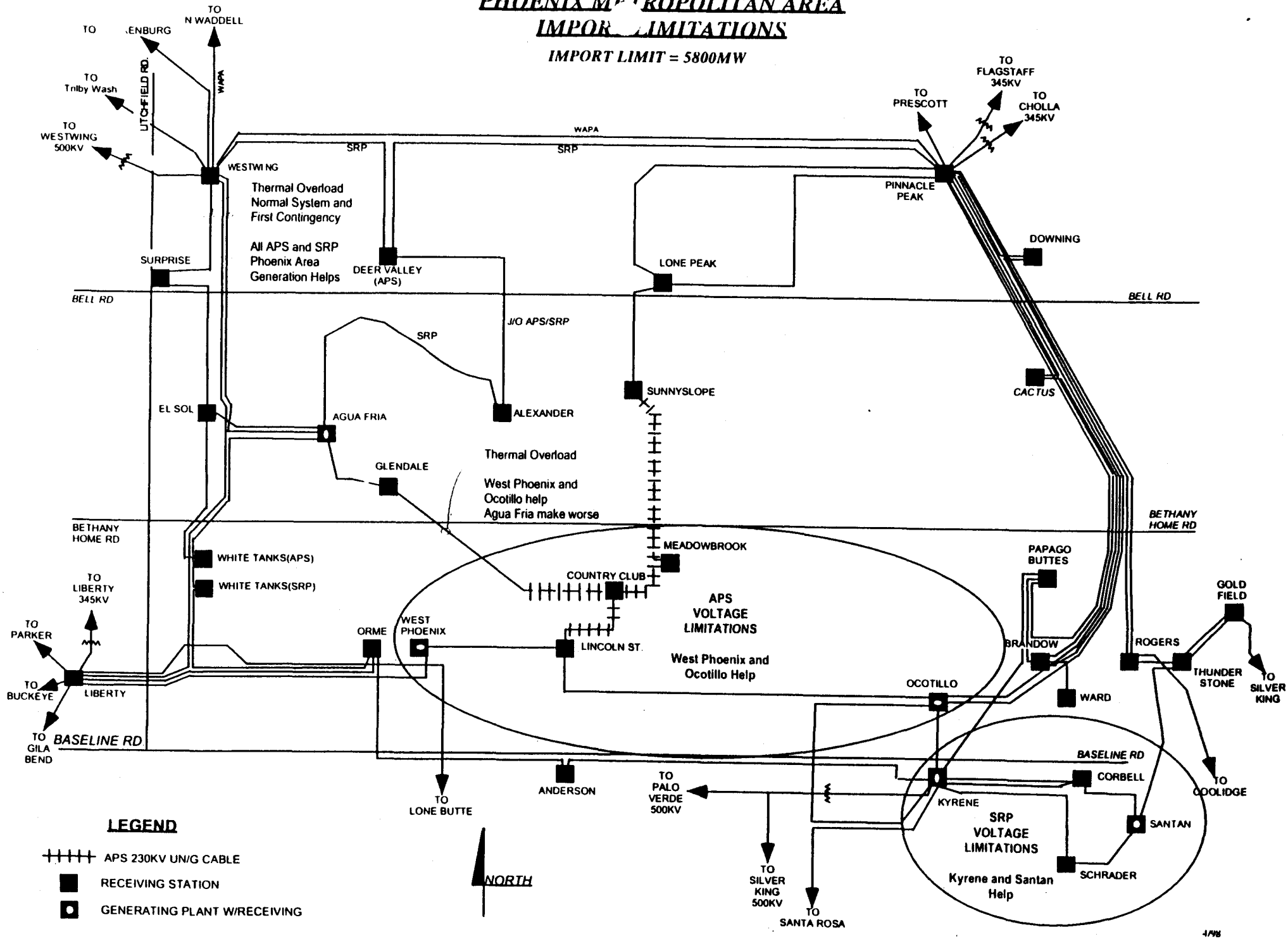
DOUGLAS "MUST RUN" GENERATION

LIMITATION: (OUTAGE OF 115kV LINE AS SHOWN BELOW)



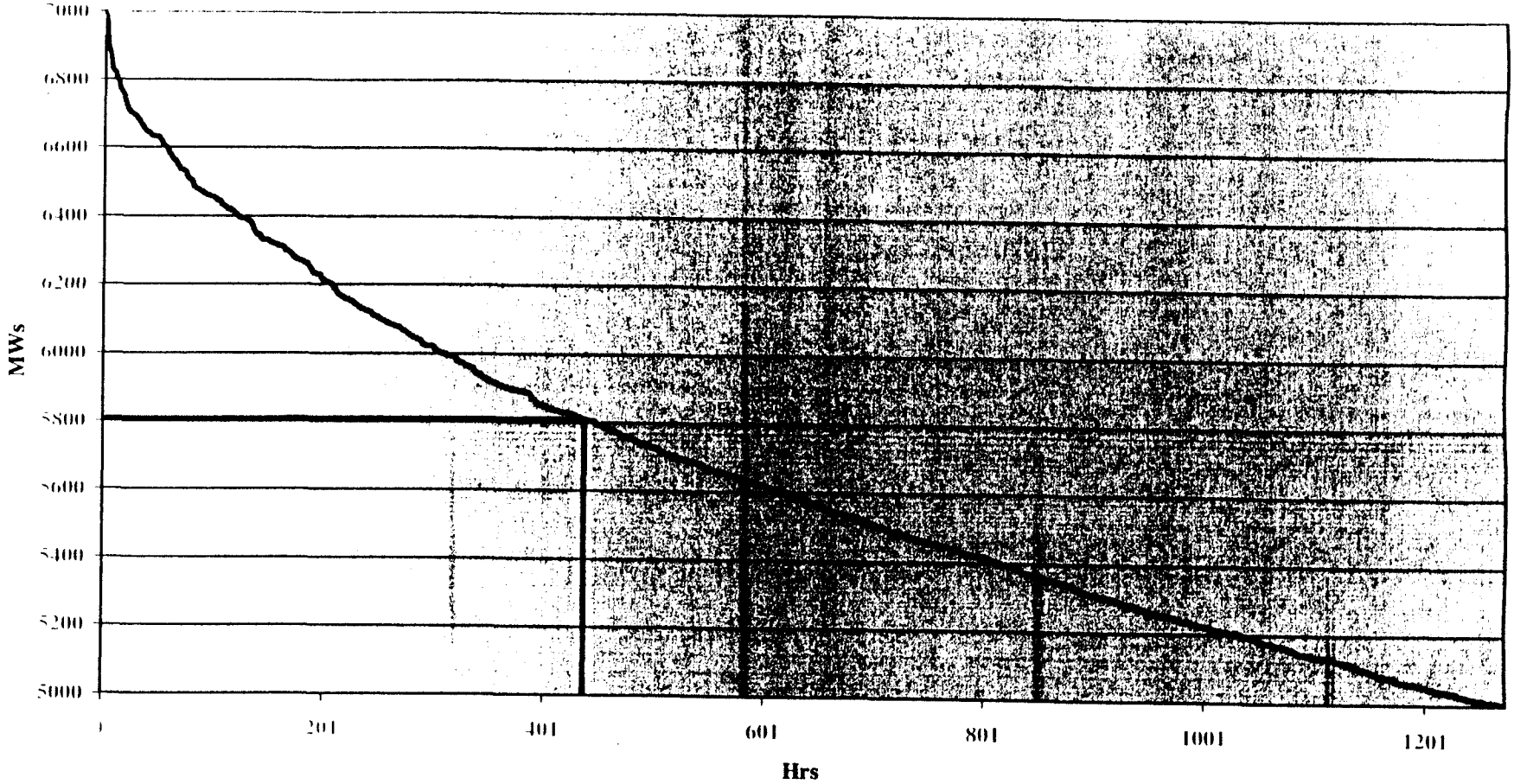
PHOENIX METROPOLITAN AREA IMPORT LIMITATIONS

IMPORT LIMIT = 5800MW



4/98
TRANSMISSION PLANNING

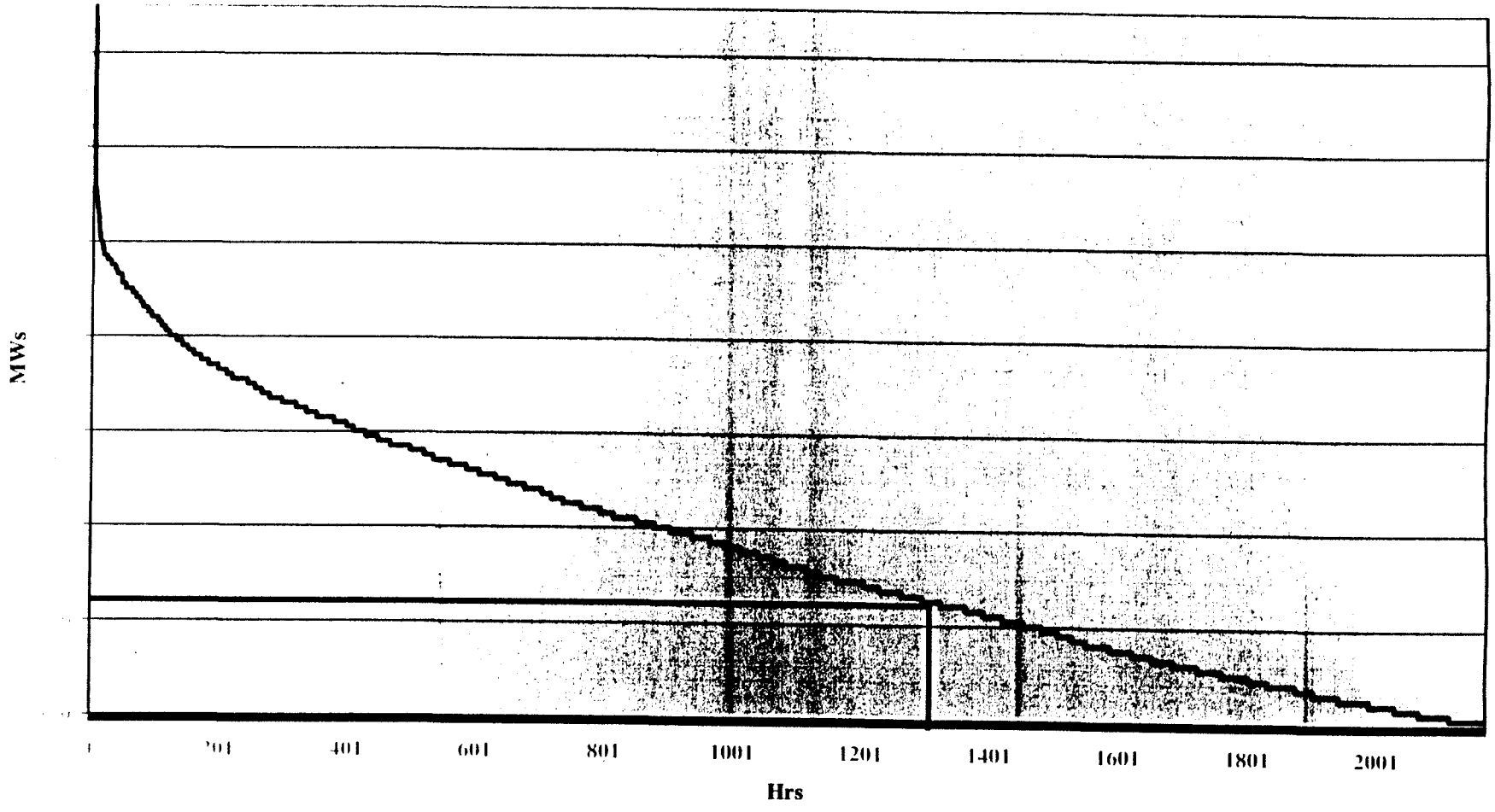
APS + SRP METRO PHOENIX AREA LOAD DURATION CURVE FOR 1997



Phoenix Area Import Limit = 5800 MW

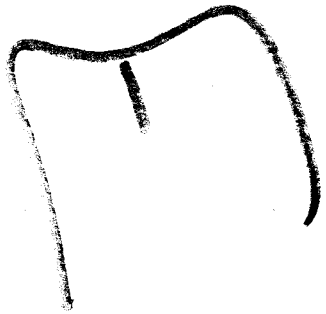
Hours load > 5800 = 447 hours

APS Yuma Area Load Duration Curve for 1997



175 MW Import Limit = 140 MW PV-NG rights + 35 MW Wheeling @ WAPA
Hours Load > 175 MW = 1295 hours

AVERY™ RECYCLED PAPER MADE FROM 20% POST CONSUMER CONTENT



DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
SECOND SET OF DISCOVERY REQUESTS

QUESTION 1: Identify each of your simultaneous and non-simultaneous transmission capacities and transfer capabilities into and out of the State of Arizona.

RESPONSE: Answers to Questions 1-6 are represented in Table #1 below:

TABLE 1

TRANSMISSION TIES	Capacity IN (MW)	Capacity OUT (MW)	LIMIT/ FACILITY	CONSTRAINT
Utah/Colorado/ New Mexico to APS	1340	1340	Four Corners Four Corners-Cholla 345kV lines 1&2	Thermal
Nevada to APS	795	795	Southern 500kV Moenkopi-Yavapai 500kV line & Navajo-Westwing 500kV line	Thermal
California to APS	1458	1318	Palo Verde East Palo Verde-Westwing #1 &2 Palo Verde- Kyrene 500kV line	Thermal
TOTALS	3593	3453		

QUESTION 2: Identify each of your simultaneous and non-simultaneous transmission capacities and transfer capabilities into and out of your control area within the State of Arizona.

RESPONSE: See response to Question 1.

QUESTION 3: Identify each of your simultaneous and non-simultaneous transmission capacities and transfer capabilities into and out of each State contiguous to the State of Arizona.

RESPONSE: See response to Question 1.

QUESTION 4: Identify each facility that limits or is a constraint upon transmission capacity by name and geographic location.

RESPONSE: See response to Question 1.

DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
SECOND SET OF DISCOVERY REQUESTS

QUESTION 11: Produce all transmission studies or other documents that deal with limits or constraints on transmission into our out of Arizona and into our out of your control area within Arizona and into or out of any State contiguous to Arizona.

RESPONSE: Due to the voluminous nature of the transmission studies and other documents that deal with limits or constraints are on file, they will be made available to view at the APS Transmission Operations Center located at 502 South 2nd Avenue.

QUESTION 12: Produce all reliability studies including, but not limited to all WSCC studies.

RESPONSE: Due to the voluminous nature of the reliability studies, they will be made available to view at its Transmission Operations Center located at 502 South 2nd Avenue.

QUESTION 13: Produce your "path rating book" or any other document that provides transmission capacity information.

RESPONSE: APS refers to the "path rating book" as the "Arizona Security Monitoring Manual", a copy of which is enclosed.

QUESTION 14: Produce any studies prepared by any third party such as consultants or experts regarding transmission constraints or capacity created from 1994 to the present.

RESPONSE: No outside consultants or experts have performed transmission studies on behalf of APS since 1993.

QUESTION 15: Identify each transmission facility and state the simultaneous and non-simultaneous capacity of each.

RESPONSE: Four Corners System:

Four Corners-Cholla 345kV lines #1 & 2
Cholla-Pinnacle Peak 345kV lines #1 & 2
Cholla-Saguaro 500kV line

Southern 500kV System:

Navajo-Moenkopi 500kV line
Navajo-Westwing 500kV line
Moenkopi-Yavapai 500kV line
Yavapai-Westwing 500kV line

Palo Verde East:

Palo Verde-Westwing 500kV lines #1 & 2
Palo Verde-Kyrene 500kV line
Palo Verde-North Gila 500kV line

Westwing-Mead 500kV lilne

Transmission capacities are listed in TABLE 1.

QUESTION 16: Provide, in machine-readable form, all TTC and ATC and related transmission data posted on OASIS regarding transmission capacity including, but not limited to your estimates of transmission capacity for 12 months.

RESPONSE: Hourly values for ATC and TTC for the month of November 1998 has been provided in machine readable form on a 3.5" disk. For December 1998 to October 1999, monthly peak values for ATC and TTC have been provided due to no hourly adjustment for ATC or TTC have been made that far in advance.

QUESTION 17: Produce every analysis, concerning any electric utility or electric service provider, by whatever name known, and every group of electric utilities or electric service providers relating to a) market power and/or b) the ability to effect prices in any of the following markets within the State of Arizona:

1) Transmission
2) Distribution
3) Generation
4) Metering
5) Meter reading and customer service

RESPONSE: Such analyses as the Company has been provided in Response to Questions 3, 5, 6 and 7 of your First Set of Data Requests.

QUESTION 18: Produce every analysis, concerning any electric utility or electric service provider, by whatever name known, and every group of electric utilities or electric service providers relating to a) market power and/or b) the ability to effect prices in any of the following markets within the Western Region of the United States:

1) Transmission
2) Distribution
3) Generation
4) Metering
5) Meter reading and customer service.

RESPONSE: See response to Question 17.

QUESTION 19: Identify the person who provided answers to these data requests.

RESPONSE: Various employees of APS as well as APS legal counsel contributed to these as well as prior APS responses.

DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL
DOCKET NO. E-01345A-98-0473, E-01345-97--0773 & RE-00000C-94-0165
THIRD SET OF DISCOVERY REQUESTS

QUESTION 1: Identify all transmission paths involving Arizona or states contiguous to Arizona that are subject to the WSCC Unscheduled Flow Mitigation Procedure, the conditions under which the transmission capacity of each path in each direction is likely to be fully utilized, and the number of hours during which line loading relief or other flow mitigation procedures were applied to each path during 1997 and during 1998. Provide all relevant documents.

RESPONSE:

PATH # - Name	CONDITIONS	HOURS OF RELIEF		
		1996	1997	1998
22 – Four Corners West: Four Corners – Moenkopi 500 kV Four Corners – Cholla 345 kV	- High generation at Four Corners - High schedules southwest of Four Corners - Clockwise loop flow	*	24	34
23 – Four Corners 500/345 kV transformer	- Four Corners Unit Five off line - Clockwise loop flow	*	53	15
21 – Arizona to California: Navajo – McCullough 500 kV Moenkopi – Eldorado 500 kV Westwing – Mead 500 kV Palo Verde – Devers 500kV Palo Verde – North Gila 500 kV Liberty – Mead 345 kV	- Full Generation Capacity at Navajo, Four Corners, & Palo Verde - High schedules - Clock wise loop flow	0	0	0

* APS does not have any records for 1996.

QUESTION 2: Identify all cases in which APS or TEP has denied a transmission service request since January 1, 1997. Identify the requesting party, the nature of the requested service (points of origin and delivery, firm or nonfirm, time period, MW), and the reason for the denial. Produce all relevant documents.

RESPONSE: See Attachment 1.

QUESTION 3: Identify all cases in which APS or TEP requested line loading relief or otherwise curtailed scheduled transfers into, out of, or within Arizona since January 1, 1996. Produce all relevant documents.

RESPONSE: Arizona Public Service (APS) does not keep records other than what is required according to the WSCC Unscheduled Flow Mitigation (USFM) Procedures. See table A, question 1.

DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
THIRD SET OF DISCOVERY REQUESTS

QUESTION 13: For each of measures listed in question 12. above that was used in 1997-1998, describe in non-technical terms what the measure involves and what effects it has.

RESPONSE:

Perkins phase shifters	SRP is the owner of this equipment. APS does not have any records.
Liberty phase shifter	WAPA is the owner of this equipment. APS does not have any records.
Bypassed series compensation	APS does not keep these records
Reduction in scheduled flow so they are within scheduled rights	APS does not allow EOR scheduling to exceed schedule rights
Unscheduled (loop) flow curtailment	See Table A
Out of merit order generation at Navajo	SRP is the operating agent of this facility. APS does not have any records.

QUESTION 14: Identify each generating unit that is, in whole or in part, owned or leased or operated by APS or TEP and that is, or during the next five years is reasonably likely to be, a must run unit.

RESPONSE: Table B

Must Run Generation Units	Condition	June - September	October - May	Load Pocket	Load Pocket Peak 1998 Load
West PhoenixCombined Cycle units 1,2,&3	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
West Phoenix Gas Turbine units 1 &2	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
Ocotillo Steam units 1&2	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
Ocotillo Gas Turbine units 1&2	Valley 230 kV lines thermal limit and voltage support	400 hrs	0 hrs	Phx	3419 MW
Yuma Gas Turbine units 1-4	Transformer Limitation	1600 hrs	0 hrs	Yuma	257 MW
Fairview Gas Turbine	Radial Source	1 hr	0 hrs	Douglas	30 MW

purchase by the highest bidder for some for all of TEP's local generation assets. In that case, will TEP be permitted to retain ownership of the generating units in question and recover 100% of stranded costs?

RESPONSE: N/A

QUESTION 25: If the answer to the preceding question is yes, why do the Settlement Agreements not require that an acceptable buyer be found?

RESPONSE: N/A

QUESTION 26: Identify each generating unit that is (i) under construction in Arizona, (ii) planned for construction in Arizona during the next five years, or (iii) announced for construction in Arizona during the next five years. For each, identify the owner, location, type of plant (e.g., CT, CC), fuel type, MW capacity, status of permitting, and expected completion date.

RESPONSE: APS currently has no plans to construct a generating unit in Arizona over the next five years, nor are any new APS generating plants currently under construction in Arizona.

QUESTION 27: Produce all internal documents regarding the value of APS's generation assets.

RESPONSE: APS objects to this data request on the grounds that it is overly broad and unduly burdensome. APS also objects to this data request on the grounds that the term "value" is vague and ambiguous. To the extent that the data request seeks information regarding generation costs, such costs are reflected in APS' current rates. This generation cost component will be separately identified in APS' unbundled rates. Cost-related detail is set forth in the FERC Form 1 filing provided in response to Data Request No. 11.

QUESTION 28: State all circumstances under which TEP or any of its affiliates will own or lease generating capacity or have long-term (over 1 year) contracts for the purchase of generating capacity or energy after 1/1/2001, and identify the generating capacity in question.

RESPONSE: N/A

DATA REQUESTS FROM OFFICE OF THE ATTORNEY GENERAL
DOCKET NO. E-01345-98-0473, E-01234-97-0773 & RE-00000C-94-0165
THIRD SET OF DISCOVERY REQUESTS

QUESTION 29: Identify all APS transmission facilities that are subject to a right of first refusal, identify the parties that have a right of first refusal, and identify the terms on which they could exercise a right of first refusal.

RESPONSE: Information is attached.

QUESTION 30: Please explain the reasoning that supports the statement (under V. Divestiture) that either a region-wide postage stamp approach or a license plate approach will prevent transmission constraints from limiting or frustrating competition.

RESPONSE: Under a "postage stamp" or "license plate" ratemaking approach for transmission service, all transmission customers in the region or pricing zone would pay the same rate for transmission service. Either of these pricing approaches would not limit transmission constraints; however, the proposal for treating transmission requests associated with retail direct access is that all Transmission Providers (including APS and TEP) would follow the Committed Uses protocols as developed by the AISA in order to fairly allocate transmission capacity over constrained transmission paths.

This treatment for allocation of transmission capacity over constrained transmission paths, coupled with the license plate ratemaking treatment would serve to mitigate any attempts to limit or frustrate competition insofar as transmission service could be used by a party in order to otherwise accomplish such a goal.

QUESTION 31: Please explain and produce documents the support any claim that APS'S control over transmission facilities rated below 345 kV cannot be used to exercise vertical market power. Specifically set forth the pricing for use of these facilities and the capacity of each. Do you claim that the pricing for use of these facilities will be so low and the capacity of these facilities is so large that terms on which these facilities are available for use will not limit competition? State what facts exist to support such a conclusion.

RESPONSE: All schedules for load on APS's 230 and 69 kV transmission facilities will be accepted. However, there will be times when a schedule coordinator will be required to purchase their load ratio share of the must run local generation requirement. Must run

pricing will be at a regulated tariff. Thus, any energy service provider can schedule any generation requirement above must run generation and APS will not have any ability to assert vertical market power.

which measures were taken to reduce flows on those paths, and explain the measures that were taken and their effects on scheduled transfers into, out of, or within Arizona.

RESPONSE:

Path	**Number of Hours During 1997 and 1998 Actual Flows were at least 90% of Capacity Limit**	
	IN	**OUT**
Utah/ Colorado/ New Mexico to APS	8/11/97 12 hours 8/12/97 9 hours 6/29/98 1 hours 7/26/98 1 hours	0
Nevada to APS		0
California to APS	0	0

*** At no time during 1997 and 1998 did actual flows on the paths listed in Table 1 exceed their capacity limit. Therefore, there were zero hours during which measures were taken to reduce flow on the paths.**

QUESTION 36: Does Table 1 imply that the simultaneous FCTTC into the State of Arizona is 3,593 MW?

RESPONSE: No

QUESTION 37: State your best estimates of the FCTTC and FCITC across each interface, and simultaneously across all interfaces combined, into (a) the smallest area that includes Arizona and the Four Corners, San Juan, Mohave, Hoover, Craig, and Hayden plants; (b) Arizona; and (c) the APS control area.

RESPONSE: APS and the Western Interconnection do not use the concept of First Contingency Incremental Transfer Capability (FCITC).

(a) As of April of 1998, the WSCC reported a non-simultaneous import for Arizona / New Mexico transfer capability as 4204 MW.
(b) As of April of 1998, the WSCC reported a non-simultaneous Arizona import transfer capability as 4684 MW.
(c) See data request 2, Table 1.

QUESTION 38: Produce a copy of each document listed in the APS response to Question 7, with the exception of documents already provided. Making documents

AVERY™ RECYCLED PAPER MADE FROM 20% POST CONSUMER CONTENT

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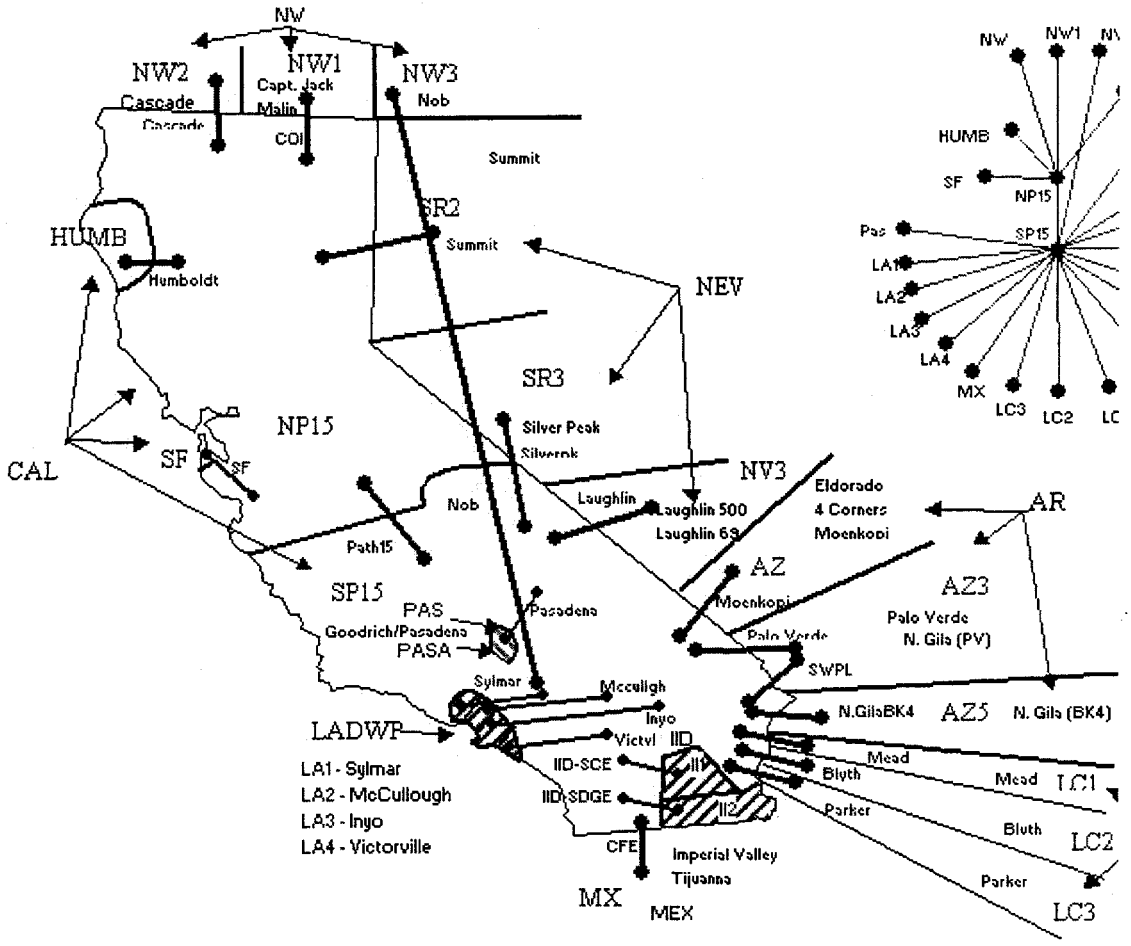
Network Model & Congestion Zones



Bold black lines identify Zone boundaries
Green lines identify transmission paths between zones (may include one or more lines)
Red letters denote Zone names
Black letters denote "abbreviated" scheduling point names
Green letters denote Path names
Blue letters denote abbreviated "geographic" location names

Back

Zone Abbreviation Legend							
AZ2	Eldorado/4 Corners/Moenkopi	AZ3	Palo Verde	AZ5	North Gila (BK4)	HUMB	Humboldt
II1	IID-SCE	II2	IID-SDG&E	LA1	Sylmar	LA2	McCullough
LA3	Inyo	LA4	Victorville	LC1	Mead	LC2	Blyth
LC3	Parker	MX	CFE	NP15	North Path 15	NV3	Laughlin
NW1	Captain Jack /Malin	NW2	Cascade	NW3	NOB	Pas	Goodrich/Pasadena
SF	San Francisco	SP15	South Path 15	SR2	Summit	SR3	Silver Peak

Q #38A

Attachment 4

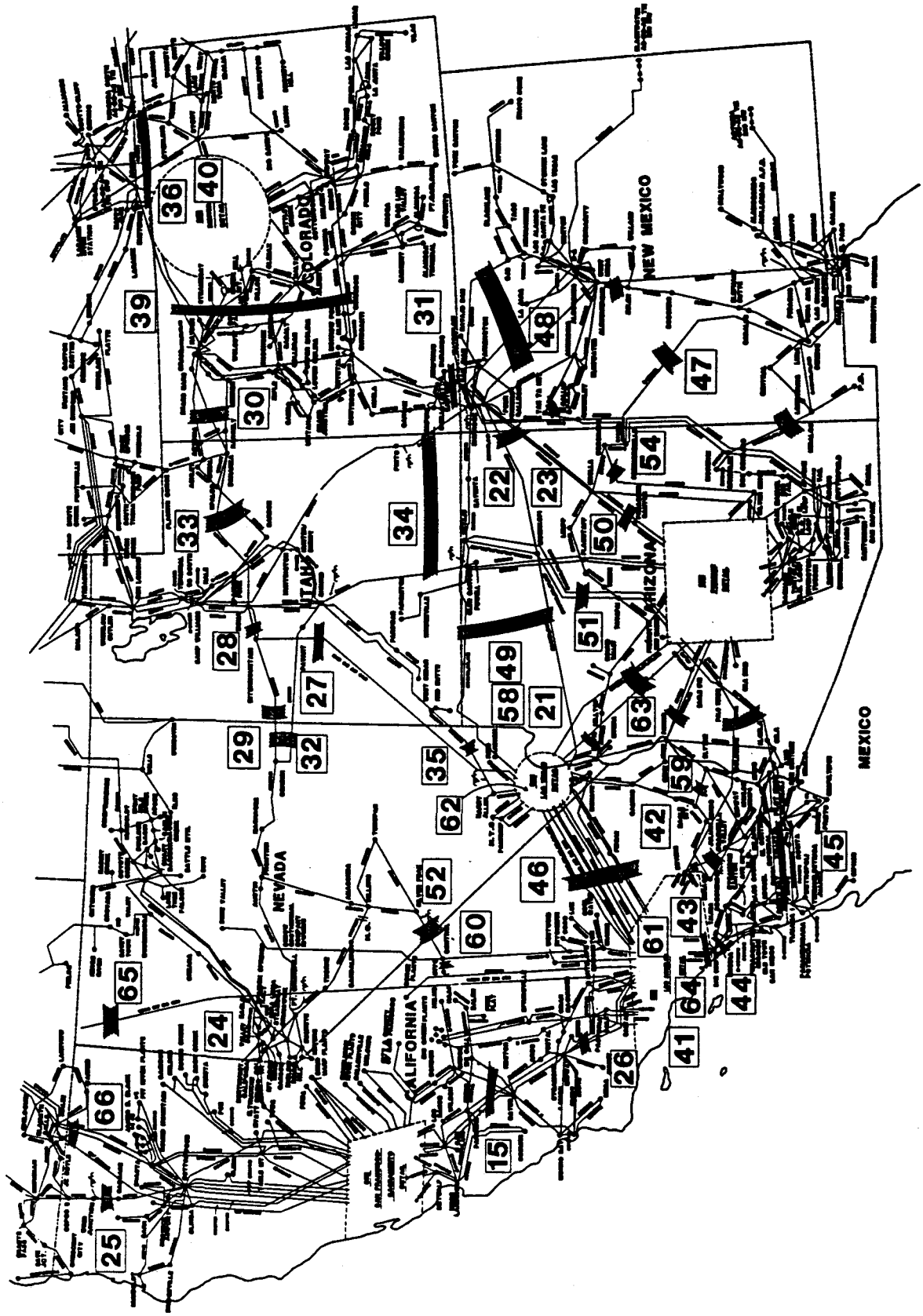
Western Systems Coordinating Council

WSCC 1998 PATH RATING CATALOG

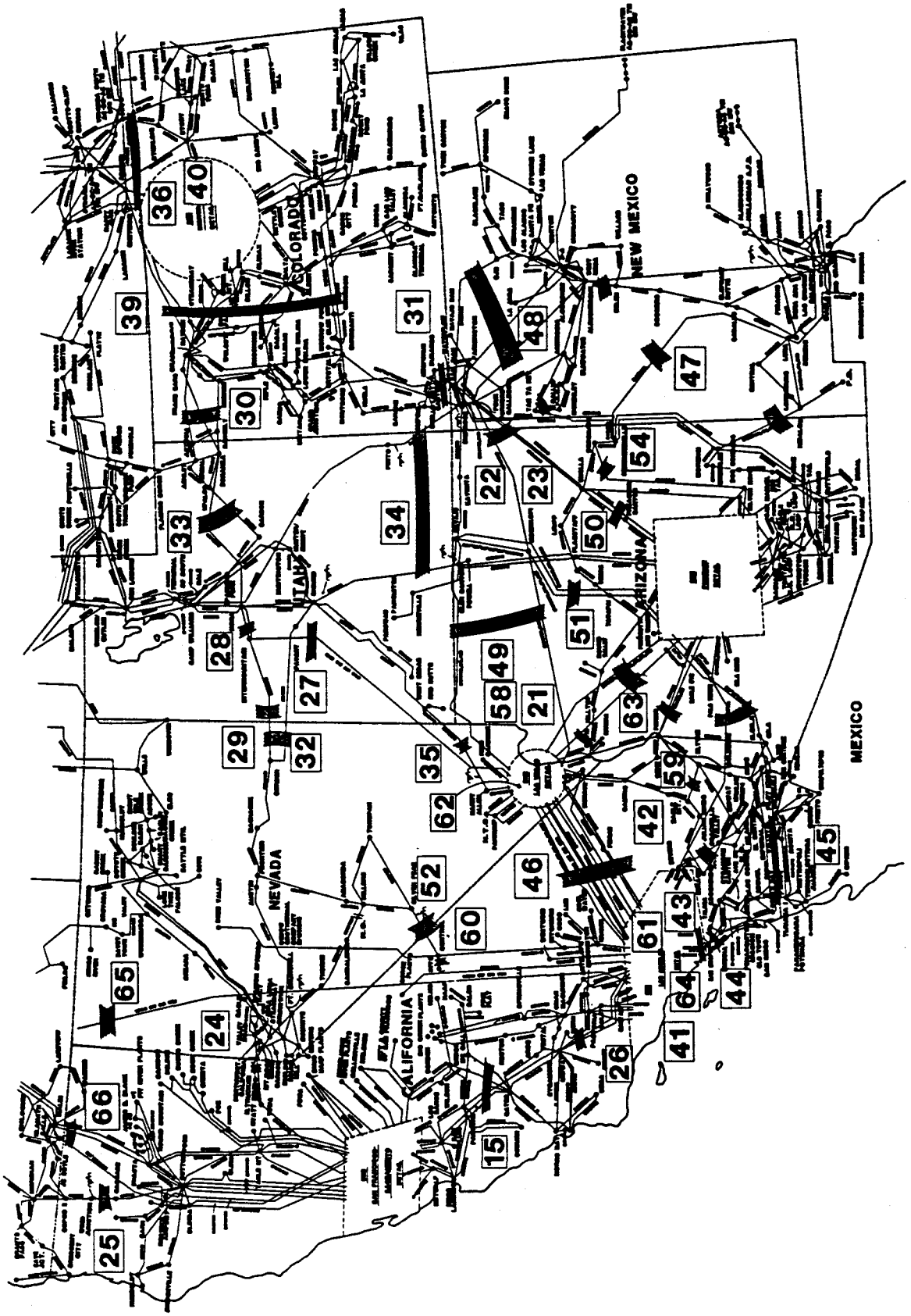
February 1998

Prepared By:
TECHNICAL STUDIES SUBCOMMITTEE

WSCC Transfer Paths



WSCC Transfer Paths



Western Systems Coordinating Council

May 1996

Ten-Year Coordinated Plan Summary 1996 - 2005

Transmission

The member systems' transmission facilities are planned in accordance with the "WSCC Reliability Criteria for Transmission System Planning," which establishes performance levels intended to limit the adverse effects of each member system's operation on others and recommends that each member system provide sufficient transmission capability to serve its customers, to accommodate planned interarea power transfers, and to meet its transmission obligations to others.

Information regarding the existing interconnected bulk power transmission system and the significant transmission facilities planned through the next ten years is compiled annually by the Council and provides the basis for this section.

As of January 1, 1996, the WSCC interconnected bulk power system was comprised of 112,798 circuit miles of transmission. No significant additions occurred during 1995 to the interconnected bulk power system. Figure 14 and Table 42 categorize existing transmission for the total WSCC region by voltage class and indicate that approximately 58 percent of the existing bulk power transmission is operated at a voltage class of 230 kV or above.

Figure 15 and Table 43 present information regarding the significant transmission additions planned for the 1996-2005 period. The planned transmission additions are categorized by voltage class, and the corresponding circuit miles are summarized for each of the four WSCC areas. Significant transmission additions include interconnections to the system from major generation sources, interconnections between control areas, and transmission lines important to interconnected system operation. The total net transmission circuit miles (3,184) planned for the 1996-2005 period represent a 2.8 percent increase over the existing circuit miles as of January 1, 1996. Approximately 81 percent of the significant net circuit mile additions planned are of the 345 kV class or higher.

Ten-year projected transmission additions in the 500 kV AC voltage category for the 1996-2005 period have decreased by 982 circuit miles compared to the projections made last year. This reduction is due to: the cancellation of the Devers-Palo Verde #2 500 kV line between Arizona and southern California and the Nicola-Meridian 500 kV line #2 in British Columbia; and the delay beyond 2005 of the Delta-Harry Allen 500 kV line between Utah and southern Nevada, the Delta-Robinson Summit 500 kV line between Utah and central Nevada and the Harry Allen-Marketplace 500 kV line #2 in southern Nevada. Additions in the 345 kV AC voltage category have decreased by 726 circuit miles compared to the projections made last year. This reduction is due to the cancellation of the Terminal-Falcon 345 kV line between Utah and northern Nevada, the Dry Fork Energy Project-Osage 345 kV line in northern Wyoming, the Dry Fork Energy Project-Colstrip 345 kV line between northern Wyoming and southern Montana, and the Coyote-Norton 345 kV line in New Mexico. Additions in the 230 kV AC voltage category have decreased by 677 circuit miles compared to the projections made last year. This reduction is due to the cancellation of the Bell-Selkirk 230 kV line between southern British Columbia and eastern Washington, the Dry Fork Energy Project-Yellowtail 230 kV line between northern Wyoming and southern Montana, and the El Centro-Coachella 230 kV line in southern California.

Significant transmission additions reported for the next ten years include 670 miles of 230 kV transmission lines, 1,038 miles of 345 kV, and 1,529 miles of 500 kV. Some of the noteworthy additions in each voltage category are highlighted on the map on the following page.

A copy of the map titled "WSCC Planned Facilities Through 2005 and Possible Transmission Beyond This Period" is included at the end of this report. The existing network as of January 1, 1996, is illustrated in black and significant facility additions planned for the

1996-2005 period are portrayed in color. Parenthetical numbers on the map indicate system ownership as defined in the legend, and anticipated in-service dates of planned transmission are also generally indicated.

The planned transmission additions for the WSCC region through the year 2005 reflect a continuing interest in the development and strengthening of interconnections to enhance system reliability; to transfer hydro, nuclear, and coal-fired energy to gas/oil-burning areas; to increase the capability for economy energy transfers; and to enable diversity in exchanging power between areas with different seasonal peak demand and energy requirements.

Transmission additions in the 500 kV category represent 48 percent of the planned significant additions. By the year 2005, the 500 kV transmission system mileage will have increased by approximately 10 percent.

To help in mitigating major unscheduled flow problems, several utilities have cooperated in the installation of phase-shifting transformers in the southern Utah/Colorado/Nevada transmission system. Phase-shifting transformers were installed in the southwestern Colorado-northwestern New Mexico lines during 1989, and additional phase-shifting transformers were installed in the lines emanating to the south from Utah during 1991.

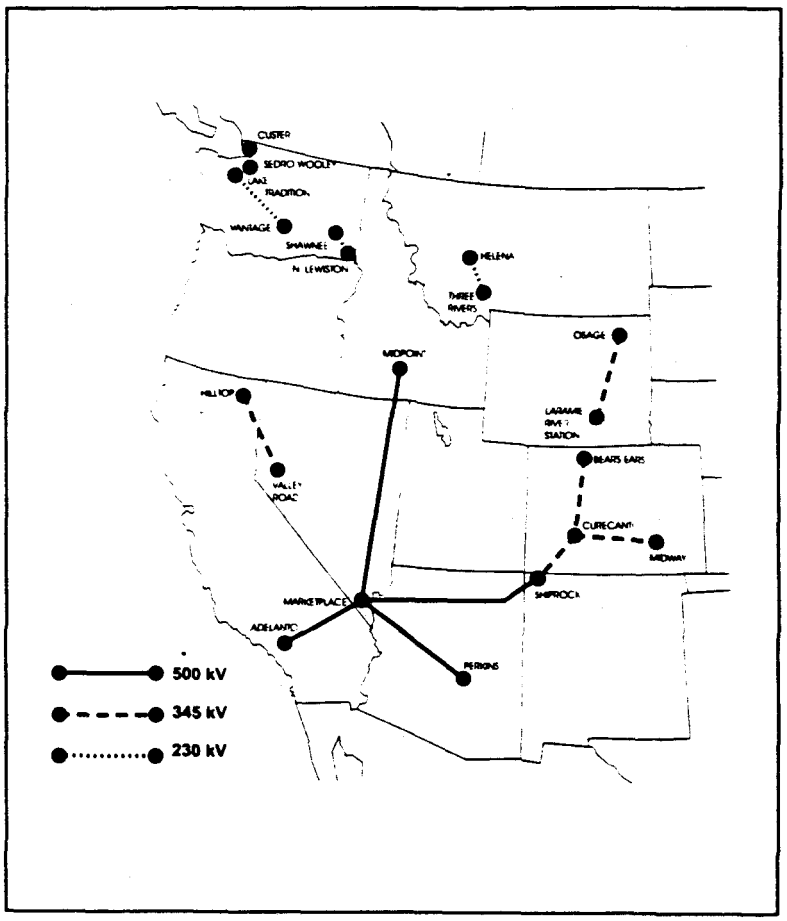
The installation of DC links in Canada, New Mexico, Nebraska, and southeastern Montana permit the transfer of electricity between WSCC and two adjacent councils: Southwest Power Pool and Mid-Continent Area Power Pool.

In effect, the WSCC system is being developed to ensure the efficient and economical use of resources and at the same time ensure adequacy, reliability, and environmental compatibility.

Figures 16 and 17 illustrate WSCC nonsimultaneous transfer capabilities for 1996 and 2001 respectively. These transfer capabilities represent the total capability of the various interconnections of the existing system and the planned 2001 system. It should be recognized that the transfer capability of an interconnection is not a single value as it is dependent upon system conditions, and the simultaneous import capability of a given area may be less than the sum of the individual interconnection capabilities. Each transfer capability depicted has been determined for a specific system condition.

Transfer capabilities between the WSCC areas are generally adequate to accommodate the existing and anticipated firm power schedules. However, there are limitations that persist in accommodating all desired economy/surplus power transfers.

In some instances, dependence has been placed on complex remedial measures to enable increased power transfer levels for use of the region's most cost-effective resources. The reliability and security of these remedial action schemes are reviewed periodically and updated when necessary.



Transmission Additions 1996-2005

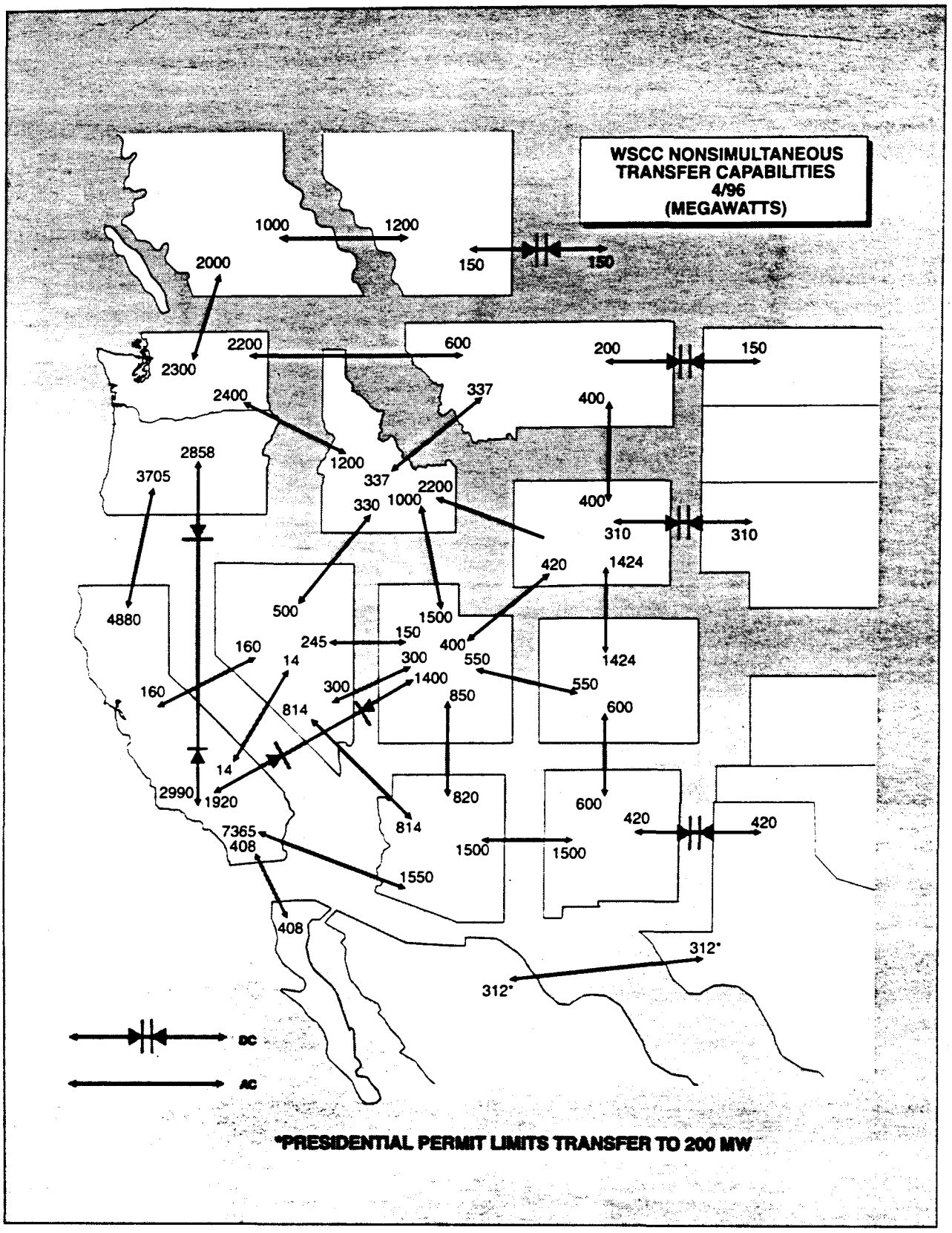

WSCC NONSIMULTANEOUS
TRANSFER CAPABILITIES
4/96
(MEGAWATTS)
1000
1200
2000
150
150
2200
600
200
150
2300
2400
337
400
2858
1200
3705
337
2200
330
1000
400
310
310
420
1424
4880
500
1500
150
245
400
160
14
300
550
1424
160
300
1400
550
814
850
600
14
2990
1920
820
600
814
420
420
7365
408
1500
1500
1550
408
312*
312*
DC
AC
*PRESIDENTIAL PERMIT LIMITS TRANSFER TO 200 MW

Figure 16

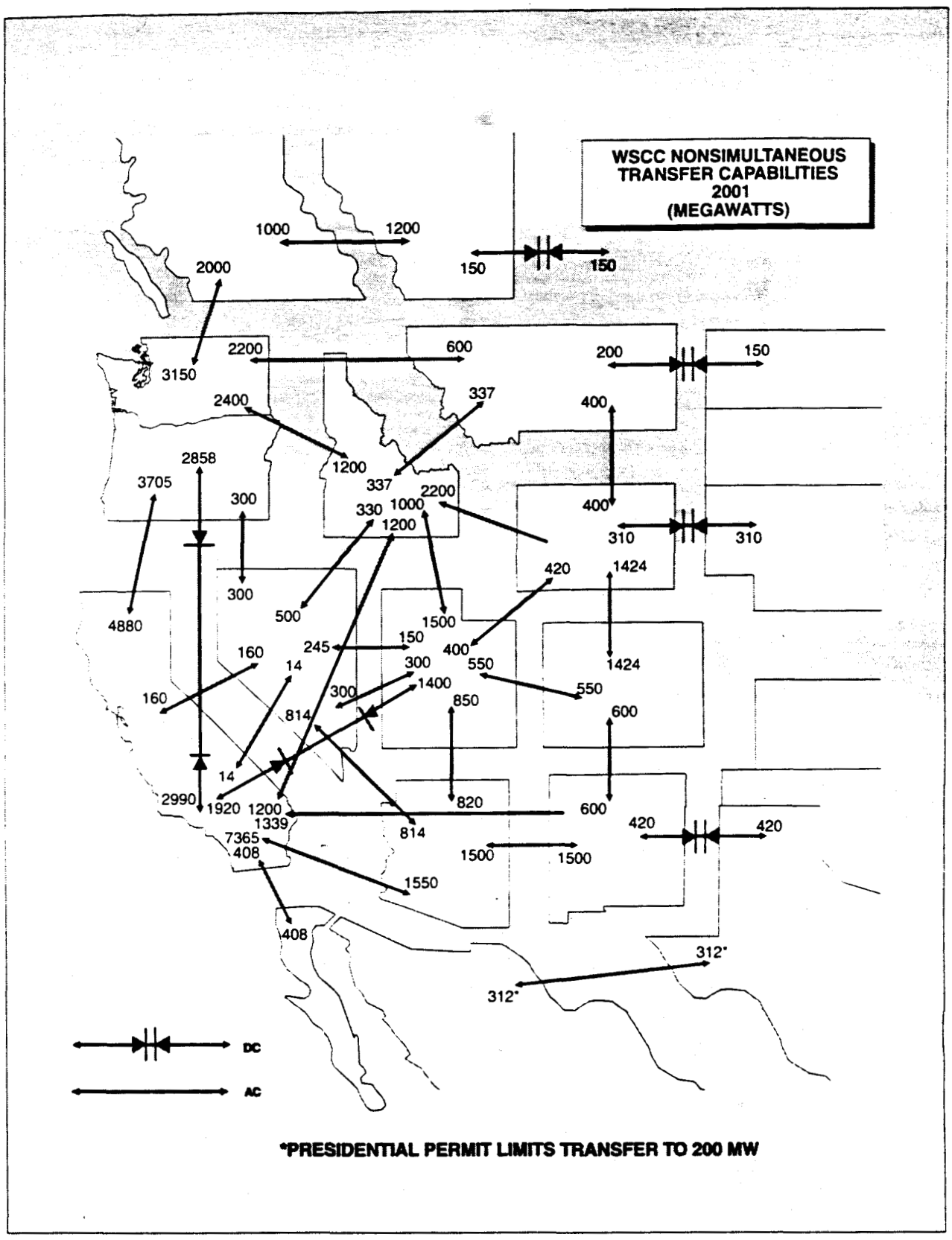

WSCC NONSIMULTANEOUS
TRANSFER CAPABILITIES
2001
(MEGAWATTS)
1000
1200
150
150
2000
3150
2200
600
200
150
2400
337
400
1200
2858
3705
300
337
2200
330
1000
1200
400
310
310
420
1424
300
500
1500
4880
245
150
400
160
14
300
550
1424
160
300
1400
550
850
814
600
14
2990
1920
1200
1339
820
600
814
420
420
7365
408
1500
1500
1550
408
312*
312*
DC
AC
*PRESIDENTIAL PERMIT LIMITS TRANSFER TO 200 MW

Figure 17

Western Systems Coordinating Council

May 1996

Ten-Year Coordinated Plan Summary 1996 - 2005

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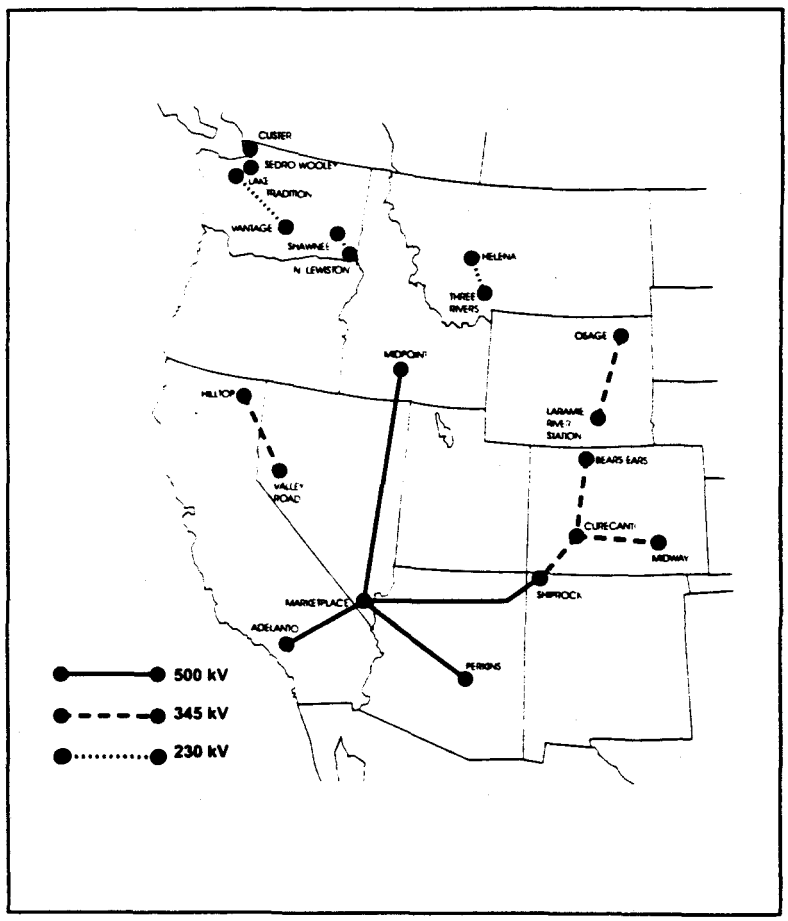

Transmission Additions 1996-2005

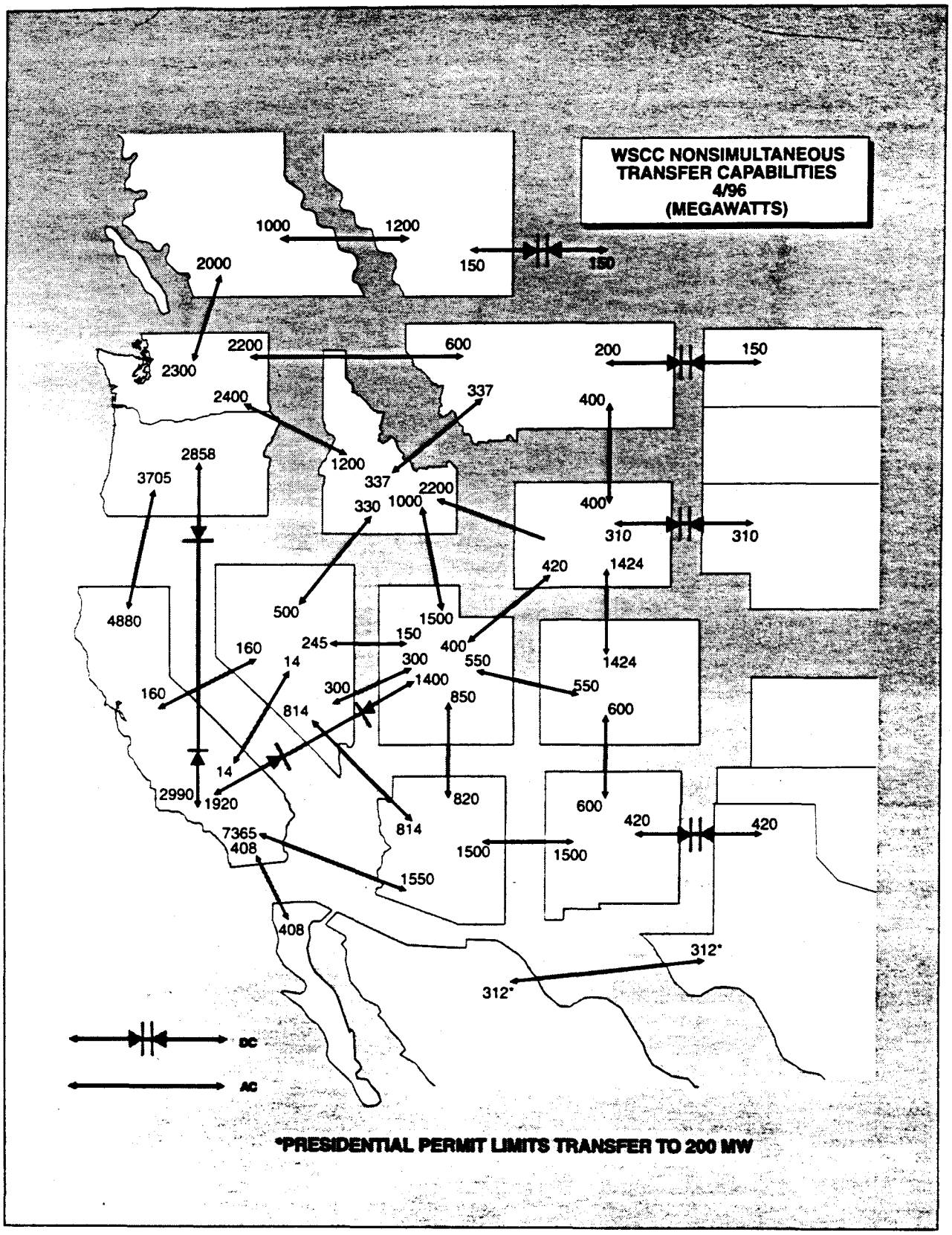
WSCC NONSIMULTANEOUS
TRANSFER CAPABILITIES
4/96
(MEGAWATTS)
1000
1200
2000
150
150
2200
600
200
150
2300
2400
337
400
2858
1200
3705
337
2200
330
1000
400
310
310
420
1424
4880
500
1500
245
150
400
160
14
300
550
1424
160
300
1400
550
814
850
600
14
2990
1920
820
600
814
420
420
7365
408
1500
1500
1550
408
312*
312*
DC
AC
*PRESIDENTIAL PERMIT LIMITS TRANSFER TO 200 MW

Figure 16

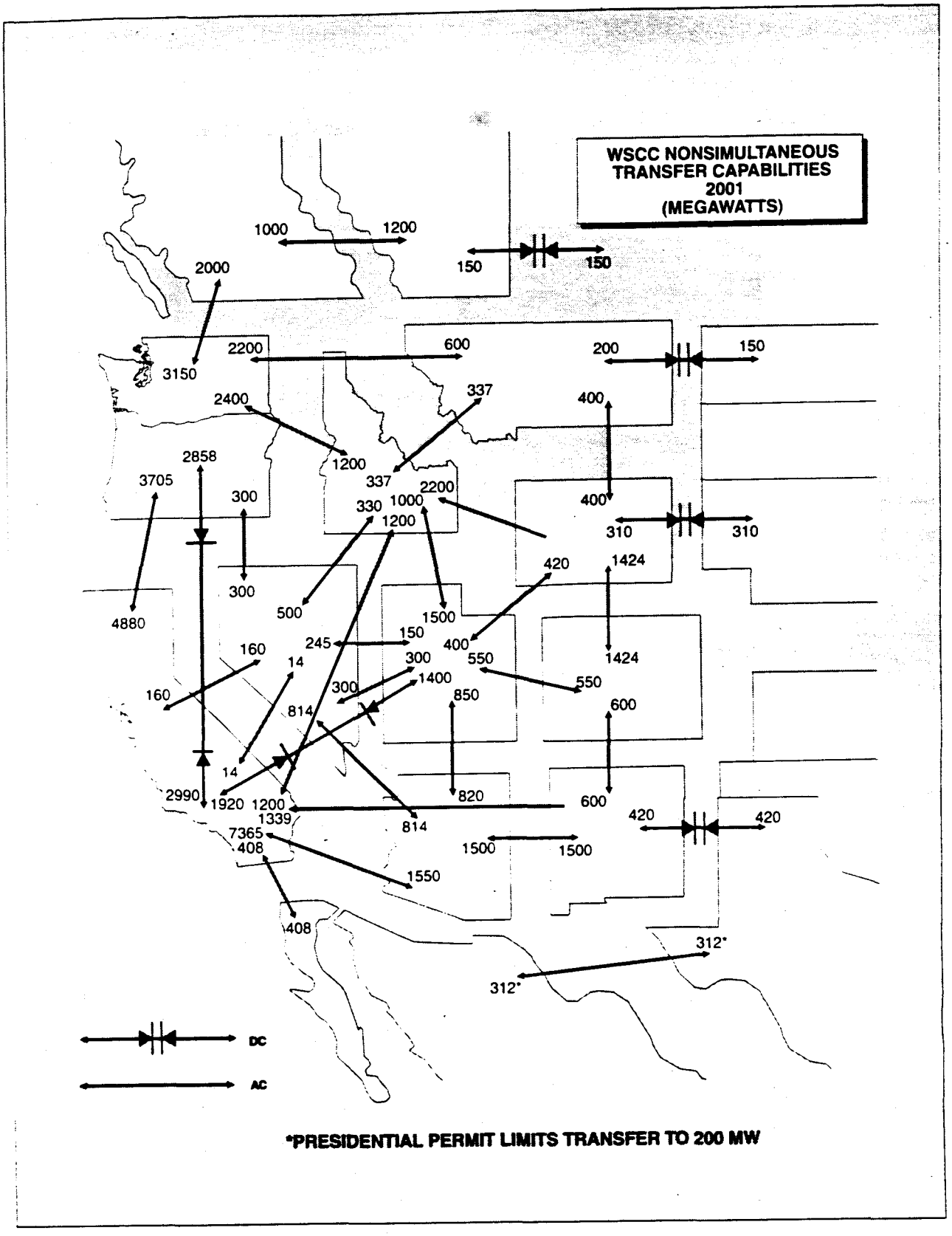
WSCC NONSIMULTANEOUS
TRANSFER CAPABILITIES
2001
(MEGAWATTS)
1000
1200
150
150
2000
3150
2200
600
200
150
2400
337
400
1200
2858
3705
300
337
2200
330
1000
1200
400
310
310
420
1424
300
500
1500
4880
150
245
400
160
14
300
550
1424
1400
550
160
300
850
814
600
14
2990
1920
1200
820
600
1339
814
420
420
7365
408
1500
1500
1550
408
312*
312*
DC
AC
*PRESIDENTIAL PERMIT LIMITS TRANSFER TO 200 MW

Figure 17

AVERY™ RECYCLED PAPER MADE FROM 20% POST CONSUMER CONTENT

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Segment,Month_Year,TTC,ATC
Cholla 345-->FC 345,Dec-98,1340,720
Cholla 345-->FC 345,Jan-99,1340,720
Cholla 345-->FC 345,Feb-99,1340,720
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Cholla 345-->FC 345,May-99,1340,720
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Cholla 345-->FC 345,Aug-99,1340,720
Cholla 345-->FC 345,Sep-99,1340,720
Cholla 345-->FC 345,Oct-99,1340,720
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Gila 69-->N. Gila 500,Apr-99,14,14
Gila 69-->N. Gila 500,May-99,14,14
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Mktplace 500-->Mead 500,Jan-99,236,236
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Mktplace 500-->Mead 500,Mar-99,236,236
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Mktplace 500-->Mead 500,May-99,236,236
Mktplace 500-->Mead 500,Jun-99,236,236
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N. Gila 500-->Gila 69,Dec-98,14,14
N. Gila 500-->Gila 69,Jan-99,14,14
N. Gila 500-->Gila 69,Feb-99,14,14
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N. Gila 500-->P. Verde 500,Jul-99,140,140
N. Gila 500-->P. Verde 500,Aug-99,140,140
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N. Gila 500-->P. Verde 500,Sep-99,140,140
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N. Gila 500-->Yucca 69,Aug-99,14,14
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Navajo 500-->Westwing 500,May-99,559,244
Navajo 500-->Westwing 500,Jun-99,559,244
Navajo 500-->Westwing 500,Jul-99,559,244
Navajo 500-->Westwing 500,Aug-99,559,244
Navajo 500-->Westwing 500,Sep-99,559,244
Navajo 500-->Westwing 500,Oct-99,559,244
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P. Verde 500-->N. Gila 500,Jan-99,140,0
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P. Verde 500-->N. Gila 500,Apr-99,140,0
P. Verde 500-->N. Gila 500,May-99,140,0
P. Verde 500-->N. Gila 500,Jun-99,140,0
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P. Verde 500-->N. Gila 500,Sep-99,140,0
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Pinn Pk. 345-->Cholla 345,May-99,2133,1653
Pinn Pk. 345-->Cholla 345,Jun-99,2133,1653
Pinn Pk. 345-->Cholla 345,Jul-99,2133,1653
Pinn Pk. 345-->Cholla 345,Aug-99,2133,1653
Pinn Pk. 345-->Cholla 345,Sep-99,2133,1653
Pinn Pk. 345-->Cholla 345,Oct-99,2133,1653
San Luis 34-->Gila 69,Dec-98,14,14
San Luis 34-->Gila 69,Jan-99,14,14
San Luis 34-->Gila 69,Feb-99,14,14
San Luis 34-->Gila 69,Mar-99,14,14
San Luis 34-->Gila 69,Apr-99,14,14
San Luis 34-->Gila 69,May-99,14,14
San Luis 34-->Gila 69,Jun-99,14,14
San Luis 34-->Gila 69,Jul-99,14,14
San Luis 34-->Gila 69,Aug-99,14,14
San Luis 34-->Gila 69,Sep-99,14,14
San Luis 34-->Gila 69,Oct-99,14,14
San Luis 34-->Yucca 69,Dec-98,14,14
San Luis 34-->Yucca 69,Jan-99,14,14
San Luis 34-->Yucca 69,Feb-99,14,14
San Luis 34-->Yucca 69,Mar-99,14,14
San Luis 34-->Yucca 69,Apr-99,14,14
San Luis 34-->Yucca 69,May-99,14,14
San Luis 34-->Yucca 69,Jun-99,14,14
San Luis 34-->Yucca 69,Jul-99,14,14
San Luis 34-->Yucca 69,Aug-99,14,14
San Luis 34-->Yucca 69,Sep-99,14,14
San Luis 34-->Yucca 69,Oct-99,14,14
Westwing 500-->Mead 500,Dec-98,236,36
Westwing 500-->Mead 500,Jan-99,236,61
Westwing 500-->Mead 500,Feb-99,236,61
Westwing 500-->Mead 500,Mar-99,236,61
Westwing 500-->Mead 500,Apr-99,236,61
Westwing 500-->Mead 500,May-99,236,86
Westwing 500-->Mead 500,Jun-99,236,86
Westwing 500-->Mead 500,Jul-99,236,86
Westwing 500-->Mead 500,Aug-99,236,86
Westwing 500-->Mead 500,Sep-99,236,86
Westwing 500-->Mead 500,Oct-99,236,86
Westwing 500-->Navajo 500,Dec-98,559,449
Westwing 500-->Navajo 500,Jan-99,559,559
Westwing 500-->Navajo 500,Feb-99,559,559
Westwing 500-->Navajo 500,Mar-99,559,559
Westwing 500-->Navajo 500,Apr-99,559,559
Westwing 500-->Navajo 500,May-99,559,559
Westwing 500-->Navajo 500,Jun-99,559,559
Westwing 500-->Navajo 500,Jul-99,559,559
Westwing 500-->Navajo 500,Aug-99,559,559
Westwing 500-->Navajo 500,Sep-99,559,559
Westwing 500-->Navajo 500,Oct-99,559,559
Westwing 500-->P. Verde 500,Dec-98,1318,968
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Westwing 500-->P. Verde 500,Jan-99,1318,968
Westwing 500-->P. Verde 500,Feb-99,1318,968
Westwing 500-->P. Verde 500,Mar-99,1318,968
Westwing 500-->P. Verde 500,Apr-99,1318,968
Westwing 500-->P. Verde 500,May-99,1318,968
Westwing 500-->P. Verde 500,Jun-99,1318,968
Westwing 500-->P. Verde 500,Jul-99,1318,968
Westwing 500-->P. Verde 500,Aug-99,1318,968
Westwing 500-->P. Verde 500,Sep-99,1318,968
Westwing 500-->P. Verde 500,Oct-99,1318,968
Yucca 69-->N. Gila 500,Dec-98,14,14
Yucca 69-->N. Gila 500,Jan-99,14,14
Yucca 69-->N. Gila 500,Feb-99,14,14
Yucca 69-->N. Gila 500,Mar-99,14,14
Yucca 69-->N. Gila 500,Apr-99,14,14
Yucca 69-->N. Gila 500,May-99,14,14
Yucca 69-->N. Gila 500,Jun-99,14,14
Yucca 69-->N. Gila 500,Jul-99,14,14
Yucca 69-->N. Gila 500,Aug-99,14,14
Yucca 69-->N. Gila 500,Sep-99,14,14
Yucca 69-->N. Gila 500,Oct-99,14,14
Yucca 69-->San Luis 34,Dec-98,14,14
Yucca 69-->San Luis 34,Jan-99,14,14
Yucca 69-->San Luis 34,Feb-99,14,14
Yucca 69-->San Luis 34,Mar-99,14,14
Yucca 69-->San Luis 34,Apr-99,14,14
Yucca 69-->San Luis 34,May-99,14,14
Yucca 69-->San Luis 34,Jun-99,14,14
Yucca 69-->San Luis 34,Jul-99,14,14
Yucca 69-->San Luis 34,Aug-99,14,14
Yucca 69-->San Luis 34,Sep-99,14,14
Yucca 69-->San Luis 34,Oct-99,14,14
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WESTERN INTERCONNECTION

BIENNIAL TRANSMISSION PLAN

May, 1998

Northwest Regional Transmission Association
Southwest Regional Transmission Association
Western Regional Transmission Association

This report was prepared in cooperation with the Western Systems.Coordinating Council, the Committee on Regional Electric Power Cooperation and the Colorado Coordinated Planning Group

B. WESTERN INTERCONNECTION COMMERCIAL USES

This section of the Plan presents an assessment of the commercial uses of the Western Interconnected transmission system. Information is presented based on User's experience obtaining access to the system for commercial purposes during 1997. This information was obtained from a survey of Transmission Users' experience with posted Available Transfer Capability (ATC) and from information available on the OASIS sites in the Western Interconnection. This Plan is the first attempt to assemble information on the ability of the Western Interconnection to meet Users' commercial needs. While problems in the Western Interconnection appear to be less than the other parts of the country, a number of concerns were identified in the above survey as described herein. These are discussed further in Section V. The effort was limited in this initial Plan to an assessment of the major transmission paths in the Western Interconnection. In future Plans, as information on path loadings and information on OASIS transmission service requests becomes more readily available, analysis can be extended to include additional paths in the Western Interconnection.

The following information is presented in this section:

Section 1. – Results of a survey of Transmission Users regarding their experience with congested paths in the Western Interconnection during 1997

Section 2. – Results of a WSCC Production / Costing study analyzing the cost impact of transmission bottlenecks in the Western Interconnection

Section 3. – An assessment of the existing loadings on the major transmission paths in the Western Interconnection, utilizing weekly peak and light load information and available hourly loading information. The percentage of time that a path exceeds 75% and 90% of its rating is shown. Most of the percentage information is associated with the paths' Rated Transfer Capability (RTC). Information was available and is presented for the Pacific AC Intertie relating this percentage to the hourly Operating Transfer Capability (OTC).

Section 4. – An assessment of OASIS posted Refused Transmission Service Requests for the months of January and August, 1997, based upon audit log information from the Western Interconnection OASIS sites.

Section 5. – A tabulation of the transmission paths in the Western Interconnection that have had ATC posted as zero on the OASIS sites during January or August 1997.

1. Transmission Congestion Survey

WICF's ATC Task Force conducted an ATC survey of Transmission Users within the Western Interconnection in November 1997. Responses were received from 31 entities. NERC and SWRTA are also conducting ATC related surveys. In WICF's survey Users were asked to indicate what their experience has been regarding obtaining or being denied transmission access as a result of congested transmission paths in the Western Interconnection. Specifically they were asked to answer the following question:

"As a transmission Customer, are there paths over which you have requested and been refused access because of unavailable capacity? Are there paths over which you have desired but not requested capacity because the posted ATC was zero? (Please indicate the path name(s) and the extent of the problem. If unavailable capacity has not been a problem, please so indicate)."

The survey requested information on the extent of the problem, however no information of this type was provided. It can be concluded from the survey that congestion as measured by unavailable ATC is occurring in the Western Interconnection. However from this survey, conclusions cannot be drawn regarding the severity of the congestion or the amount of energy not being transacted as a result of the lack of available capacity or lack of information on parallel paths. The ATC Task Force will address further analysis of these congestion issues in the future.

The following Paths were identified in this survey as those Paths over which Customers have either been denied access or over which they have desired but not requested access because the ATC was posted as zero:

Pacific Northwest/Canada

BC Hydro to BPA
BC Hydro to Alberta
John Day to COB
LaGrande - Brownlee – Boise (BPA to Idaho)
Big Eddy to NOB
Montana to BPA

California/Southern Nevada and into Arizona

COB to Midway or Sylmar
Palo Verde to Sylmar
NOB to Sylmar
PG&E to SCE (Path 15)
COB to Palo Verde
NOB to Palo Verde
COB to MD (Mead)
NOB to MD (Mead)
Midway to MD (Mead)
Midway to Palo Verde
Drum to PG&E 115 kV
Cascade to PG&E 115 kV

Arizona/New Mexico

Four Corners to Pinnacle Peak
Four Corners to Glenn Canyon
Palo Verde to Westwing
Four Corners to Mexico (through El Paso)
WSCC to Southwest Power Pool (dc tie)
Four Corners/San Juan to Blackwater dc tie

Utah/Colorado/Wyoming

Borah to Glen Canyon
Yellowtail to WW
Yellowtail to Navajo
WSCC to MAPP (dc tie)

One Transmission User indicated in response to the survey that there is very little Monthly Firm ATC available in the Western Interconnection. That User indicated that "the only paths that are somewhat available are Mead to Westwing (ATC in February to May and October to December), Sylmar to Palo Verde (ATC available January through November), COB to Mead (January, March, April, September to November), COB to Palo Verde (January, March, April, September to November), Midway to Mead (January, March April, September to November). All of the others are zero."

2. WSCC 1996 Transmission Bottleneck Study

WSCC conducted a transmission bottleneck study of the Western Interconnection transmission system in 2004 and issued the report "WSCC Transmission Bottleneck Study Report" dated January 1997. There are currently no plans to update the 1996 study. These studies investigate the effect of various assumptions and conditions on the cost of energy production. Results of these studies are valid only for the assumptions studied. In addition, the analysis tools are still under development. For example, improved hydro models are needed for Western Interconnection studies because of the large hydro resource base.

Among the sensitivities that were investigated were changes in hydro conditions (high, median and critical), changes in gas prices, changes in load growth rates, removal of transmission congestion, inclusion or deletion of various future planned projects.

Generation was added in accordance with projected resource plans. In addition to planned generation, unplanned resources were added in southern Nevada and Alberta to keep from overloading transmission under normal conditions.

Sensitivity studies were conducted with and without planned transmission projects in Phases 1 and 2 of the "Project Review and Rating Procedure" to evaluate the associated potential production cost savings. Therefore, the following major projects were not included in the study:

Southwest Intertie Project
Navajo Transmission Project

Given these assumptions, the study concluded that the following paths are the five most congested transmission areas in the Western Interconnection. This does not mean that it is economical to build new transmission facilities to remove the congestion. In some cases, projects have been considered in the past or are being currently studied. Additional feasibility and cost/benefit analysis by project sponsors will be needed.

Transmission into Alberta
Transmission into southern Nevada
Transmission from Colorado

Transmission into northern Nevada
Transmission from Idaho and Montana

The Bottleneck studies were performed prior to the outages during the summer of 1996. Therefore the California – Oregon Intertie (COI) was not represented as having a reduced OTC and study results did not identify the current congestion on the COI.

3. Existing System Loadings on the Main Grid System

An analysis of path loadings on the major control area interconnections, both actual and scheduled, gives an indication of the commercial use being made on today's system. This can be an indicator of where commercial demand on the system is high and where there may be a need to consider expansion of the system to meet future commercial needs.

As addressed by the reliability studies in Section A.1 and A.2 of this Section III, path loadings may also be indicative of potential reliability risk. Generally, the more often a path is loaded at high levels the greater the exposure to the effects of system outages or other emergency conditions.

Most of the path loading and schedule information presented in this Section of the Plan was obtained from the WSCC Weekly Interchange Diagrams. Hourly path loading information is not readily available and therefore very little of this information is presented. The Weekly Interchange Diagrams provide both actual and scheduled path loadings recorded on a once a week basis for a peak load hour and a light load hour. This information is not available after June 1996. It is recognized that weekly path loading data is not a good sample for statistical analysis, however it does give an indication of how the paths are being used, though most severe loading information is not obtained. Table III lists the Paths analyzed in this section of the Plan and the lines within those paths. Figure 6 shows the location of the Paths within the WSCC system.

Except for the Pacific AC Intertie, the loading analysis included in this Plan utilizes the Rated Transfer Capability (RTC) of the paths for calculation of percentage use or utilization. This was done because Operating Transfer Capability (OTC) information, the actual capability of a path at a specific operating time, was generally not available. Use of RTC understates the percentage usage relative to the actual capability. Utilization measured against OTC is a preferred indicator.

It should be noted that the path ratings shown in the following tables and throughout this report do not provide the formally adopted path ratings by the owners/participants of the transmission paths. New and revised transmission path ratings need to be reviewed and agreed upon by the transmission path owners and market participants. Final path ratings shall be granted through the WSCC path rating process.

Because of recent interest in the Pacific AC Intertie, the Bonneville Power Administration has performed considerable statistical analysis of the Intertie loadings. This information is available on the BPA Web Site (**http://www.bpa.gov**). Using BPA's work, information on Pacific AC Intertie loadings relative to the Operating Transfer Capability (OTC) is presented. This information may also be available from other Transmission Providers, however it has not been readily obtainable and is therefore not included in this report. It may be beneficial for future reports to include this type of assessment for other major

paths in the Western Interconnection. Table VI presents information on the Pacific AC Intertie utilization relative to OTC.

The following Tables summarize the results of the path loading assessment:

Table IV

This table presents the actual and scheduled loadings on the major Western Interconnection paths for 1995 and 1996 (through June). Average and maximum loadings, both peak load and light load, are presented. Information is presented by both MW and % of RTC.

Table V

This table presents the percentage of time the actual and scheduled loadings exceed 75% and 90% of path rating or RTC. This gives an indication of how frequently the major paths are operated near their full capacity. Where hourly information was available, this information is presented on an annual basis. The table notes whether the information is derived from Hourly or Weekly data. Information is presented in the table for the Pacific AC Intertie relative to OTC, using hourly data.

Table VI

This table presents, for the Pacific AC Intertie, the utilization compared to OTC for 1995 and 1996 by month. Maximum and average loadings by month are also presented.

TABLE III

TRANSFER PATH DESCRIPTION

PATH NAME	FACILITIES
1. Arizona - New Mexico	Four Corners – San Juan 345 kV Four Corners – West Mesa 345 kV Four Corners – Gallegos – Ambrosia 230 kV McKinley – San Juan 345 kV McKinley – Yah Ta Hey 115 kV Greenlee – Hidalgo 345 kV Springerville – Luna 345 kV
2. California – Oregon Intertie	Malin - Round Mtn. #1 and #2 500 kV lines Captain Jack - Olinda 500 kV
3. East of the Colorado River	Navajo - McCullough 500 kV Moenkopi - Eldorado 500 kV Palo Verde - Devers 500 kV Palo Verde - North Gila 500 kV Liberty - Mead 345 kV Perkins - Mead 500 kV
4. Four Corners Area	Four Corners - Moenkopi 500 kV Four Corners - Cholla #1 & #2 345 kV
5. Idaho Area - Borah West	Kinport – Midpoint 345 kV Borah – Adelaide – Midpoint #1 & #2 345 kV AmFalls – Pleasant Valley – Adelaide 138 kV AmFalls – Raft River – Minidoka 138 kV
6. Idaho Area - Brownlee East	Brownlee – Boise #1, #2, #3 230 kV Brownlee – Ontario – Boise 230 kV Oxbow – McCall 138 kV Quartz – Ontario 138 kV Quartz – Weiser – Ontario 69 kV
7. Idaho to Northwest	Midpoint - Summer Lake 500 kV Oxbow - Lolo 230 kV Hells Canyon - Enterprise 230 kV Quartz Tap - La Grande 230 kV Hines - Harney 138/115 kV tie
8. Idaho – Sierra	Midpoint – Valmy 345 kV
9. IPP DC Line	Intermountain Power Project +/- 500 kV DC line
10. Midway - Vincent	Midway - Vincent #1, #2, & #3 500 kV lines

11. Midpoint – Summer Lake	Midpoint – Summer Lake 500 kV
12. Montana to Northwest	Broadview - Garrison #1 & #2 500 kV Anaconda - Garrison #1 & #2 230 kV Ovando - Garrison 230 kV Ovando - Hot Springs 230 kV Garrison - Rattlesnake 230 kV Rattlesnake - Hot Springs 230 kV Kerr - Elmo 115 kV Thompson Falls - Burke 115 kV Crow Creek - Burke 115 kV
13. Northwest – Canada	Custer – Ingledow 500 kV #1 and #2 Boundary – Waneta 230 kV Boundary – Nelway 230 kV
14. Pacific DC Intertie	Pacific DC Intertie - +/- 500 kV
15. South of SONGS	San Onofre 230 kV bus looking south into SDG&E system
16. TOT 1A	Bears Ears - Bonanza 345 kV Hayden - Artesia 138 kV Meeker - Southwest Rangely 138 kV
17. TOT 2A	Lost Canyon - Shiprock 230 kV Durango - Shiprock 115 kV Waterflow - San Juan 345 kV
18. TOT 2B	Sigurd - Glenn Canyon 230 kV Pinto - Four Corners 345 kV
19. TOT 2C	Red Butte - Harry Allen 345 kV
20. TOT 4A	Dave Johnston - Difficulty 230 kV Riverton - Wyopo 230 kV Spence - Mustang 230 kV
21. TransAlta – BC Hydro	Langdon – Cranbrook 500 kV Pocatera – Fording Coal Tap 138 kV Colman – Natal 138 kV

FIGURE 6.

WSCC TRANSMISSION PATHS

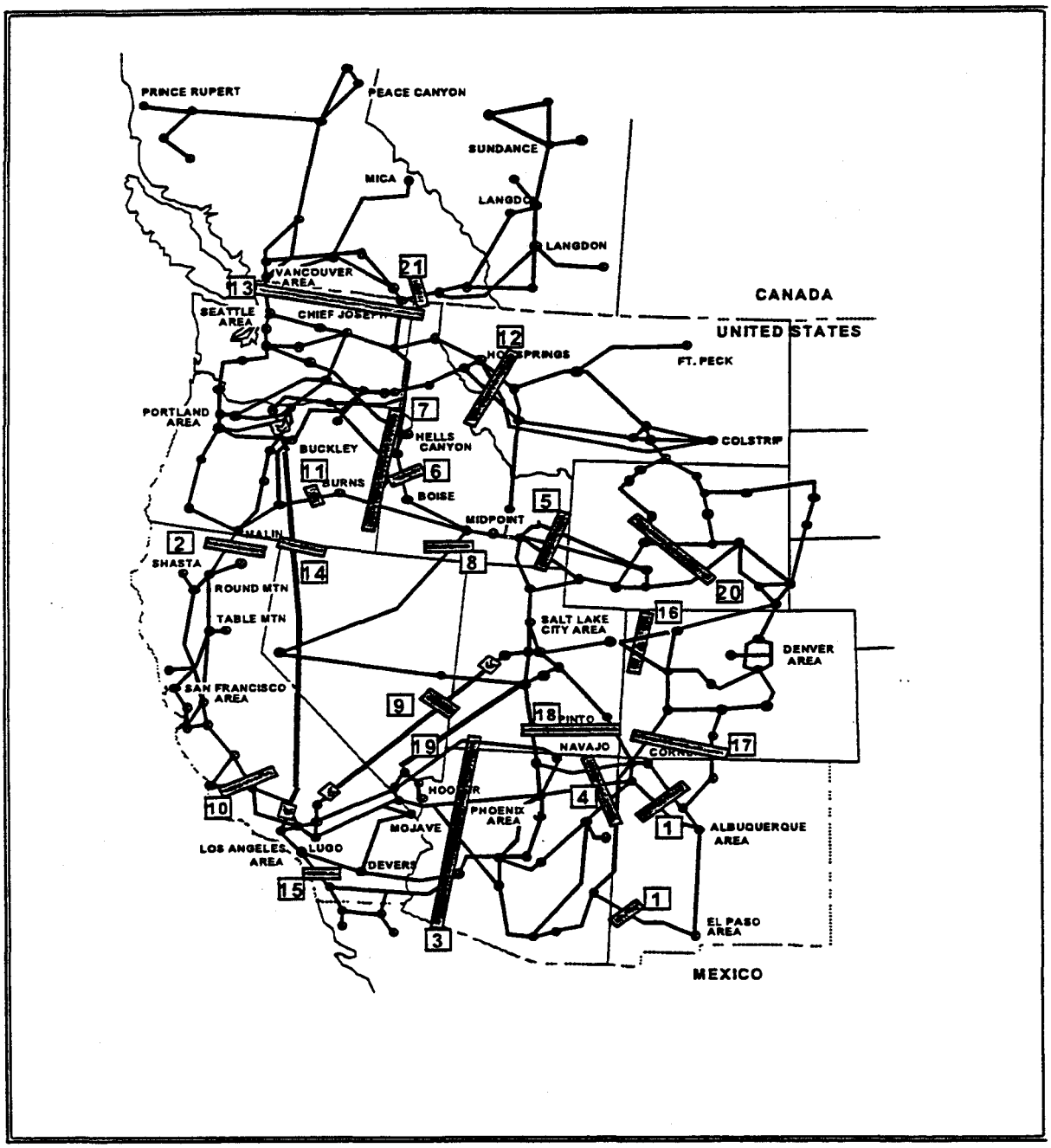

TABLE IV

PATH LOADINGS FOR MAJOR WESTERN INTERCONNECTION PATHS
WSCC Weekly Interchange Diagram Summary
January 1995 through June 1996 (see note 3)
Actual Flow and Schedule Flow - Peak and Light Load Hours

PATH	RATING (WSCC Accepted Rating in bold)	PEAK LOAD HOURS				LIGHT LOAD HOURS			
		Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)	Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)
East of Colorado River (See Note 4)	7550 (1996 rating)	2827 (37%)	4829 (64%)	N.A.	N.A.	2370 (31%)	4512 (60%)	N.A.	N.A.
NE/SE Boundary (2A + 2B + 2C) (See Note 1)	2A - 690 2B - 820 2C - 300	674	1242	N.A.	N.A.	499	997	N.A.	N.A.
TOT 1A (Colorado to Utah)	650	232 (36%)	509 (78%)	N.A.	N.A.	199 (31%)	389 (60%)	N.A.	N.A.
TOT 2A (Colorado to New Mexico)	690	203 (29%)	437 (63%)	170 (25%)	448 (65%)	145 (21%)	398 (58%)	124 (18%)	362 (52%)
TOT 2B (Utah to Arizona/New Mexico)	820	174 (21%)	449 (55%)	242 (30%)	559 (68%)	132 (16%)	579 (71%)	182 (22%)	546 (67%)
TOT 2C (Utah to Nevada)	300	168 (56%)	307 (102%)	180 (60%)	300 (100%)	147 (50%)	292 (97%)	126 (42%)	300 (100%)
TOT 4A (Wyoming)	810	235 (29%)	490 (60%)	N.A.	N.A.	246 (30%)	509 (63%)	N.A.	N.A.
Four Corners Area	2300	1400 (61%)	1959 (85%)	N.A.	N.A.	1061 (46%)	1971 (86%)	N.A.	N.A.
Midway – Vincent	3000	1152 (38%)	2543 (85%)	1203 (40%)	N-S 2525	922 (Note 2)	N-S 2879 S-N 2095	922 **	N-S 1694 S-N 2310
California – Oregon Intertie	4800	1978 (41%)	4270 (89%)	1998 (42%)	N-S 4136	1036 (Note 2)	2926 (61%)	925 **	N-S 2806 S-N 1755
Pacific DC Intertie	3100	1150 (37%)	2789 (90%)	1150 (37%)	N-S 2811	778 (Note 2)	2904 (95%0	778 **	N-S 2904 S-N 1291

TABLE IV (Continued)

PATH	RATING	PEAK LOAD HOURS				LIGHT LOAD HOURS			
		Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)	Actual Mean (% of Rating)	Actual Max. (% of Rating)	Schedule Mean (% of Rating)	Schedule Max. (% of Rating)
Idaho to Northwest	2400	540 **	1256 (52%)	546 **	1308 (54%)	836 (35%)	1637 (68%)	987 (41%)	1739 (72%)
Montana to Northwest	2200	776 (35%)	1678 (76%)	871 (40%)	1992 (91%)	1000 (45%)	2130 (97%)	1015 (46%)	2190 (100%)
IPP DC Line	1920	1445 (75%)	1917 (100%)	1445 (75%)	1917 (100%)	864 (45%)	1717 (89%)	864 (45%)	1778 (93%)

Note 1 - Combined rating of 2A, 2B, and 2C has not been determined, therefore percentage of rating is not calculated

Note 2 - Mean flow represents the mean of flows in both directions. Since the ratings are different in both directions, a "percentage of rating" was not calculated.

Note 3 – The WSCC Hourly Interchange Data from which this table was developed ceased to be available after June, 1996 and is not available today.

Note 4 – East of Colorado River statistics are calculated using the 1996 rating of 7550 MW.

N.A. = Not Available

TABLE V

PERCENTAGE OF TIME PATH LOADINGS EXCEED 75% and 90% of PATH RATING

Path Name	Path Rating (RTC) (See Note 6 re. WSCC ratings)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
Arizona to New Mexico	2000 MW E to W	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
	(See Note 4)	W	75%	Scheduled	0	0	0	0
		W	90%	Scheduled	0	0	0	0
California – Oregon Intertie	Using OTC (variable)	H	75%	Actual	6 %		37 %	
	Using OTC (variable)	H	90%	Actual	1 %		18 %	
	4800 MW N to S	W	75%	Scheduled	2 %	0	16%	0
	4800 MW N to S	W	90%	Scheduled	0	0	0	0
East of Colorado River (See Note 1 below)	5700 MW - 1995	H	75%	Actual	8 %		0 %	
		H	90%	Actual	0 %		0 %	
	7550 MW – 1996 (Accepted Rating)	H	75%	Scheduled	5 %		0 %	
		H	90%	Scheduled	0 %		0 %	
Four Corners Area	2300 MW	W	75%	Actual	12 %	12%	12 %	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
Idaho Area - Borah West	2307 MW E to W	H	75%	Actual	9 %		7%	(4% in '97)
		H	90%	Actual	1 %		<1%	(0% in'97)
		H	75%	Scheduled	17 %		12%	(5% in '97)
		H	90%	Scheduled	3 %		4%	(<1% in '97)
		H	90%	Scheduled	1 %		5 %	(3% in '97)

TABLE V (Continued)

Path Name	Path Rating (RTC)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
Idaho Area - Brownlee East	2100MW W to E	H	75%	Actual	8 %		6%	(4% in '97)
		H	90%	Actual	0		< 1%	(0% in '97)
		H	75%	Scheduled	10 %		13%	(14% in '97)
Idaho – Northwest East to West	2400 MW E to W	H	75%	Actual	0		1 %	(2% in '97)
		H	90%	Actual	0		0	(0% in '97)
		H	75%	Scheduled	<1%		4 %	(5% in '97)
		H	90%	Scheduled	0		<1 %	(0% in '97)
Idaho – Northwest West to East	1200 MW W to E	H	75%	Actual	0		0	(0% in '97)
		H	90%	Actual	0		0	(0% in '97)
		H	75%	Scheduled	0		1 %	(0% in '97)
		H	90%	Scheduled	0		0	(0% in '97)
Idaho to Sierra	500 MW E to W	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	2	6	16	32
		W	90%	Scheduled	0	2	4	12
IPP DC Line	1920 MW E to W	W	75%	Actual	73%	15%	35%	0
		W	90%	Actual	38%	0	15%	0
		W	75%	Scheduled	73%	15%	35%	0
		W	90%	Scheduled	38%	38%	15%	0
Midway - Vincent	3000 MW N to S	W	75 %	Actual	4 %	0%	13 %	0
		W	90 %	Actual	0	0	0	0
		W	75 %	Scheduled	2 %	0%	4 %	0
		W	90 %	Scheduled	0	0	0	0

TABLE V (Continued)

Path Name	Path Rating (RTC)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
Midpoint – Summer Lake	1500 MW E to W	W	75%	Actual	0	6	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
Montana – Northwest	2200 MW E to W (Accepted Rating)	H	75%	Actual	19 %		12 %	
		H	90%	Actual	2 %		2 %	
		W	75%	Scheduled	8 %	51 %	0	0
		W	90%	Scheduled	2 %	22%	0	0
Northwest - Canada	2300 MW N to S	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
Northwest - Canada	2000 MW S to N	W	75%	Actual	8 %	0	0	18 %
		W	90%	Actual	4%	0	0	5 %
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
Pacific DC Intertie	3100 MW N to S	H	75%	Actual	1 %		16 %	
		H	90%	Actual	<1 %		4 %	
		W	75%	Scheduled	0	2%	12%	4%
		W	90%	Scheduled	0	0	4%	4%
South of San Onofre (SONGS)	1200 MW (See Note 5)	W	75%	Actual	0	8 %	0	0
		W	90%	Actual	0	8 %	0	0
		W	75%	Scheduled	0	71 %	0	0
		W	90%	Scheduled	0	71 %	0	0

TABLE V (Continued)

Path Name	Path Rating (RTC)	Hourly or Weekly Data	% of Path Rating	Actual or Scheduled	Peak L 1995	Light L 1995	Peak L 1996	Light L 1996
TOT 1A (Colorado - Utah)	650 MW	W	75%	Actual	2%	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
TOT 2A (Colorado - NM)	690 MW N to S	W	75%	Actual	0	0	0	0
		W	90 %	Actual	0	0	0	0
		W	75 %	Scheduled	0	0	0	0
		W	90 %	Scheduled	0	0	0	0
TOT 2B (Utah - Arizona/NM)	820 MW N to S	W	75%	Actual	0	0	0	0
		W	90 %	Actual	0	0	0	0
		W	75 %	Scheduled	0	0	0	0
		W	90 %	Scheduled	0	0	0	0
TOT 2C (Utah - Nevada)	300 MW E to W	W	75 %	Actual	17 %	16%	13 %	12%
		W	90 %	Actual	2 %	0	4 %	4%
		W	75 %	Scheduled	34 %	4%	52 %	25%
		W	90 %	Scheduled	19 %	0	44 %	25%
TOT 4A (Wyoming)	810 MW	W	75%	Actual	0	0	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*
TransAlta – BC Hydro	1000 MW E to W	W	75%	Actual	0	13 %	0	0
		W	90%	Actual	0	0	0	0
		W	75%	Scheduled	*	*	*	*
		W	90%	Scheduled	*	*	*	*

- **Note 1** - Prior to uprating to 7550 MW in 1996, EOR had these loading statistics: In 1994 - actual exceeded 75% of rating 22 % of time and 90 %, 2 % of time; scheduled interchange exceeded 75% of rating 15% of time and 90%, 1 % of time
- **Note 2** - Information in this table comes from (1) WSCC Weekly Interchange Diagrams, noted as weekly (W) or (2) hourly SCADA data on the paths for which this was available, noted as hourly (H). Where hourly data is noted, the analysis is over the entire year rather than separated into peak and light load hours. Limited 1997 information was available and is noted where reported.
- **Note 3** - Information not available denoted by (*)
- **Note 4** – The Arizona – New Mexico path is a combination of the Southern New Mexico (NM1) path which has a WSCC Accepted Rating of 1048 MW and the Northern New Mexico (NM2) path which has a WSCC rating of 1450 MW. The combined path does not have a WSCC Accepted Rating.
- **Note 5** – South of SONGS rating was 1200 MW in 1995-96. There is now a WSCC Accepted Rating of 1800 MW in the North to South direction.
- **Note 6** – All ratings are "Existing Ratings" as noted in the WSCC 1997 Path Rating Catalog except where WSCC "Accepted Ratings" are noted in bold.

TABLE VI

PACIFIC AC INTERTIE UTILIZATION

1995 and 1996

Measured relative to Operating Transfer Capability (OTC)

Month	Average Capacity Available N to S - (%)	Average Loading (MW)	Maximum Loading (MW)	Average Utilization relative to OTC (%)
January, 1995	96.3	-30	1262	12.6
February	94.5	-8	2031	14.9
March	97.6	-27	2397	17.2
April	90.1	-470	1710	22.9
May	93.8	389	2812	22.4
June	97.0	1521	4279	35.5
July	98.9	1504	4190	34.0
August	99.6	980	3602	23.9
September	96.7	660	3231	22.3
October	91.5	1314	3400	35.9
November	96.5	1943	4080	46.4
December	80.5	2336	4019	70.2
January, 1996	57.5	2196	2998	80.1
February	95.5	1675	3482	36.9
March	85.2	1577	3422	39.3
April	92.4	2469	4593	56.6
May	97.4	2490	4514	53.2
June	93.4	3187	4861	71.4
July	86.9	3218	4775	77.4
August (Note)	72.8	2948	4478	84.9
September	66.1	2317	3262	73.3
October	65.4	2115	3247	67.9
November	66.5	1516	3130	47.6
December	66.6	1030	2744	39.0

Note: Intertie OTC was limited to 3200 MW during the months of August through December, 1996, following the August 10, 1996, system disturbance. Previous to this, the OTC was generally 4800 MW.

Average Capacity Available – actual capacity (OTC) / rated capacity (RTC), averaged for each hour over the month

Average Loading – hourly actual loadings averaged algebraically over the month, pos = N to S, neg = S to N

Maximum Loading – hourly maximum loading over the month

Average Utilization relative to OTC – actual loading / actual capacity (OTC), averaged for each hour over the month, includes both N to S and S to N flows and includes loop flow in actual flow numbers

4. Assessment of Denied Schedule Requests

In order to assess the ability of the Western Interconnection transmission system to meet the commercial needs for transmission availability for buying and selling energy, information on Refused requests has been gathered from the OASIS sites. This information might indicate the existence of a congested path. This information by itself does not give a complete indication of the existence of congested paths. For example, paths with posted ATC = 0 may not receive schedule requests because the paths are posted as not being available for other business. This does not mean there isn't potential business that could use the path if capacity were available.

OASIS posted Refusal actions are identified in Table VIII for the months or January and August 1997. Not all Refusals are due to lack of ATC; many are due to lack of agreement on price. When Refusals due to lack of ATC could be determined, the information is presented. Only those Refusals due to lack of ATC are significant to the identification of transmission congestion.

Refused requests for all types of service are combined into a single number, that is, hourly, daily, monthly and firm/non-firm are not identified separately. Refusals of over 50 MW capacity are identified separately, to give some indication of the number of Refusals of larger capacity amounts. In future reports, it may be worthwhile to identify separately the firm and non-firm Refusals. It may also provide more insight if the number of MWHs are totaled for firm and non-firm Refusals associated with lack of ATC and whether requests are made for on or off-peak seasonal periods. Not all Paths with Refused requests are listed for each Transmission Provider. Only the five Paths having the most Refused requests for each Transmission Provider are listed. In some cases, there were fewer than five paths having Refused requests.

The analysis was limited to the months of January 1997 and August 1997. These were selected as representing heavy winter and summer loading months. Future analysis could include analysis of other months such as spring with heavy Northwest hydro runoff and/or fall. As data becomes more readily available, OASIS Refusals could be presented for all months to give a more complete assessment for each path.

The information in this report was obtained from the following Transmission Providers and OASIS nodes:

TABLE VII

WESTERN INTERCONNECTION OASIS NODES

OASIS NODE	TRANSMISSION PROVIDER
Northwest OASIS	Bonneville Power Administration
	Portland General Electric
	Seattle City Light
	Montana Power Company
	BC Hydro
	Washington Water Power Company
	Snohomish PUD
Southwest OASIS	Salt River Project
	San Diego Gas & Electric
	Sacramento Municipal Utility District
	Public Service of New Mexico
	Northern California Power Authority
	El Paso Electric Company
	Sierra Pacific
	Southern California Edison Company
	Nevada Power Company
Idaho Power OASIS	Idaho Power Company
PacifiCorp OASIS	PacifiCorp
	Deseret G & T
Western OASIS	Western Area Power Administration
	Tucson Electric
	Utah Associated Municipal Power Systems
	Arizona Electric Power Cooperative
	Texas – New Mexico Power Company
Colorado OASIS	Public Service of Colorado
	Tri-State G & T
	Platte River
	WAPA – Rocky Mountain
	West Plains Energy
Los Angeles Department of Water & Power OASIS	Los Angeles Department of Water & Power
Pacific Gas & Electric OASIS	Pacific Gas & Electric
Puget Sound Energy OASIS	Puget Sound Energy
Arizona Public Service OASIS	Arizona Public Service Company

These OASIS sites can be accessed from the WSCC Web Site, http://www.wscc.com/rinpage.htm

TABLE VIII

OASIS POSTED REFUSALS OF REQUESTS FOR TRANSMISSION CAPACITY

For Months of January 1997 & August 1997
Top 5 paths per Provider

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
AEPC	None	Not Available	0	0	0	0	0
APS	Mead 500 / P. Verde 500	0	0	0	62 for all Paths	2 (2)	2
	FC 345 / N. Gila 500	0	0	0		1 (0)	0
	FC 345 / FC 230	0	0	0		1 (0)	0
	Navajo 500 / P. Verde 500	0	0	0		1 (0)	0
	Westwing 500 / Mktplace 500	0	0	0		1 (0)	0
BC Hydro	BC to PNW	N.A.	N.A.	N.A.	302 for all Paths		
	BC to Alberta	N.A.	N.A.	N.A.			
BPA	BPA to BCHydro	4 for all Paths	0	0	86 for all Paths	4	0
	BPA to IPC (Lagrande)		0	0		4	0
	BPA share of AC Pacific Intertie		1	0		1	0
	BPA to MidC.		0	0		1	0
El Paso	EPE control/HIDG	4	3 (0)	0	3	1 (1)	0
	Four C / San Juan	0	0	0	1	1 (1)	0

TABLE VIII (Continued)

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
Idaho Power	-	N.A.	N.A.	N.A.	1800 Queued for all Paths	98 for all Paths	N.A.
Montana	MPC to BPA		0	0	319 for all Paths	3	0
	MPC to PEO Yellowtail		0	0		3	2
	MPC to WAPA		1	0		1	0
	MPC to WWP		1	1		1	1
Nevada Power	El Dorado to Mead	168 for all Paths	2(2)	2	42 for all Paths	0	0
	Red Butte to Harry Allen		7(1)	0		6(0)	0
	Navajo – McCullough		2(0)	0		0	0
	Harry Allen - McCullough		2(0)	0		0	0
Pacific Gas & Electric	Not Available	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Pacificorp	Utah / APS	4199 for all paths	35 (32)	32	494 for all Paths	9 (5)	1
	IPC / Utah		15 (10)	10		1 (1)	0
	Brg / Wyoming		8 (7)	7		0	0
	Utah / Sierra		8 (8)	6		1 (1)	1
	COB / PACW		7 (7)	3		0	0
	Utah / Nevada		5 (3)	3		33 (30)	30
PGE	PGE share of AC Pacific Intertie	60 for all Paths	2	1	230 for all Paths	4	1
PNM	FCN_SJN to WNM_ABQ	146 for all Paths	7(4)	4	148 for all Paths	3(0)	0
	SJN to GRN		1(1)	0		4(0)	0

TABLE VIII (Continued)

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
PNM	ABQ to SPS		2(0)	0		0	0
	SJN_WMN_ ABQ to NEA		0	0		1(0)	0
PSCo	all paths	91 for all Paths	0	0	28 for all Paths	0	0
Puget Sound Energy	J. Day / COB		1 (0)	0		5 (2)	1
Salt River	4 Corn 230 / 4 Corn 345	60 for all Paths	3(0)	0	228 for all Paths	0	0
	Mead 230 / PV		0	0	129	11 (3)	0
	PP / PV		0	0	2	1 (0)	0
	PV / West wing				18	2 (0)	0
SCE	4 Corn / SCE	308 for all Paths	16 (4)	4	201 for all Paths	0	0
	COB / SCE		11 (6)	6		0	0
	NOB / PVD		5 (4)	4		0	0
	PVD / SON		7 (2)	2		0	0
	COB / PVD		5 (3)	3		0	0
SDG&E	SDG&E to SONGS	120 for all Paths	4(3)	3	50 for all Paths	0	0
	SONGS to NOB		7(5)	5		0	0
	SONGS to COB		1(1)	1		0	0
	SDG&E to CFE		2(0)	0		0	0

TABLE VIII (Continued)

Provider	Line / Path	# of Jan. Request	# of Jan. Refusals (See Note)	# ATC Refusals in Jan. > 50 MW	# of Aug. Request	# of Aug. Refusals (See Note)	# ATC Refusals in Aug. > 50 MW
Sierra Pacific	Sierra/Gonder IPP	15	3 (0)	0	206 for all Paths	0	0
	Sierra/Gonder-Pavant	7	1 (0)	0	27	4 (0)	0
	Midpoint/Gonder-Pavant	6	2 (0)	0	95	10 (5)	5
	Control/Gonder-IPP	2	2 (0)	0	3	1 (0)	0
	Gonder-Pavant/Summit	2	2 (0)	0	0	0	0
TNP	None	Not Available	0	0	0	0	0
Tucson	None	Not Available	0	0	4 for all Paths	0	0
UMPA	None	Not Available	0	0	0	0	0
WALC	LIB 345 - MED 345	Not Available	2	0	24 for all Paths	0	0
WAUC	None	Not Available	0	0	0	0	0
WASN	None	Not Available	0	0	0	0	0
WWP	.WWP to IPC	N.A.	0	0	43 for all Paths	16 (0)	0
	WWP to MidC	N.A.	0	0		9 (0)	0
	WWP to MPC	N.A.	0	0		9 (0)	0
	WWP to BPA/E	N.A.	0	0		2 (0)	0

Notes: - Number inside the parenthesis represents the total number of path refusals due to lack of ATC
- Number outside the parenthesis represents the total number of path refusals for any reason
- If there is no parenthetical number, the cause of the refusal could not be determined from the posted OASIS information.
- N.A. = Information Not Available

5. Paths with OASIS postings of ATC=0

Transmission Providers were requested to indicate which major Paths had ATC=0 posted at some time during the months of January and August, 1997. This information is important because it indicates that a path may be fully subscribed for some services offered. Non-firm capacity is often available when firm ATC = 0. With a posting of zero ATC, Users may choose to not request capacity and there may be few if any Refusals even though the path is fully subscribed. Therefore, information on Paths with posted ATC = 0 and information on Paths with Refused service requests are both important to developing a more complete picture of the availability of capacity on a given Path.

Table IX below indicates the Paths or lines that were reported by the Transmission Providers as having firm ATC=0 postings in either January or August, 1997 (responses were not received from all Transmission Providers):

TABLE IX

PATHS WITH OASIS FIRM ATC=0 POSTINGS
Months of January 1997 and August 1997

TRANSMISSION PROVIDER	MONTH	PATH	COMMENTS
Bonneville Power Adm.	August	West of Hatwai, E to W	
		BPA to LaGrande (Idaho Power)	
		LaGrande to BPA	
		Pacific AC Intertie, N to S	
		Pacific DC Intertie, N to S	
Puget Sound Energy	January	Mid Columbia to Puget	
		Colstrip to Garrison	
		Centralia to Puget	
		BPA to Puget	
	August	Colstrip to Garrison	
		Centralia to Puget	
Public Service of New Mexico	January & August	Alberquerque to El Paso Electric	
		SNJ/WNM/ABQ/ABQ - NEA	
		SPS - ABQ	
		WW – Four Corners	
BC Hydro	August	BCH to Alberta	ATC = 0 19% of time
Public Service of Colorado	January & August	TOT 5 W to E	
		TOT 3 N to S	
PacifiCorp	January & August	PacifiCorp to COB	

TABLE IX (Continued)

TRANSMISSION PROVIDER	MONTH	PATH	COMMENTS
		COB to PacifiCorp	
		Idaho Power to PacifiCorp West	
Platte River	Not Specified	Craig to Ault	TOT 5 W to E
		Craig to Blue River	TOT 5 W to E
		Ault to St. Vrain	TOT 7 N to S
West Plains Energy	January & August	none	No ATC=0 postings
Arizona Public Service	Not Specified	Four Corners 345 to Cholla 345	
		Cholla 345 to Pinnacle Peak 345	
		Palo Verde 500 to Westwing 500	
		Palo Verde 500 to North Gila 500	
		Mead 500 to Westwing 500	Both directions
		Mead 500 to Mead 230	
Salt River Project	Not Specified	Navajo to McCullough	
		Four Corners 345 to Coronado	Both directions
		Liberty to Mead 230	
		Palo Verde to Coronado	
		Palo Verde to Hayden (AZ)	
		Palo Verde to Mead 230	
		Palo Verde to Pinnacle Peak	
		Palo Verde to Westwing	
		Silver King to Hayden (AZ)	
		Westwing to Marketplace	
		Westwing to Mead 230	
		Westwing to Mead 500	
El Paso Electric	Not Specified	EPE Control to Arts 345/230	
		EPE Control to Picho 115/24	
		Four Corners 345 to West Mesa 345	
		Springer 345 to Arts 345/230	
		Luna 345/115 to EPE Control	
		Hidg 345/115 to EPE Control	
		Amrad 115 to EPE Control	
		Picho 115/24 to EPE Control	
Tri State G & T	January & August	Craig to Bonanza	Tri State posted ATC=0 on all its paths for January & August
		Bonanza to Craig	
		Craig to San Juan	Both directions
		Craig to Ault	Both directions
		Craig to Midway	
		Craig to Blue River	

C. SUMMARY OF RELIABILITY AND COMMERCIAL USES

This Plan has assessed the reliability of the Western Interconnection transmission system based upon WSCC reliability studies of the bulk power system. The Plan has also assessed the ability of the transmission system to meet the commercial needs of Users based upon posted OASIS information and the actual capacity loadings on the major interconnection paths in the Western Interconnection.

Table X summarizes this assessment for several of the major paths in the Western Interconnection. Only those Paths for which there was complete information are summarized in Table X. Additional information on these and other Paths is included in Tables IV, V, VIII and IX. In addition, Table X notes whether there are currently plans for increasing Path capacity, as reflected by the Proposed projects in Section IV and Appendix A of this Plan or whether there are closely related Proposed Projects.

The Projects in Appendix A are primarily subtransmission level projects. The WSCC and OCSG reliability assessment in this Plan is primarily a bulk system reliability assessment. In addition, the reliability studies by the OCSG are performed to assess the reliability of the existing system and the existing path transfer ratings. These studies are not performed to identify new projects or to provide economic justification for new projects. Therefore, the information in this Plan does not demonstrate a clear linkage between the reliability and commercial assessment of the existing system in Section III and the Proposed Projects in Section IV and Appendix A. Future Plans may address the "needs" analysis differently to improve the causal relationship between proposed projects and needs.

From the information presented in this Plan, it cannot be concluded at this time that the capacity of any transmission path in the Western Interconnection should be upgraded. Rather, this Plan provides information on the uses being made of the major transmission paths. It is the responsibility of the Transmission Providers and the Transmission Users to use this and other information to assess the cost and benefits of capacity expansion. The results of this assessment are not meant to imply that it is economic to replace existing facilities or to construct new facilities.

The following identifies the information contained in Table X:

Column 1 lists the major paths that are summarized in this report and summarized in the table.

Column 2 identifies those major paths which have experienced a reduction in Operating Transfer Capability (OTC) related to reliability concerns with operation at the Rated Transfer Capability.

Column 3 identifies whether the Paths have exceeded 75% or 90% of their rating. This is based upon the information shown in Table V. The rating is assumed as OTC if that information was available. This was only available for the AC Pacific Intertie. Otherwise the rating is assumed to be the RTC for the Path. The effect of simultaneous operating constraints is not factored in except for the Pacific AC Intertie because this information was not available. In future reports, it would be helpful to collect OTC values for the paths reflecting simultaneous limits, system outages, etc. to provide more meaningful utilization information.

Column 4 identifies Paths that have experienced Refused transmission service requests as posted on the Transmission Provider's OASIS sites. (This information could be more readily obtained from the OASIS sites in the future if each transmission line posted on the OASIS is identified with a particular Path. Transmission Users expressed this concern in response to the Western Interconnection ATC survey.) This information is contained in Table VIII.

Column 5 identifies those Paths that have had firm ATC postings of zero at some time during the months of January or August 1997. This information was obtained from the Transmission Providers and is shown in Table IX.

Column 6 identifies those transmission paths in the Western Interconnection on which Transmission Users reported they have experienced congestion during 1997. This information was reported in response to the Western Interconnection ATC Survey in November 1997.

Column 7 identifies those transmission Paths on which there are conceptual or proposed projects to increase capacity. This information is taken from the list of projects submitted to the RTAs by Transmission Providers.

TABLE X

SUMMARY OF MAJOR TRANSMISSION PATH RELIABILITY AND COMMERCIAL USE ANALYSIS

Within the Western Interconnection

PATH	Has a Reliability concern Derated the Path?	Have Flows or Schedules Exceeded 75/90% of Path Rating?	Have there been Refused Requests involving the Path? (See Note 8)	Have there been postings of zero Firm ATC on the Path? (See Note 8)	Have Users reported Congestion involving the Path?	Are there conceptual or proposed plans to increase Path capacity?
California – Oregon Intertie	Yes	Yes / Yes	Yes	Yes	Yes	No – See Note 7.
Pacific DC Intertie	No	Yes / Yes	Yes	Yes	Yes	No
East of Colorado River	No	Yes / No	Yes	Yes	Yes	No – See Note 5.
Four Corners Area	No	Yes / No	Yes	Yes	Yes	Yes – See Note 6.
Idaho - Northwest	No	No / No	Yes	Yes	Yes	No – See Note 4.
Idaho Area Brownlee - Boise	No	Yes / Yes	Yes	Yes	Yes	Yes – See Note 4.
IPP DC Line	No	Yes / Yes	No	No report	No	No
Midway-Vincent	Yes	Yes / No	Yes	Yes	Yes	No - Note 3. Regarding Path 15
Montana – Northwest	No	Yes / Yes	Yes	No report	No	No

TABLE X (Continued)

PATH	Has a Reliability concern Derated the Path?	Have Flows or Schedules Exceeded 75/90% of Path Rating?	Have there been Refused Requests involving the Path? (See Note 8)	Have there been postings of zero Firm ATC on the Path? (See Note 8)	Have Users reported Congestion involving the Path?	Are there conceptual or proposed plans to increase Path capacity?
TOT 1A (Colorado – Utah)	No	Yes / No	No	Yes	No	No
TOT 2A (Colorado - NM)	No	No / No	No	Yes	Yes	Yes - Note 1.
TOT 2B (Utah - Ariz/NM)	No	No / No	Yes	No	Yes	Yes - Note 2.
TOT 2C (Utah - Nevada)	No	Yes / Yes	Yes	No report	No	Yes - Note 2.
TOT 4A (Wyoming)	No	No / No	Yes	No	Yes	No

Note 1. - See Northeast New Mexico Reinforcement Project, page 68.
Note 2. - See SWIP Project, page 74
Note 3. - See PG&E sponsored Los Banos – Gates 500 kV Project in Appendix A, California Project Summary Tables, page 121. This Project will increase the capacity of WSCC Path 15, but not the capacity of Midway – Vincent.
Note 4. - See Brownlee – Boise Project on page 71. This project will not increase capacity of the Idaho – Northwest Path, but will increase capacity east of the Idaho - Northwest Path
Note 5. - Capacity of East of Colorado River was increase from 5700 to 7550 MW in 1996.
Note 6. - See "Shiprock – Four Corners 345 kV Interconnection Project" in Appendix A, Arizona Project Summary Tables, page 104.
Note 7. – Several hundred MVAR of shunt compensation has been added in the Northwest since 1996 to provide voltage support to the California – Oregon Intertie project
Note 8. – Many of the listed Paths are not posted on the OASIS sites on a Path basis; rather the individual owners in the Path post ATC based upon their individual ownership shares. Therefore a "Yes" may indicate an owner posted ATC=0, but the path as a whole may have had available capacity.

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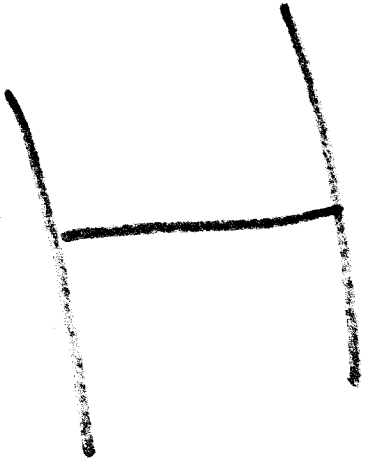

ACC DOCKET NOS. E-01933A-98-0471, E-01933A-97-0772

AG'S REQUEST NO. 18

REQUEST: For each generating unit that is, in whole or part, owned or leased or under the control of APS or TEP, identify all load pockets including that unit that exist or are likely to exist for some or all hours of the year.

RESPONSE **By:** **Mike Flores**
Title: Manager, System Control

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.

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ANTITRUST

Re: Stranded Costs and Divestiture

Arizona Corporation Commission
DOCKETED

JUN 2 2 1998

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165 DECISION NO. 60977 **OPINION AND ORDER**

DATES OF HEARING:	December 9, 1997 and February 5, 1998 (Procedural Conferences); February 9, 10, 11, 12, 13, 17, 18, 19, 20, 23, 25, 26 and 27, 1998
PLACE OF HEARING:	Phoenix, Arizona
PRESIDING OFFICER:	Jerry L. Rudibaugh
IN ATTENDANCE:	Renz D. Jennings, Commissioner Carl J. Kunasek, Commissioner
APPEARANCES:	Mr. Steven M. Wheeler, Mr. Thomas L. Mumaw and Mr. Jeffrey B. Guldner, SNELL & WILMER, LLP, on behalf of Arizona Public Service Company;
	Ms. Deborah R. Scott and Ms. Teena Wolfe, on behalf of the Residential Utility Consumer Office;
	Mr. Raymond S. Heyman, ROSHKA, HEYMAN & DEWULF, P.C., and Mr. Bradley S. Carroll, on behalf of Tucson Electric Power Company;
	Mr. Craig A. Marks, on behalf of Citizens Utilities Company;
	Mr. Lex J. Smith, BROWN and BAIN, P.A., on behalf of Ajo Improvement Company, Morenci Water and Electric Company, and Phelps Dodge Corporation;
	Mr. Michael M. Grant, GALLAGHER & KENNEDY, on behalf of Arizona Electric Power Cooperative, Graham County Electric Cooperative, and Duncan Valley Electric Cooperative;
	Mr. Walter W. Meek, President, on behalf of Arizona Utility Investors Association;
	Mr. Norman J. Furuta, on behalf of the Department of the Navy;

DISCUSSION

Introduction

Pursuant to Decision No. 59943, the Commission approved a phase-in transition to a competitive generation electric power market commencing on January 1, 1999. In the long-run, it is believed that competition will result in lower prices, better service, more choices and increased innovation. However, the transition from regulated monopoly to a competitive market has raised some contentious issues. One of the primary issues is who should pay for the costs associated with the transition from a cost-based regulated environment to a market environment. The Affected Utilities[2] have claimed a reliance on building large baseline generation plants/long-term power contracts to provide electric service for all those who desired service for a promise of regulated returns over the life of the plant. This is in conflict with market priced rates, especially during a period of excess generation capacity in the Southwest Region. According to APS, there will be excess capacity up through 2006. The difference between market based prices and the regulated cost of power has been generally referred to as "stranded costs". Rates that customers pay today include 100 percent recovery of stranded costs. These stranded costs consist of the following general categories: Generation related assets; Regulatory assets; and Social costs.

Pursuant to the Electric Competition Rules, the Group developed recommendations for the analysis and recovery of stranded costs. The Group held its initial meeting on March 4, 1997. There were several other meetings held during 1997, culminating in a Working Group Report on September 30, 1997. Because of the complexity of the stranded cost issue as well as the diversity of interests, there was little consensus reached by the Group. As a result, an evidentiary hearing was established to address the stranded costs issues.

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[2] Pursuant to R14-2-1601(1), "Affected Utilities" means the following public service corporations providing electric service: Tucson Electric Power Company, Arizona Public Service Company, Citizens Utilities Company, Arizona Electric Power Cooperative, Trico Electric Cooperative, Duncan Valley Electric Cooperative, Graham County Electric Cooperative, Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative, Navajo Electric Cooperative, Ajo Improvement Company, and Morenci Water and Electric Company.

ARIZONA PUBLIC SERVICE COMPANY

1998 -- 2007

TEN-YEAR PLAN

Prepared for the

Arizona Corporation Commission

January 1998

ARIZONA PUBLIC SERVICE COMPANY
1998 -- 2007
TEN-YEAR PLAN

GENERAL INFORMATION

This annual *Ten-Year Plan* is filed with the Arizona Corporation Commission (ACC) in compliance with Arizona Revised Statutes, Section 40-360.02, pertaining to the siting of electric power generating units and transmission lines. The *Ten-Year Plan* describes the plans of Arizona Public Service Company (APS) to construct or begin to construct, within the ten-year interval from 1998 to 2007, generating units of one hundred million watts (100 MW) or greater capacity and transmission lines having more than two spans of one hundred and fifteen thousand volts (115 kV) or higher voltage.

APS projects that the only significant generating capacity for which construction is scheduled to begin in 2007 or earlier will be four annual installments of approximately 178 MW to be placed in service in the four consecutive years from 2003 to 2006. While tentatively identified as single-cycle combustion turbines, it is uncertain at this time whether any of the annual additions in generating capacity would be in the form of one 178-MW unit or two small units of less than 100 MW each. Furthermore, plant siting has not been determined; thus, any requirement to construct transmission lines along with the generating units is unknown. Although the primary fuel is assumed to be natural gas, sources of natural gas and water are unidentified at this time. Moreover, APS has not committed to building the generating units; therefore, basic parameters such as unit size, plant configuration, and ownership are preliminary and tentative.

Western Systems Coordinating Council

EXISTING GENERATION AND SIGNIFICANT ADDITIONS AND CHANGES TO SYSTEM FACILITIES 1997 - 2007

Data as of

January 1, 1998

Prepared by

Loads and Resources Subcommittee

Data Collection Task Force

WSCC Technical Staff

ISSUED

APRIL 1998

WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF GENERATION ADDITIONS AND CHANGES
TABULATION BASED ON LOCATION OF UTILITY OPERATING THE GENERATION
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

(SUMMER CAPABILITY - MW)

GENERATION TYPE	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	10-YR. PERIOD	PERCENT OF TOTAL
HYDRO CONVENTIONAL	0	0	0	0	0	0	0	0	0	0	0	0.0%
HYDRO - PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0.0%
STEAM - COAL	0	0	0	0	0	0	0	0	0	0	0	0.0%
STEAM - OIL	0	0	0	0	0	0	0	0	0	0	0	0.0%
STEAM - GAS	0	0	0	0	0	0	0	0	0	0	0	0.0%
NUCLEAR	0	0	0	0	0	0	0	0	0	0	0	0.0%
COMBUSTION TURBINE	0	76	0	86	153	239	-158	276	397	424	1493	62.5%
COMBINED CYCLE	0	0	195	0	0	0	450	214	0	0	859	36.0%
GEOTHERMAL	0	0	0	0	0	0	0	0	0	0	0	0.0%
INTERNAL COMBUSTION	0	0	0	0	0	0	0	0	0	0	0	0.0%
COGENERATION	1	4	5	5	4	3	2	1	1	0	26	1.1%
OTHER	1	1	7	0	0	0	0	0	0	0	9	0.4%
TOTAL	2	81	207	91	157	242	294	491	398	424	2387	100.0%

WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF GENERATION ADDITIONS AND CHANGES
ARIZONA-NEW MEXICO-SO. NEVADA POWER AREA

ORG.	PLANT NAME / UNIT NO. / LOCATION	UNIT TYPE	NET CAPABILITY MW SUMMER	NET CAPABILITY MW WINTER	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL DELIV. METHOD	ALT. FUEL TYPE	COMMERCIAL OPERATION DATE ORGNL	COMMERCIAL OPERATION DATE NEW DATE	STAT	OWNR	COMMENTS
APS	Palo Verde 1, Wintersburg AZ	NP	16	16	UR				1-97		J	Unit uprated
APS	Palo Verde 2, Wintersburg AZ	NP	16	16	UR				1-97		J	Unit uprated
TEP	Springerville 1, Apache Cnty AZ	ST	40	40	SUB	RR	NONE		1-97		U	Unit uprated 40MW
TEP	Springerville 2, Apache Cnty AZ	ST	40	40	SUB	RR	NONE		1-97		U	Unit uprated 40MW
APS	Palo Verde 3, Wintersburg AZ	NP	16	16	UR				4-97		J	Unit uprated
APS	Solar , AZ	PV	1	0	SUN			6-97	6-97		U	Distributed small units
APS	Generic Cogen 1, AZ	CG	1	1	NA			1-02	1-98	I	N	Independent power producer
APS	Solar , AZ	PV	1	1	SUN			1-98	3-98	V	U	Distributed small units
APS	Generic Cogen 2, AZ	CG	4	4	NA			1-03	1-99	I	N	Independent power producer
APS	Solar , AZ	PV	1	1	SUN			1-99	6-99	P	U	Distributed small units
APS	Mohave GT 1, Kingman AZ	GT	76	84	NG	PL	NONE	3-99	6-99	U	U	Built, owned and operated by APS. Output sold to CUC
APS	Generic Cogen 3, AZ	CG	5	5	NA			1-04	1-00	I	N	Independent power producer
APS	Solar , AZ	PV	7	6	SUN			1-00	1-00	P	U	Distributed small units
IPP	Santa Teresa CC 1, Dona Ana NM	CS	195	212	NG	PL	NONE	5-00	5-00	OT	N	Independent power producer Developer: Destec Energy
APS	Generic Cogen 4, AZ	CG	5	5	NA			1-01	1-01	I	N	Independent power producer
TEP	North Loop 5, Marana AZ	GT	86	86	NG	PL	NONE	6-00	6-01	L	U	
APS	Generic Cogen 5, AZ	CG	4	4	NA			1-02	1-02	I	N	Independent power producer
NEVP	Allen GT2, Clark County NV	GT	153	153	NG	PL	FO2	6-02	6-02	P	U	To be converted to CC operation June 2004
APS	Generic Cogen 6, AZ	CG	3	3	NA			1-03	1-03	I	N	Independent power producer
TEP	North Loop 6, Marana AZ	GT	86	86	NG	PL	NONE	6-03	6-03	L	U	
NEVP	Allen GT3, Clark County NV	GT	153	153	NG	PL	FO2	6-03	6-03	P	U	To be converted to CC operation June 2004
APS	Generic Cogen 7, AZ	CG	2	2	NA			1-04	1-04	I	N	Independent power producer
APS	Generic GT1, AZ	GT	148	178	NG	PL	FO2	6-00	6-04	P	U	One 178MW unit
NEVP	Allen GT2, Clark County NV	GT	-153	-153	NG	PL	FO2	6-04	6-04	RP	U	Converted to CC operation
NEVP	Allen GT3, Clark County NV	GT	-153	-153	NG	PL	FO2	6-04	6-04	RP	U	Converted to CC operation
NEVP	Allen CC1A, Clark County NV	CT	153	153	NG	PL	FO2	6-04	6-04	RP	U	Converted from GT operation
NEVP	Allen CC1B, Clark County NV	CT	153	153	NG	PL	FO2	6-04	6-04	RP	U	Converted from GT operation
NEVP	Allen CC1C, Clark County NV	CW	144	144	WH			6-04	6-04	P	U	
APS	Generic Cogen 8, AZ	CG	1	1	NA			1-05	1-05	I	N	Independent power producer
APS	Generic GT2, AZ	GT	148	178	NG	PL	FO2	6-01	6-05	P	U	One 178MW unit
APS	Unidentified 1, Pima County AZ	GT	128	128	NG	PL	FO2	6-05	6-05	L	U	
TEP	Generic CC 1, Pima County AZ	CC	214	214	NG	PL	NONE	6-05	6-05	P	U	
LPE	Turbine 1,	GT	121	121	NG	PL	FO2	1-06	1-06	P	U	Location not determined
APS	Generic Cogen 9, AZ	CG	1	1	NA			1-02	1-06	I	N	Independent power producer
APS	Generic GT3, AZ	GT	148	178	NG	PL	FO2	6-06	6-06	P	U	One 178MW unit
APS	Unidentified 2, Pima County AZ	GT	128	128	NG	PL	FO2	6-06	6-06	L	U	
APS	Generic GT4, AZ	GT	148	178	NG	PL	FO2	6-07	6-07	P	U	One 178MW unit
APS	Generic GT5, AZ	GT	148	178	NG	PL	FO2	6-07	6-07	P	U	One 178MW unit

news release

(9/16/98)

Contact: Dan McCarthy, (610) 774-5758

PP&L Global Plans to Build Arizona Power Plant

ALLENTOWN, Pa.---PP&L Global, Inc., a subsidiary of PP&L Resources, Inc. (NYSE: PPL), plans to build a gas-fired power plant near Kingman, Ariz., with nominal base load capacity of 520 megawatts and a maximum output capability of 650 megawatts.

Robert D. Fagan, president of PP&L Global, said the proposed power plant, which is known as the Griffith Energy Project, is an excellent opportunity for the company. PP&L Global, which is headquartered in Fairfax, Va., has $635 million in investments and commitments around the world.

"As the generation of electricity is deregulated in the United States, PP&L Global is seeking to develop and acquire power plants in key areas of the country," said Fagan. "The Griffith Energy Project site is an excellent location, in a region with significant growth in demand for electricity. In addition, the project should improve electricity transmission capability in the Kingman and Lake Havasu City region."

The Arizona Corporation Commission's Siting Committee on Monday (9/14) gave unanimous approval to PP&L Global's plans for the facility. The committee's approval was required for the project to move forward.

"We are very pleased with the expeditious action of the Siting Committee, which will allow us to proceed with our project work without delay," said Fagan. "The local support that we have been receiving from the Mohave County Economic Development Authority and the leaders of Mohave County also has been instrumental in PP&L Global pursuing this project. Work on the environmental impact study and air-quality permits are moving forward rapidly."

Fagan said PP&L Global is working with the Western Area Power Administration on interconnection, construction and services agreements for the electrical interconnection to Western's regional transmission system. The company also is negotiating with a construction contractor to build the facility.

NP Energy, the Louisville, Ky.-based energy marketing company owned 50 percent by National Power, plc, has agreed to purchase between 240 and 520 megawatts of the electricity produced by the facility, Fagan said. NP Energy, which is a major wholesale marketer in the Western United States, then will market the electricity through the region.

PP&L Global has formed an operating subsidiary, Griffith Energy LLC, to oversee construction of the project and to operate and maintain the power plant. When complete, the plant is expected to employ about 25 people.

Kingman is located near Arizona's border with Nevada, about 50 miles south of Lake Mead.

PP&L Global, in partnership with Stone & Webster, also is in negotiations to build a natural gas-fired power plant in the town of Wallingford, Conn.

The Griffith Energy and Wallingford projects would mark PP&L Global's first ventures in the United States. PP&L Global has ownership interests in, and participates in the management of, companies in the United Kingdom, Chile, El Salvador, Peru, Argentina and Brazil, which together serve about 3 million electric distribution customers. In addition, PP&L Global owns interests in electric generation facilities in Spain, Portugal, Bolivia and Peru.

PP&L Resources, with headquarters in Allentown, Pa., also is the parent company of PP&L, Inc. which provides electricity delivery service to 1.2 million homes and businesses in Pennsylvania; generates electricity; sells retail electricity throughout Pennsylvania through its PP&L EnergyPlus Co.; and markets or trades wholesale energy to 26 states and Canada through its Energy Marketing Center.

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Press Release

Date: April 23, 1999

Contact: Paul Reynolds
Director of Communications
(602) 379-2629

Pinnacle West and Calpine Announce Partnership for Power Expansion at West Phoenix Plant

PHOENIX, ARIZ. Phoenix-based Pinnacle West Capital Corporation [NYSE: PNW] and Calpine Corporation [NYSE: CPN], a San Jose, Calif.-based independent power producer, announced today plans to develop a modern 500-megawatt natural gas-fired combined cycle power plant in Phoenix. The proposed $220 million facility will be located on the site of Arizona Public Service's West Phoenix Power Station near the intersection of 43rd Avenue and Buckeye Road. APS is a subsidiary of Pinnacle West.

The joint project is the second phase of a potential 750-megawatt expansion at West Phoenix. The first phase of the expansion includes a $60 million repowering of an existing unit to create a 130-megawatt combined cycle unit. The remainder of the expansion involves repowering other existing units at the site.

Electricity from the new facilities will help meet the expanding need for environmentally sound generation in the rapidly growing Phoenix metropolitan area. Construction is scheduled to begin in mid-2000 with commercial operation of the 130-megawatt unit in mid-2001 and the 500-megawatt plant in late 2001.

In the past five years, growth in electricity needs has totaled approximately 6 percent a year across Arizona, including nearly 10 percent between 1997 and 1998. Peak demand for power in the Phoenix metropolitan area is expected to continue to increase due to both population growth and increased economic expansion.

"We are committed to meeting the growing needs of our customers as well as pursuing new opportunities in competitive generation markets," said Bill Post, Pinnacle West chief executive officer. "We believe Calpine's experience in the IPP industry will bring immediate value to the project."

Said Calpine Chief Executive Officer Peter Cartwright, "Phoenix is a strategic power market in the West. There are important synergies between Pinnacle West and Calpine that make this project beneficial to both companies and the communities and markets we serve. We look forward to

our partnership with Pinnacle West."

The companies said they will install advanced pollution-control equipment at the plant that will attain the lowest achievable emissions rate. The new generating units actually will result in cleaner air for the Phoenix metropolitan area because emissions will be more than offset by reductions at other Phoenix facilities.

"Natural gas-fired combined cycle technology is highly efficient compared with today's aging gas-fired power fleet - providing tremendous opportunities to lower energy prices while safeguarding the environment," added Cartwright.

Said Bill Stewart, Generation president, "We have a strong record of low-cost, efficient plant operations. This is the right kind of plant at the right time for Phoenix and Arizona."

Pinnacle West companies own or operate nearly 8,000 megawatts of generation in Arizona and New Mexico. Calpine Corporation is a leading independent power company dedicated to providing customers with clean, reliable and competitively priced electricity. Calpine currently has 7,600 megawatts of capacity in operation, under construction or in announced development in 11 states.

Pinnacle West (NYSE: PNW) is a Phoenix-based holding company with consolidated assets of approximately $7 billion. Its major subsidiary is APS, Arizona's largest electric utility.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF JACK E. DAVIS

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473

Docket No. E-01345A-97-0773

Docket No. RE-00000C-94-0165

January 21, 2000

EXHIBIT
APS-1
admitted

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DIRECT TESTIMONY OF JACK E. DAVIS

(Docket Nos. E-01345A-98-0473, et al.)

I. INTRODUCTION

1.Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

1.A. My name is Jack E. Davis, and my business address is 400 North Fifth Street, Phoenix, Arizona 85004

2.Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

2.A. I am President of Energy Delivery and Sales for Arizona Public Service Company ("APS" or "Company"). My educational, professional qualifications and experience are set forth in Schedule JED-1, which is attached to my testimony.

3.Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

3.A. Last October, the Arizona Corporation Commission ("Commission") adopted the final Electric Competition Rules, A.A.C. R14-2-1601, *et seq.* ("Rules"), and approved APS' Settlement Agreement on Electric Competition-related issues ("Settlement Agreement"). The Rules were adopted in Decision No. 61969 (September 29, 1999) and the Settlement Agreement was approved in Decision No. 61973 (October 6, 1999).

Rule R14-2-1616 requires each Affected Utility to propose a code of conduct that addresses nine subject areas within 90 days of the adoption of the Rules. APS thereafter submitted a Code of Conduct on October 28, 1999. APS then filed its final proposed code of conduct ("Code of Conduct") on January 5, 2000 after receiving and considering numerous comments from Staff and several other interested parties. A copy of APS' final proposed Code of Conduct can be found as Attachment JED-2 to my testimony.

To assist the parties and the Hearing Officer in considering the Code of Conduct, my testimony will first provide an overview of APS' Code of Conduct and the background behind its adoption. I will then briefly discuss APS' Policies and Procedures for the Code of Conduct ("Policies and Procedures"), which were filed with the Commission on January 12, 2000. The Policies and Procedures show how APS will implement specific provisions of the Code of Conduct. Finally, I will address some of the comments and the alternative proposed code of conduct submitted by Staff's outside consultant, Ms. Gretchen McClain, as well as some comments submitted by other parties. Although APS did not adopt all the recommendations regarding its Code of Conduct from Staff and other parties, I believe that our proposed Code of Conduct meets both the letter and the spirit of Rule R14-2-1616 and, of equal importance, will be effective with and clear to our employees.

Finally, I would hasten to add that due to the number of suggestions and recommendations that APS received on its Code of Conduct in the various rounds of comments, I have not addressed every issue raised by every party. By not addressing a specific comment of a specific party, neither I nor APS are necessarily indicating agreement with the comment.

II. BACKGROUND AND OVERVIEW OF APS' PROPOSED CODE OF CONDUCT

4.Q. PLEASE DESCRIBE THE PROCEDURAL BACKGROUND OF APS' PROPOSED CODE OF CONDUCT.

4.A. First, I would point out that as part of the Settlement Agreement APS has had an Interim Code of Conduct in effect since August 1999 to govern APS' relationship with its competitive retail electric affiliate, APS Energy Services. A revised version of that Interim Code of Conduct was filed with the Commission and served on all parties to the APS Settlement Docket on October 28, 1999, as required by Decision No. 61973.

Subsequently, the Hearing Division's November 9, 1999 Procedural Order invited interested parties to file comments with APS regarding its original proposed Code of Conduct. APS received comments from Staff, New West Energy ("NWE"), Enron Corp. ("Enron"), and the Arizona Transmission Dependent Utilities Group ("ATDUG"). Staff filed its comments as direct testimony, and their

consultant proposed an alternative code of conduct. NWE supported APS' proposed Code of Conduct without modification.

APS considered all of the suggestions on revising its original proposed Code of Conduct. Ultimately, several suggestions were adopted in the final proposed Code of Conduct filed with the Commission on January 5, 2000. A brief explanation of why APS accepted or rejected certain comments appears in the January 5, 2000 cover letter transmitting the final proposed Code of Conduct.

On January 18, 2000, Staff filed comments (characterized as rebuttal testimony from its consultant) and a revised alternative code of conduct. The only other party that filed comments on this date was ATDUG.

5.Q. WHAT UNDERLYING POLICIES DID APS SEEK TO ADDRESS IN ITS CODE OF CONDUCT?

5.A. In addition to covering the nine areas described in Rule R14-2-1616, APS' Code of Conduct was drafted to address two core issues: cross-subsidization by APS' customers and anticompetitive discrimination. APS agrees that it is improper for a regulated electric distribution company to cross-subsidize; that is to include a competitive retail electric affiliate's costs in APS' regulated rates. Similarly, it would be improper for APS to discriminate in an anticompetitive fashion by, for

example, providing only APS Energy Services with marketing leads obtained through APS' role as a provider of distribution service.

Cross-subsidization and anticompetitive discrimination are legitimate areas of concern that should be addressed in a code of conduct, and APS has, in fact, addressed these issues in its Code of Conduct.

In addition to addressing these core policies, a well-drafted code of conduct institutionalizes rules and policies that prevent improper anticompetitive conduct. Written rules and policies are a tool to help guide our employees and corporate leadership to make the right decisions. Indeed, for these same reasons, APS has had for many years a formal Corporate Ethics Policy that provides written ethical and standards of conduct guidelines for all Pinnacle West personnel. We have thus tried to draft the Code of Conduct, as well as implementing Policies and Procedures, in a manner and style that will be clear and effective with our employees.

6.Q. TURNING TO THE CORE ISSUES YOU JUST IDENTIFIED, HOW DOES APS' CODE OF CONDUCT ADDRESS CROSS-SUBSIDIZATION?

6.A. First, Section 3.1 of the Code of Conduct contains a directive that APS will not subsidize its competitive retail electric affiliates through improper charges to APS customers. That directive is then elaborated upon, with Section 3.2 requiring APS

to segregate costs and revenues and Section 3.3 requiring both APS and a competitive retail electric affiliate to allow the Commission to inspect books and records to determine compliance with the Code of Conduct.

In addition to Section 3, the Code of Conduct requires structural separations between APS and affiliates in Section 4. Those structural separations—which also protect against anticompetitive discrimination—help make APS' cost allocation process more effective. The physical separation of APS and APS Energy Services ensures, for example, that an employee of APS Energy Services doesn't inadvertently use an APS photocopier to copy a document for APS Energy Services, make calls on APS phones, etc.

Section 6 of the Code of Conduct contains specific pricing provisions to restrict cross-subsidization. If an affiliate wishes to purchase goods or services from APS, it must pay the full tariffed rate applicable to all purchasers of the good or service. If there is no tariffed rate, the affiliate must pay the market price. If there is no readily identifiable or ascertainable market price, the affiliate must pay no less than the Company's fully allocated cost of providing the good or service. On the other hand, if APS wishes to purchase a good or service from an affiliate, it cannot pay more than the market price or, if no market price is readily identifiable or ascertainable, it must pay no more than the fully allocated cost of providing the good or service.

Finally, I believe that it is important to recognize that the rate moratorium that resulted from the APS Settlement Agreement also protects against cross-subsidization. Because APS is giving rate reductions between now and 2004, we cannot increase rates to subsidize a competitive retail electric affiliate.

7.Q. HOW DOES APS' CODE OF CONDUCT ADDRESS ANTICOMPETITIVE DISCRIMINATION?

7.A. Section 4 of the Code of Conduct requires physical separation between APS and its competitive retail electric affiliates. Such separation necessarily reduces the opportunities for information to be improperly transferred between APS and an affiliate. Additionally, we have adopted Enron's suggestion that if computer, telecommunications, or information systems are shared with an affiliate, there must be security safeguards to protect against the improper disclosure of information.

Additionally, Sections 4.1.7 and 4.2 require that requests for regulated services be handled the same way, regardless of whether the requestor is APS Energy Services or an unaffiliated ESP. APS is committed to administering its tariffs and providing regulated services in a completely impartial manner.

Section 5 of the Code of Conduct addresses information sharing. Essentially, there are three types of competitive information that must be addressed: (1) system information (such as transmission availability), (2) customer

information, and (3) supplier information. APS will provide system information to all parties equally and at the same time—much of it by simply posting on APS' OASIS when released. There will be no secret channels passing such information to APS' competitive retail electric affiliates. Customer information will not be released to any ESP, including APS Energy Service, unless the customer has specifically authorized the release of the information in writing. Similarly, APS will not share—with APS Energy Services or any other ESP—supplier information regarding a specific ESP, such as specific scheduling information, etc.

8.Q. WHAT OTHER PROTECTIONS ARE INCLUDED IN APS' CODE OF CONDUCT?

8.A. In addition to protections for cross-subsidization and discrimination, Section 4.3 contains detailed provisions to address advertising and marketing. These provisions ensure that customers are informed of the nature of APS Energy Services' relationship to APS, and will not be confused about this relationship.

Section 7 describes how APS will provide its employees with access to the Code of Conduct and Policies and Procedures, as well as the training program that we have developed. This section also addresses compliance with the Code of Conduct.

Finally, as suggested by Staff, Section 9 was added to explicitly address dispute resolution under Rule R14-2-212. Additionally, for internal complaints,

APS has expanded its former "Employee Concerns Line" to provide an avenue for our employees to seek assistance on Code of Conduct concerns and to report violations, in addition to covering the health and welfare matters that were previously available through that system.

III. IMPLEMENTING APS' CODE OF CONDUCT

9.Q. WAS APS' PROPOSED CODE OF CONDUCT INTENDED TO BE A ONE HUNDRED PERCENT SELF-CONTAINED, SELF-IMPLEMENTING DOCUMENT?

9.A. No. Just as the enactment of legislation does not mean there is no need for implementing agency regulations or other interpretive agency documents, both internal and external, it was always contemplated and intended that APS have policy and procedure documents. These documents are important to Company employees and management, as well as regulators and other affected parties, to both understand and implement the more general Code of Conduct provisions. These could also be of assistance in measuring our compliance with such provisions.

10.Q. COULD YOU BRIEFLY DESCRIBE THESE POLICIES AND PROCEDURES?

10.A. Yes. The policies and procedure documents submitted to Staff on January 12th were divided into nine topics corresponding to sections of the Company's final proposed Code of Conduct:

1. APS/Affiliate Accounting (Code of Conduct Sections 3 and 6);
2. Physical Separation of Entities (Code of Conduct Section 4);
3. Shared Officers and Directors (Code of Conduct Section 4);
4. Contracting for Services (Code of Conduct Section 4);
5. ESP Contacts and Requests for Service (Code of Conduct Section 4);
6. Joint Promotion, Sales and Advertising (Code of Conduct Section 4);
7. Access to Information (Code of Conduct Section 5);
8. Code of Conduct Training (Code of Conduct Section 7); and
9. Code of Conduct Complaint Resolution (Code of Conduct Section 9).

As you can see, not every Section of the proposed final Code of Conduct has an associated policy or procedure document. Section 1 of the Code of Conduct contains only definitions. To the extent such definitions are important to understanding how a specific policy or procedure should be implemented (e.g., the Affiliate Accounting Procedures), they are included as part of the implementing document itself. Sections 2 and 8 of the Code of Conduct are, in the Company's

opinion, self-explanatory and do not need any further guidelines for their implementation. The same is true of certain specific provisions of Section 4.

11.Q. ARE THESE POLICIES AND PROCEDURES SUBJECT TO FURTHER CHANGE?

11.A. Yes. They will undoubtedly have to be modified and additional detail will have to be added depending both on the final Commission-approved Code of Conduct and, more importantly, on our actual subsequent experience. No matter how specific one makes these kinds of policies and procedures, there will be factual instances where their application in practice will be unclear. No matter how generalized they are, there will be factual instances that do not fit within any general rule. No matter how effective they appear on paper, there will be factual instances where the policies and procedures are ineffective in implementing the intent of the Code of Conduct. In all these cases, the policies and procedures will have to be changed or supplemented in some respect.

12.Q. ARE YOU NOW ASKING THE COMMISSION TO APPROVE THE POLICIES AND PROCEDURES FILED ON JANUARY 12, 2000?

12.A. No. Such approval might imply that APS would also require Commission approval to modify its Policies and Procedures in the types of situations described above. The Company must have the ability to make these necessary changes without the requirement of seeking formal Commission approval. Additionally, while it may

be appropriate for the Director of the Utilities Division to approve the initial Policies and Procedures, and it may be appropriate for APS' subsequent modifications to be provided to the Director, modifications to the Policies and Procedures should not be subject to a formal approval process by the Director.

IV. COMMENTS ON STAFF'S AND OTHER PARTIES' CODE OF CONDUCT PROPOSALS

13.Q DOES APS AGREE WITH STAFF'S DISCUSSION ON JOINT SUPPORT OFFICERS AND DIRECTORS?

13.A. Yes. After Staff filed Ms. McClain's Direct Testimony, representatives from APS met with Staff and discussed Staff's concerns on this issue. As a result, APS was able to agree to restrictions on common officers and directors that I believe address valid concerns about cross-subsidization and improper information sharing, without interfering with legitimate corporate governance issues unrelated to the Code of Conduct.

14.Q. IN HER DIRECT TESTIMONY, STAFF'S CONSULTANT ARGUED THAT ALLOWING AN AFFILIATE TO CONTRACT FOR SERVICES FROM AN APS EMPLOYEE EFFECTIVELY CONSTITUTES JOINT EMPLOYMENT. DO YOU AGREE?

14.A. No. APS' position is best illustrated by an example. APS routinely contracts for services with outside vendors. If, for example, APS contracts to have an engineer from XYZ Software write and install a software patch on an APS system, that

engineer does not thereby become a joint employee of APS and XYZ Software. Rather, the engineer is an employee of XYZ Software only. There is no prohibition in the Rules on APS contracting with an affiliate for services. Indeed, even Staff's proposed code of conduct recognizes that APS and its affiliates may provide services to each other, as long as the pricing guidelines are followed.

Moreover, in its Policies and Procedures, APS has limited the ability for it and its affiliates to contract for such services. These procedures were intentionally drafted to prohibit "matrixing"—where an employee is assigned to an affiliate for an indefinite period with an undefined scope of work but remains, for all practical purposes, an APS employee. Under APS' Code of Conduct, the person providing the services must have a recognized expertise needed for a project that has a specified scope and a finite duration. The procedures also require personnel involved in providing these services to formally sign a confidentiality/non-disclosure agreement.

15.Q. STAFF'S CONSULTANT ALSO REFERS TO "APS' COMPETITIVE ACTIVITIES" AND APPEARS TO SUGGEST THAT APS MUST ADOPT VARIOUS <u>INTRA</u>-COMPANY SEPARATIONS. DO YOU HAVE ANY COMMENTS ON THESE REFERENCES?

15.A. First let me say that I am not particularly clear on what Ms. McClain means by "APS' competitive activities." Under Rule R14-2-1615, all Competitive Services

as defined by the Electric Competition Rules must be divested to an affiliate or an unaffiliated third party. There are, however, a few services, such as providing metering and meter reading services for load-profiled residential customers, that are admittedly excluded from the separation requirements.

It appears that Section X.C of Staff's proposed Code of Conduct is meant to prohibit, for example, APS from using the same employee to read both the residential load-profiled meter of a direct access customer and Standard Offer customers' meters on a particular meter route—even if the meter reading costs are properly charged to such customers. If this is Staff's intent, APS will not be willing to absorb the costs to segregate these intra-company services, or to eliminate the very economies of scale that were the reason for excluding these services from the definition of "Competitive Services" in the first place. Rather, APS would not provide metering or meter reading services for residential load-profiled customers because it could not justify providing these services from a business standpoint. It may also foreclose APS from ever offering consolidated billing, if Staff considers such billing to be a "Permitted Competitive Service" requiring structural separation and burdensome reporting.

As to "Interim Competitive Services," APS is not now, and has no intention of, providing such services, as defined by Ms. McClain, during the transition prior

to December 31, 2002. All competitive retail electric services will be provided through an affiliate.

16.Q. DO YOU AGREE WITH STAFF'S PROVISIONS IN SECTION XI OF STAFF'S REVISED CODE OF CONDUCT, REGARDING TRANSFER PRICING FOR NON-TARIFFED GOODS AND SERVICES?

16.A. No, I do not. Such a restriction would unfairly deny APS Energy Services the opportunity to purchase goods and services from a sister corporation, and would prevent APS customers from benefiting from transactions that may be below fully allocated cost but still above incremental cost.

17.Q. ENRON CLAIMS THAT APS' CODE OF CONDUCT DOES NOT ADEQUATELY ADDRESS ITS CONTINUED OWNERSHIP OF GENERATION ASSETS. DO YOU AGREE?

17.A. No. As Staff acknowledged in its Rebuttal Testimony, the Code of Conduct is intended to address retail electric competition. APS generation (pre-divestiture) will be used only for: (1) Standard Offer Service, a defined "noncompetitive service" under the Electric Competition Rules; and (2) wholesale transactions. APS is not selling competitive generation at retail, and will not sell competitive generation at retail, during the transition period. Thus, the numerous questions that

Enron poses at page 5 of its testimony are completely unrelated to retail electric competition or, conversely, are subject to APS' FERC Code of Conduct.

For example, Enron questions how APS will "dispose of excess [generation] capacity and how will it treat the revenues therefrom?" APS will sell its excess generation capacity on the open market and will—as it has done for the more than 25 years I have worked for the Company—account for such sales according to the requirements of FERC's and this Commission's Uniform System of Accounts. APS' sales of generation at the wholesale level are by no means a new development brought about by the Electric Competition Rules. Moreover, APS' rate increase moratorium, along with annual fixed decreases, are in place irrespective of the level of or price for any wholesale sales.

Enron also suggests that the Commission should require that APS sell "excess" generation to the highest bidder. That is in fact our goal.

Finally, Enron's concerns over how APS will manage its transmission and distribution capacity are misplaced given the subject matter of this proceeding. Those concerns are not code of conduct issues. APS' FERC-imposed OATT and OASIS requirements address the management of transmission, and the Electric Competition Rules require APS to ensure that there is adequate distribution capacity to serve its customers.

18.Q. DO YOU AGREE WITH ENRON THAT THE DISCLOSURE REQUIREMENTS FOR PROMOTIONAL OR ADVERTISING MATERIALS SHOULD EXTEND BEYOND WRITTEN MATERIALS.

18.A. No. What I think of as the utility equivalent of "Miranda" warnings on written promotional and advertising material are sufficient to prevent customer confusion. Requiring an APS Energy Services employee to provide Enron's 50-word "Miranda" warning prior to speaking with any potential customer or even before speaking, in say an Open Meeting, is unreasonable. It certainly goes beyond the "guidelines" that are required by Rule R14-2-1616(B)(4).

19.Q. DO YOU AGREE WITH THE RECOMMENDATION OF STAFF'S CONSULTANT THAT APS SHOULD SUBMIT ANNUAL REPORTS ON ITS COST ALLOCATIONS?

19.A. No. The Electric Competition Rules and APS' Code of Conduct give the Commission the authority to inspect the books and records of APS and its competitive retail electric affiliates. There is no evidence that this authority, together with the existing reports required of APS and its affiliates, will be inadequate to provide sufficient information for the Commission to determine compliance with the Code of Conduct. The Commission should not impose burdensome, routine reporting requirements unless and until they are necessary.

V. CONCLUSION

20.Q. PLEASE SUMMARIZE YOUR TESTIMONY.

20.A. APS has developed a Code of Conduct, and implementing Policies and Procedures, that complies with the nine requirements for codes of conduct under Rule R14-2-1616(B). We appreciate the hard work of Staff and the intervenors to this proceeding who recommended modifications to APS' Code of Conduct. I can assure you that each recommendation was considered by the Company, and I believe that an improved Code of Conduct resulted from that process.

APS does not, however, believe that either it or the Commission should accept recommendations to modify the proposed Code of Conduct in a way that would impose conditions beyond those in the Electric Competition Rules. The intra-company separations for "Permitted Competitive Services" proposed by Staff do that, as do proposals for required reporting and outside audits.

APS' proposed Code of Conduct submitted on January 5, 2000 and its implementing Policies and Procedures will effectively address legitimate concerns of cross-subsidization and anticompetitive discrimination involving APS and its competitive retail electric affiliates. The proposed Code of Conduct meets both the substance and the intent of Rule R14-2-1616, without imposing unreasonable burdens and obligations that would really do no more than improperly subsidize

new market entrants at the expense of the Company, its customers, and ultimately the consumers in this state.

21.Q. WHAT IS APS' INTENT REGARDING ITS CODE OF CONDUCT?

21.A. Above all else, APS will continue to do business in a fair and honest manner. We will meet the letter, spirit, and intent of the Code of Conduct. I ask the Commission and new market entrants not to presume—as do some of the comments and recommendations filed in this proceeding—that APS will act unethically or anticompetitively in a restructured electric industry. Our history of service in this state warrants precisely the opposite presumption.

22.Q. DOES THIS CONCLUDE YOUR DIRECT WRITTEN TESTIMONY?

22.A. Yes.

Attachment JED-1

STATEMENT OF WITNESS QUALIFICATIONS

Jack E. Davis is President of Energy Delivery and Sales for Arizona Public Service Company. As President of Energy Delivery and Sales, Mr. Davis has responsibility for Bulk Power Trading, Transmission Planning and Operations, Customer Service, Economic Development, and Pricing and Regulation.

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 Arizona Public Service Company that same year and has held various supervisory and managerial positions in both the System Planning and Power Contracts and Systems Operations Departments. In 1990, Mr. Davis was named Director of System Development and Power Operation and thereafter promoted to Vice-President of Generation and Transmission in 1993. In October 1996, he was named Executive Vice President of Commercial Operations.

Mr. Davis is the Past President of the Western Energy Supply and Transmission, Chairman of the Western Systems Coordinating Council (WSCC), a member of the WSCC Board of Trustees, and (past chairman of the WSCC Regional Planning Policy Committee), a member of the National Electric Reliability Council Board of Trustees, and past President of the Western Systems Power Pool. Additionally, he is a registered professional electrical engineer in the State of Arizona.

777259.1

Attachment JED-2

Code of Conduct

ARIZONA PUBLIC SERVICE COMPANY
Code of Conduct

Arizona Public Service Company ("APS") is committed to establishing standards of conduct that will produce confidence in the integrity of the competitive retail electric market and that will be consistent with the requirements of the Electric Competition Rules.

The following Code of Conduct shall apply to APS and, where indicated, its Affiliates.

1 Definitions

1.1 "ACC" means the Arizona Corporation Commission.

1.2 "Affiliate Interest Rules" means A.A.C. R14-2-801, et. seq.

1.3 "APS" means Arizona Public Service Company in its capacity of providing Distribution Service and any other electric services permitted by law.

1.4 "Competitive Electric Affiliate" means a business enterprise related to APS in the manner described in A.A.C. R14-2-801 (1) that is also an Electric Service Provider; hereinafter referred to as "Affiliate" or "Affiliates".

1.5 "Distribution Service" means those services described in A.A.C. R14-2-1601 (14), i.e., "the delivery of electricity to a retail consumer through wires, transformers, and other devices that are not classified as transmission services subject to the jurisdiction of the Federal Energy Regulatory Commission."

1.6 "Electric Competition Rules" means A.A.C. R14-2-1601, et. seq.

1.7 "Electric Service Provider" or "ESP" means a company supplying, marketing, or brokering at retail competitive electric services pursuant to a Certificate of Convenience and Necessity. This term has the same definition as in A.A.C. R14-2-1601 (16).

2 *General*

2.1 All employees and authorized agents of APS shall conduct their activities in compliance with the requirements of this Code of Conduct.

2.2 Failure to conduct activities in compliance with this Code of Conduct will subject the employee or agent to disciplinary actions described in Section 7.

2.3 APS shall adopt and follow written policies and procedures regarding the implementation of this Code of Conduct.

3 *Financial*

3.1 *Subsidization.* APS shall not subsidize the competitive electric services provided by an Affiliate through any charge for goods or services which is not in conformance with Section 6.

3.2 *Segregation.* Costs and revenues of APS shall be segregated from costs and revenues of Affiliates in a manner sufficient to ensure compliance with Section 3.1.

3.3 *Books and Records.* APS shall maintain its books of account and records separately from those of its Affiliates. As a precondition to transacting any business with APS, Affiliate books and records must be made available for inspection by the ACC to the extent reasonably necessary to determine compliance with this Code of Conduct.

4 *Separation of Functions*

4.1 *Operations*

4.1.1 APS shall exist as a separate corporate entity from any Affiliate.

4.1.2 APS shall not use shared corporate support functions as a means to circumvent Section 5.

4.1.3 Nothing in this Code of Conduct shall prevent APS and an Affiliate from receiving shared services from Pinnacle West Capital Corporation. Such shared services and the assignment or allocation of costs therefor shall be as set forth in APS' Affiliate Accounting Policies and Procedures.

4.1.4 Shared telecommunication, computer and information systems shall be secured with appropriate security devices and procedures to protect against the disclosure of information in a manner inconsistent with this Code of Conduct.

4.1.5 Except as permitted by this Code of Conduct, APS shall not jointly employ the same employees as its Affiliates.

4.1.5.1 For purposes of common oversight and governance, APS and its Affiliates may share one or more officers and directors. Officers and directors may be shared only where sufficient mechanisms are in place so that such sharing does not result in circumventing any of the Code of Conduct provisions. Officers and directors shall sign a statement annually that they understand the Code of Conduct and the attendant consequences for violations thereof.

4.1.6 An Affiliate may contract for services from APS when a written service agreement is executed in accordance with established policies and procedures and when the charges for such services comply with Section 6.

4.1.7 Requests from Affiliates and non-affiliated ESPs and their customers for ACC-regulated services provided by APS shall be processed on a non-discriminatory, first come, first served-basis and in accordance with established policies and procedures and also as set forth in Schedule 10 of APS' ACC-approved tariffs.

4.2 *Administering Tariffs.*

4.2.1 Administration and enforcement of all ACC-approved tariffs for APS, including terms and conditions of service, shall be conducted solely by employees and authorized agents of APS.

4.2.2 With respect to the terms and conditions of providing Distribution Services subject to ACC approval (including price, curtailments, scheduling and priority), APS shall not provide its Affiliates, or the customers of its Affiliates, any preferential treatment over non-affiliated ESPs or their customers as a result of such status as an Affiliate or customer of an Affiliate.

4.2.3 If a tariff provision allows for discretion in its application, APS shall apply that provision in a non-discriminatory manner between an Affiliate and all other market participants and their respective customers.

4.2.4 APS shall not condition or otherwise tie any non-competitive electric service it provides nor the availability of discounts of rates or other charges or fees, rebates, or waivers of terms and conditions of such service to a Distribution Service customer taking any goods or services from an Affiliate.

4.2.5 Prior to the divestiture of APS generation pursuant to ACC Decision No. 61973 (October 6, 1999), APS generation shall not be sold by APS on a discounted basis to Standard Offer customers without the express permission of the ACC.

4.3 *Promotion, Sales and Advertising of Non-Distribution Services.*

4.3.1 APS shall not engage in any joint advertising, marketing or sales activity of any sort with an Affiliate.

4.3.2 APS shall not permit an Affiliate to use APS' name or logo in written promotional or advertising material unless the Affiliate discloses that: 1) the Affiliate is not the same company as APS and 2) customers do not have to buy the Affiliate's product in order to continue to receive Distribution Service at regulated rates from APS.

4.3.3 APS shall not promote, market, or sell an Affiliate's services for or on behalf of an Affiliate.

4.3.4 APS shall not state or imply in any advertising or customer communication that the provision of any Distribution Service, or the terms and conditions governing such services, are conditioned upon, related to or tied to the purchase of any other product or service from an Affiliate, or that APS is the same entity as such Affiliate.

4.3.5 APS shall not provide advice regarding an Affiliate to APS' customers nor state or imply that Distribution Service provided to an Affiliate's customer is safer or more reliable than those provided to a non-Affiliate or that an Affiliate's customers will receive preferential treatment from APS regarding their Distribution Services.

4.3.6 APS shall not provide an Affiliate with advertising space in any APS written customer communication (e.g., billing) unless access is made available to non-affiliated ESPs on the same terms and conditions.

4.3.7 APS shall inform customers who inquire about competitive services that a list of authorized ESPs is available from the ACC. APS may offer customers the ACC website address and telephone number or, upon request, may provide the customer with a copy of the current ACC list of authorized ESPs as shown on the ACC website at the time of the customer's inquiry.

5 Access to Information

5.1 *System Information.* APS shall provide Affiliates and non-Affiliates access to Distribution Service-specific information (including information about available distribution capability, transmission access and curtailments) under the same terms and conditions and in accordance with established policies and procedures.

5.2 *Customer Information.* Non-public customer-specific information shall not be provided by APS to an Affiliate unless release of such information is expressly authorized by the customer or the ACC or is otherwise permitted by law.

6 Transactions with Affiliates

6.1 *Accounting.* Transactions between APS and an Affiliate shall be accounted for in accordance with Generally Accepted Accounting Principles.

6.1.1 Accounting provisions for Affiliate transactions shall be governed by written policies and procedures that include but are not limited to general provisions, allocation methodologies for direct and indirect charges, goods or services produced, purchased or developed for sale and those not produced, purchased or developed for sale, transfer of assets, and inter-company billing and reimbursements.

6.2 *Purchase of Goods and Services from Affiliates.* APS shall not purchase goods and services from an Affiliate at a price that is above the market price of such goods and services or, where a market price for any particular good or service is not readily available, at a price that is above the Affiliate's fully allocated cost of providing the good or service.

6.3 *Sale of Goods and Services to Affiliates.* Goods and services sold by APS to an Affiliate shall be charged in accordance with any applicable tariff. Where a tariff is not applicable, such goods and services shall be

sold at the market price or where there is no readily identified market price, at the fully allocated cost of providing the good or service.

6.4 *Reporting Requirements*. Contracts pertaining to transactions between APS and an Affiliate as described in Sections 6.2 and 6.3 shall be provided to the ACC in compliance with the reporting requirements of the Affiliate Interest Rules.

7 Dissemination, Education and Compliance

7.1 *Employee Access to Code of Conduct*. Copies of this Code of Conduct and associated policies and procedures shall be provided to employees of APS and all Affiliates and those authorized agents of APS and all Affiliates that are likely to be engaged in activities subject to the Code of Conduct. A copy of the Code of Conduct and associated policies and procedures shall be maintained on Pinnacle West's Intranet.

7.2 *Employee Training*. Training on the provisions of the Code of Conduct and its implementation through associated policies and procedures, shall be provided to APS employees and authorized agents likely to be engaged in activities subject to the Code of Conduct.

7.3 *Compliance*.

7.3.1 Compliance with the Code of Conduct is mandatory. An APS employee's or agent's failure or refusal to abide by or to act according to such standards may subject the employee or agent to disciplinary action, up to and including discharge from employment or termination of the agent's relationship with APS.

7.3.2 Compliance with this Code of Conduct shall be administered as part of the Pinnacle West Business Practices program and in accordance with Pinnacle West Business Practices policies.

8 Modifications to the Code of Conduct

8.1 APS shall request modifications to this Code of Conduct by filing an application with the ACC. The application shall set forth the proposed modifications and supporting reasons.

9 Dispute Resolution

9.1 To the extent permitted by law, complaints concerning violations of this Code of Conduct shall be processed under the procedures established in A.A.C. R14-2-212.

Questions regarding this Code of Conduct should be directed to the Pinnacle West Business Practices Department.

ARIZONA PUBLIC SERVICE COMPANY
Code of Conduct

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The following Code of Conduct shall apply to APS and, where indicated, its Affiliates.

1 Definitions

1.1 ~~"Affiliate" or "Affiliates" means an Electric Service Provider related to APS in the manner described in A.A.C. R14-2-801 (1).~~"ACC" means the Arizona Corporation Commission.

1.2 "Affiliate Interest Rules" means A.A.C. R14-2-801, et. seq.

1.3 "APS" means Arizona Public Service Company in its capacity of providing Distribution Service and any other electric services permitted by law.

~~1.3"Commission" means the Arizona Corporation Commission.~~

1.4 ~~"Electric Competition Rules" means A.A.C. R14-2-1601 et. seq., as set forth in Decision No. 61969 (September 29, 1999).~~"Competitive Electric Affiliate" means a business enterprise related to APS in the manner described in A.A.C. R14-2-801 (1) that is also an Electric Service Provider; hereinafter referred to as "Affiliate" or "Affiliates".

1.5 "Distribution Service" means those services described in A.A.C. R14-2-1601 (14), i.e., "the delivery of electricity to a retail consumer through wires, transformers, and other devices that are not classified as transmission services subject to the jurisdiction of the Federal Energy Regulatory Commission."

1.6 "Electric Competition Rules" means A.A.C. R14-2-1601, et. seq.

~~1.6~~1.7 "Electric Service Provider" or "ESP" means a ~~provider of~~company supplying, marketing, or brokering at retail competitive electric ~~services,~~

~~as defined~~services pursuant to a Certificate of Convenience and Necessity. This term has the same definition as in A.A.C. R14-2-1601 (16).

2 General

2.1 All employees and authorized agents of APS shall conduct their activities in compliance with the requirements of this Code of Conduct.

2.2 Failure to conduct activities in compliance with ~~the~~this Code of Conduct will subject the employee or agent to disciplinary actions described in Section 7.

2.3 APS shall adopt and follow written policies and procedures regarding the implementation of this Code of Conduct.

3 Financial

3.1 *Subsidization.* APS shall not subsidize the competitive electric services provided by an Affiliate through any ~~rate or charge for non-competitive electric services~~charge for goods or services which is not in conformance with Section 6.

3.2 *Segregation*. Costs and revenues of APS ~~will~~shall be segregated from costs and revenues of Affiliates in ~~the~~a manner sufficient to ensure ~~that there is no subsidization of the business activities of Affiliates by any rate or charge for non-competitive services of APS.~~compliance with Section 3.1.

3.3 *Books and Records*. APS ~~will~~shall maintain its books of account and records separately from those of its Affiliates. As a precondition to transacting any business with APS, Affiliate books and records must be made available for inspection by the ~~Commission~~ACC to the extent reasonably necessary to determine compliance with this Code of Conduct.

4 Separation of Functions

4.1 *Operations*~~.~~

4.1.1 ~~Except as otherwise permitted by law or in this Code of Conduct,~~ APS shall ~~operate~~exist as a separate corporate entity from any Affiliate.

4.1.2 APS shall not use shared corporate support functions as a means to circumvent Section 5.~~transfer confidential customer information or create significant opportunities for cross subsidization of its competitive electric affiliates.~~

4.1.3 Nothing in this Code of Conduct shall prevent APS and an Affiliate from receiving shared services from Pinnacle West Capital Corporation. Such shared services and the assignment or allocation of costs therefor shall be as set forth in APS' Affiliate Accounting Policies and Procedures.

~~4.1.2~~4.1.4 Shared telecommunication, computer and information systems shall be secured with appropriate security devices and procedures to protect against the disclosure of information in a manner inconsistent with this Code of Conduct.

4.1.5 Except as permitted by this Code of Conduct, APS ~~will~~shall not jointly employ the same employees as its Affiliates.

4.1.5.1 For purposes of common oversight and governance, APS and its Affiliates may share one or more officers and directors. Officers and directors may be shared only where sufficient mechanisms are in place so that such sharing does not result in circumventing any of the Code of Conduct provisions. Officers and directors shall sign a statement annually that they understand the Code of Conduct and the attendant consequences for violations thereof.~~Affiliates. However, to provide for joint corporate oversight, governance and support, this provision shall not prevent APS and any Affiliate from having common Directors or Officers. An Affiliate may also~~

4.1.6 An Affiliate may contract for services from APS ~~as long as~~when a written service agreement is executed in accordance with established policies and procedures and when the charges for such services comply with Section 6~~of this Code of Conduct~~.

4.1.7 Requests from Affiliates and non-affiliated ESPs and their customers for ACC-regulated services provided by APS shall be processed on a ~~non discriminatory basis~~non-discriminatory, first come, first served-basis and in accordance with established

policies and procedures and also as set forth in Schedule 10 of APS' ACC-approved tariffs.

4.2 *Administering Tariffs.*

4.2.1 Administration and enforcement of all ~~Commission approved~~ACC-approved tariffs for APS, including terms and conditions of service, ~~will~~shall be conducted solely by employees and authorized agents of APS.

4.2.2 With respect to the terms and conditions of providing Distribution Services subject to ACC approval (including price, curtailments, scheduling and priority), APS shall not provide its Affiliates, or the customers of its Affiliates, any preferential treatment over non-affiliated ESPs or their customers as a result of such status as an Affiliate or customer of an Affiliate.

4.2.3 If a tariff provision allows for discretion in its application, APS shall apply that provision in a non-discriminatory manner between an Affiliate and all other market participants and their respective customers.

4.2.4 APS shall not condition or otherwise tie any non-competitive electric service it provides nor the availability of discounts of rates or other charges or fees, rebates, or waivers of terms and conditions of ~~its~~such service to ~~the~~a Distribution Service customer taking~~of~~ any goods or services from an Affiliate.

4.2.5 Prior to the divestiture of APS generation pursuant to ACC Decision No. 61973 (October 6, 1999), APS generation ~~will~~shall not be sold by APS on a discounted basis to Standard Offer customers without the express permission of the ACC.

4.3 *Promotion, Sales and Advertising of Non-Distribution Services.*

4.3.1 APS shall not engage in any joint advertising, marketing or sales activity of any sort with an Affiliate.

~~4.3.1~~4.3.2 APS shall not permit an Affiliate to use APS' name or logo~~shall not be used~~ in written promotional or advertising material~~circulated by an Affiliate~~ unless the Affiliate discloses that: 1) the Affiliate is not the same company as APS and 2) customers do not have to buy the Affiliate's product in order to continue to receive Distribution Service at regulated rates from APS.

~~4.3.2APS will not engage in joint advertising, marketing or sales with its Affiliate.~~

4.3.3 APS shall not promote, market, or sell an Affiliate's services for or on behalf of an Affiliate.

4.3.4 APS shall not state or imply in any advertising or customer communication that the provision of any Distribution Service~~s~~, or the terms and conditions governing such services, are conditioned upon, related to or tied to the purchase of any other product or service from an Affiliate, or ~~Affiliate.~~ that APS is the same entity as such Affiliate.

4.3.5 APS shall not~~offer or~~ provide advice regarding an Affiliate to APS' customers nor state or imply that Distribution ~~service~~Service provided to an Affiliate's customer is safer or more reliable than those provided to a non-Affiliate or that an Affiliate's customers will receive preferential treatment from APS regarding their Distribution Services.

4.3.6 APS shall not~~offer or~~ provide an Affiliate with advertising space in any APS written customer communication (e.g., billing) unless access is ~~provided to non-Affiliates~~made available to non-affiliated ESPs on the same terms and conditions.

4.3.7 APS shall inform customers who inquire about competitive services that a list of authorized ESPs is available from the ACC. APS may offer customers the ACC website address and telephone number or, upon request, may provide the customer with a copy of the current ACC list of authorized ESPs as shown on the ACC website at the time of the customer's inquiry.

5 Access to Information

5.1 *System Information*. APS shall provide ~~an Affiliate and non-Affiliate ESPs~~Affiliates and non-Affiliates access to Distribution Service-specific information (including information about available distribution capability, transmission access and curtailments)~~concurrently and~~ under the same terms and conditions. and in accordance with established policies and procedures.

5.2 *Customer Information*. Non-public customer-specific information ~~will~~shall not be provided by APS to an Affiliate~~or to a non-Affiliate~~ unless release of such information is expressly authorized by the customer or

the ~~Commission~~ACC or is otherwise ~~authorized or required~~permitted by law.

6 *Transactions with Affiliates*

6.1 *Accounting.* ~~Except where regulatory requirements provide otherwise, transactions~~Transactions between APS and an Affiliate ~~will~~shall be accounted for in accordance with Generally Accepted Accounting Principles.

6.1.1 Accounting provisions for Affiliate transactions shall be governed by written policies and procedures that include but are not limited to general provisions, allocation methodologies for direct and indirect charges, goods or services produced, purchased or developed for sale and those not produced, purchased or developed for sale, transfer of assets, and inter-company billing and reimbursements.

6.2 *Purchase of Goods and Services from Affiliates.* APS shall not purchase goods and services from an Affiliate at a price that is above the market price of such goods and services or, where a market price for any particular good or service is not readily available, at a price that is above the Affiliate's fully allocated cost of providing the good or service.

6.3 *Sale of Goods and Services to Affiliates.* Goods and services sold by APS to an Affiliate shall be charged in accordance with any applicable tariff. Where a tariff is not applicable, such goods and services shall be sold at the market price or where there is no readily identified market price, at the fully allocated cost of providing the good or service.

6.4 ~~*Policies and Procedures.* APS shall maintain, or cause to be maintained, written policies and procedures regarding the accounting and segregation of costs as between APS and an Affiliate, which policies and procedures shall be made available to the Commission on request.~~*Reporting Requirements.* Contracts pertaining to transactions between APS and an Affiliate as described in Sections 6.2 and 6.3 shall be provided to the ACC in compliance with the reporting requirements of the Affiliate Interest Rules.

7 *Dissemination, Education and Compliance*

7.1 *Employee Access to Code of Conduct.* Copies of this Code of Conduct ~~will~~and associated policies and procedures shall be provided to

employees of APS and all Affiliates and those authorized agents of APS and all Affiliates that are likely to be engaged in activities subject to the Code of Conduct. A copy of the Code of Conduct ~~will~~and associated policies and procedures shall be maintained on ~~the Company's electronic bulletin board known as Vista Public Folders.~~Pinnacle West's Intranet.

7.2 *Employee Training*. Training on the provisions of the Code of Conduct and its implementation ~~will~~through associated policies and procedures, shall be provided to APS employees and authorized agents likely to be engaged in activities subject to the Code of Conduct.

7.3 *Compliance.*

7.3.1 ~~Compliance.~~Compliance with the Code of Conduct is mandatory. An APS employee's or agent's failure or refusal to abide by or to act according to such standards may subject the employee or agent to disciplinary action, up to and including discharge from employment or termination of the agent's relationship with APS.

7.3.2 ~~Questions regarding this Code of Conduct should be directed to the~~Compliance with this Code of Conduct shall be administered as part of the Pinnacle West Business Practices program and in accordance with Pinnacle West Business Practices policies~~Department. the willAPS Standard of Conduct program.~~

8 Modifications to the Code of Conduct

8.1 APS shall request modifications to this Code of Conduct by filing an application with the ACC. The application shall set forth the proposed modifications and supporting reasons.

9 Dispute Resolution

9.1 To the extent permitted by law, complaints concerning violations of this Code of Conduct shall be processed under the procedures established in A.A.C. R14-2-212.

Questions regarding this Code of Conduct should be directed to the Pinnacle West Business Practices Department.

Attachment JED-3

Policies and Procedures

THE POWER TO MAKE IT HAPPEN™

CODE OF CONDUCT POLICY	CODE SECTION NO. 4.1.1
SUBJECT: Physical Separation of Entities	

Purpose:

This policy sets forth measures to ensure that APS maintains physical separation from its competitive retail electric affiliates. Physical separation protects against the unauthorized transfer of confidential information and the improper subsidization of its competitive retail electric affiliates.

Policy:

1. Unescorted access to APS-occupied areas is restricted to APS employees, shared services employees and authorized vendors and contractors. Only escorted access to APS-occupied areas will be allowed for employees and agents of a competitive retail electric affiliate and only on an as-needed basis and will under no circumstances allow employees or agents of a competitive retail electric affiliate to read, review, copy or otherwise have access to information that may not be shared with such employees or agents under the Code of Conduct.

2. To control personnel access to APS offices and facilities at Two Arizona Center, the 502 building, the Deer Valley complex, and the Paradise Valley complex, APS shall utilize card-key access security systems. Employee access to these facilities will be granted through security-coded photo identification badges. Each business entity's badges shall be color-coded for clear identification of different business entities. The access security system shall be capable of recording employee access to secured areas.

3. All employees, contractors, visitors and vendors shall be required to wear identification badges in full view when on secured property. Persons without identification badges will be required to obtain a temporary Daily Visitor badge.

4. Pinnacle West Capital Corporation (Pinnacle West) Security shall maintain control over the coding of access available to employees. Pinnacle West Security or any business group or Affiliate may request that Pinnacle West Business Practices make determinations on the status of employee access, as necessary.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN™

CODE OF CONDUCT POLICY	CODE SECTION NOS. 4.1.2; 4.1.5.1
SUBJECT: Shared Officers and Directors	

Purpose:

The purpose of this policy is to establish appropriate measures to ensure that APS satisfies Section 4.1.5.1 of the Code of Conduct. That provision allows officers and directors of APS to also serve as officers and directors of a competitive retail electric affiliate for purposes of common oversight and governance where sufficient mechanisms are in place so that such sharing does not result in circumventing any of the Code of Conduct provisions.

Policy:

1. An officer or director of APS may serve as an officer or director of a competitive retail electric affiliate for purposes of common oversight and governance under the conditions of this policy.

2. **Officers.** Subject to the conditions below, the Chief Executive Officer of APS may also serve in that capacity with any competitive retail electric affiliate. Additionally, APS may share Support Officers, but shall not share Line Officers, with a competitive retail electric affiliate. Support Officers are officers responsible for corporate support services, including, for example, General Counsel, Secretary, Treasurer, Chief Financial Officer, and Controller. Line Officers are officers directly responsible for operational matters, including, for example, President, Energy Delivery and Sales; President, Generation; Executive Vice President, Generation; Senior Vice President, Nuclear; Vice President, Distribution; Vice President, Nuclear Production; and Vice President, Nuclear Engineering and Support.

3. **Directors.** Subject to the conditions below, a director of APS may also serve as a director of any competitive retail electric affiliate, provided that the director is not also an officer that is not permitted to be shared under this policy.

4. The sharing of the officer or director shall not result in cross-subsidization, nor shall the sharing of the officer or director result in unfair preferential treatment or unfair competitive advantage over other ESPs, in a manner prohibited by the Code of Conduct. The shared support provided by the officer or director shall be priced, reported, and conducted in accordance with APS' Code of Conduct and the policies and procedures implementing the Code of Conduct, including APS' Affiliate Accounting Policies.

5. The shared officer or director shall not allow or facilitate the transfer of information from APS to a competitive retail electric affiliate if the transfer of such information is prohibited by the Code of Conduct and its implementing policies and procedures.

6. The shared officer or director shall review the Code of Conduct, and its implementing policies and procedures upon hiring or promotion and at least annually thereafter. At least annually, the shared officer or director shall also sign a statement of affirmation which states:

   a. that the officer or director has read and understands the Code of Conduct and its implementing policies and procedures;

   b. that the officer or director understands the ramifications for violating the Code of Conduct and its implementing policies and procedures; and

   c. that the sharing of the officer or director satisfies the provisions of the Code of Conduct and its implementing policies and procedures.

7. Pinnacle West Capital Corporation's Business Practices Department shall retain at its offices signed statements of affirmation for a period of five years.

8. APS officers and directors shall retain separate files for any competitive retail electric affiliate for which they are also an officer or director pursuant to this policy. Information obtained from APS and known or retained by such shared officer or director, that cannot be shared with a competitive retail electric affiliate under the Code of Conduct, shall not be conveyed to any other officer, director, or to any employee of a competitive retail electric affiliate, and must remain under the exclusive control of the common officer or director.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN℠

CODE OF CONDUCT POLICY	CODE SECTION NO. 4.1.6
SUBJECT: Contracting for Personnel Services Between APS and Its Competitive Retail Electric Affiliates	

Purpose:

The purpose of this policy is to establish general terms and conditions under which APS and its competitive retail electric affiliates may obtain each other's services.

Policy:

1. The department or employee from whom the services are being contracted must have a recognized expertise needed for the project.

2. The project or assignment must have a specified scope and finite duration (no open-ended contracts, as-needed or on-retainer provisions or "blanket POs").

3. Any competitive retail electric affiliate personnel involved in supporting an APS project or APS personnel involved in supporting a competitive retail electric affiliate project must sign a confidentiality/non-disclosure agreement.

4. All agreements for services between APS and a competitive retail electric affiliate, except for allowable shared services, must be in writing and authorized by both an appropriate officer of APS and an appropriate officer of the competitive retail electric affiliate.

5. All agreements for services must be priced in accordance with APS' Affiliate Accounting Policies.

6. The executed service agreement shall be forwarded to Pinnacle West Capital Corporation Business Practices Department.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN℠

CODE OF CONDUCT POLICY	CODE SECTION NO. 4.1.7
SUBJECT: ESP Contacts and Requests for Service	

Purpose:

The purpose of this policy is to:

- Provide all Electric Service Providers (ESPs), including APS Energy Services, with a single point of contact at APS for initiating requests for Utility Distribution Company (UDC)-provided services and for processing direct access-related requests for service.

- Ensure that APS provides consistent and equitable treatment to all ESPs when handling ESP transactions and requests for UDC-provided services.

- Ensure that APS' actions regarding ESP requests comply with the requirements of the ACC Electric Competition Rules.

Policy:

1. ESP Services is APS' single point of contact for all ESP requests pertaining to direct access processing as well as requests for UDC-provided services.

2. Requests from all ESPs shall be initiated through ESP Services only. Other APS departments and employees shall promptly refer any requests for services received from an ESP to ESP Services for handling and processing or shall advise the ESP to make its request to ESP Services. These departments and employees shall not begin action on an ESP's request for service until notified by ESP Services.

3. ESP Services shall review ESP requests, assign the appropriate organizations to address the requests, determine the appropriate charges, and bill the ESP for the services provided.

4. Requests for UDC-provided services from an APS competitive retail electric affiliate and non-affiliated ESPs shall be processed on a non-discriminatory basis.

5. ESP Services may release information relating to an ESP's request for UDC-provided services only to those APS departments or employees involved in responding to or providing the requested service. Such information will not be released or made available to Affiliates or other APS departments, employees or third parties.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN℠

CODE OF CONDUCT POLICY	CODE SECTION NO. 4.3
SUBJECT: Joint Promotion, Sales and Advertising with a Competitive Retail Electric Affiliate	

Purpose:

The purpose of this policy is to address issues regarding joint promotions, sales and advertising.

Policy:

1. APS will not engage in joint advertising, marketing or sales with a competitive retail electric affiliate.

2. APS will not jointly sponsor civic, industry, or charity functions and events with a competitive retail electric affiliate. For those events sponsored by APS, only the APS name and logo will be used.

3. A competitive retail electric affiliate and APS may participate in the same types of events described above when the event is sponsored by a non-affiliated party; however, they must maintain physically separate booths, displays and/or other facilities. Each facility must bear the name and/or logo of only the company occupying or sponsoring that space or location and may only promote or advertise the services of that company.

4. APS will not provide a competitive retail electric affiliate with preferential treatment over non-affiliated electric service providers (ESPs) regarding the inclusion of advertising materials in customer billings and related customer mailings. APS will also inform non-affiliated ESPs of opportunities to include their advertising materials in APS customer billings or related mailings at the same time and in the same manner that it informs its competitive retail electric affiliate.

5. APS employees will not provide customers with unsolicited information regarding its competitive retail electric affiliate. APS employees can, upon request, provide a customer with the ACC's list of authorized ESPs or provide the ACC's website address for authorized ESPs. If a customer asks an APS employee for information regarding a specific ESP, including APS' competitive retail electric affiliate, the APS employee may provide the customer with a contact name and phone number for the ESP.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN™

CODE OF CONDUCT POLICY	CODE SECTION NO. 5
SUBJECT: Access to Information	

Purpose:

The purpose of this policy is to address the provision of various types of information by APS to Affiliates.

Policy:

1. Customer-Specific Information

Except as permitted by this Policy, APS shall not provide non-public customer-specific information to any other party, including APSES, unless APS has received *written* authorization from the customer to provide the information to the other party. Customer-specific information subject to this restriction includes, but is not limited to: name and address; credit and payment history; deposit information; load profile and usage data; and billing information. APS may, however, release customer-specific information without such authorization if required by law (such as in response to a subpoena) or if necessary to obtain collection and payment of a delinquent account or if otherwise authorized by statute or an order or regulation of the ACC.

2. Non-customer Specific Information

Utility Distribution Company (UDC)-Specific Information

APS may provide UDC-specific information (information derived by virtue of APS' status as a UDC and transmission operator), to a competitive retail electric affiliate only if such information is concurrently available to all other ESP's under the same terms and conditions ***and*** the competitive retail electric affiliate pays the same amount for the information as APS charges other ESPs. UDC-specific information includes, but is not limited to: system resource plans; load growth data; system outage information; extension requests; and transmission access information.

Corporate Administrative Information

APS may provide to Pinnacle West Capital Corporation corporate administrative information that is proprietary and confidential. Corporate administrative information includes, but is not limited to: company policies; personnel policies; shared system information; budgets;

financial reports; company newsletters and employee-related communications; organization charts and benefits information; and material logistics information systems.

Such information provided by APS to Pinnacle West shall not thereafter be provided to a competitive retail electric affiliate unless such sharing is for the purpose of administering shared services, joint corporate oversight, governance, support systems or personnel and the information so provided does not include customer-specific information or UDC-specific information that is not made available to other ESPs in accordance with this procedure.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN℠

CODE OF CONDUCT POLICY	CODE SECTION NO. 7.2
SUBJECT: Training Policy	

Purpose:

The purpose of this policy is to establish appropriate training mechanisms to ensure that APS and its employees comply with the Arizona Corporation Commission (ACC) Electric Competition Rules (the Rules) and the APS Code of Conduct.

Policy:

Program Description:

The APS Code of Conduct Training course content includes:

1. Review of the Rules, paying particular attention to the provisions set forth in the Code of Conduct section of the Rules.

2. Identify and discuss the sections of the APS Code of Conduct that correspond with specific provisions of the Code of Conduct section of the Rules.

3. Use of participatory exercises that reflect some of the typical workplace scenarios that employees may encounter. Employees must identify the Code of Conduct-related issues within the scenarios and develop responses that are appropriate and that comply with the provisions of the Rules and Code of Conduct.

The classes are customized for the various functions throughout APS. For example, the scenarios used for employees working in construction-related functions differ significantly from those used in training employees who work in the Customer Call Center.

The importance of compliance with both the APS Code of Conduct and the Rules is emphasized and, using current industry examples, the consequences of non-compliance are discussed.

The necessity for and expectation of ongoing compliance will also be reflected in Pinnacle West Capital Corporation's (Pinnacle West) Business Practices program.

A companion training program has been developed for and is conducted with the competitive retail electric affiliate's employees.

Participants:

All Utility Distribution Company (UDC) employees need to know the provisions and requirements contained in the Rules and the APS Code of Conduct and understand how those provisions and requirements impact the way they do their jobs.

Those APS employees, whether UDC or not, who have significant customer, ESP, and/or public contact are required to attend the in-depth training sessions. Such employees include, but are not limited to, Distribution Service Leaders, Business Office staff, Call Center staff, Design Project Leaders, Troublemen and Meter Shop staff and contract personnel in those positions.

Leaders and front-line employees in shared service functions such as Community Relations, Accounting, Finance, and Human Resources, also must attend the in-depth training.

Attendance:

Attendance is mandatory for the UDC employee groups specified above. Attendance is taken at each class for UDC groups and is reported to the UDC's training organization for recording the in Company's database to ensure full participation by UDC Leaders.

New Hire Training Schedule/Reporting:

For newly hired employees, the employee's Leader shall either arrange for or conduct the requisite training. UDC Leaders must also notify Customer Service Training and Development once the employee has completed training in order for the employee's participation to be recorded in APS' database.

Program/Requirement Changes and Revisions:

The course content and materials will be updated as developments and changes occur and subsequent training sessions will be conducted as needed.

For general revisions and updates, Leaders will be provided a copy of the revisions and talking points to share with their teams at the earliest opportunity.

UDC Leaders must notify their training organization to update employee records documenting that employees have been informed of the changes and/or program updates.

Pinnacle West's Business Practices Department will keep a master file of all changes and updates complete with the dates the materials were distributed to Leaders.

Compliance:

Pinnacle West's Business Practices Department will conduct reviews of the UDC's training attendance records in conjunction with periodic self-assessments to ensure UDC compliance in conducting training for new hires and subsequent updates for continuing employees.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN™

CODE OF CONDUCT POLICY	CODE SECTION NO. 9
SUBJECT: Complaint Resolution	

Purpose:

The purpose of this policy is to document the procedures used by the Pinnacle West Capital Corporation (Pinnacle West) Business Practices Department on behalf of APS to handle complaints concerning violations of the APS Code of Conduct received from APS and its competitive retail electric affiliates' employees and agents.

Background:

The Pinnacle West Business Practices HelpLine (HelpLine), formerly the APS Employee Concerns Line, (1-800-446-8441) was previously established to handle employee concerns. A similar program, known as the Palo Verde Employee Concerns Program exists at the Palo Verde Nuclear site. The HelpLine did not replace the Palo Verde line; but instead it serves the balance of the Pinnacle West family of companies.

The HelpLine is equipped with voice mail so that the program is active 24 hours a day, seven days a week. Voice mail will receive the call during normal working hours if the line is unattended or busy when the call is received. A message is provided to encourage callers to provide sufficient detail when leaving a message.

Scope:

Concerns involving harassment or discrimination in the workplace, unethical behavior, theft, fraud, bribes and/or kickbacks, misuse or abuse of company equipment and materials, alcohol or illegal drug abuse, environmental concerns or safety violations may be raised through the HelpLine. In addition, employees and/or agents of APS may call to receive guidance in the areas of corporate ethics, corporate standards of conduct, regulatory codes/standards of conduct or to report violations of corporate or regulatory codes/standards of conduct.

Responsibility:

The HelpLine is administered by Pinnacle West's Business Practices Department, which reports to the Vice President and General Counsel of Pinnacle West. Confidentiality is a top priority. The program will respect a person's wish to remain anonymous. Although a HelpLine representative

cannot guarantee confidentiality to everyone, whenever possible, the identities of callers will be kept confidential.

If an employee volunteers his/her identity and some disclosure is necessary, reprisal is prohibited. Pinnacle West and its affiliates will not tolerate harassment, intimidation, discrimination, or other acts of retaliation against any employee for identifying any concern, not only to the HelpLine program but also to supervision or management or any governmental agency. Employees who believe they have been discriminated against for identifying a concern should notify Pinnacle West's Human Resources Department or Business Practices Department. If it is determined that an employee or member of management has retaliated against any employee for raising a concern, that person will be subject to appropriate disciplinary action.

Procedures:

Receipt of allegations:

1. Allegations may be received in several ways:

    - Pinnacle West Business Practices HelpLine (1-800-446-8144)
    - Pinnacle West Business Practices HelpLine's internal phone extensions (602-250-3235/2979)
    - Office visit to Pinnacle West Business Practices Department
    - Internal and external mail
    - Referral

2. Each allegation received by the HelpLine will be assigned a unique number when it is received. The number will be provided to the caller as one way of identifying that caller at a later time. In addition to the allegation's number, a unique identifier will be assigned each concern and provided to the caller. The identifier gives one more way of identifying the caller at a later date.

3. The allegation file will include:

    - File Number
    - Identifier
    - Date
    - Time
    - Name
    - Address
    - Type of allegation (confidential or anonymous)
    - Allegation
    - Disposition of the allegation
    - Correspondence related to the allegation

4. Each file related to the APS Code of Conduct will be kept separate from Pinnacle West Business Practices HelpLine files pertaining to non-Code of Conduct-related concerns.

5. Callers will be asked whether or not they request confidentiality. Names of employees requesting confidentiality will not be disclosed to anyone outside the HelpLine program, including investigative assignees, unless there is a "need to know."

   Once confidentiality has been requested, the submitter's name may normally be released only with the explicit concurrence of the submitter. If the submitter will not release confidentiality, and release is necessary to address particular concerns, the submitter will be notified that release will be made without their concurrence and the reason why the release is necessary. This decision and action will be thoroughly documented in the respective file.

   When confidentiality has been released, the submitter's identity should not be referred to or released to any individual except those determined to have a "need to know." Discretion in the release of confidentiality will be exercised in all cases.

6. Callers not wishing to identify themselves should be told to call back if they wish to receive a report on the status of the concern they have raised. The unique number and identifier will be required before any information will be provided to the caller.

Audit:

This policy will be subject to periodic audits performed by the internal auditors of Pinnacle West.

THE POWER TO MAKE IT HAPPEN™

CODE OF CONDUCT POLICY	CODE SECTION NOS. 3 and 6
SUBJECT: Affiliate Accounting Policies	

Purpose:

The purpose of these policies is to provide guidelines and standards to ensure compliance with regulatory requirements related to Affiliate relationships. All transactions between APS and its Affiliates, including the provision of services and transfer of assets and liabilities, shall be accounted for in accordance with these policies.

Policies:

I. APPLICABILITY

These Affiliate Accounting Policies set forth business practices for transactions between APS and all Affiliates.

II. COMPLIANCE

The Pinnacle West Capital Corporation (Pinnacle West) Controller is responsible for issuing, updating, and monitoring compliance with these policies and approving specific Affiliate agreements as described below.

III. DEFINITIONS

Affiliate is a separate legal entity that is controlled by, controls, or is under common control with APS.

Assets include real property, depreciable personal property, and intangible property.

Depreciable Personal Property includes vehicles, machinery, furniture, fixtures not attached to land, equipment, computer hardware and related software applications, and any other tangible property, which are not goods or real property.

Fully Loaded Cost consists of the direct cost of a good or service and all applicable indirect charges and overheads.

Goods are non-depreciable personal property, such as inventory, materials and supplies.

Intangible Property includes any asset having no physical existence, its value being set by the rights and anticipated benefits that an owner obtains by possessing it.

Labor Charges consist of direct payroll costs and all wage related costs such as pension, post employment benefits, health insurance, payroll taxes, etc.

Liabilities include accounts payable, notes payable, lease obligations, debt, pension and other post retirement benefits, deferred compensation, and other employee related benefits.

Pinnacle West Capital Corporation (Pinnacle West) is the parent holding company for APS and other Affiliates.

Proprietary Information includes written, verbal, or visual information, material, data, or knowledge belonging to APS or an Affiliate which APS or the Affiliate considers being valuable, confidential, and proprietary. Such proprietary information could be owned by an Affiliate and/or by third parties and licensed to an Affiliate. Proprietary information includes trade secrets, data, software, computer programs and related documentation, specifications, documents, methods, inventions, discoveries, drawings, customer lists, and employee or personnel information and records. Proprietary information also includes information and records relating to research, developments, operations or activities of APS, Affiliates, contractors, or others, which have not been generally released to the public by duly authorized representatives of the entity in lawful possession of the same.

IV. OVERVIEW

These accounting policies provide guidelines and standards to ensure compliance with regulatory accounting requirements related to Affiliate financial relationships, including those requirements of the Arizona Corporation Commission ("ACC"), the Federal Energy Regulatory Commission ("FERC") and the Securities and Exchange Commission ("SEC"). All transactions between APS and its Affiliates, including the provision of services and transfer of assets or liabilities, shall be accounted for in accordance with these policies.

It is the policy of APS and Pinnacle West to ensure that the costs related to Affiliates are segregated and accounted for separately. Specifically:

- All relationships between APS and its Affiliates are to be conducted in a manner that prevent subsidization of competitive retail electric services provided by such Affiliate through any rate or charge by APS for non-competitive electric services.
- Compensation or reimbursement for all assets, liabilities, goods and services transferred or provided between APS and its Affiliates shall be in accordance with these Affiliate Accounting Policies.
- All transactions between APS and an Affiliate shall be segregated and shall separately account for all costs incurred and revenues received by APS as a result of such transaction.

V. SHARED SERVICES GENERAL

Shared services are those corporate support services performed by Pinnacle West on behalf of its Affiliates. These services are organized at Pinnacle West in order to ensure consistency, efficiency and leverage of resources for the mutual benefit of all Pinnacle West Affiliates. Examples of shared services include the following:

- Accounting and Finance
- Audit
- Tax Services
- Information and Communications Technology
- Corporate Communications
- Shareholder Services
- Law and Business Practices
- Environmental Services
- Public Affairs
- Human Resources

Charges for shared services to the various Affiliates are either direct or indirect. Direct charges result from shared services that benefit a single Affiliate and will be directly assigned to that Affiliate in accordance with this policy. Indirect charges are allocated to the appropriate Affiliate based on a measure representing the Affiliate's proportionate relationship to other Affiliates. The allocation method used is Pinnacle West's net equity invested in its Affiliates. These factors will be reviewed periodically by Pinnacle West Accounting.

A. DIRECT CHARGES

1. <u>Identification</u>

Direct charges are applicable to those shared services that are assignable to a specific Affiliate based on a causal or beneficial relationship to that Affiliate. Where direct shared services benefit more than one Affiliate, such services may be assigned to more than one Affiliate based on the support provided. In other cases, such services will be based on the actual demands for such services by the Affiliate. Examples of direct support services may include some human resources services, information technology support, communications services, and legal services. The provision of direct services will be formalized in a general services agreement.

2. <u>Charging Methodology:</u>

Direct charges are charged to specific Affiliates based on a causal or beneficial relationship or, in the case of special services requested by the Affiliate, on the basis of the service level provided. Direct labor charges will be captured on an "as provided basis" and charged to a specific account number for that Affiliate using variable payroll distribution when the provider can specifically identify the actual hours to provide the service. When the service is provided on a regular or monthly basis and the specific Affiliate is not easily identifiable, as in the case of accounts payable or payroll processing, the time to be charged will be based on a time study or another measurable quantity (i.e., number of invoices processed or number of employees being paid) to

determine the "average" time spent as a percent of total time, with the subsequent use of a payroll fixed distribution.

B. INDIRECT CHARGES

1. Identification:

Indirect charges are those shared services that are essential for the overall corporate enterprise and generally benefit all Affiliates. The associated costs are assignable to each Affiliate. Examples of indirect shared services include preparing consolidated financial statements, filing tax returns, meetings of the Pinnacle West Board of Directors and shareholder services.

2. Charging Methodology:

Because indirect shared services represent functions not specifically identifiable to an Affiliate, it is impractical to charge those costs to the specific Affiliate as the costs are incurred. Therefore, individual employees charge time to Pinnacle West charge numbers when performing those general corporate functions. Indirect charges are allocated to the appropriate Affiliate based on Pinnacle West's net equity invested in its affiliates, including APS.

VI. SERVICES AND GOODS PROVIDED BETWEEN APS AND AFFILIATES

A. GENERAL

This section provides guidelines for the transfer of goods and services, other than shared services described in Section V, between APS and its Affiliates. It provides guidelines to assign monetary value to other goods and services transferred between APS and all Affiliates. There are two general types of transactions that can occur (each of which is discussed in detail at B and C below):

- Goods or services produced, purchased or developed for sale
- Goods or services not produced, purchased, or developed for sale

B. GOODS OR SERVICES PRODUCED, PURCHASED OR DEVELOPED FOR SALE

1. Identification:

Goods or services produced, purchased, or developed for sale include those goods or services intended for sale in the normal course of APS' or the Affiliate's business. To be considered produced, purchased, or developed for sale, the goods and services must be routinely available to third parties in addition to Affiliates and APS and would usually be the product of resources which are planned and dedicated to providing those goods or services. The provision of such goods and services between APS and Affiliates should be formalized in writing and approved by the appropriate Affiliate Officer and Pinnacle West's Controller (or designee), except for goods and services provided pursuant to authorized ACC or FERC tariffs.

Goods or services produced, purchased, or developed for sale include, but are not limited to:

- Electric generation, transmission, and distribution services
- Engineering and development services

2. Charging Methodology:
Goods and services produced, purchased, or developed for sale will be priced based on the following:

From APS to Affiliates:
- Tariff price for services subject to a tariff.
- Market price for services not subject to tariff price and for which a market price for comparable services is readily identifiable (i.e., the good or service is regularly traded on a recognizable market; APS has received a recent, bona fide offer for a comparable good or service; APS has purchased the good or service within the last 6 months from an outside source).
- At fully loaded cost of providing the good or service where there is no readily identifiable market price.

From Affiliates to APS:
- At a price not to exceed market price where a readily determinable market price for comparable services exists (i.e., the good or service is regularly traded on a recognizable market; APS has received a recent, bona fide offer; APS has purchased the good or service within the last 6 months from an outside source).
- At a price not to exceed fully loaded costs where a readily determinable market price does not exist.

3. Recording:
Goods or services produced, purchased or developed for sale will be a direct charge to the recipient Affiliate or APS based upon the pricing described above.

C. GOODS OR SERVICES NOT PRODUCED, PURCHASED, OR DEVELOPED FOR SALE

1. Identification: Goods or services not produced, purchased, or developed for sale include those goods or services that are provided only incidentally to the primary business of APS or an Affiliate and are not provided to unaffiliated third parties. These services (excluding corporate shared services) include but are not limited to:

- Directly requested Affiliate services
- Market analysis
- Research and development

An Affiliate's use of APS' resources or APS' use of an Affiliate's resources shall be supported by a general service agreement.

a. Labor:
No APS employee may perform any work for an Affiliate unless a written agreement is in place. Service agreements must price all goods and services provided in accordance with the provisions for Goods and Services Produced, Purchased or Developed for sale. All costs incurred by APS and revenues received on account of such service agreements shall be recorded in accordance with section VI-B-3 above. Where a service agreement calls for direct labor charges, such labor charges will be based on the rate for that employee and the actual number of hours devoted to providing services. All direct labor will be priced at fully loaded cost by Pinnacle West Accounting, with overhead rates that are updated annually. These overhead rates include associated employee benefits, payroll taxes, performance incentive plan, workers compensation, and other administrative and general costs.

b. Materials:
Purchases of materials or services by an Affiliate from APS or by APS from an Affiliaterequire the preparation of a requisition form. The materials requisition or purchase order should charge the cost to the appropriate Affiliate charge numbers.

2. Charging Methodology:
Goods and services not produced, purchased, or developed for sale will be priced based on the following:

From APS to Affiliates:
- At the market price for services and for which a market price for comparable services is readily identifiable (as defined in section VI-B-2 above).
- At the fully loaded cost of providing the good or service where there is no readily identifiable market price.

From Affiliates to APS:
- At a price not to exceed market price where a readily determinable market price for comparable services exists (as defined in section VI-B-2 above).
- At a price not to exceed fully loaded costs where a readily determinable market price does not exist.

3. Recording:
Charges for goods or services will be calculated by the entity providing the service. The entity receiving the goods or services may request that Pinnacle West audit the transactions. APS will record the fully loaded cost of any such goods or services provided by APS, and any corresponding revenues, below-the-line.

D. TRANSFER OF ASSETS & LIABILITIES

When specific assets or liabilities are identified for transfer between APS and Affiliates, an agreement must be formalized in writing covering the specific assets or liabilities to be transferred. All such agreements must be approved by an appropriate officer of Pinnacle West and each Affiliate and by the Pinnacle West Controller or designee. Copies of the agreements

must be provided to the Pinnacle West Controller or designee. Procedures for accounting and billing for the value of the assets or liabilities transferred shall be included in the agreement.

1. Identification:
Transfers of assets include transfers of tangible real or depreciable personal property and intangible property used in a trade or business.

Real property:
Includes, but is not limited to:

- Land
- Buildings
- Improvements
- Easements
- Other real property rights

Personal property:
Includes, but is not limited to:

- Automobiles
- Power-operated equipment
- Computer hardware
- Computer software or application software
- Furniture
- Materials and supplies

Intangible property:
Includes, but is not limited to:

- Copyrights
- Patent rights
- Royalty interests
- Licenses
- Trademarks
- Other proprietary information

Transfers of liabilities include, but are not limited to, accounts payable, notes payable, lease obligations, debt, pension and other post retirement benefits, deferred compensation and other items related to employees of APS and the Affiliates.

2. Valuation:
Transfers of assets and liabilities between APS and its Affiliates will be at net book value as of the date of the transfer in accordance with Generally Accepted Accounting Principles and SEC requirements.

3. Recording:
Transfers of assets or liabilities will be recorded through a direct charge.

VII. INTERCOMPANY BILLINGS AND REIMBURSEMENTS

A. GENERAL

Billing for inter-company transactions shall be issued on a timely basis, at least monthly, for goods or services and at the time of transfer for assets or liabilities. Sufficient detail will be provided to ensure an adequate audit trail and enable prompt reimbursement from the recipient of the assets, liabilities, goods, or services.

B. INTER-COMPANY BILLINGS AND PAYMENTS

Inter-company billing issued for transfers of assets, liabilities, goods, or services will be accompanied by or referenced to appropriate supporting documents. Allocations will be based upon methods set forth in these policies or applicable references. Such computations must be documented in order to facilitate verification of the costs of transferred assets, liabilities, goods, or services. Costs incurred on behalf of APS or its Affiliates shall be accumulated, priced, and billed no later than the end of the following month to enable timely payment.

Payments, or formal arrangement for payment, for assets, liabilities, goods, or services received from APS or an Affiliate shall be made no later than 30 days after receipt of an invoice. Inter-company billing and payments shall be adequately documented so that an audit trail exists to facilitate verification of the accuracy and completeness of all billings and reimbursements.

C. RECORDING

The receipt of an inter-company billing shall promptly be recorded in the accounting records of APS or the Affiliate receiving the billing. Disputes shall not preclude recording of the billing. Adjustments to prices, if necessary, will be proposed and resolved as soon as practicable after the billing is recorded.

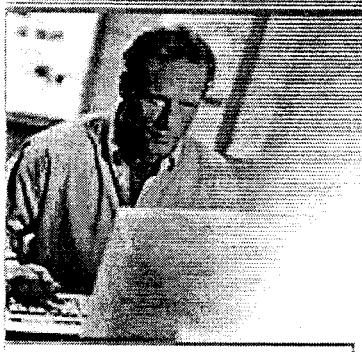
VIII. INCOME AND OTHER TAXES

Federal and State tax liabilities and benefits and allocations will be handled in accordance with the Tax Allocation Agreement in place between Pinnacle West and its Affiliates.

IX. AUDITS

These Affiliate Accounting Policies will be subject to periodic audits performed by the internal auditors of Pinnacle West.

EXHIBIT
Commonwealth
2
Admitted



Saturday, July 10, 1999

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Reduced costs. Smarter energy products. Outstanding service. That's what the promise of deregulation holds for you, the new electricity consumer. And it's a promise kept by APS Energy Services.

Backed by more than a century of experience and market knowledge, APS Energy Services can offer you the following advantages:

- Competitive energy prices
- Energy related products and services
- Exceptional customer service
- Technical expertise
- Uncomplicated energy solutions

And, business customers can also benefit by:

- Assistance to reduce energy costs
- Help in optimizing your energy use

Whether you run a business or a household, APS Energy Services has advantages tailored to fit your needs.

To speak to someone immediately, call toll-free 800-723-9566.

APS Energy Services is not the same company as APS.You do not have to be an APS Energy Services customer to receive quality regulated services from APS.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF ALAN PROPPER

On Behalf of

Arizona Public Service Company

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

June 4, 1999

EXHIBIT
Admitted
APS-2

Q. What is your name and business address?

A. My name is Alan Propper. My business address is 400 N. 5th Street, Phoenix Arizona, 85004.

Q. By whom are you employed and what is your position?

A. I am employed by Arizona Public Service Company (APS) as Director of Pricing and Regulation. In this position, I am responsible for establishing and administrating APS's tariffs and contracts that are under the jurisdictions of the Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC).

Q. Would you discuss your educational background and business experience?

A. My background and experience are set forth in Appendix-A to this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present APS's proposed rates for Direct Access Service, as specified in the Settlement Agreement dated May 17, 1999. In addition, I will discuss the philosophies and methodologies used in the development of the proposed rates, as well as related issues concerning cost allocation, Stranded Cost recovery, and certain terms and conditions pertaining to Direct Access Service.

Q. Are you sponsoring any Schedules?

A. Yes. I am sponsoring Schedule AP-1, which contains the embedded cost-of-service study; Schedule AP-2, which summarizes the pro-forma adjustments to the 1996 test year; Schedule AP-3, the 1996 Settlement Rate Reduction filed in May, 1999; Schedule AP-4, which summarizes the calculation of fair value rate base and fair value rate of return; Schedule AP-5, which summarizes System Benefits costs; Schedule AP-6, which contains the calculation and summary of the Competitive Transition Charges (CTC); Schedule AP-7, which contains the Direct Access Service rate design computations; Schedule AP-8, which is the proposed Direct Access Service rate schedules set forth in the Settlement Agreement; and Schedule AP-9, which summarizes the rate credits applicable to Direct Access Service customers not receiving Metering, Meter Reading, or Billing services from APS.

Q. Was this testimony and were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Would you define what is meant by Standard Offer Service?

A. Standard Offer Service customers are those retail customers who choose to continue to have their electric service bundled and provided by APS. In other words, these customers opt for keeping the status quo when it comes to competition and customer choice, and will continue to have APS provide bundled electric service comprised of Generation, Transmission, Ancillary Services, Distribution, Metering, Meter Reading, and Billing.

Q. Have you developed new Standard Offer Service rates in conjunction with the Settlement Agreement?

A. No. The initial Standard Offer Service rates will be those currently effective in APS's retail tariff and contracts. However, these rates will receive periodic reductions, as specified in Section 2.2 of the Settlement Agreement.

Q. Would you discuss what is meant by Direct Access Service?

A. Direct Access Service customers are retail customers who choose to have their electric service unbundled and purchase their Generation, Transmission, Ancillary, and generally Metering, Meter Reading, and Billing Services through an Electric Service Provider(s) (ESP) and Scheduling Coordinator rather than APS. These customers will still receive certain services from APS, but they will only be charged for Basic Delivery Service, Distribution Service (which includes recovery of Regulatory Assets), System Benefits, and Stranded Costs.

Q. Was an embedded class cost-of-service study used in the development of the Direct Access Service rates?

A. Yes. A cost allocation study was specifically prepared and utilized to identify and apportion bundled rates into the Direct Access delivery charges as proposed by APS for retail Direct Access Service. This study appears as Schedule AP-1.

Q. Would you discuss the development of the embedded cost allocation study?

A. This study was prepared using industry accepted principles and practices. In general, the numerous expense and rate base items that comprise APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance Expense. Each of these categories was first broken down into Production, Transmission, or Distribution related functions, then classified as Demand, Energy, or Customer related. Allocation factors based on kilowatts, kilowatthours, and number of customers were then developed so that allocations of the functionalized and classified costs could be made to the federal and state jurisdictions and to the three newly established customer classes.

Q. What was the next step in the process after the allocations were performed?

A. Once allocations of this nature are completed, the rate designer would normally accumulate the expense and rate base costs so that revenue requirements could be established for each customer class or each function. However, for the purposes of this filing, the apportionment factors shown in Schedule AP-7 were developed instead of revenue requirements so that existing bundled rates could be transformed into proposed unbundled Direct Access Service rates at existing revenue levels.

Q. Why did you choose to use an apportionment process rather than designing unbundled rates directly from a functional revenue requirement analysis?

A. There were two primary reasons: (1) revenue stability; and (2) rate continuity. It is APS's intent that the process of rate unbundling produce neither large revenue erosion due to rate migration nor customer dislocation due to reallocation of revenue requirements. By apportioning current bundled rates into functional charges that total to the bundled rate, appropriate revenue recovery is assured. This is particularly helpful for APS at this time when the current bundled rates will have been decreased three times under the 1996 Settlement mechanism prior to the start of competition. Apportioning the current bundled rates assures us that the unbundled rates are synchronized with current bundled rate levels.

Q. In addition to an assurance of comparable total revenue recovery, does apportionment provide an advantage when dealing with the rates of the individual classes of business?

A. Yes. Apportioning the current rate structures for the General Service customers preserves, to the extent possible, the blend between the bundled rates and the ACC regulated unbundled rates. APS's Rate E-32, for customers with peak demand less than 3MW, has a relatively complex rate structure, with its effective demand charge varying by load factor and energy usage through the use of a kWh/kW block expander. The apportionment of the E-32 rate structure preserves this structure, including the seasonal price differentials, for the corresponding unbundled Distribution rate, thus reducing the rate dislocations that would result from the transition to competitive service.

Q. Was the use of a 1996 test year suitable for this cost-of-service study?

A. Yes. The 1996 test year was used for consistency with APS's previous filings and settlement negotiations on the subject of Direct Access Service and Stranded Costs. Since pro-forma adjustments were made to the 1996 data, and since the study results were used for cost apportionment as opposed to establishing revenue requirements, I did not feel a more recent test year would produce an improved estimate of functionalized costs. Although complete 1998 data was not available at the time the study was performed, enough 1998 information was available to develop suitable pro-forma adjustments. The pro-forma adjustments used for the 1996 test year are presented in Schedule AP-2.

Q. Why is it appropriate to adjust the 1996 test year level to 1998 levels?

A. The final rate reduction under the 1996 Settlement mechanism is based upon 1998 unit costs and unit prices. Therefore, the 1996 costs adjusted to 1998 is appropriate. Attached as Schedule AP-3 is the .68% rate reduction APS filed with the ACC on May 21, 1999.

Q. Have you calculated the fair value rate base and fair value rate of return based upon the adjusted test year and the revenue level pursuant to the 1996 Settlement mechanism?

A. Yes, based on 1998 and as shown in Schedule AP-4, APS has a fair value rate base of $5,195,675,000 and a fair value rate of return of 6.63%.

Q. Have any new or special procedures been used in preparing this cost allocation study?

A. Yes. Due to the nature and anticipated use of the cost allocation study somewhat unique procedures were used to establish the allocated retail class costs associated with Transmission Service, Ancillary Services, and Must Run, as well as the costs associated with System Benefits and Regulatory Assets.

Q. How were retail Transmission costs determined?

A. In compliance with FERC Order No. 888, APS filed an Open Access Transmission Tariff (OATT). The outcome of that case resulted in an Annual Transmission Revenue Requirement for APS of $86.5 million. To develop the retail classes' cost responsibility for Transmission Service, the retail jurisdiction's four summer months' contributions to the system peak, or 4CP methodology, was utilized. This is consistent with FERC precedent regarding the APS Transmission system.

Q. How were the retail costs associated with Ancillary Services determined?

A. Three Ancillary Services were identified for cost analysis purposes, and to accommodate Direct Access. These are Regulation, Spinning Reserve, and Supplemental Reserve. In addition, Scheduling was identified as a required Ancillary Service, but its associated costs and charges were included with Transmission. Similar to Transmission Service, APS' FERC OATT established Ancillary Service rates at levels that would recover the revenue requirement for each of the Ancillary Services. The cost responsibility for each retail class was determined based on each class's allocated portion of the revenue requirement associated with each of the Ancillary Services.

Q. Would you explain what you mean by Must Run?

A. Must Run resources are existing generation units utilized to supply power and energy to load areas (or zones) within a utility's system that are limited on the amount of remote generation that could otherwise be imported into the area because of thermal limitations on transmission paths, as well as voltage and stability considerations within the constrained area. If the load within the congested area exceeds the transmission import capability into the area, local generation resources located within these zones must be dispatched in order to meet the total load requirements in the constrained area. APS's resources dispatched out of economic sequence for this purpose are deemed to be Must Run resources.

Q. Would you briefly describe the unbundling methodology used to determine the costs associated with Must Run?

A. In order to unbundle the costs associated with providing Must Run, it was necessary to identify which of APS's generating units were utilized to perform this service, the percentage of each unit's availability that is used to perform Must Run, and the appropriate costs associated with each of the units. The proportionate share of the fixed and variable costs of the units related to Must Run were then calculated. For cost responsibility purposes, these Must Run costs were refunctionalized as Distribution.

Q. Would you explain what is meant by System Benefits?

A. System Benefits refer to the costs associated with low income programs, renewable resources, demand side management, nuclear plant

decommissioning, nuclear fuel disposal, customer education, and other items that are included in rates by approval of the ACC. For the purposes of this cost allocation study, System Benefits costs have been separately accumulated and unbundled. The System Benefits items that have been included in the proposed rates and their associated costs appear in Schedule AP-5.

Q. Would you explain what is meant by Regulatory Assets?

A. Regulatory Assets are expenses already incurred by APS on projects, equipment, and financial obligations that have not as yet been charged to customers. Pursuant to ACC Decision No. 59601, the ACC authorized the collection of these expenses from customers through electric rates over an extended period of time, thereby avoiding significant increases to customer bills. Examples of Regulatory Assets are deferred income tax payments, coal mine reclamation costs, and financing costs for generation units. For the purposes of this cost allocation study, Regulatory Assets have been separately accumulated and assigned to Distribution.

Q. Would you discuss the development of the apportionment factors used in designing the rates for Direct Access Service?

A. Once the costs associated with the specific sub-functions, such as System Benefits and Regulatory Assets, were segregated, the Production, Transmission, and Distribution costs were allocated to each proposed Direct Access Service class. Percentages were then calculated for each of the functions for each of the three classes, as shown in Schedule 4 of Schedule AP-7. These percentages served as the apportionment factors that were

applied to each of the three bundled rates to yield the Direct Access charges as shown in Schedules 1, 2, and 3 of Schedule AP-7.

Q. Why is there a need for CTCs, and how were they developed?

A. CTCs are charges that are included in rates to recover a defined level of Stranded Costs. Using projections of generation costs, market prices, and sales, annual revenue requirements to recover a total of $350 million through 2004 were determined. These costs were then allocated to each of the three retail Direct Access Service classes, using each of the class's contribution to the system peak load as an allocating factor. Unit Costs per kWh for each class for each year were then developed by dividing the costs by the anticipated sales.

Q. What adjustments were made to the unit Stranded Costs to convert them to CTCs?

A. The unit Stranded Costs were adjusted so that Direct Access Service and Standard Offer Service rate decreases provided for in the Settlement Agreement would be better synchronized with each other and to reflect the implicit stranded cost levels in special contracts APS has with BHP Copper, Cyprus Bagdad Copper, and Ralston Purina.

Q. Were any additional changes made to the unit Stranded Costs to produce the final CTCs?

A. For the General Service classes, the energy related CTC charges were converted to demand charges using class average load factors. This conversion

to demand charges better reflects cost incidence and better blends the Direct Access rates with the corresponding Standard Offer rates. The CTCs, as well as the proof of revenue used to confirm the $350 million recovery level are shown on Schedule AP-6.

Q. How will the CTCs be used in tracking the recovery of $350 in Stranded Costs?

A. At the end of each calendar year of the Stranded Cost recovery period ending December 31, 2004, the annual ACC jurisdictional sales to both Standard Offer and Direct Access customers will be multiplied by the percentage of APS load eligible for Direct Access Service during that year. This sales amount, calculated by class, will then be multiplied by the CTC in effect for that class for that year. This will result in an annual dollar amount of Stranded Cost recovery. This formula is shown in Exhibit B to the Settlement Agreement. After the annual recovery amount for the year 2004 is calculated, the recovery amounts for all years for all classes will be summed. The NPV of this total stranded cost recovery will be calculated, and the resultant dollar amount will then be compared to the $350 million recovery allowed by the Settlement Agreement.

Q. Will these recovery amounts then be reconciled?

A. Yes. Any amount of stranded cost over- or under-recovered of the $350 million will be incorporated into the adjustment clause as provided for in Section 2.6(3) and Section 3.3 of the Settlement Agreement.

Q. How were the Direct Access Service rates developed?

A. Basically, the rate design involved a five step process. First, rates for three basic classes were determined. Second, after adjusting for the recovery of specific costs, the apportionment factors were applied to each of these rates, which resulted in unbundled functionalized prices for each rate. Third, final Direct Access Service rates were established that were comprised of charges for Basic Delivery Service, Distribution and Regulatory Assets, System Benefits, and a CTC, as well as provisions for Transmission and Primary service level discounts. Fourth, Direct Access Service rates for special contracts with BHP Copper, Cyprus Bagdad Copper, and Ralston Purina were established. Fifth, monthly credits were developed for those Direct Access Service customers using an ESP for their Metering, Meter Reading, and Billing requirements. The final proposed rate schedules for Direct Access Service appear in Schedule AP-8.

Q. Schedule B of Exhibit A of the Settlement Agreement contains the Distribution Charges to be effective January 1 of each year from 1999 to 2004. How were the changes in these charges calculated?

A. The Distribution Charges are comprised of revenue requirements for both Distribution and Regulatory Assets. To comply with the provisions of the Settlement Agreement concerning Regulatory Asset Amortization, it was

necessary to reduce the Regulatory Assets components by 8.9% in the years 2000 through 2003 and 6.5% in 2004, as can be seen in Schedules 1 through 3 of Schedule AP-7. Additional computations were made to reflect the lower, implicit Regulatory Assets costs in special contracts APS has with BHP Copper, Cyprus Bagdad Copper, and Ralston Purina.

Q. Why have only three class rates plus three contract rates been chosen under which Direct Access Service will be offered?

A. Traditionally, APS's tariff has contained a large number of individual rates for each general class of business in order to reflect cost-to-serve differences that are primarily related to generation cost differences, and to allow for intraclass and interclass subsidization and rate of return differentials. Generation cost differences should play no part in the design of non-generation related Direct Access Service charges, and intraclass rate of return differentials should not be a complicating and anti-competitive factor in an era of multiple potential service providers that are competing to supply various components of Direct Access Service. As a step towards implementing this concept, only three general class rates--Residential (DA-R1), General Service under 3MW (DA-GS1), and General Service 3MW and greater (DA-GS10)--have been developed to serve customers desiring Direct Access Service.

Q. Have any aspects of intraclass, generation related rate of return differentials in the rate designs been preserved?

A. Yes, for the time being. In order to avoid drastic customer dislocations, the proposed three rate designs retain several of the generation related features

inherent in the current bundled full service rates. These include such features as load factor blocks and seasonality.

Q. Have interclass return differentials been preserved?

A. To a certain extent, yes. But, once again the intention is only for the time being, and to ease into cost based rates through a transition period. The rate levels, and therefore cost recovery relationships, among the Residential, General Service under 3MW, and General Service 3MW and greater classes in the proposed Direct Access Service rates are the same as those for the similar services provided under APS's current tariff. In addition, and as stated in a previous answer, the rate designs for the three Direct Access Service rates parallel those of the dominant rate for similar services under APS's current tariff. In fact, the proposed Direct Access Service rate for General Service under 3MW is the apportionment of the current Rate E-32, and the proposed rate for General Service 3MW and greater is the apportionment of the current Rate E-34. This methodology was used for the express purpose of limiting the magnitude of pricing dislocations to individual customers.

Q. You indicated that interclass return differentials would be maintained "for the time being." Why have you adopted this approach, and in what time frame would you anticipate that it would end?

A. This approach is consistent with the ACC's stated objective that the transition to competition should not result in rate increases. Immediately eliminating class return differentials would have significant dislocation impacts. The remaining rate of return differentials should be eliminated when Direct Access

Service and competition in general is fully operational. Whether this actually occurs in the market place at the end of the phase-in period or when the Stranded Cost recovery and the CTCs expire cannot be definitively stated at this time. However, the elimination of class rate of return differentials should be a major objective of a future rate case.

Q. How were the rate credits developed for a Direct Access Customer using an ESP for the required Metering, Meter Reading, and Billing services?

A. The "avoided costs" associated with each of these particular services were identified and quantified. Avoided costs were defined as the estimated cost reductions that would be experienced by APS by providing a specific service to one less or the decremental customer. Avoided costs were used in these calculations since most embedded costs do not disappear for APS when a customer chooses an alternative supplier for Metering, Meter Reading, or Billing services. If full embedded costs had been used as the measure of these credits, a revenue shortfall would occur that would increase the unitized revenue requirements of all remaining customers. A summary of these credits appears in Schedule AP-9.

Q. Could you further explain avoided costs as they pertain to Metering?

A. Retail rates presently include charges for the capital expenditures APS has made over time to acquire and install meters, and for the costs of the meter shop and related equipment. These charges are composed of depreciation expenses and a return on the net book value of the meters. The only avoided cost, at least for the transition period, would be the cost of the actual meter on

the customer premise, assuming its sale or re-use, adjusted to reflect the cost of retrieval and testing.

Q. Could you further explain avoided costs as they pertain to Meter Reading?

A. If a customer chooses a service provider other than APS to read his meter, the only cost reductions that would initially be experienced by APS would be the cost associated with reading this particular meter. This cost is no more than the time it takes for the meter reader to go from the curb to the meter, read or probe that meter, and return to the curb. The meter reader would still be required to walk past the premise to continue his route. There could actually be an increase in cost if certain meters are not read, since the meter reader must continually adjust his routine to accommodate a continually changing route. In addition, costs could increase as a result of the customer information system being regularly updated to reflect Direct Access Service related meter changes.

Q. Could you further explain avoided costs as they pertain to Billing?

A. The only cost reductions that would initially be experienced by APS would be related to the production and mailing of the physical bill. APS would still be required to retain its current level of personnel, a billing system, and customer inquiry support. In fact, with Direct Access Service, APS anticipates an increase in calls from customers asking billing related questions which could easily exceed any Billing related cost savings.

Q. Could customers choosing Direct Access Service still have APS provide some of their non-Distribution related services?

A. It is possible that relatively low use customers choosing Direct Access Service will not all have their ESP provide or arrange for all their requirements for Generation, Transmission, Ancillary Services, Metering, Meter Reading, and Billing. However, the exceptions would probably only apply to Metering, Meter Reading, and possibly Billing.

Q. Aside from the development of the three Direct Access Service rates, are there any other portions of the APS retail tariff that need modification to accommodate this service?

A. Yes. Certain provisions in APS's Terms and Conditions of Service should be modified to accommodate the transition to Direct Access Service. However, these selected updates to APS's Schedules will be filed separately at a later date.

Q. Would you discuss Generation, Transmission, and Ancillary Services as they apply to Direct Access Service customers?

A. The Direct Access Service customer could contract for Generation from any certified ESP he chooses, assuming that all required Transmission and Ancillary Services could be obtained. That portion of the Transmission and Ancillary Services required from APS would be provided indirectly to the retail customer through a Scheduling Coordinator selected by the customer or the customer's ESP. APS would bill the Scheduling Coordinator for these services under the rates and terms and conditions to be specified in APS's

OATT as authorized by FERC. It cannot be assumed that the Scheduling Coordinator will simply pass these costs along to the customer's ESP, who in turn could pass them on to the customer since, as unregulated entities, the Scheduling Coordinator and the ESP would each be free to define their own rate levels and designs. They may choose to rebundle charges to the customer or charge a premium above the Transmission and Ancillary Services prices charged to the Scheduling Coordinator by APS.

Q. Will a Direct Access Service customer need to have direct involvement with the Arizona Independent Scheduling Administrator (AISA) or the planned Desert STAR Independent System Operator (ISO)?

A. No, although customers or their representatives are welcome to join and/or participate in these organizations. The purpose of the AISA and the ISO are to establish the operating and later pricing protocols to assure a non-discriminatory and reliable operation of Arizona's and the Southwest's transmission systems. APS is a member of both organizations, intends to participate in the development of the operational and pricing protocols to be implemented by these organizations, and will file a revised OATT with FERC that will reflect how Transmission and Ancillary Services would be provided to Scheduling Coordinators in a Direct Access Service environment.

Q. Why is it necessary to develop new protocols, instead of using the provisions in the Company's current OATT as accepted by FERC?

A. FERC's pro-forma Transmission tariff, upon which APS' OATT is based, is geared to Transmission Service for wholesale customers. It is not readily

amenable for service to retail Direct Access Service customers. AISA's Operating Committee participants have identified those aspects of service to retail customers taking network Transmission Service that were not adequately addressed in FERC's pro-forma Transmission tariff. They are in the process of developing suitable operating and pricing protocols that would facilitate Transmission Service to retail customers.

Q. Will AISA's protocols be finalized in time for APS to implement them for retail access in accordance with the Settlement Agreement?

A. Most of the protocols have already been developed or are in the final stages of development. It is hoped that they will all be finalized by the time APS must revise and file its OATT with FERC to accommodate retail access. In the event that some of the protocols are not completed by the time APS must file its revised OATT with the FERC, APS plans to submit the completed protocols along with interim versions of those protocols remaining to be completed. At such time as the AISA files its own OATT with the FERC containing the completed protocols, APS would again revise its OATT to include the AISA's protocol manual.

Q. Is any action by the ACC necessary in order for APS to implement the proposed revisions to its OATT as contemplated by the Settlement Agreement in a timely manner?

A. Yes. The ACC's support of APS's proposed changes is very important for FERC's acceptance. Therefore, APS requests that the ACC either a) intervene in APS's OATT filing with FERC and support APS's revisions; or b) provide

a letter to FERC in support of APS's revisions which APS would include as part of its filing to FERC. In addition, FERC's rules normally require 60 days before changes to rates or tariffs can be implemented. If the ACC were to issue an Order approving the Settlement Agreement on August 1, absent requesting a waiver of FERC's Notice requirements, retail access would not be available on a practical basis prior to September 30. Therefore, the ACC's support of APS' request to FERC for waiver of FERC's Notice requirements would be desirable.

Q. **How does APS intend to implement the rate decreases for Standard Offer Service rates specified in Section 2.2 of the Settlement Agreement?**

A. APS intends to use the same method that has been used for the last three annual decreases under the 1996 Settlement. That is, each year APS will calculate for each major class of service the decrease percentage applicable to the Demand and Energy charges that yields the overall class decrease as specified in Section 2.2 of the Settlement Agreement. This method allows the Basic Service Charge in each of the Standard Offer rates to remain unchanged.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Appendix - A

Qualifications of

ALAN PROPPER

Alan Propper is Arizona Public Service Company's Director of Pricing & Regulation. He is a veteran of the electric and gas utility industry with over 30 years of experience in utility company management and as an industry consultant. Mr. Propper holds the degrees of Mechanical Engineer from Stevens Institute of Technology and Master of Business Administration from San Francisco State University. The Arizona State Community College Certification Board has certified him as an Instructor of Engineering and Business Administration. In addition, Mr. Propper has completed Advanced Alternative Dispute Resolution Training and has been certified to act as a Mediator by the Northwest Regional Transmission Association and by the Western Regional Transmission Association. He is a contributing author of the widely used utility industry text, Gas Rate Fundamentals, Fourth Edition, published by the American Gas Association.

Mr. Propper's areas of expertise include pricing and rate design, embedded and marginal cost analyses, marketing and load management programs, state and federal regulatory matters, contract negotiations between utilities concerning resale and wheeling services, contract negotiations between utilities and their major retail customers, and organizational training and planning. He is also a highly experienced expert witness, having testified on numerous occasions on contract, pricing, and cost matters before many state and federal regulatory agencies.

Prior to rejoining APS earlier this year after an eight year absence and seventeen years of service, Mr. Propper served as Regional Manager and Managing Executive Consultant for Resource Management International and Principal Consultant and Director of Consulting Services for A&C Enercom. Prior to initially joining APS, Mr. Propper was employed as Supervisor of Rates for Consumers Power Company, Executive Consultant for Commonwealth Services, Forecast Engineer and Rate Engineer for Pacific Gas and Electric Company, and in Power Plant Operations for Public Service Electric and Gas Company.

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
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LINE NO	SUMMARY	ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	*** REVENUES ***										
	*** OPERATING EXPENSES ***										
1	OPERATION & MAINTENANCE EXPENSE	617081	581906	35175	581906	279072	296139	5466	1228	75288	220851
2	ADMINISTRATIVE & GENERAL EXPENSE	71644	68971	2673	68971	43784	23918	913	356	4669	19249
3	DEPRECIATION & AMORT. EXPENSE	209324	198335	10989	198335	107022	88316	2426	572	17389	70927
4	AD VALOREM & OTHER TAXES	121685	115165	6520	115165	63160	50022	1600	383	9703	40320
5	AMORTIZATION OF GAINS	-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
6	REG. ASSETS & DECOM. EXPENSE	178280	170444	7836	170444	76494	93651	234	66	22859	70792
7	SALES TAXES	0	0	0	0	0	0	0	0	0	0
8	REGULATORY EXPENSE (FERC)	701	0	701	0	0	0	0	0	0	0
9	INCOME TAXES	126500	122182	4318	122182	30455	91071	9	648	7529	83542
10	TOTAL OPERATING EXPENSES	1320667	1252715	67951	1252715	597961	640856	10647	3252	136935	503921
	*** RATE BASE ***										
11	PROD., TRANMS., & DISTR. PLANT	6773502	6387718	385784	6387718	3385120	2910727	74974	16898	577116	2333611
12	GENERAL & INTANG. PLANT	474077	454155	19922	454155	287565	157714	6678	2199	29086	128628
13	FUTURE USE PLANT / CWIP	0	0	0	0	0	0	0	0	0	0
14	RESERVE FOR DEPREC. & AMORIT.	-2755471	-2567454	-188017	-2567454	-1336129	-1202172	-23534	-5620	-249274	-952897
15	** NET PLANT **	4492108	4274419	217689	4274419	2336556	1866269	58117	13477	356927	1509342
16	REGULATORY ASSETS & DECOM.	1292649	1239189	53460	1239189	570853	667252	846	238	155649	511603
17	GAIN FROM PLANT	-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
18	MATERIAL & SUPPLIES	139185	130180	9005	130180	58980	70407	636	157	17520	52887
19	CUSTOMER ADVANCES	-24044	-24044	0	-24044	-11301	-12743	0	0	-8	-12735
20	CUSTOMER DEPOSITS	-32137	-32137	0	-32137	-15104	-17033	0	0	-11	-17022
21	WORKING CASH/PREPAYMENTS	-256288	-242754	-13534	-242754	-122311	-118399	-1563	-482	-27358	-91041
22	ACCUM. DEFERRED TAXES	-1462067	-1380236	-81831	-1380236	-688856	-681827	-7760	-1793	-145435	-536392
23	TOTAL RATE BASE	4062467	3882647	179820	3882647	2090073	1730701	50276	11597	347702	1382999

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LINE NO	INCOME TAX CALCULATION	ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
	*** OPERATING EXPENSES ***										
1	OPERATION & MAINTENANCE EXPENSE	617081	581906	35175	581906	279072	296139	5466	1228	75288	220851
2	ADMINISTRATIVE & GENERAL EXPENSE	71644	68971	2673	68971	43784	23918	913	356	4669	19249
3	DEPRECIATION & AMORIT. EXPENSE	209324	198335	10989	198335	107022	88316	2426	572	17389	70927
4	AD VALOREM & OTHER TAXES	121685	115165	6520	115165	63160	50022	1600	383	9703	40320
5	AMORTIZATION OF GAIN	-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
6	REG. ASSETS & DECOM. EXPENSE	178280	170444	7836	170444	76494	93651	234	66	22859	70792
7	SALES TAXES	0	0	0	0	0	0	0	0	0	0
8	REGULATORY EX. (FERC)	701	0	701	0	0	0	0	0	0	0
9	TOTAL EXPENSE	1194167	1130533	63634	1130533	567506	549785	10638	2604	129406	420380
10	**OPERATING INCOME BEFORE TAXES**	459531	442365	17166	442365	150667	287846	1831	2022	31163	256682
	INTEREST EXPENSE										
11	RATE BASE	4062467	3882647	179820	3882647	2090073	1730701	50276	11597	347702	1382999
12	LONG TERM DEBT RATE	3.60%									
13	INTEREST EXP. (RB * LTD)	146249	139775	6474	139775	75243	62305	1810	417	12517	49788

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LINE No.	PROD/TRANM/DIST PLANT		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE STREET LIGHTING	GE DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	3582144	3377390	204754	3377390	1596405	1780985	0	0	394812	1386173
2	ANC.-REGULATION	D-01	77604	73168	4436	73168	34585	38583	0	0	8553	30030
3	ANC.-SPINNING RES.	D-01	99788	94084	5704	94084	44471	49613	0	0	10998	38615
4	ANC.-READY RES.	D-01	26188	24691	1497	24691	11671	13020	0	0	2886	10134
5	SPEC AFUDC	DS-07	-120009	-115425	-4584	-115425	-54558	-60867	0	0	-13493	-47374
6	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
7	ENERGY-REGULATION	E-01	0	0	0	0	0	0	0	0	0	0
8	TOTAL PRODUCTION		3665715	3453908	211807	3453908	1632573	1821335	0	0	403757	1417578
	TRANSMISSION *****											
9	SUBSTATION	D-02	298760	259854	38906	259854	122826	137028	0	0	30377	106651
10	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
11	SUBTOTAL SUBSTAT		298760	259854	38906	259854	122826	137028	0	0	30377	106651
12	LINES	D-02	450838	392128	58710	392128	185349	206779	0	0	45839	160940
13	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
14	-SPEC AFUDC	DS-03	-2490	-2490	0	-2490	-1177	-1313	0	0	-291	-1022
15	SUBTOTAL LINES		448348	389638	58710	389638	184172	205466	0	0	45548	159918
16	TOTAL TRANSMISSION		747108	649491	97617	649491	306998	342494	0	0	75925	266569
	DISTRIBUTION *****											
17	SUBSTATION	D-07	176053	170708	5345	170708	94357	74857	1188	306	15268	59589
	O.H. LINES											
18	-OH PRIMARY	D-09	433167	422799	10368	422799	240762	178224	3032	781	27814	150409
19	-OH SECONDARY	D-11	125686	125669	17	125669	107240	17045	1100	284	0	17045
	U.G. LINES											
20	-UG PRIMARY	D-14	738181	731981	6200	731981	421980	303319	5313	1369	47804	255515
21	-UG SECONDARY	D-17A	37859	37859	0	37859	32974	4519	291	75	0	4519
	LINE TRANSFORMER											
22	-OH LINE TRANS.	D-12	138656	134961	3695	134961	93162	41060	588	151	1967	39094
23	-UG LINE TRANS.	D-12A	273030	273030	0	273030	188468	83066	1189	306	3979	79087
	SERVICES											
24	-O.H. SERVICES	C-08	39159	38816	343	38816	33447	5369	0	0	0	5369
25	-U.G. SERVICES	C-09	142132	141578	554	141578	127718	13860	0	0	284	13575
26	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
27	METERS-ALLOCABLE	C-03	132839	131020	1819	131020	105440	25580	0	0	318	25261
28	DUSK TO DAWN	CS-13	13625	13625	0	13625	0	0	0	13625	0	0
29	STREET LIGHTING	CS-12	62272	62272	0	62272	0	0	62272	0	0	0
			0	0	0	0	0	0	0	0	0	0
30	TOTAL DISTRIBUTION		2312659	2284319	28340	2284319	1445549	746898	74974	16898	97435	649464
31	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
32	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
33	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
34	TOTAL DEMAND		6335455	6000407	335048	6000407	3118514	2865919	12702	3273	576513	2289405
35	TOTAL ENERGY		0	0	0	0	0	0	0	0	0	0
36	TOTAL CUSTOMER		390027	387311	2716	387311	266606	44808	62272	13625	603	44206
37	TOTAL (EX SCE)		6725482	6387718	337764	6387718	3385120	2910727	74974	16898	577116	2333611
38	500 KV SCE	S-10	48020	0	48020	0	0	0	0	0	0	0
39	TOTAL COMPANY		6773502	6387718	385784	6387718	3385120	2910727	74974	16898	577116	2333611

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LINE No.	GENERAL & INTANG PLANT		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE STREET LIGHTING	GE DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	105836	99786	6050	99786	47166	52620	0	0	11665	40955
2	ANC.-REGULATION	D-01	2191	2066	125	2066	976	1089	0	0	241	848
3	ANC.-SPINNING RES.	D-01	2498	2355	143	2355	1113	1242	0	0	275	967
4	ANC.-READY RES.	D-01	357	337	20	337	159	177	0	0	39	138
5	ENERGY	E-01	41363	38481	2882	38481	15388	22886	162	45	6508	16378
6	ENERGY-REGULATION	E-01	906	843	63	843	337	501	4	1	143	359
7	TOTAL PRODUCTION		153151	143868	9283	143868	65140	78516	166	46	18872	59645
	TRANSMISSION ******											
8	SUBSTATION	D-02	4809	4183	626	4183	1977	2206	0	0	489	1717
9	SUBTOTAL SUBSTAT		4809	4183	626	4183	1977	2206	0	0	489	1717
10	LINES	D-02	39209	34103	5106	34103	16120	17983	0	0	3987	13997
11	SUBTOTAL LINES		39209	34103	5106	34103	16120	17983	0	0	3987	13997
12	TOTAL TRANSMISSION		44018	38286	5732	38286	18097	20189	0	0	4476	15714
	DISTRIBUTION *****											
13	SUBSTATION	D-07	18580	18016	564	18016	9958	7900	125	32	1611	6289
	O.H. LINES											
14	-OH PRIMARY	D-09	27489	26831	658	26831	15279	11310	192	50	1765	9545
15	-OH SECONDARY	D-11	7977	7976	1	7976	6806	1082	70	18	0	1082
	U.G. LINES											
16	-UG PRIMARY	D-14	32763	32488	275	32488	18729	13462	236	61	2122	11341
17	-UG SECONDARY	D-17A	1681	1681	0	1681	1464	201	13	3	0	201
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	2405	2341	64	2341	1616	712	10	3	34	678
19	-UG LINE TRANS.	D-12	4735	4609	126	4609	3181	1402	20	5	67	1335
	SERVICES											
20	-O.H. SERVICES	C-08	2485	2463	22	2463	2123	341	0	0	0	341
21	-U.G. SERVICES	C-09	6306	6281	25	6281	5667	615	0	0	13	602
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	49476	48799	677	48799	39271	9527	0	0	119	9409
24	DUSK TO DAWN	CS-13	719	719	0	719	0	0	0	719	0	0
25	STREET LIGHTING	CS-12	5758	5758	0	5758	0	0	5758	0	0	0
26	TOTAL DISTRIBUTION		160374	157962	2412	157962	104094	46552	6425	891	5731	40822
27	CUSTOMER ACCOUNTS	C-04	100787	100581	206	100581	88405	10986	77	1113	7	10979
28	CUST SERV & INFO	C-04A	4230	4230	0	4230	3718	462	3	47	0	462
29	SALES	C-04	9247	9228	19	9228	8111	1008	7	102	1	1007
30	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
31	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
32	TOTAL DEMAND		250530	236771	13759	236771	124546	111387	667	172	22296	89091
33	TOTAL ENERGY		42269	39324	2945	39324	15725	23388	166	46	6651	16737
34	TOTAL CUSTOMER		179008	178059	949	178059	147294	22939	5845	1981	139	22800
35	TOTAL (EX SCE)		471807	454155	17652	454155	287565	157714	6678	2199	29086	128628
36	500 KV SCE	S-10	2270	0	2270	0	0	0	0	0	0	0
37	TOTAL COMPANY		474077	454155	19922	454155	287565	157714	6678	2199	29086	128628

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LINE No.	RESERVE FOR DEPREC & AMORIT		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	-1476614	-1392211	-84403	-1392211	-658062	-734149	0	0	-162747	-571401
2	ANC.-REGULATION	D-01	-47755	-45025	-2730	-45025	-21282	-23743	0	0	-5263	-18480
3	ANC.-SPINNING RES.	D-01	-55590	-52412	-3178	-52412	-24774	-27638	0	0	-6127	-21512
4	ANC.-READY RES.	D-01	-18192	-17152	-1040	-17152	-8107	-9045	0	0	-2005	-7040
5	SPEC AFUDC	DS-08	43181	41512	1669	41512	19622	21890	0	0	4853	17038
6	ENERGY	E-01	-20934	-19476	-1458	-19476	-7788	-11583	-82	-23	-3294	-8289
7	ENERGY-REGULATION	E-01	-405	-377	-28	-377	-151	-224	-2	0	-64	-160
8	TOTAL PRODUCTION		-1576309	-1485142	-91167	-1485142	-700543	-784492	-84	-23	-174648	-609844
	TRANSMISSION ******											
9	SUBSTATION	D-02	-116931	-101704	-15227	-101704	-48073	-53631	0	0	-11889	-41742
10	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
11	SUBTOTAL SUBSTAT		-116931	-101704	-15227	-101704	-48073	-53631	0	0	-11889	-41742
12	LINES	D-02	-194771	-169407	-25364	-169407	-80074	-89333	0	0	-19803	-69529
13	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
14	-SPEC AFUDC	DS-03	1382	1382	0	1382	653	729	0	0	162	567
15	SUBTOTAL LINES		-193389	-168025	-25364	-168025	-79421	-88604	0	0	-19642	-68962
16	TOTAL TRANSMISSION		-310320	-269729	-40591	-269729	-127494	-142235	0	0	-31531	-110704
	DISTRIBUTION *****											
17	SUBSTATION	D-07A	-46575	-44460	-2115	-44460	-24575	-19496	-309	-80	-3976	-15520
	O.H. LINES											
18	-OH PRIMARY	D-09A	-129121	-123867	-5254	-123867	-70536	-52214	-888	-229	-8149	-44065
19	-OH SECONDARY	D-11	-37466	-37461	-5	-37461	-31967	-5081	-328	-85	0	-5081
	U.G. LINES											
20	-UG PRIMARY	D-14A	-214034	-212042	-1992	-212042	-122240	-87866	-1539	-397	-13848	-74018
21	-UG SECONDARY	D-17A	-10978	-10978	0	-10978	-9561	-1310	-84	-22	0	-1310
	LINE TRANSFORMER											
22	-OH LINE TRANS.	D-12A	-38749	-37372	-1377	-37372	-25797	-11370	-163	-42	-545	-10825
23	-UG LINE TRANS.	D-12A	-76301	-76301	0	-76301	-52669	-23214	-332	-86	-1112	-22102
	SERVICES											
24	-O.H. SERVICES	C-08A	-11714	-11544	-170	-11544	-9947	-1597	0	0	0	-1597
25	-U.G. SERVICES	C-09A	-41360	-41134	-226	-41134	-37107	-4027	0	0	-83	-3944
26	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
27	METERS-ALLOCABLE	C-03	-57249	-56465	-784	-56465	-45441	-11024	0	0	-137	-10887
28	DUSK TO DAWN	CS-13	-4012	-4012	0	-4012	0	0	0	-4012	0	0
29	STREET LIGHTING	CS-12	-19399	-19399	0	-19399	0	0	-19399	0	0	0
			0	0	0	0	0	0	0	0	0	0
30	TOTAL DISTRIBUTION		-686958	-675035	-11923	-675035	-429842	-217199	-23043	-4951	-27850	-189349
31	CUSTOMER ACCOUNTS	C-04	-42999	-42911	-88	-42911	-37716	-4687	-33	-475	-3	-4684
32	CUST SERV & INFO	C-04A	-1893	-1893	0	-1893	-1664	-207	-1	-21	0	-207
33	SALES	C-04	-4138	-4130	-8	-4130	-3630	-451	-3	-46	0	-451
34	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
35	SYSTEM BENEFITS	E-01	-95504	-88615	-6889	-88615	-35240	-52901	-370	-104	-15243	-37659
36	TOTAL DEMAND		-2514018	-2366114	-147904	-2366114	-1192685	-1168372	-4014	-1043	-245693	-922679
37	TOTAL ENERGY		-21339	-19852	-1487	-19852	-7938	-11807	-84	-23	-3357	-8449
38	TOTAL CUSTOMER		-182764	-181488	-1276	-181488	-135506	-21992	-19437	-4553	-223	-21769
39	TOTAL (EX SCE)		-2718121	-2567454	-150667	-2567454	-1336129	-1202172	-23534	-5620	-249274	-952897
40	500 KV SCE	S-10	-37350	0	-37350	0	0	0	0	0	0	0
41	TOTAL COMPANY		-2755471	-2567454	-188017	-2567454	-1336129	-1202172	-23534	-5620	-249274	-952897

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LINE No.	GAIN FROM PLANT		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
2	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
3	SPECIFIC	D-01A	0	0	0	0	0	0	0	0	0	0
4	TOTAL PRODUCTION		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
	TRANSMISSION ******											
5	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
6	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
7	LINES	D-02	0	0	0	0	0	0	0	0	0	0
8	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
9	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
10	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
11	O.H. LINES											
12	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
13	* -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
14	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
15	*LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
16	* O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
17	* U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
18	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
19	* -ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
20	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
21	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
22	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
23	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
24	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
25	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
26	TOTAL DEMAND		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
27	TOTAL ENERGY		0	0	0	0	0	0	0	0	0	0
28	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
29	TOTAL (EX SCE)		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643
30	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
31	TOTAL COMPANY		-86939	-81970	-4969	-81970	-38745	-43225	0	0	-9582	-33643

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LINE No.	MATERIALS & SUPPLIES		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	50461	47577	2884	47577	22488	25088	0	0	5562	19527
2	ANC.-REGULATION	D-01	583	550	33	550	260	290	0	0	64	226
3	ANC.-SPINNING RES.	D-01	1004	947	57	947	447	499	0	0	111	389
4	ANC.-READY RES.	D-01	351	331	20	331	156	175	0	0	39	136
5	ENERGY	E-01	64182	59711	4471	59711	23877	35512	251	71	10098	25414
6	ENERGY-REGULATION	E-01	883	821	62	821	328	489	3	1	139	350
7	TOTAL PRODUCTION		117464	109936	7528	109936	47557	62053	255	72	16013	46040
	TRANSMISSION ******											
8	SUBSTATION	D-02	7579	6592	987	6592	3116	3476	0	0	771	2706
9	SUBTOTAL SUBSTAT		7579	6592	987	6592	3116	3476	0	0	771	2706
10	LINES	D-02	2370	2061	309	2061	974	1087	0	0	241	846
11	SUBTOTAL LINES		2370	2061	309	2061	974	1087	0	0	241	846
12	TOTAL TRANSMISSION		9949	8653	1296	8653	4090	4563	0	0	1012	3552
	DISTRIBUTION *****											
13	SUBSTATION	D-07	896	869	27	869	480	381	6	2	78	303
	O.H. LINES											
14	-OH PRIMARY	D-09	2205	2152	53	2152	1226	907	15	4	142	766
15	-OH SECONDARY	D-11	640	640	0	640	546	87	6	1	0	87
	U.G. LINES											
16	-UG PRIMARY	D-14	3758	3726	32	3726	2148	1544	27	7	243	1301
17	-UG SECONDARY	D-17A	193	193	0	193	168	23	1	0	0	23
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	706	687	19	687	474	209	3	1	10	199
19	-UG LINE TRANS.	D-12	1390	1353	37	1353	934	412	6	2	20	392
	SERVICES											
20	-O.H. SERVICES	C-08	199	197	2	197	170	27	0	0	0	27
21	-U.G. SERVICES	C-09	723	720	3	720	650	71	0	0	1	69
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	676	667	9	667	537	130	0	0	2	129
24	DUSK TO DAWN	CS-13	69	69	0	69	0	0	0	69	0	0
25	STREET LIGHTING	CS-12	317	317	0	317	0	0	317	0	0	0
26	TOTAL DISTRIBUTION		11772	11591	181	11591	7333	3791	382	86	495	3295
27	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
28	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
29	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
30	TOTAL DEMAND		72136	67678	4458	67678	33419	34178	65	17	7279	26899
31	TOTAL ENERGY		65065	60532	4533	60532	24205	36001	255	72	10237	25763
32	TOTAL CUSTOMER		1984	1970	14	1970	1356	228	317	69	3	225
33	TOTAL (EX SCE)		139185	130180	9005	130180	58980	70407	636	157	17520	52887
34	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
35	TOTAL COMPANY		139185	130180	9005	130180	58980	70407	636	157	17520	52887

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LINE No.	REGULATORY ASSET & DECOMMISSIONING		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND -ACC	D-01A	0	0	0	0	0	0	0	0	0	0
2	DEMAND-ALLOCABLE	D-01	0	0	0	0	0	0	0	0	0	0
3	ENERGY-ALLOCABLE	E-01	0	0	0	0	0	0	0	0	0	0
4	TOTAL PRODUCTION		0	0	0	0	0	0	0	0	0	0
	TRANSMISSION ******											
5	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
6	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
7	LINES	D-02	0	0	0	0	0	0	0	0	0	0
8	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
9	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
10	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
11	O.H. LINES											
12	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
13	* -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
14	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
15	*LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
16	* O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
17	* U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
18	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
19	METERS ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
20	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
21	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
22	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
23	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
24	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
25	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
26	REGULATORY ASSETS	E-01	79096	73586	5510	73586	29425	43764	310	87	12445	31319
27	REGULATORY ASSETS	D-01	78113	73648	4465	73648	34812	38837	0	0	8609	30227
28	REGULATORY ASSETS	D-01	516722	487186	29536	487186	230280	256906	0	0	56951	199955
29	REGULATORY ASSETS	D-01	71778	67675	4103	67675	31988	35687	0	0	7911	27776
30	REGULATORY ASSETS	D-01A	-5108	-5108	0	-5108	-2414	-2694	0	0	-597	-2096
31	REGULATORY ASSETS	E-01	42462	39504	2958	39504	15796	23494	166	47	6681	16813
32	REGULATORY ASSETS	D-01A	414082	414082	0	414082	195726	218356	0	0	48406	169951
33	SYSTEM BENEFITS	E-01	95504	88615	6889	88615	35240	52901	370	104	15243	37659
34	TOTAL DEMAND		1171091	1126099	44992	1126099	525632	599993	370	104	136523	463470
35	TOTAL ENERGY		121558	113090	8468	113090	45221	67259	476	134	19126	48133
36	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
37	TOTAL (EX SCE)		1292649	1239189	53460	1239189	570853	667252	846	238	155649	511603
38	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
39	TOTAL COMPANY		1292649	1239189	53460	1239189	570853	667252	846	238	155649	511603

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LINE No.	WORKING CASH / PREPAYMENTS		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	-125351	-118186	-7165	-118186	-55863	-62323	0	0	-13816	-48507
2	ANC.-REGULATION	D-01	-1347	-1270	-77	-1270	-600	-670	0	0	-148	-521
3	ANC.-SPINNING RES.	D-01	-1629	-1536	-93	-1536	-726	-810	0	0	-180	-630
4	ANC.-READY RES.	D-01	-334	-315	-19	-315	-149	-166	0	0	-37	-129
5	ENERGY	E-01	-72546	-67492	-5054	-67492	-26988	-40140	-284	-80	-11414	-28726
6	ENERGY-REGULATION	E-01	-271	-252	-19	-252	-101	-150	-1	0	-43	-107
7	TOTAL PRODUCTION		-201478	-189051	-12427	-189051	-84428	-104258	-285	-80	-25638	-78620
	TRANSMISSION *****											
8	SUBSTATION	D-02	-3265	-2840	-425	-2840	-1342	-1498	0	0	-332	-1166
9	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
10	SUBTOTAL SUBSTAT		-3265	-2840	-425	-2840	-1342	-1498	0	0	-332	-1166
11	LINES	D-02	-1156	-1005	-151	-1005	-475	-530	0	0	-118	-413
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	-SPEC AFUDC	DS-03	0	0	0	0	0	0	0	0	0	0
14	SUBTOTAL LINES		-1156	-1005	-151	-1005	-475	-530	0	0	-118	-413
15	TOTAL TRANSMISSION		-4421	-3845	-576	-3845	-1818	-2028	0	0	-450	-1578
	DISTRIBUTION *****											
16	SUBSTATION	D-07	-1940	-1881	-59	-1881	-1040	-825	-13	-3	-168	-657
	O.H. LINES											
17	-OH PRIMARY	D-09	-6447	-6293	-154	-6293	-3583	-2653	-45	-12	-414	-2239
18	-OH SECONDARY	D-11	-1870	-1870	0	-1870	-1596	-254	-16	-4	0	-254
	U.G. LINES											
19	-UG PRIMARY	D-14	-9441	-9362	-79	-9362	-5397	-3879	-68	-18	-611	-3268
20	-UG SECONDARY	D-17A	-485	-485	0	-485	-422	-58	-4	-1	0	-58
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12	-1359	-1323	-36	-1323	-913	-402	-6	-1	-19	-383
22	-UG LINE TRANS.	D-12	-2678	-2607	-71	-2607	-1799	-793	-11	-3	-38	-755
	SERVICES											
23	-O.H. SERVICES	C-08	-580	-575	-5	-575	-495	-80	0	0	0	-80
24	-U.G. SERVICES	C-09	-1816	-1809	-7	-1809	-1632	-177	0	0	-4	-173
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03	-6479	-6390	-89	-6390	-5143	-1248	0	0	-16	-1232
27	DUSK TO DAWN	CS-13	-183	-183	0	-183	0	0	0	-183	0	0
28	STREET LIGHTING	CS-12	-1102	-1102	0	-1102	0	0	-1102	0	0	0
29	TOTAL DISTRIBUTION		-34380	-33879	-501	-33879	-22020	-10368	-1265	-225	-1270	-9098
30	CUSTOMER ACCOUNTS	C-04	-11058	-11035	-23	-11035	-9699	-1205	-8	-122	-1	-1205
31	CUST SERV & INFO	C-04A	-1554	-1554	0	-1554	-1366	-170	-1	-17	0	-170
32	SALES	C-04	-3397	-3390	-7	-3390	-2980	-370	-3	-38	0	-370
33	REGULATORY ASSETS	E-01	0	0	0	0	0	0	0	0	0	0
34	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
35	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
36	TOTAL DEMAND		-157302	-148972	-8330	-148972	-73907	-74860	-163	-42	-15881	-58979
37	TOTAL ENERGY		-72817	-67744	-5073	-67744	-27089	-40290	-285	-80	-11457	-28833
38	TOTAL CUSTOMER		-26169	-26039	-130	-26039	-21315	-3250	-1114	-360	-20	-3229
39	TOTAL (EX SCE)		-256288	-242754	-13534	-242754	-122311	-118399	-1563	-482	-27358	-91041
40	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
41	TOTAL COMPANY		-256288	-242754	-13534	-242754	-122311	-118399	-1563	-482	-27358	-91041

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LINE No.	DEFERRED TAXES / RATE BASE - ALLOC		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE STREET LIGHTING	GE DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	-532144	-501727	-30417	-501727	-237153	-264573	0	0	-58651	-205922
2	ANC.-REGULATION	D-01	-14924	-14071	-853	-14071	-6651	-7420	0	0	-1645	-5775
3	ANC.-SPINNING RES.	D-01	-19165	-18070	-1095	-18070	-8541	-9529	0	0	-2112	-7416
4	ANC.-READY RES.	D-01	-5009	-4723	-286	-4723	-2232	-2490	0	0	-552	-1938
5	ENERGY	E-01	-4462	-4151	-311	-4151	-1660	-2469	-17	-5	-702	-1767
6	ENERGY-REGULATION	E-01	-86	-80	-6	-80	-32	-48	0	0	-14	-34
7	TOTAL PRODUCTION		-575790	-542821	-32969	-542821	-256270	-286529	-18	-5	-63676	-222853
	TRANSMISSION ******											
8	SUBSTATION	D-02	-38154	-33185	-4969	-33185	-15686	-17500	0	0	-3879	-13620
9	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
10	SUBTOTAL SUBSTAT		-38154	-33185	-4969	-33185	-15686	-17500	0	0	-3879	-13620
11	LINES	D-02	-68674	-59731	-8943	-59731	-28233	-31498	0	0	-6982	-24515
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	-SPEC AFUDC	D-01A	0	0	0	0	0	0	0	0	0	0
14	SUBTOTAL LINES		-68674	-59731	-8943	-59731	-28233	-31498	0	0	-6982	-24515
15	TOTAL TRANSMISSION		-106828	-92916	-13912	-92916	-43919	-48997	0	0	-10862	-38135
	DISTRIBUTION *****											
16	SUBSTATION	D-07	-18827	-18255	-572	-18255	-10090	-8005	-127	-33	-1633	-6372
	O.H. LINES											
17	-OH PRIMARY	D-09	-49184	-48007	-1177	-48007	-27337	-20236	-344	-89	-3158	-17078
18	-OH SECONDARY	D-11	-14271	-14269	-2	-14269	-12177	-1935	-125	-32	0	-1935
	U.G. LINES											
19	-UG PRIMARY	D-14	-83323	-82623	-700	-82623	-47631	-34237	-600	-155	-5396	-28842
20	-UG SECONDARY	D-17A	-4274	-4274	0	-4274	-3722	-510	-33	-8	0	-510
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12	-15564	-15149	-415	-15149	-10457	-4609	-66	-17	-221	-4388
22	-UG LINE TRANS.	D-12	-30648	-29831	-817	-29831	-20592	-9076	-130	-33	-435	-8641
	SERVICES											
23	-O.H. SERVICES	C-08	-4458	-4419	-39	-4419	-3808	-611	0	0	0	-611
24	-U.G. SERVICES	C-09	-16087	-16024	-63	-16024	-14456	-1569	0	0	-32	-1537
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03	-16561	-16334	-227	-16334	-13145	-3189	0	0	-40	-3149
27	DUSK TO DAWN	CS-13	-1547	-1547	0	-1547	0	0	0	-1547	0	0
28	STREET LIGHTING	CS-12	-7154	-7154	0	-7154	0	0	-7154	0	0	0
29	TOTAL DISTRIBUTION		-261898	-257888	-4010	-257888	-163416	-83978	-8579	-1914	-10914	-73064
30	CUSTOMER ACCOUNTS	C-04	-3526	-3519	-7	-3519	-3093	-384	-3	-39	0	-384
31	CUST SERV & INFO	C-04A	-495	-495	0	-495	-435	-54	0	-5	0	-54
32	SALES	C-04	-1083	-1081	-2	-1081	-950	-118	-1	-12	0	-118
33	REGULATORY ASSETS	D-01	21007	19806	1201	19806	9362	10444	0	0	2315	8129
34	REGULATORY ASSETS	E-01	-30911	-28758	-2153	-28758	-11499	-17103	-121	-34	-4864	-12240
35	REGULATORY ASSETS	D-01	-57085	-53822	-3263	-53822	-25440	-28382	0	0	-6292	-22090
36	REGULATORY ASSETS	D-01	-10608	-10002	-606	-10002	-4728	-5274	0	0	-1169	-4105
37	REGULATORY ASSETS	D-01	-225834	-212925	-12909	-212925	-100644	-112281	0	0	-24891	-87390
38	REGULATORY ASSETS	D-01	-87723	-82709	-5014	-82709	-39094	-43614	0	0	-9669	-33946
39	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
40	TOTAL DEMAND		-1254404	-1183567	-70837	-1183567	-591049	-590726	-1425	-367	-124369	-466357
41	TOTAL ENERGY		-35459	-32989	-2470	-32989	-13191	-19620	-139	-39	-5579	-14041
42	TOTAL CUSTOMER		-50911	-50573	-338	-50573	-35886	-5925	-7158	-1603	-72	-5853
43	TOTAL (EX SCE)		-1340774	-1267129	-73645	-1267129	-640127	-616271	-8721	-2010	-130021	-486250
44	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
45	TOTAL COMPANY		-1340774	-1267129	-73645	-1267129	-640127	-616271	-8721	-2010	-130021	-486250

**** ARIZONA PUBLIC SERVICE ***** COST OF SERVICE STUDY 4 CP Allocation Adjusted TYE 12/31/96			<----------	GJ	---------->	:----------	----------	GE-1	---------->	---------->	<---------- GE	---------->
			ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
LINE No.	DEFERRED TAXES RATE BASE - FERC											
====	PRODUCTION *******											
1	DEMAND	D-01F	-4448	0	-4448	0	0	0	0	0	0	0
2	ANC.-REGULATION	D-01F	-36	0	-36	0	0	0	0	0	0	0
3	ANC.-SPINNING RES.	D-01F	-45	0	-45	0	0	0	0	0	0	0
4	ANC.-READY RES.	D-01F	-11	0	-11	0	0	0	0	0	0	0
5	ENERGY	E-01F	-53	0	-53	0	0	0	0	0	0	0
6	ENERGY-REGULATION	E-01F	-1	0	-1	0	0	0	0	0	0	0
7	TOTAL PRODUCTION		-4594	0	-4594	0	0	0	0	0	0	0
	TRANSMISSION ******											
8	SUBSTATION	D-02F	-416	0	-416	0	0	0	0	0	0	0
9	SUBTOTAL SUBSTAT		-416	0	-416	0	0	0	0	0	0	0
10	LINES	D-02F	-521	0	-521	0	0	0	0	0	0	0
11	SUBTOTAL LINES		-521	0	-521	0	0	0	0	0	0	0
12	TOTAL TRANSMISSION		-937	0	-937	0	0	0	0	0	0	0
	DISTRIBUTION *****											
13	SUBSTATION	D-07F	-280	0	-280	0	0	0	0	0	0	0
	O.H. LINES											
14	-OH PRIMARY	D-09F	-486	0	-486	0	0	0	0	0	0	0
15	-OH SECONDARY	D-11F	-141	0	-141	0	0	0	0	0	0	0
	U.G. LINES											
16	-UG PRIMARY	D-14F	-864	0	-864	0	0	0	0	0	0	0
17	-UG SECONDARY	D-14F	0	0	0	0	0	0	0	0	0	0
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12F	-153	0	-153	0	0	0	0	0	0	0
19	-UG LINE TRANS.	D-12F	-301	0	-301	0	0	0	0	0	0	0
	SERVICES											
20	-O.H. SERVICES	C-08F	-44	0	-44	0	0	0	0	0	0	0
21	-U.G. SERVICES	C-09F	-159	0	-159	0	0	0	0	0	0	0
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03F	-166	0	-166	0	0	0	0	0	0	0
24	DUSK TO DAWN	CS-06	0	0	0	0	0	0	0	0	0	0
25	STREET LIGHTING	CS-06	0	0	0	0	0	0	0	0	0	0
26	TOTAL DISTRIBUTION		-2594	0	-2594	0	0	0	0	0	0	0
27	CUSTOMER ACCOUNTS	C-04F	-42	0	-42	0	0	0	0	0	0	0
28	CUST SERV & INFO	DS-05F	-6	0	-6	0	0	0	0	0	0	0
29	SALES	DS-05F	-13	0	-13	0	0	0	0	0	0	0
30	TOTAL DEMAND		-7721	0	-7721	0	0	0	0	0	0	0
31	TOTAL ENERGY		-54	0	-54	0	0	0	0	0	0	0
32	TOTAL CUSTOMER		-411	0	-411	0	0	0	0	0	0	0
33	TOTAL (EX SCE)		-8186	0	-8186	0	0	0	0	0	0	0
34	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
35	TOTAL COMPANY		-8186	0	-8186	0	0	0	0	0	0	0

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
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LINE No.	DEFERRED TAXES RATE BASE - ACC		ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
			<----------	GJ	---------->	:----------	----------	GE-1	---------->		<---------- GE	---------->
====	PRODUCTION *******											
1	DEMAND	D-01A	498	498	0	498	235	263	0	0	58	204
2	ANC.-REGULATION	D-01A	4	4	0	4	2	2	0	0	0	2
3	ANC.-SPINNING RES.	D-01A	5	5	0	5	2	3	0	0	1	2
4	ANC.-READY RES.	D-01A	1	1	0	1	0	1	0	0	0	0
5	ENERGY	E-01A	6	6	0	6	2	4	0	0	1	3
6	ENERGY-REGULATION	E-01A	0	0	0	0	0	0	0	0	0	0
7	TOTAL PRODUCTION		514	514	0	514	243	271	0	0	60	211
	TRANSMISSION ******											
8	SUBSTATION	D-02A	47	47	0	47	22	25	0	0	5	19
9	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
10	SUBTOTAL SUBSTAT		47	47	0	47	22	25	0	0	5	19
11	LINES	D-05A	59	59	0	59	28	31	0	0	7	24
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	-SPEC AFUDC	D-01A	0	0	0	0	0	0	0	0	0	0
14	SUBTOTAL LINES		59	59	0	59	28	31	0	0	7	24
15	TOTAL TRANSMISSION		106	106	0	106	50	56	0	0	12	44
	DISTRIBUTION *****											
16	SUBSTATION	D-07A	2252	2252	0	2252	1245	988	16	4	201	786
	O.H. LINES											
17	-OH PRIMARY	D-09A	5544	5544	0	5544	3157	2337	40	10	365	1972
18	-OH SECONDARY	D-11A	1608	1608	0	1608	1372	218	14	4	0	218
	U.G. LINES											
19	-UG PRIMARY	D-14A	9447	9447	0	9447	5446	3915	69	18	617	3298
20	-UG SECONDARY	D-17A	484	484	0	484	422	58	4	1	0	58
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12A	1774	1774	0	1774	1225	540	8	2	26	514
22	-UG LINE TRANS.	D-12A	3493	3493	0	3493	2411	1063	15	4	51	1012
	SERVICES											
23	-O.H. SERVICES	C-08A	501	501	0	501	432	69	0	0	0	69
24	-U.G. SERVICES	C-09A	1819	1819	0	1819	1641	178	0	0	4	174
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03A	1703	1703	0	1703	1371	332	0	0	4	328
27	DUSK TO DAWN	CS-13	174	174	0	174	0	0	0	174	0	0
28	STREET LIGHTING	CS-12	797	797	0	797	0	0	797	0	0	0
			0	0	0	0	0	0	0	0	0	0
29	TOTAL DISTRIBUTION		29596	29596	0	29596	18721	9697	962	216	1268	8430
30	CUSTOMER ACCOUNTS	C-04A	5	5	0	5	4	1	0	0	0	1
31	CUST SERV & INFO	C-04A	1	1	0	1	1	0	0	0	0	0
32	SALES	C-04A	1	1	0	1	1	0	0	0	0	0
33	REGULATORY ASSETS	D-01A	-143330	-143330	0	-143330	-67748	-75582	0	0	-16755	-58827
34	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
35	TOTAL DEMAND		-118114	-118114	0	-118114	-52181	-66140	165	42	-15423	-50717
36	TOTAL ENERGY		6	6	0	6	2	4	0	0	1	3
37	TOTAL CUSTOMER		5001	5001	0	5001	3449	581	797	174	8	573
38	TOTAL (EX SCE)		-113107	-113107	0	-113107	-48729	-65556	962	217	-15415	-50142
39	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
40	TOTAL COMPANY		-113107	-113107	0	-113107	-48729	-65556	962	217	-15415	-50142

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LINE No.	OPERATING & MAINT EXPENSE		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	GE-1 RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	132842	125249	7593	125249	59202	66047	0	0	14641	51406
2	ANC.-REGULATION	D-01	2260	2131	129	2131	1007	1124	0	0	249	875
3	ANC.-SPINNING RES.	D-01	2461	2320	141	2320	1097	1224	0	0	271	952
4	ANC.-READY RES.	D-01	390	368	22	368	174	194	0	0	43	151
5	ENERGY-OTHER	E-01	58015	53973	4042	53973	21582	32100	227	64	9128	22972
6	ENERGY-RELATED FUEL	E-04	271547	252630	18917	252630	101020	150248	1063	299	42725	107523
7	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
8	ENERGY-REGULATION	E-01	12837	11943	894	11943	4776	7103	50	14	2020	5083
9	ENERGY-REGULATION	E-01	860	800	60	800	320	476	3	1	135	341
10	TOTAL PRODUCTION		481212	449413	31799	449413	189177	258515	1344	378	69213	189301
	TRANSMISSION ******											
11	SUBSTATION	D-02	2432	2115	317	2115	1000	1115	0	0	247	868
12	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
13	SUBTOTAL SUBSTAT		2432	2115	317	2115	1000	1115	0	0	247	868
14	LINES	D-02	12695	11042	1653	11042	5219	5823	0	0	1291	4532
15	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
16	*-SPEC AFUDC*	*D-01A*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
17	SUBTOTAL LINES		12695	11042	1653	11042	5219	5823	0	0	1291	4532
18	TOTAL TRANSMISSION		15127	13157	1970	13157	6219	6938	0	0	1538	5400
	DISTRIBUTION *****											
19	SUBSTATION	D-07A	19033	19026	7	19026	10516	8343	132	34	1702	6641
	O.H. LINES											
20	-OH PRIMARY	D-09A	9275	9268	7	9268	5278	3907	66	17	610	3297
21	-OH SECONDARY	D-11A	2691	2691	0	2691	2296	365	24	6	0	365
	U.G. LINES											
22	-UG PRIMARY	D-14A	11048	11048	0	11048	6369	4578	80	21	722	3857
23	-UG SECONDARY	D-17A	566	566	0	566	493	68	4	1	0	68
	LINE TRANSFORMER											
24	-OH LINE TRANS.	D-12A	434	434	0	434	300	132	2	0	6	126
25	-UG LINE TRANS.	D-12A	855	855	0	855	590	260	4	1	12	248
	SERVICES											
26	-O.H. SERVICES	C-08A	839	839	0	839	723	116	0	0	0	116
27	-U.G. SERVICES	C-09A	2127	2127	0	2127	1919	208	0	0	4	204
28	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
29	METERS-ALLOCABLE	C-03	10575	10430	145	10430	8394	2036	0	0	25	2011
30	DUSK TO DAWN	CS-13	222	222	0	222	0	0	0	222	0	0
31	STREET LIGHTING	CS-12	3724	3724	0	3724	0	0	3724	0	0	0
32	RENTS	CS-03	3517	2771	746	2771	1532	1215	19	5	248	967
33	TOTAL DISTRIBUTION		64906	64001	905	64001	38409	21228	4056	308	3329	17899
34	CUSTOMER ACCOUNTS	C-04	32934	32867	67	32867	28888	3590	25	364	2	3588
35	CUST SERV & INFO	C-04A	526	526	0	526	462	57	0	6	0	57
35	CUST SERV & INFO	C-04A	0	0	0	0	0	0	0	0	0	0
36	SALES	C-04	14972	14941	31	14941	13133	1632	11	165	1	1631
37	REGULATORY ASSETS	D-01	0	0	0	0	0	0	0	0	0	0
38	SYSTEM BENEFITS	E-01	0	0	0	0	0	0	0	0	0	0
39	SYSTEM BENEFITS	E-01A	7000	7000	0	7000	2784	4179	29	8	1204	2975
40	TOTAL DEMAND		203982	194113	9869	194113	96325	97358	342	89	20999	76359
41	TOTAL ENERGY		343259	319346	23913	319346	127697	189927	1344	378	54009	135918
42	TOTAL CUSTOMER		69436	68447	989	68447	55050	8855	3780	762	281	8574
43	TOTAL (EX SCE)		616677	581906	34771	581906	279072	296139	5466	1228	75288	220851
44	500 KV SCE	S-10	404	0	404	0	0	0	0	0	0	0
45	TOTAL COMPANY		617081	581906	35175	581906	279072	296139	5466	1228	75288	220851

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LINE No.	ADMIN & GENERAL EXPENSE		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION ******											
1	DEMAND	D-01	11327	10680	647	10680	5048	5632	0	0	1248	4383
2	ANC.-REGULATION	D-01	826	779	47	779	368	411	0	0	91	320
3	ANC.-SPINNING RES.	D-01	934	881	53	881	416	464	0	0	103	361
4	ANC.-READY RES.	D-01	134	126	8	126	60	67	0	0	15	52
5	ENERGY	E-01	12894	11996	898	11996	4797	7134	50	14	2029	5106
6	ENERGY-REGULATION	E-01	327	304	23	304	122	181	1	0	51	129
7	TOTAL PRODUCTION		26442	24765	1677	24765	10810	13889	52	15	3537	10351
	TRANSMISSION ******											
8	SUBSTATION	D-02	552	480	72	480	227	253	0	0	56	197
9	SUBTOTAL SUBST		552	480	72	480	227	253	0	0	56	197
10	LINES	D-02	4538	3947	591	3947	1866	2081	0	0	461	1620
11	SUBTOTAL LINES		4538	3947	591	3947	1866	2081	0	0	461	1620
12	TOTAL TRANSMISSION		5090	4427	663	4427	2093	2335	0	0	518	1817
	DISTRIBUTION *****											
13	SUBSTATION	D-07	717	695	22	695	384	305	5	1	62	243
	O.H. LINES											
14	-OH PRIMARY	D-09	3673	3585	88	3585	2042	1511	26	7	236	1275
15	-OH SECONDARY	D-11	1066	1066	0	1066	910	145	9	2	0	145
	U.G. LINES											
16	-UG PRIMARY	D-14	4375	4338	37	4338	2501	1798	31	8	283	1514
17	-UG SECONDARY	D-17A	225	225	0	225	196	27	2	0	0	27
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	321	312	9	312	216	95	1	0	5	91
19	-UG LINE TRANS.	D-12	633	616	17	616	425	187	3	1	9	178
	SERVICES											
20	-O.H. SERVICES	C-08	330	327	3	327	282	45	0	0	0	45
21	-U.G. SERVICES	C-09	843	840	3	840	758	82	0	0	2	81
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	6609	6519	90	6519	5246	1273	0	0	16	1257
24	DUSK TO DAWN	CS-13	96	96	0	96	0	0	0	96	0	0
25	STREET LIGHTING	CS-12	768	768	0	768	0	0	768	0	0	0
26	TOTAL DISTRIBUTION		19656	19387	269	19387	12958	5468	845	116	612	4855
27	CUSTOMER ACCOUNTS	C-04	13537	13509	28	13509	11874	1476	10	149	1	1475
28	CUST SERV & INFO	C-04A	2892	2892	0	2892	2542	316	2	32	0	316
29	SALES	C-04	3998	3990	8	3990	3507	436	3	44	0	436
30	REGULATORY ASSETS	E-01	0	0	0	0	0	0	0	0	0	0
31	SYSTEM BENEFITS	D-01	0	0	0	0	0	0	0	0	0	0
32	TOTAL DEMAND		29321	27730	1591	27730	14658	12976	77	20	2570	10406
33	TOTAL ENERGY		13221	12300	921	12300	4918	7315	52	15	2080	5235
34	TOTAL CUSTOMER		29073	28940	133	28940	24208	3627	784	322	19	3608
35	TOTAL (EX SCE)		71615	68971	2644	68971	43784	23918	913	356	4669	19249
36	500 KV SCE	S-10	29	0	29	0	0	0	0	0	0	0
37	TOTAL COMPANY		71644	68971	2673	68971	43784	23918	913	356	4669	19249

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LINE No.	DEPREC & AMORIT EXPENSE		ELECTRIC TOTAL	ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
			<----------	GJ	---------->	:----------	----------	GE-1	---------->	---------->	<---------- GE	---------->
====	PRODUCTION ******											
1	DEMAND	D-01	110144	103848	6296	103848	49086	54762	0	0	12140	42622
2	ANC.-REGULATION	D-01	840	792	48	792	374	418	0	0	93	325
3	ANC.-SPINNING RES.	D-01	1071	1010	61	1010	477	532	0	0	118	414
4	ANC.-READY RES.	D-01	272	256	16	256	121	135	0	0	30	105
5	SPEC AFUDC	DS-09	3553	3414	139	3414	1614	1800	0	0	399	1401
6	ENERGY	E-01	1363	1268	95	1268	507	754	5	1	214	540
7	ENERGY-REGULATION	E-01	26	24	2	24	10	14	0	0	4	10
8	TOTAL PRODUCTION		117269	110613	6656	110613	52190	58416	5	2	12998	45418
	TRANSMISSION ******											
9	SUBSTATION	D-02	4733	4117	616	4117	1946	2171	0	0	481	1690
10	-SPEC ACC	D-01A	0	0	0	0	0	0	0	0	0	0
11	SUBTOTAL SUBSTAT		4733	4117	616	4117	1946	2171	0	0	481	1690
12	LINES	D-02	9256	8051	1205	8051	3805	4245	0	0	941	3304
13	-SPEC ACC	DS-03	0	0	0	0	0	0	0	0	0	0
14	-SPEC AFUDC	D-01A	73	73	0	73	35	38	0	0	9	30
15	SUBTOTAL LINES		9329	8124	1205	8124	3840	4284	0	0	950	3334
16	TOTAL TRANSMISSION		14062	12240	1822	12240	5786	6455	0	0	1431	5024
	DISTRIBUTION *****											
17	SUBSTATION	D-07	4934	4784	150	4784	2644	2098	33	9	428	1670
	O.H. LINES											
17	-OH PRIMARY	D-09	13587	13262	325	13262	7552	5590	95	25	872	4718
18	-OH SECONDARY	D-11	3943	3942	1	3942	3364	535	35	9	0	535
	U.G. LINES											
19	-UG PRIMARY	D-14	22602	22412	190	22412	12920	9287	163	42	1464	7823
20	-UG SECONDARY	D-17A	1159	1159	0	1159	1009	138	9	2	0	138
	LINE TRANSFORMER											
21	-OH LINE TRANS.	D-12	4114	4004	110	4004	2764	1218	17	4	58	1160
22	-UG LINE TRANS.	D-12	8101	7885	216	7885	5443	2399	34	9	115	2284
	SERVICES											
23	-O.H. SERVICES	C-08	1232	1221	11	1221	1052	169	0	0	0	169
24	-U.G. SERVICES	C-09	4367	4350	17	4350	3924	426	0	0	9	417
25	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
26	METERS-ALLOCABLE	C-03	5794	5715	79	5715	4599	1116	0	0	14	1102
27	DUSK TO DAWN	CS-13	423	423	0	423	0	0	0	423	0	0
28	STREET LIGHTING	CS-12	2031	2031	0	2031	0	0	2031	0	0	0
			0	0	0	0	0	0	0	0	0	0
29	TOTAL DISTRIBUTION		72287	71189	1098	71189	45273	22976	2417	523	2960	20016
30	CUSTOMER ACCOUNTS	C-04	3955	3947	8	3947	3469	431	3	44	0	431
31	CUST SERV & INFO	C-04A	109	109	0	109	96	12	0	1	0	12
32	SALES	C-04	238	238	0	238	209	26	0	3	0	26
33	TOTAL DEMAND		188382	179010	9372	179010	93156	85368	386	100	17148	68220
34	TOTAL ENERGY		1389	1292	97	1292	517	769	5	2	219	550
35	TOTAL CUSTOMER		18149	18033	116	18033	13349	2179	2034	470	23	2156
36	TOTAL (EX SCE)		207920	198335	9585	198335	107022	88316	2426	572	17389	70927
37	500 KV SCE	S-10	1404	0	1404	0	0	0	0	0	0	0
38	TOTAL COMPANY		209324	198335	10989	198335	107022	88316	2426	572	17389	70927

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
4 CP Allocation
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LINE No.	AD VALOREM & OTHER TAXES		ELECTRIC TOTAL	GJ ACC JURISD.	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GE-1 GENERAL SERVICE	STREET LIGHTING	DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	48881	46087	2794	46087	21784	24303	0	0	5387	18915
2	ANC.-REGULATION	D-01	1434	1352	82	1352	639	713	0	0	158	555
3	ANC.-SPINNING RES.	D-01	1824	1720	104	1720	813	907	0	0	201	706
4	ANC.-READY RES.	D-01	460	434	26	434	205	229	0	0	51	178
5	ENERGY	E-01	2729	2539	190	2539	1015	1510	11	3	429	1081
6	ENERGY-REGULATION	E-01	53	49	4	49	20	29	0	0	8	21
7	TOTAL PRODUCTION		55381	52181	3200	52181	24476	27691	11	3	6235	21456
	TRANSMISSION ******											
8	SUBSTATION	D-02	4864	4231	633	4231	2000	2231	0	0	495	1736
9	SUBTOTAL SUBSTAT		4864	4231	633	4231	2000	2231	0	0	495	1736
10	LINES	D-02	9735	8467	1268	8467	4002	4465	0	0	990	3475
11	SUBTOTAL LINES		9735	8467	1268	8467	4002	4465	0	0	990	3475
12	TOTAL TRANSMISSION		14599	12698	1901	12698	6002	6696	0	0	1484	5212
	DISTRIBUTION *****											
13	SUBSTATION	D-07	3512	3405	107	3405	1882	1493	24	6	305	1189
	O.H. LINES											
14	-OH PRIMARY	D-09	8982	8767	215	8767	4992	3696	63	16	577	3119
15	-OH SECONDARY	D-11	2606	2606	0	2606	2224	353	23	6	0	353
	U.G. LINES											
16	-UG PRIMARY	D-14	15006	14880	126	14880	8578	6166	108	28	972	5194
17	-UG SECONDARY	D-17A	770	770	0	770	671	92	6	2	0	92
	LINE TRANSFORMER											
18	-OH LINE TRANS.	D-12	2740	2667	73	2667	1841	811	12	3	39	773
19	-UG LINE TRANS.	D-12	5394	5250	144	5250	3624	1597	23	6	77	1521
	SERVICES											
20	-O.H. SERVICES	C-08	813	806	7	806	694	111	0	0	0	111
21	-U.G. SERVICES	C-09	2889	2878	11	2878	2596	282	0	0	6	276
22	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
23	METERS-ALLOCABLE	C-03	3622	3572	50	3572	2875	697	0	0	9	689
24	DUSK TO DAWN	CS-13	279	279	0	279	0	0	0	279	0	0
25	STREET LIGHTING	CS-12	1329	1329	0	1329	0	0	1329	0	0	0
26			0	0	0	0	0	0	0	0	0	0
27	TOTAL DISTRIBUTION		47942	47209	733	47209	29978	15300	1587	345	1983	13317
28	CUSTOMER ACCOUNTS	C-04	2130	2126	4	2126	1868	232	2	24	0	232
29	CUST SERV & INFO	C-04A	299	299	0	299	263	33	0	3	0	33
30	SALES	C-04	654	653	1	653	574	71	1	7	0	71
31	TOTAL DEMAND		106208	100636	5572	100636	53255	47056	258	66	9250	37806
32	TOTAL ENERGY		2782	2588	194	2588	1035	1539	11	3	438	1102
33	TOTAL CUSTOMER		12015	11941	74	11941	8870	1427	1331	313	15	1412
34	TOTAL (EX SCE)		121005	115165	5840	115165	63160	50022	1600	383	9703	40320
35	500 KV SCE	S-10	680	0	680	0	0	0	0	0	0	0
36	TOTAL COMPANY		121685	115165	6520	115165	63160	50022	1600	383	9703	40320

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
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LINE No.	AMORTIZATION OF GAIN		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
2	ENERGY	E-01	0	0	0	0	0	0	0	0	0	0
3	TOTAL PRODUCTION		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
	TRANSMISSION ******											
4	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
5	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
6	LINES	D-05	0	0	0	0	0	0	0	0	0	0
7	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
8	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
9	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
10	O.H. LINES											
11	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
12	* -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
13	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
14	*LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
15	* O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
16	* U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
17	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
18	* -ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
19	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
20	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0
21	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
22	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
23	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
24	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
25	TOTAL DEMAND		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
26	TOTAL ENERGY		0	0	0	0	0	0	0	0	0	0
27	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
28	TOTAL (EX SCE)		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760
29	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
30	TOTAL COMPANY		-4548	-4288	-260	-4288	-2027	-2261	0	0	-501	-1760

**** ARIZONA PUBLIC SERVICE *****
COST OF SERVICE STUDY
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LINE No.	REGULATORY ASSET & DECOM. EXPENSE		ELECTRIC TOTAL	GJ ACC JURISD.	GJ ALL OTHER	GJ TOTAL RETAIL	GE-1 RESIDENTIAL	GE-1 GENERAL SERVICE	GE-1 STREET LIGHTING	GE-1 DUSK TO DAWN	GE GEN. SER. (OVER 3MW)	GE GEN. SER. (LESS 3MW)
====	PRODUCTION *******											
1	DEMAND	D-01	0	0	0	0	0	0	0	0	0	0
2	ACC SPEC-DEMAND	D-01A	0	0	0	0	0	0	0	0	0	0
3	TOTAL PRODUCTION		0	0	0	0	0	0	0	0	0	0
	TRANSMISSION ******											
4	SUBSTATION	D-02	0	0	0	0	0	0	0	0	0	0
5	SUBTOTAL SUBSTAT		0	0	0	0	0	0	0	0	0	0
6	LINES	D-05	0	0	0	0	0	0	0	0	0	0
7	SUBTOTAL LINES		0	0	0	0	0	0	0	0	0	0
8	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
	DISTRIBUTION *****											
9	SUBSTATION	D-07	0	0	0	0	0	0	0	0	0	0
10	O.H. LINES											
11	-PRIMARY	D-09	0	0	0	0	0	0	0	0	0	0
12	* -SECONDARY	D-11	0	0	0	0	0	0	0	0	0	0
13	U.G. LINES	D-14	0	0	0	0	0	0	0	0	0	0
14	*LINE TRANSFORMER	D-12	0	0	0	0	0	0	0	0	0	0
15	* O.H. SERVICES	C-08	0	0	0	0	0	0	0	0	0	0
16	* U.G. SERVICES	C-09	0	0	0	0	0	0	0	0	0	0
17	METERS-SPECIFIC	CS-06	0	0	0	0	0	0	0	0	0	0
18	* -ALLOCABLE	C-03	0	0	0	0	0	0	0	0	0	0
19	DUSK TO DAWN	CS-13	0	0	0	0	0	0	0	0	0	0
20	STREET LIGHTING	CS-12	0	0	0	0	0	0	0	0	0	0
21	TOTAL DISTRIBUTION		0	0	0	0	0	0	0	0	0	0
22	CUSTOMER ACCOUNTS	C-04	0	0	0	0	0	0	0	0	0	0
23	CUST SERV & INFO	DS-03	0	0	0	0	0	0	0	0	0	0
24	SALES	DS-05	0	0	0	0	0	0	0	0	0	0
25	REGULATORY ASSETS	E-01	36590	34041	2549	34041	13612	20245	143	40	5757	14488
26	REGULATORY ASSETS	D-01A	35271	35271	0	35271	16672	18599	0	0	4123	14476
27	REGULATORY ASSETS	E-01	2076	1931	145	1931	772	1149	8	2	327	822
28	REGULATORY ASSETS	D-01A	19994	19994	0	19994	9451	10543	0	0	2337	8206
29	REGULATORY ASSETS	E-01	9678	9004	674	9004	3600	5355	38	11	1523	3832
30	REGULATORY ASSETS	D-01	9388	8851	537	8851	4184	4668	0	0	1035	3633
31	REGULATORY ASSETS	D-01	49493	46664	2829	46664	22057	24607	0	0	5455	19152
32	REGULATORY ASSETS	D-01	4847	4570	277	4570	2160	2410	0	0	534	1876
33	REGULATORY ASSETS	D-01A	-500	-500	0	-500	-236	-264	0	0	-58	-205
34	SYSTEM BENEFITS	E-01	11443	10618	825	10618	4222	6338	44	12	1826	4512
35	TOTAL DEMAND		129936	125468	4468	125468	58509	66902	44	12	15252	51650
36	TOTAL ENERGY		48344	44976	3368	44976	17985	26749	189	53	7606	19142
37	TOTAL CUSTOMER		0	0	0	0	0	0	0	0	0	0
38	TOTAL (EX SCE)		178280	170444	7836	170444	76494	93651	234	66	22859	70792
39	500 KV SCE	S-10	0	0	0	0	0	0	0	0	0	0
40	TOTAL COMPANY		178280	170444	7836	170444	76494	93651	234	66	22859	70792

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Expenses
Total Company
Test Year Twelve Months Ended 12/31/96

(Dollars inThousands)

Line No.	Description	(a) EEASE Fund, DSM & Renewables	(b) Accelerated Amortization Reg. Assets [6 Months]	(c) Miscellaneous Adjustments	(d) 1998 Expense Adjustment	(e) Regulatory & Franchise Assessments
1.	Operating Expenses:					
2.	Fuel Expenses					
3.	Operations & Maint. Exc. Fuel Expense	$ 1,136			16,503	(24,969)
4.	Depreciation and Amortization		57,391			
5.	Amortization of Gain					
6.	Administrative and General			(7,626)	(28,282)	
7.	Other Taxes				582	
8.	Total	1,136	57,391	(7,626)	(11,197)	(24,969)

(a) DSM & renewable adjustment from 1996 settlement
(b) Accelerated amortization of regulatory assets from 1996 settlement
(c) Pinnacle West charges, net of costs for shareholders services
(d) Adjustment to reflect 1998 expenses
(e) Adjustment to exclude regulatory and franchise assesments from both operating revenue and operating expense accounts to allow calculation of "base" operating revenue deficiency

Line No.	Description	(f) SRP T&C Adjustment	(g) Fuel Adjustment	(h) Normal Amortization Regulatory Assets	(i) Total Pro Forma Adjustment
1.	Operating Expenses:				
2.	Fuel Expenses		(8,404)	(2,413)	$ (10,817)
3.	Operations & Maint. Exc. Fuel Expense	(16,700)		(604)	$ (24,634)
4.	Depreciation and Amortization			33,004	$ 90,395
5.	Amortization of Gain			-	$ -
6.	Administrative and General			-	$ (35,908)
7.	Other Taxes			-	$ 582
8.	Total	(16,700)	0	32,400	$ 30,435

(f) Adjustment to reflect reduction in demand charges for SRP T&C purchases
(g) Adjustment to reflect 1998 generation fuel costs
(h) Reclassification of normal amortization associated with regulatory assets

ARIZONA PUBLIC SERVICE COMPANY
Pro Forma Adjustments to Original Cost Rate Base
Total Company
Test Year Twelve Months Ended 12/31/96

(Dollars in Thousands)

Line No.	Description	1998 Rate Base Adjustment Total Co.
1.	Production, Transmission, & Distribution Plant In Service	$ 370,610
2.	General and Intangible Plant	105,852
3.	Reserve for Depreciation and Amortization	343,483
4.	** NET PLANT** (Line 1 + Line 2 less Line 3)	132,979
5.	Regulatory Assets & Decommissioning	
6.	Gain from Plant	
7.	Materials & Supplies	
	Less:	
8.	Customer Advances	
9.	Customer Deposits	
10.	Working Cash/Prepayments	
11.	Accumulated Deferred Income Taxes	-41,977
12.	Pro Forma Adjustment to Rate Base	$ 174,956

SCHEDULE AP-3

1996 SETTLEMENT RATE REDUCTION

FILED MAY 21, 1999

APS
Commitment. Innovation. Energy.

Barbara A. Klemstine
Manager
Regulatory Affairs

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May 21, 1999

Mr. Ray Williamson
Acting Director, Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Re: Docket No. E-01345-95-491 (U-1345-95-491)
Arizona Public Service Company
Reduction in Retail Rates Pursuant to Paragraph 15.B of the
Second Restated and Amended Rate Reduction Agreement

Dear Mr. Williamson:

Pursuant to Decision No. 59601 (April 18, 1996), Arizona Public Service Company ("APS") is filing the annual calculation to determine the reduction to base rates provided for under Paragraph 15.B of the Second Restated and Amended Rate Reduction Agreement ("1996 Agreement"). The 1996 Agreement provided for a $48.5 million decrease in APS' retail rates, effective July 1, 1996 and also established a moratorium period (through July 1, 1999) on rate increases, while providing consumers an opportunity to automatically receive future price reductions based on the Company's ability to continue to lower its average cost.

Future rate reductions through the term of the 1996 Agreement were to be based on a comparison of the Company's average price per kilowatt-hour and its average cost per kilowatt-hour resulting from operations for the proceeding calendar year as defined in Attachment 3 of the 1996 Agreement. Any reduction for the current year would become effective for usage on or after July 1, if approved by the Commission. Under this provision, APS has decreased retail rates on July 1, 1997 by $17.6, and by an additional $16.9 million effective July 1, 1998.

Based upon the Company's 1998 financial performance, as adjusted pursuant to Attachment 3 from the 1996 Agreement and calculated pursuant to Exhibit No. 1 attached to Decision No. 60225, APS is able to further reduce rates through the rate incentive mechanism established in the 1996 Agreement. More specifically, the Company proposes to reduce annual retail rates by approximately $10.8 million, or .68%, effective July 1, 1999.

APS

Arizona Public Service Company

COMPANY CORRESPONDENCE

The Company is requesting that this reduction be considered by the Commission for approval in conjunction with the 1999 Settlement Agreement, dated May 17, 1999. The 1999 Settlement Agreement (Article II, Section 2.2) provides for a 1.5% rate reduction, effective July 1, 1999, which is inclusive of the .68% reduction. The reduction will be applied with a uniform percent to customer's demand and energy charges, except as provided for in Attachment 2 of the 1996 Agreement.

Attached are: (1) a calculation of the proposed reduction in retail rates, (2) a copy of Attachment 3 from the 1996 Agreement, (3) a copy of Exhibit #1, Decision 60225, (4) a worksheet of adjustments to comply with the definitions from Attachment 3, (5) a worksheet that applies the reduction to eligible customers, and (6) a comparison of present and proposed rates.

Please call me at (602)250-2031 if you or your Staff have any questions.

Sincerely,

Barbara A. Klemstine

Barbara A. Klemstine
Manager
Regulatory Affairs

BAK/pb

Enclosures

Cc: Lori Hoover (w/o enclosures)
All Parities of Record- Docket No. U-1345-95-491
Docket Control

Arizona Public Service Company
Reduction in Retail Rates
Rate Reduction Agreement (Decision No. 59601 ¶15.B,Decision No. 60225 Exh. #1)
(000s)

1) Total Company Property Tax Expense

1997	$107,060
1998	($101,761)
Decrease in Property Taxes	$5,299

¢/kWh Reduction in Property Taxes

1.1) Decrease in Total Company Property Taxes / Annual Total Company mWh Sales = $5,299 / 21,873,475 = 0.0242 ¢/kWh

2) Comparison of Unit Price Ratio ("UPR") and Unit Cost Ratio ("UCR")

2.1) UPR Annual Total Company Electric Revenues / Annual Total Company mWh Sales = $1,744,983 / 21,873,475 = 7.9776 ¢/kWh

2.2) UCR Annual Total Company Electric Costs / Annual Total Company mWh Sales = $1,728,343 / 21,873,475 = 7.9015 ¢/kWh

2.3) Excess of UPR over UCR = 0.0761 ¢/kWh

3) Excess of UPR over UCR Not Due to Property Taxes

3.1) Excess of UPR over UCR (Line 2.3) less ¢/kWh Reduction in Property Taxes (Line 1.1) = 0.0519 ¢/kWh

3.2) Consumers' 55% Share (Line 3.1 x 55%) = 0.0285 ¢/kWh

4) Retail Rate Reduction

4.1)	100% of ACC Property Tax Expense Reductions	0.0242 ¢/kWh
4.2)	Consumers' 55% Share	0.0285 ¢/kWh
4.3)	Total ¢/kWh Reduction	0.0527 ¢/kWh
4.4)	Retail Sales	x 20,463,083 mWh
4.5)	Total Retail Rate Reduction	$10,784

5) Annual Retail Revenues Less Contracts Not Subject to Decrease $1,590,560

6) Percentage Decrease in Retail Rates Subject to Decrease 0.68%

Attachment 3

Unit Cost Ratio and Unit Price Ratio Definitions
(The revenues and costs to be utilized in this calculation well be derived from the actual audited financial statements of the Company)

Unit Cost Ratio (UCR): Annual cents-per-kilowatt-hour average cost of electric services.

$$UCR = \frac{\text{Annual Total Electric Costs}^{1/}}{\text{Annual Total Company kWh Sales}^{2/}}$$

Unit Price Ratio (UPR): Annual cent-per-kilowatt hour average price of electric services.

$$UPR = \frac{\text{Annual Electric Revenues}^{3/}}{\text{Annual Total Company kWh Sales}^{2/}}$$

1/ **Excludes** sales taxes (as in the case of the income statement), all ITC amortization (as required by federal tax laws), annual Pinnacle West charges net of costs for shareholder services, fuel expenses for non-traditional and interchange sales (generally defined as opportunity sales which are cost justified on an incremental basis), and non-utility income or deductions and related income tax effects.
Includes fuel, operations and maintenance, depreciation and amortization (including the accelerated amortization of regulatory assets), property and other taxes, cost of capital (consisting of long-term interest, debt discount, premium and expense, preferred stock dividend requirements, and a return on equity of 11.25% applied to the average annual equity balance), the gross profit margin on non-traditional and interchange sales, DSM and renewable expenditures (including net lost revenues and incentives), and income taxes on Operating Income including adjustments to income taxes for the above exclusions and inclusions.

2/ **Excludes** kwh sales for non-traditional and interchange sales.

3/ **Includes** miscellaneous revenues. **Excludes** sales taxes (as in the case of the income statement) and non-traditional and interchange revenues.

Exhibit N

Arizona Public Service Company
Reduction in Retail Rates
Rate Reduction Agreement (Decision No. 59601 ¶15.B)
(000s)

1) **Total Company Property Tax Expense**

1995	$127,773
1996	($104,900)
7/1/96 Reduction	($4,600)
Decrease in Property Taxes	$18,273

¢/kWh Reduction in Property Taxes = Decrease in Total Company Property Taxes / Annual Total Company mWh Sales = $18,273 / 20,510,966 = 0.0891 ¢/kWh

2) **Comparison of Unit Price Ratio ("UPR") and Unit Cost Ratio ("UCR")**

2.1) UPR = Annual Total Company Electric Revenues / Annual Total Company mWh Sales = $1,683,822 / 20,510,966 = 8.209 ¢/kWh

2.2) UCR = Annual Total Company Electric Costs / Annual Total Company mWh Sales = $1,664,325 / 20,510,966 = 8.114 ¢/kWh

2.3) Excess of UPR over UCR = 0.095 ¢/kWh

3) **Excess of UPR over UCR Not Due to Property Taxes = (.095 - .0891) ¢/kWh = .006 ¢/kWh**

3.1) Consumers' 55% Share (0.006 ¢/kWh * .55%) = .0033 ¢/kWh

4) **Retail Rate Reduction**

4.1) 100% of ACC Property Tax Expense Reductions	0.0891 ¢/kWh
4.2) Consumers' 55% Share	0.0033 ¢/kWh
4.3) Total ¢/kWh Reduction	0.0924 ¢/kWh
4.4) Retail Sales	x 19,020,696 mWh
4.5) Total Retail Rate Reduction	$17,575

5) **Annual Retail Revenues Less Contracts Not Subject to Decrease** $1,513,379

6) **Percentage Decrease in Retail Rates Subject to Decrease** 1.16%

Arizona Public Serv. Company
Reduction in Retail Rates
Rate Reduction Agreement (Decision No. 59601 ¶15.B, Decision No. 60225 Exh. #1)
Adjustments for Attachment 3
(000s)

	1998 Audited Financials	System Related Opportunity Sales	DSM Net Lost Rev. & financial Incentives	Pinnacle West charges net of costs	Non-utility Income or Deductions (Net of Tax)	Adjustment for 11.25% ROE	Adjusted Total UCR & UPR
		(1)	(2)	(3)	(4)	(5)	(6)
Annual Electric Revenues							
Annual Electric Operation Revenues	$2,006,398	($165,999)			($95,416)		$1,744,983
Annual Total Electric Costs							
Fuel Expenses - Total	$537,501	($165,999)			($85,105)		$286,397
Other Operating Expenses:							
Operations & Maintenance (Ex. fuel expense)	$414,041		$557	($7,250)	($1,854)		$405,494
Depreciation & Amortization	$376,574						$376,574
Income Taxes	$192,207		($224)	$2,916	($3,401)	($10,240)	$181,258
Other Taxes	$115,264						$115,264
Total Other Operating Expenses	$1,098,086	$0	$333	($4,334)	($5,255)	($10,240)	$1,078,590
Cost of Capital:							
Interest on Long-Term Debt	$137,214						$137,214
Debt Discount, Premium & Expense	$7,580						$7,580
Preferred Stock Dividend Requirements	$9,703						$9,703
Earnings	$245,544		($333)	$4,334	($25,504)	($15,182)	$208,859
Total Cost of Capital	$400,041	$0	($333)	$4,334	($25,504)	($15,182)	$363,356
Annual Total Electric Costs	$2,035,628	($165,999)	$0	$0	($115,864)	($25,422)	$1,728,343

(1) System related opportunity sales revenue ($166.0M) and Fuel Expenses ($151.2M) are excluded. The benefit of the gross profit margin on the System Related Opportunity sales revenue ($14.8M) is reducing Fuel Expenses, per Attachment 3.

(2) DSM Net Loss Revenues ($0.28M) and Financial Incentives ($0.28M) are included as adjustment with the appropriate tax and earnings effect, per Attachment 3.

(3) Pinnacle West charges, net of costs for shareholders services ($1.8M), are excluded with the appropriate tax and earnings effects, per Attachment 3.

(4) Per Attachment 3, Non-utility Net Income ($5.056M) and Other Income Deductions ($20.448M) are excluded from Earnings Net of Tax. This also reflects the exclusion of ITC Amortization (27.6M), per Attachment 3.

(5) Per Attachment 3, an adjustment is applied to allow for only a 11.25% Return on Equity based on the average annual equity balance. The income tax effect is calculated by dividing the equity adjustment by (1-Tax rate) and then multiplying by the Company's Tax Rate of 40.22%.

Arizona Public Service Company
July 1, 1999 Rate Decrease
Summary of Retail Rate Reductions By Class
($000)

(A)	(B)	(C)				(D)	(E)	(F)
		1998 Actual Revenues						
Retail Class	1998 Actual MWH Sales	Total $ [1]	Reg. Ass. $	Base $	BSC $	Demand & Energy $ [2]	Revenue Reduction By Class $	% Decrease to Apply to Class Demand & Energy Charges[5]
				(3)-(4)-(5)			[0 678% x (C)] [3]	[(E)/(D)]
Residential	8,310,689	766,378	1,487	764,891	83,132	683,246	**5,196**	0.76%
General Service	11,976,827	871,312	1,196	870,116				
Less Contracts not subject to decrease	(1,602,572)	(64,872)	(92)	(64,780)				
Net General Service	10,374,255	806,440	1,104	805,336	14,479	791,961	**5,468**	0.69%
Irrigation	84,640	7,288	10	7,278	135	7,153	**49**	0.69%
Street & Highway Lighting	90,927	10,645	15	10,630				
Less E-67 Muni. Lighting	(5,078)	(191)	-	(191)				
Net Other	85,849	10,454	15	10,439	-	10,454	**71**	0.68%
TOTAL ELIGIBLE FOR DECREASE	18,855,433	1,590,560		1,587,944	97,747	1,492,813	**10,784** [4]	0.678%

[1] Total retail revenues from sales, excluding sales tax.

[2] Revenues associated with demand and energy charges included in Total $.

[3] % Class Reduction = Total Reduction/Total Retail Revenue subject to decrease = $10,784/$1,590,560 = 0 678%

[4] Total Retail Decrease as calculated on page 1.

[5] Pursuant to Rate Reduction Agreement, decrease will be allocated among customers by means of a uniform percent reduction in the demand and energy charges.

h \lrda\7_99 Decrease\H schedules\sharon xls

ARIZONA PUBLIC SERVICE COMPANY
CHANGES TO RATE SCHEDULE PRICES
COMPARISON OF PRESENT AND PROPOSED 7/1/99 RATES
(Under Rate Reduction Agreement Decision No. 59601 and Decision No. 60225)

Rate Schedule	Description	Billing Designation	Season		Current Rates	Percent Change	Proposed Rates	Dollar Change
E-12	Residential Service	Rate	Summer (May-Oct)	Basic Service Charge	$ 7.50 /mo		$ 7.50 /mo	$ - /mo
				First 400 kWh	0.08028 /kWh	0.76%	0.07967 /kWh	(0.00061) /kWh
				Next 400 kWh	0.11191 /kWh	0.76%	0.11106 /kWh	(0.00085) /kWh
				All additional kWh	0.13051 /kWh	0.76%	0.12952 /kWh	(0.00099) /kWh
			Winter (Nov-Apr)	Basic Service Charge	$ 7.50 /mo		$ 7.50 /mo	$ - /mo
				All kWh	0.08047 /kWh	0.76%	0.07986 /kWh	(0.00061) /kWh
ET-1	Residential Service * Time of Use	Rate	Summer (May-Oct)	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /kWh
				All On-Peak kWh	0.13948 /kWh	0.76%	0.13842 /kWh	(0.00106) /kWh
				All Off-Peak kWh	0.04495 /kWh	0.76%	0.04461 /kWh	(0.00034) /kWh
			Winter (Nov-Apr)	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /mo
				All On-Peak kWh	0.11598 /kWh	0.76%	0.11510 /kWh	(0.00088) /kWh
				All Off-Peak kWh	0.04495 /kWh	0.76%	0.04461 /kWh	(0.00034) /kWh
ECT-1R	Residential Service Time of Use with Demand Charge	Rate	Summer (May-Oct)	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /mo
				All On-Peak kW	12.33 /kW	0.76%	12.24 /kW	(0.09371) /kW
				All kWh (demand cap)	0.09864	0.76%	0.09792 /kWh	(0.00072) /kWh
				All On-Peak kWh	0.04976 /kWh	0.76%	0.04938 /kWh	(0.00038) /kWh
				All Off-Peak kWh	0.02767 /kWh	0.76%	0.02746 /kWh	(0.00021) /kWh
			Winter (Nov-Apr)	Basic Service Charge	$ 15.00 /mo		$ 15.00 /mo	$ - /mo
				All On-Peak kW	8.83 /kW	0.76%	8.76 /kW	(0.06712) /kW
				All kWh (demand cap)	0.07064	0.76%	0.07008 /kWh	(0.00056) /kWh
				All On-Peak kWh	0.03938 /kWh	0.76%	0.03908 /kWh	(0.00030) /kWh
				All Off-Peak kWh	0.02767 /kWh	0.76%	0.02746 /kWh	(0.00021) /kWh
E-32	General Service	Rate	Summer (Jun-Oct)	Basic Service Charge	$ 12.50 /mo		$ 12.50 /mo	$ - /mo
				All kW over 5	1.85 /kW	0.69%	1.84 /kW	(0.01276) /kW
				First 2,500 kWh	0.11018 /kWh	0.69%	0.10942 /kWh	(0.00076) /kWh
				Next 100 kWh per kW over 5	0.11018 /kWh	0.69%	0.10942 /kWh	(0.00076) /kWh
				Next 42,000 kWh	0.07550 /kWh	0.69%	0.07498 /kWh	(0.00052) /kWh
				All additional kWh	0.04756 /kWh	0.69%	0.04723 /kWh	(0.00033) /kWh
			Winter (Nov-May)	Basic Service Charge	$ 12.50 /mo		$ 12.50 /mo	$ - /mo
				All kW over 5	1.67 /kW	0.69%	1.66 /kW	(0.01153) /kW
				First 2,500 kWh	0.09925 /kWh	0.69%	0.09857 /kWh	(0.00068) /kWh
				Next 100 kWh per kW over 5	0.09925 /kWh	0.69%	0.09857 /kWh	(0.00068) /kWh
				Next 42,000 kWh	0.06780 /kWh	0.69%	0.06733 /kWh	(0.00047) /kWh
				All additional kWh	0.04252 /kWh	0.69%	0.04223 /kWh	(0.00029) /kWh
		Minimum	Sum & Win	Basic Service Charge	$ 12.50 /mo		$ 12.50 /mo	$ - /mo
				Demand Charge	1.74 /kW	0.69%	1.73 /kW	(0.01201) /kW
E-34	Extra Large General Service	Rate	Sum & Win	Basic Service Charge	$ 2,430.00 /mo		$ 2,430.00 /mo	$ - /mo
				All kW	11.16 /kW	0.69%	11.09 /kW	(0.07704) /kW
				All kWh	0.03288 /kWh	0.69%	0.03265 /kWh	(0.00023) /kWh

ARIZONA PUBLIC SERVICE COMPANY
Fair Value Rate Base and Rate of Return
ACC Jurisdictional
Adjusted Test Year Ended 12/31/96

(Dollars inThousands)

Line No.	Description	Original Cost	RCND	Fair Value
1.	Gross Utlity Plant In Service	$ 6,841,873	$ 10,819,830	
2.	Less: Accumulated Depreciation & Amort.	2,567,454	3,919,356	
3.	Net Utility Plant In Service	4,274,419	6,900,474	
	Deductions:			
4.	Deferred taxes	1,380,236	1,380,236	
5.	Customer Advances for Construction	24,044	24,044	
6.	Customer Deposits	32,137	32,137	
7.	Deferred Gains from Sale of Utility Plant	81,970	81,970	
8.	Working Cash/Prepayments	242,754	242,754	
9.	Total Deductions	1,761,141	1,761,141	
	Additions:			
10.	Regulatory Assets & Decommissioning	1,239,189	1,239,189	
11.	Materials & Supplies	130,180	130,180	
12.	Total Additions	1,369,369	1,369,369	
13.	Total Rate Base	$3,882,647	$6,508,702	
a.	Adjusted Rate Base	$ 3,882,647	$ 6,508,702	$ 5,195,675
b.	Adjusted Operating Income	344,391	344,391	344,391
c.	Required Rate of Return	8.87%	5.29%	6.63%

ARIZONA PUBLIC SERVICE COMPANY
System Benefits Costs in Proposed Tariffs
Adjusted Test Year Twelve Months Ended 12/31/96

(Dollars in Thousands)

Line No.	Description	Total Retail
1.	DSM, Renewables, and Low Income Program	$7,000 /1/
2.	Decommissioning	10,618 /2/
3.	Low Income, E-3 & E-4	3,680 /3/
4.	Functionalized Franchise Fee	542
5.	Total	$21,840
6.	Retail Energy Sales (MWh)	18,957,939
7.	System Benefits Charge - ¢/kWh (Line 5/Line 6)	0.115

/1/ Pursuant to 1996 Settlement.
/2/ 1998 Funding Level.
/3/ Year ended 1996 Actual.

ARIZONA PUBLIC SERVICE COMPANY

Unit Stranded Costs, Competition Transition Charges
And Total Stranded Costs, 1999 - 2004

	1999	2000	2001	2002	2003	2004	Totals
A. Class Unit Stranded Costs (¢/kWh)							
1. Residential	0.93	0.84	0.63	0.56	0.50	0.36	
2. <3MW	0.75	0.68	0.52	0.45	0.40	0.29	
3. >3MW	0.54	0.49	0.37	0.33	0.29	0.21	
4. Retail Average	0.67	0.61	0.54	0.48	0.43	0.31	
B. Class CTCs							
5. Residential, DA-R1 (¢/kWh)	0.93	0.84	0.63	0.56	0.50	0.36	
6. < 3 MW, DA-GS1 ($/kW/month)	2.43	2.20	1.66	1.46	1.30	0.94	
7. > 3 MW, DA-GS10 ($/kW/month)	2.82	2.55	1.89	1.72	1.51	1.09	
C. Direct Access Sales (MWh)							
8. Residential	149,835	334,829	9,278,962	9,638,006	10,007,458	10,378,922	39,788,012
9. <3MW	2,877,404	2,916,067	9,692,577	9,994,069	10,348,341	10,706,288	46,534,746
10. >3MW	2,387,620	2,455,855	3,644,756	3,644,756	3,644,756	3,644,756	19,422,499
11. Total DA	5,414,859	5,706,751	22,616,295	23,276,831	24,000,555	24,729,966	105,745,257
D. Direct Access Strandable Cost ($000) [A x C]							
12. Residential	1,393	2,813	58,457	53,973	50,037	37,364	204,038
13. <3MW	21,581	19,829	50,401	44,973	41,393	31,048	209,226
14. >3MW	12,893	12,034	13,486	12,028	10,570	7,654	68,664
15. Total -- Nominal Dollars	35,867	34,676	122,344	110,974	102,000	76,066	481,928
16. Total -- Net Present Value @ 1/1/99	32,966	29,293	94,994	79,196	66,905	45,858	349,213

ARIZONA PUBLIC SERVICE COMPANY

Direct Access Residential Rate DA-R1
Derivation of Distribution Prices
9/1/98 Rate Level

	Billing Element	(a) Bundled Rate	(b) System Benefits	(c) Energy Prices Less S/B (a) - (b)	(d) Distribution Only (c) x L5	(e) Regulatory Assets (c) x L5	(f) 1999 Tariff Distribution Prices (d) + (e)
	Summer						
1.	BDC	$ 10.00					$ 10.00
2.	All kWh	$ 0.08733	$0.00115	$ 0.08618	$0.02840	$0.01318	0.04158
	Winter						
3.	BDC	$ 10.00					$ 10.00
4.	All kWh	$ 0.07407	$0.00115	$ 0.07292	$0.02403	$0.01115	0.03518
5.	Percent of TY Rev. Req.				32.95%	15.29%	

ARIZONA PUBLIC SERVICE COMPANY

Direct Access General Service Rate DA-GS1 (0 to 2,999 kW)
Derivation of Distribution Prices
9/1/98 Rate Level

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Billing Element	Standard Offer	System Benefits	Energy Prices Less S/B (a) - (b)	Distribution Only (c) x L13	Distribution Only @ Sec. Voltage (d) x 102%	Regulatory Assets (c) x L13	Adjusted Regulatory Assets (f) x 104%	1999 Tariff Distribution Prices (e) + (g)
Summer								
1. BDC	$ 12.50							$ 12.50
2. kW per month	$ 1.850			$ 0.372	0.379	$ 0.329	$ 0.342	$ 0.721
3. First 2,500	$ 0.11018	$0.00115	$ 0.10903	$ 0.02194	0.02238	$ 0.01939	$ 0.02017	$ 0.04255
4. Next 100kWh/kW Over 5 kW	$ 0.11018	$0.00115	$ 0.10903	$ 0.02194	0.02238	$ 0.01939	$ 0.02017	$ 0.04255
5. Next 42,000 kWh	$ 0.07550	$0.00115	$ 0.07435	$ 0.01496	0.01526	$ 0.01322	$ 0.01375	$ 0.02901
6. All Additional kWh	$ 0.04756	$0.00115	$ 0.04641	$ 0.00934	0.00953	$ 0.00825	$ 0.00858	$ 0.01811
Winter								
7. BDC	$ 12.50							$ 12.50
8. kW per month	$ 1.670			$ 0.336	0.343	$ 0.297	$ 0.309	$ 0.652
9. First 2,500 kWh	$ 0.09925	$0.00115	$ 0.09810	$ 0.01974	0.02013	$ 0.01744	$ 0.01814	$ 0.03827
10. Next 100kWh/kW Over 5 kW	$ 0.09925	$0.00115	$ 0.09810	$ 0.01974	0.02013	$ 0.01744	$ 0.01814	$ 0.03827
11. Next 42,000 kWh	$ 0.06780	$0.00115	$ 0.06665	$ 0.01341	0.01368	$ 0.01185	$ 0.01232	$ 0.02600
12. All Additional kWh	$ 0.04252	$0.00115	$ 0.04137	$ 0.00832	0.00849	$ 0.00736	$ 0.00765	$ 0.01614
13. Percent of TY Rev. Req.				20.12%		17.78%		

ARIZONA PUBLIC SERVICE COMPANY

Direct Access General Service Rate DA-GS10 (3,000 kW or Greater)
Derivation of Distribution Prices
9/1/98 Rate Level

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Billing Element	Standard Offer	System Benefits	Energy Prices Less S/B (a) - (b)	Distribution Only (c) x L4	Distribution Only @ Sec. Voltage (d) x 108%	Regulatory Assets (c) x L4	Adjusted Regulatory Assets (f) x 104%	1999 Tariff Distribution Prices (e) + (g)
1. BDC	$ 2,430.00							$ 2,430.00
2. kW per month	$ 11.160			$ 1.20	1.30	$ 2.14	$ 2.23	$ 3.53
3. All kWh	$ 0.03288	$0.00115	$ 0.03173	$ 0.00340	0.00367	$ 0.00608	$ 0.00632	$ 0.00999
4. Percent of TY Rev. Req.				10.71%		19.18%		

ARIZONA PUBLIC SERVICE COMPANY

Revenue Requirements for Direct Access Services by Rate Class
Pro Forma Cost of Service Study
Test Year Ended 12/31/96
(Dollars in Thousands)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Production	Transmission	Distribution	BDC	Distribution Ex. BDC	Regulatory Assets	System Benefits	Totals Totals - (d) - (g)
Residential								
1. Revenue Requirement	$336,678	$31,649	$258,139	$79,498	$234,492	$108,790	$8,669	$799,776
2. Percent of (Total - BSC - S/B)	47.31%	4.45%	36.28%	11.17%	32.95%	15.29%	1.22%	$711,609 100.00%
General Service (0 - 2,999 kW)								
3. Revenue Requirement	$317,041	$27,481	$113,312	$12,341	$111,635	$98,641	$9,256	$576,395
4. Percent of (Total - BSC - S/B)	57.15%	4.95%	20.42%	2.22%	20.12%	17.78%	1.67%	$554,798 100.00%
GeneralService (3,000 kW +)								
5. Revenue Requirement	$105,031	$7,827	$18,628	$1,487	$17,242	$30,869	$3,750	$166,206
6. Percent of (Total - BSC - S/B)	65.25%	4.86%	11.57%	0.92%	10.71%	19.18%	2.33%	$160,969 100.00%

ARIZONA PUBLIC SERVICE COMPANY

Direct Access Rates

1. DA-R1, Residential Service
2. DA-GS1, General Service
3. DA-GS10, Extra Large General Service
4. DA-GS11, Ralston Purina
5. DA-GS12, BHP Copper
6. DA-GS13, Cyprus Bagdad

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

(CONTINUED ON REVERSE SIDE)

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.

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

(CONTINUED ON REVERSE SIDE)

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.

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.

(CONTINUED ON REVERSE SIDE)

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. T he 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.

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.

(CONTINUED ON REVERSE SIDE)

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. T he 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.

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.

(CONTINUED ON REVERSE SIDE)

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. T he 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.

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.

(CONTINUED ON REVERSE SIDE)

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. T he 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

Summary of Direct Access Monthly Rate Credits

Competitively Supplied Service	(a) Residential DA-R1	(b) General Service Under 3 mW DA-GS1	(c) General Service Over 3 mW DA-GS10
1. Metering	$1.30	$4.00	$55.00
2. Meter Reading	$0.30	$0.30	$0.30
3. Billing	$0.30	$0.30	$0.30

Alan Propper
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June 28, 1999

Mr. Douglas C. Nelson, Esq.
7000 North 16th Street, Ste. 120
PMB 307
Phoenix, Arizona 85020

RE: COMMONWEALTH ENERGY CORPORATION'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY PROPOSED SETTLEMENT AGREEMENT, ACC DOCKETS E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165

Dear Mr. Nelson:

Enclosed is Arizona Public Service Company's ("APS") response to Commonwealth's first data request of June 25, 1999.

Sincerely,

Alan Propper
Director
Pricing and Regulation

AP/srm

Enclosure

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
SETTLEMENT AGREEMENT DATED MAY 14, 1999
FIRST SET OF DISCOVERY REQUESTS

APS DISCOVERY REQUESTS

QUESTION 1: Standard Offer

a. Please provide any study conducted on the "five rate reductions" referred to in the Settlement.

b. Please provide any study prepared on projected savings to customers resulting from retail electric competition in the APS service area.

c. Please furnish any study and provide an explanation as to how many customers (by customer classes) are presumed to purchase competitive electric services in preparing your assessment that Standard Offer customers would receive a $475 million rate reduction by 2004. (JED at 3).

d. Explain what assumptions were used in breaking down APS's Plant in Service or Operating Maintenance Expenses into Production, Transmission or Distribution functions. (AP at 4).

e. Describe the assumptions used in classifying the Production, Transmission and Distribution functions into Demand, Energy and Customer categories. (AP at 4).

f. Explain what allocation assumptions and factors were used in separating those Demand, Energy and Customer categories among customer classes and between the Standard Offer bundled tariffs and the direct access tariffs. (AP at 4).

g. What criteria were used in allocating APS's general and administrative costs (a) among Production, Transmission or Distribution, (b) among Demand, Energy and Customer, and (c) between the Standard Offer and direct access tariffs. (AP at 4).

h. Please provide the 1996 test year cost-of-service study and any cost study using a test year more recent than 1996. (AP at 5).

i. Please explain which generation units were declared to be Must Run units and the Must Run costs that were imputed within the Standard Offer tariffs, and in setting the direct access tariffs. Please explain how these Must Run charges reduced the potential stranded costs. (AP at 7-8).

RESPONSE:

a. The Company has not prepared a "study" on the "five rate reductions".

b. The Company has projected savings of $475 million associated with its proposed standard offer rate reductions (Attachment Q.1.b.). The Company is unable to project savings to customers choosing direct access service without knowing the prices ESP's intend to charge customers.

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
SETTLEMENT AGREEMENT DATED MAY 14, 1999
FIRST SET OF DISCOVERY REQUESTS

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c. The computation of the $475 million rate reduction by 2004 was calculated using APS' customer forecast assuming no Standard Offer customers would choose to purchase competitive electric services. Presumably when customers select direct access then they would receive even greater bill reductions than standard offer.

d. As discussed in Mr. Alan Propper's Direct Testimony on pages 3 through 4, APS performed a cost of service study in order to develop apportionment factors which were then applied to a blended residential rate and rates E-32 and E-34 in order to develop direct access rates. The cost of service was not used in the traditional sense in developing APS' proposed direct access rates.

Functionalization refers to the disaggregation of the categories of rate base and expense into the major functions of Production, Transmission, and Distribution, as well as various sub-functions and minor functions. The purpose of functionalization is to identify and quantify items of rate base and expense that are associated with each function. In a class cost allocation study, functionalization also serves the purpose of isolating items of cost that are to be allocated to the classes in a specific manner. Functionalization has been accomplished in this study using two general procedures. The first was through the use of accounting records such as for Plant in Service. The second was by using known functional relationships, such as for Wages and Salaries, to functionalize a portion of another category such as Administrative and General Expense. Very often a combination of these procedures was used.

Classification refers to identifying each functionalized cost item as being Demand, Energy, or Customer related. Demand related items are almost always associated with fixed costs and the rate at which energy is consumed. Energy related items are generally associated with variable costs and the total amount of energy consumed. Customer related items are associated with a portion of fixed costs at the distribution level, as well as for customer related services, and are related to the number and type of customers on the system. The purpose of classification is to accumulate the fixed and variable components of cost, so that unit costs can be developed based on energy usage, demand requirements, and delivery point configurations, and so that cost based rate designs can be established. In a class cost allocation study, classification also serves the purpose of isolating items for which a particular factor will be used to allocate items of cost to the various classes of business.

Production plant is a fixed cost, built to meet the maximum demands of the firm customers each month, and therefore has been classified as Demand. Production operating expenses have been classified as Demand or Energy based on their fixed or variable nature. Variable energy related Production expenses include such costs as fuel, boiler maintenance, and the energy component of purchases from third parties.

Transmission plant and expenses are a fixed part of the power supply system, are not related to total energy production or use, and have been classified as Demand related. Similarly, distribution plant and expenses are fixed for the test period and do not vary with the amount of energy produced or delivered, and have been classified as Demand related.

e. Please refer to 1.d.

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
SETTLEMENT AGREEMENT DATED MAY 14, 1999
FIRST SET OF DISCOVERY REQUESTS

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f. Since Standard Offer rates are not impacted by the Commission's Competition Plan, no studies or analyses were performed to evaluate Standard Offer rates.

APS' proposed direct access tariffs were not developed in the traditional sense as described in Mr. Propper's testimony and APS' response to questions 1.d. and 1.e. Utilization of the "apportionment factor" methodology so that direct access tariffs would be revenue neutral to Standard Offer rates, precludes determining the magnitude of any given cost included in the direct access tariffs.

g. Please refer to 1.f.

h. The 1996 Cost of Service Study is Schedule AP-1 attached to Mr. Propper's Direct Testimony. There are no studies utilizing more recent periods.

i. Must run units are:

- Yucca combustion turbine units 1-4
- Douglas combustion turbine
- Ocotillo combustion turbine units 1 & 2 and steam units 1 & 2
- West Phoenix combustion turbine units 1 & 2 and combined units 1-3

APS Standard Offer rates contain all costs associated with all of APS' generation. Standard Offer rates are not unbundled. As previously stated in the response to 1.g. the "apportionment" methodology doesn't assign a determinable amount of specific costs to any of the proposed direct access tariffs.

In calculating APS' stranded costs, and in the calculation of CTC's, Must Run units were assumed to receive market prices for their generation. APS did an alternative scenario in which it constrained Must Run units to cost-of-service rates. This increased APS' stranded costs by $25 million.

QUESTION 2: Unbundled Tariffs for Customers Selecting Competitive Services

a. Explain the assumptions used in setting the declining rates for unbundled rates and provide any study performed in setting those figures used in the Settlement. (JED at 7).

b. Explain whether or not a customer will pay the same costs for non-competitive services regardless of whether that customer receives service under the Standard Offer or from an ESP. Please furnish any study that discusses this similarity or inconsistency.

c. Please provide an illustration of the average customer's charges per month under the Direct Access Residential Service tariff (Settlement Exhibit A) by explaining the assumptions for kWh and the average monthly costs of (a) basic delivery service, (b) distribution, (c) system benefits, and (d) CTC, and illustrate the corresponding disaggregated average monthly charges for (a) basic delivery service, (b) distribution, (c) transmission, (d) ancillary services, (e)

metering, (f) meter reading, (g) billing (f) system benefits, (g) CTC and (h) generation costs, under the Standard Offer for that same "average" customer. (AP at 2).

d. Please provide an illustration of the average customer's charges per month under the Direct Access General Service tariff (Settlement Exhibit A) by explaining the assumptions for kW and kWh and the average monthly costs of (a) basic delivery service, (b) distribution, (c) systems benefits, and (d) CTC, and illustrate the corresponding disaggregated average monthly charges for (a) basic delivery service, (b) distribution, (c) transmission, (d) ancillary services, (e) metering, (f) meter reading, (g) billing (f) system benefits, (g) CTC and (h) generation costs, under the Standard Offer for that same "average" customer. Please prepare an illustration for the Summer Cycle and a separate illustration for the Winter Cycle. (AP at 2).

e. Please provide an illustration of the average customer's charges per month under the Direct Access Extra Large General Service tariff (Settlement Exhibit A) by explaining the assumptions for kW and kWh and the average monthly costs of (a) basic delivery service, (b) distribution, (c) system benefits, and (d) CTC, and illustrate the corresponding disaggregated average monthly charges for (a) basic delivery service, (b) distribution, (c) transmission, (d) ancillary services, (e) metering, (f) meter reading, (g) billing (f) system benefits, (g) CTC and (h) generation costs, under the Standard Offer for that same "average" customer. (AP at 2).

f. Describe what transmission costs, if any, are imputed within the direct access tariffs. (AP at 7).

g. Describe what ancillary services and their respective costs, if any, are imputed within the direct access tariffs. (AP at 7).

h. What specific costs were adjusted in developing the Direct Access Service rates before the apportionment factors were applied in unbundling those rates? (AP at 12).

i. What future changes in APS's Terms and conditions for Service by direct access customers are contemplated at this time or in the future? (AP at 17).

RESPONSE:

a. The Regulatory Asset price components that are included in the direct access Distribution Charges as shown in (g) of Schedule AP-7, Schedules 2 and 3, were reduced by 8.9% in each year for the Distribution Charges effective January 1 of 2000 through 2003. The 2003 price components were reduced by 6.5% for the Distribution Charge effective January 1 of 2004. These percentages reflect changes in the average unit costs for Regulatory Assets per the settlement.

b. It can be assumed that customers of the same class will pay the same costs for non-competitive services regardless of whether the customers receive service under the Standard Offer or from an ESP. The direct access charges are the only basis for determining costs for non-competitive services for both Standard Offer and Direct Access customers, so no study is required.

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
SETTLEMENT AGREEMENT DATED MAY 14, 1999
FIRST SET OF DISCOVERY REQUESTS

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c. An illustration of a typical residential customer's monthly charges for both Direct Access Rates and the applicable Standard Offer rate is provided in Attachment Q.2.c., Page 1 of 3. Assumptions for monthly kWh usage and on- and off-peak splits are shown in the table. As discussed in Mr. Propper's testimony at page 2, and as agreed to in the Settlement at Paragraph 2.1, the Company's presently authorized rate schedules shall become its Standard Offer rates. These rates are bundled and therefore do not contain disaggregated monthly charges.

d. An illustration of monthly charges for a typical general service customer under 3 mW for both Direct Access Rates and the applicable Standard Offer rate is provided in Attachment Q.2.d., Page 2 of 3. Assumptions for monthly kW and kWh usage are shown in the table. As discussed in Mr. Propper's testimony at page 2, and as agreed to in the Settlement at Paragraph 2.1, the Company's presently authorized rate schedules shall become its Standard Offer rates. These rates are bundled and therefore do not contain disaggregated monthly charges.

e. An illustration of monthly charges for a typical general service customer 3 mW or greater for both Direct Access Rates and the applicable Standard Offer rate is provided in Attachment Q.2.e., Page 3 of 3. Assumptions for monthly kW and kWh usage are shown in the table. As discussed in Mr. Propper's testimony at page 2, and as agreed to in the Settlement at Paragraph 2.1, the Company's presently authorized rate schedules shall become its Standard Offer rates. These rates are bundled and therefore do not contain disaggregated monthly charges.

f. APS' direct access tariffs do not contain any transmission costs.

g. APS' direct access tariffs do not contain any ancillary services costs.

h. As previously mentioned APS' direct access rates were not developed in a manner where specific costs were assigned to customer classes.

i. The general terms and conditions applicable to retail customers will remain much as they are today regardless of the services being provided by APS. However, changes will be necessary to accommodate direct access. For instance, to accommodate the provision of metering and meter reading from alternative Electric Service Providers.

QUESTION 3: Promotion of Competition

a. Explain how the Settlement will "promote entry of new competitors." Please provide any study as to how the Settlement will "promote entry of new competitors." (JED at 3).

b. Please provide any study that supports your argument that economic development will benefit from guaranteed rate reductions and the continuation of renewable and energy efficiency programs. (Settlement at 1-2).

c. How was the 140 Mw for non-residential load calculated? Please provide any study pertaining to such calculation.

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
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d. Please state the expected number of customer (by class with their respective loads in Mw) that APS expect will purchase competitive generation service by January 1, 2000. (JEB at 13).

e. Under the APS Direct Access Residential Phase-In Program (JED, Schedule 4), only 8,750 residential customers will be eligible for direct access, per quarter starting on January 1, 1999. Will the first 26,250 customers seeking an alternative energy supplier, as of June 30, 1999, be eligible to participate in retail direct access? Please explain the workings of this Phase-In Program.

RESPONSE:

a. The Settlement will "promote entry of new competitors" by establishing specific unbundled rates, determining the treatment of stranded costs and setting standard offer and unbundled distribution rates for a number of years. These actions remove the remaining impediments to competition which should promote the entry of new competitors. The Company did not conduct a study.

b. The Company did not prepare a specific study. However, as electric rates continue to decline, opportunities for economic development in the area should be enhanced.

c. The 140 MW load was to represent the amount of load eligible to participate in direct access that Decision No. 61272 shifted from non-residential to residential customers. The Residential Phase-in Program filed to reflect this change in the Rules was attached to Mr. Davis' testimony as Schedule JED-4. A copy of the original Residential Phase-in Program filed with the ACC on 9/15/98, is attached (Attachment Q.3.c).

d. The Company does not have a specific number of customers that it expects would purchase competitive generation service by January 1, 2000.

e. No. As of 6/30/99 two quarters have passed; therefore, 2 times the 8,750 customers per quarter eligible (or 17,500) will be eligible to participate in retail direct access. On 7/1/99, and each quarter thereafter through 10/1/2000, an additional 8,750 customers will be eligible to participate. APS will maintain a waiting list of DSARs for those that have chosen an ESP as described on page 4 of Schedule JED-4.

QUESTION 4: Generation Shopping Credit

a. Please provide any study performed on the generation shopping credit (also known as the "market generation credit") which shall be available for all classes of APS customers under the Settlement.

b. Explain how the Settlement will promote competition if the generation shopping credit (and CTC) does not result in any savings to customers?

c. Please provide an illustration of the generation shopping credit for each of the direct access tariffs.

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
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RESPONSE:

a. The Company has not proposed a "market generation credit" in this Settlement.

b. The parties to the Settlement who represent the vast majority of the Company's customers believe that the Settlement will provide opportunities for competition. Second, by removing legal and regulatory barriers to competition, this will promote competitive pressures on all market participants, including incumbents.

c. Although the Company has not proposed specific generation shopping credits in its direct access tariffs, the difference between the sum of the direct access charges and the applicable Standard Offer rate would be the effective shopping credit. Illustrations of such difference for each of the Direct Access rate classes are contained in the Company's responses to Questions 2.c., 2.d. and 2.e.

QUESTION 5: Stranded Costs

a. Please explain why regulatory assets are now recovered under the Distribution charge rather than the CTC.

b. Please state how much of the regulatory assets, by category, have been recovered as of December 31, 1998.

c. Regulatory assets include mine reclamation costs and financing costs for generation units. Please itemize the net present value of each of these regulatory assets as of December 31, 1998. Please explain why these types of regulatory assets which relate to generation should be included in the Distribution charge for both Standard Offer customers and those that select an ESP. (AP at 9).

d. Please provide any study on the projected regulatory assets APS expects will not be recovered as of June 30, 2003. (JED at 8).

e. Please explain how any deferred credit (amounts owned by APS to customers) of the CTC will be allocated back to "APS customers."

f. Please explain how the CTC was allocated among Direct Access Rate Class customers in Exhibit A, Schedule A of the Settlement.

g. Will a customer pay the same CTC regardless of whether it purchases services from APS under the Direct Access tariffs or the Standard Offer? If not, please explain the discrepancy.

h. Please explain how many customers and their respective loads in kW (by class) were assumed to be actually purchasing competitive generation services when APS prepared its (a) Stranded Cost Estimate (JED, Exh. 2), and (b) Regulatory Asset Amortization Schedule under Schedule C, Exhibit A of the Settlement.

DATA REQUESTS FROM COMMONWEALTH ENERGY CORPORATION (DATED 6/25/99)
DOCKET NO. E-01345A-98-0473, E-01345-97-0773 & RE-00000C-94-0165
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i. Describe how many customers and their respective loads in kW (by class) were assumed to be actually purchasing competitive generation services when APS prepared its stranded cost projection of $350 million. (JHL at 16). Please describe what "aggressive capacity factors" were used for the power plants in calculating stranded costs, for each of the generation units described in Exhibit C of the Settlement for the period 1999 through 2004. (JHL at 16).

j. Please explain what assumptions were used in creating the amortization of regulatory assets in Schedule C, Exhibit A of the Settlement.

k. Describe the assumptions used in calculating the $350 million "net present value" for the stranded cost recovery.

l. Please explain the source of "Bundled Rate" as used in Schedule AP-7, Schedule 1, and the assumptions underlying the rate used for "All kWh."

m. Please provide any study performed on APS's stranded costs (and/or regulatory assets).

n. Please provide the market-based price(s), their source(s) and the assumptions used in setting the stranded cost figure on the Settlement. Please furnish any study performed on this stranded cost calculation.

RESPONSE:

a. The Company is continuing to recover regulatory assets as set forth in Decision No. 59601. The Company has never proposed recovering them through the CTC.

b. The net amount of regulatory assest that have been recovered from June 30, 1996 to December 31,1998 per ACC Decision No. 59601 are as follows:

PRUDENCE AUDIT RESPONSE COST AND PRUDENCE AUDIT OTHER COST	$ 9,458,945
DESIGN BASIS STUDY	4,695,455
PV2 SALE/LEASEBACK REFINANCING COST AND RENT COST	3,527,690
DECOMMISSIONING & DECONTAMINATION FEES	2,808,451
PV DEFERRALS	138,027,281
WESTINGHOUSE NUCLEAR FUEL TERMINATION FEE	3,261,078
NUCLEAR FUEL TERMINATION FEE- EVEREST	438,945
SFAS 109 INCOME TAX	206,659,000

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PV UNIT 2 SALE/LEASEBACK RENT LEVELIZATION	10,383,884
PREMIUM ON REACQUIRED PREFERRED STOCK	(678,615)
NUCLEAR FUEL TERMINATION FEE- TOTAL	674,691
COAL RECLAMATION	23,021,875
UNAMORTIZED LOSS ON REACQUIRED DEBT	17,384,920
PV UNIT 1 IN SERVICE DATE CHANGE	(1,702,560)
UNAMORTIZED GAIN REACQUIRED DEBT	51,311
TOTAL NET RECOVERY	$418,012,351

c. The Regulatory Asset balance currently being recovered per Decision No. 59601 includes the following items as of December 31, 1998.

REGULATORY ASSET	BALANCE
Prudence Audit	$ 20,809,679
Design Basis Study	10,329,273
PV Sale Leaseback Refinancing Cost And Rent Cost	7,760,919
DOE -Decommissioning & Decontamination Fees	7,902,867
PV Plant Deferrals	303,660,020
Westing Nuclear Fuel Termination Fee	5,616,712
Everest Nuclear Fuel Termination Fee	30,028.44
SFAS 109 Income Tax	416,207,000
PV Unit 2 Sale Leaseback Rent Levelization	48,529,257
Premium On Reacquired Preferred Stock	3,326,059

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TMC Nuclear Fuel Termination Fee		91,333
Pathfinder Nuclear Fuel Termination Fee		846,741
Coal Reclamation		50,648,125
Unamortized Loss On Reacquired Debt		53,744,133
PV Unit 1 In Service Date Change		(3,745,632)
Unamortized Gain Reacquired Debt		(714,332)
Regulatory Assets Balance	$	925,042,261

Regulatory assets represent costs which would have previously been recovered in rates, but which were deferred because of regulatory action. They do not relate to any specific functional category of cost. These costs were incurred for all customers and should be recovered from all customers.

d. Regulatory assets are scheduled to be fully amortized by June 30, 2004. As of 6/30/03, there will be an unamortized balance which APS has not calculated.

e. The method to determine the allocation of CTC credits or debits under Section 2.6 of the Settlement will be filed with the Commission by June 1, 2002.

f. After the retail stranded cost was derived by year, APS used a load factor allocation methodology in order to derive the cost responsibility for each class. We started with the 4CP @ Generation Level for each class compared with the Annual Energy @ Generation to determine the individual load factors by class. These load factors were then applied to the direct access sales to determine the demand for each class. Then we derived the percentage each class load contributed to the direct access loads, and applied that percentage to the Annual Retail Strandable Cost.

g. The implicit CTC "paid" by Standard Offer and explicit CTC paid by Direct Access customers will be same as computed shown in Exhibit B of the Settlement.

h. For purposes of these calculations, the Company assumed that 100% of their customers would choose competitive generation as soon as they were eligible (Schedule JED-3). The Company did not make a projection of customers choosing competitive generation in preparing Schedule C to Exhibit A of the Settlement.

i. The $350 million was a negotiated number. See response to 5h. The capacity factors for APS' coal and nuclear units used in Exhibit C are provided on Page 17 of John H. Landon's testimony. The capacity factors that APS has assumed for its coal and nuclear generation units are significantly greater than the average capacity factors of these units in recent years. The gas fired units capacity factors are as follows:

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	W. PHX. CC	OCOTILLO 1&2	SAGUARO 1&2	ALL CT'S
1999	42.5	19.2	5.7	4.9
2000	46.4	28.1	6.8	6.4
2001	60.3	35.6	15.9	4.5
2002	----	42.6	17.1	5.3
2003	----	45.8	16.7	6.4
2004	----	44.6	13.6	6.6

j. The settlements disallowance of recovering certain costs and the agreed to rate reduction patterns are predicated on the revised regulatory asset amortization pattern shown on Schedule C, Exhibit A. The basic logic for the changed amortization levels is the matching principle.

k. The $350 million was a negotiated amount.

l. The bundled rate in Schedule AP-7, Schedule 2, was calculated as a seasonally revenue neutral rate for the residential class for the test year ended December 31, 1996. The computation of this rate is contained in the attached table Q.5.l

m. See Schedule JED-3

n. The market- based prices used in setting the stranded cost figure of $533 million is as follows:

1999	$26.30 / MWh
2000	25.70
2001	27.00
2002	28.30
2003	30.04
2004	32.20

QUESTION 6: Market Power

a. Explain when APS will "functional" separate its power production and delivery functions and how that will promote retail access faster. (Settlement at 1).

b. Please explain how the Settlement addresses market structure if APS's competitive lines of business are transferred to an affiliate? (JEB at 9 & Settlement at 6).

c. Please explain whether or not a competitive affiliate of APS (or its parent) will be able to provide services within the APS service area and, if so, how that will mitigate market power.

d. Explain how the waiver of the Commission's general affiliate transaction rules (A.A.C. R14-2-801 *et seq.*) will mitigate market power and protect against market abuses. (JED at 10).

e. Explain what types of "prudent costs" of corporate restructuring APS claims should be recovered? (JED at 10).

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f. What approvals from FERC and NRC are anticipated in completing APS's restructuring? (JED at 10).

g. For each of the generation assets described in Exhibit C to the Settlement, please describe its book value, fuel source, and generation capacity in Mw.

h. Please furnish any study on the conclusion that the book value of APS's generation portfolio will be greater than the market value of those assets. (JHL at 10).

i. Please furnish any study of the amount of energy production, as set forth in JEB, Exhibit 2, that is anticipated to be used by Standard Offer customers, for each year during 1999 through 2004.

j. Please furnish any study prepared by APS (or its consultants) on market power issues relating to the Settlement.

k. Please explain any plans by APS to divest its generation and provide a copy of any study relating to divestiture of APS's generation assets. (JED at 8).

l. Please describe and itemize "the reasonable and prudent costs" APS anticipates incurring in separating competition generation assets and competitive services, under Section 4.2 of the Settlement. Please explain how those costs will be distinguished from the "costs of transferring the APS power marketing function to an affiliate."

RESPONSE:

a. Section 4.1 of the Agreement calls for forming a separate generation affiliate by 12/31/02. The Agreement states that retail access will be faster than would occur without the Agreement because August 1st is the date targeted. This is many months sooner than would occur absent the Agreement.

b. The Settlement implements the market structure changes mandated by both the stayed electric competition rules and the presently proposed electric competition rules.

c. APS Energy Services has received a CC&N from the ACC which will allow it to provide services within the APS service territory as well as other areas. APS Energy Services has no market power.

d. These are standard waivers granted to competitive public service corporations and are necessary for APS to functionally separate its business as required by the Settlement.

e. There are a number of types of costs associated with corporate restructuring including, but not limited to, attorney fees, accountant fees, investment banker fees, additional investment costs.

f. <u>FERC</u>

(1) APS would need to make a Section 203 filing and obtain FERC approval to transfer its transmission assets to the new "transco" affiliate.

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(2) The APS transco affiliate would need to revise the Open Access Transmission Tariff, Schedules 2,3,4,5 and 6. These Schedules contain rates associated with generation related ancillary services, which APS' transco would heretofore purchase on the open market and merely flow the costs related to the purchases of these services through to customers.

(3) APS' new Merchant affiliate, Generation affiliate(s) and APS Energy Services would need to make a filing and gain FERC's approval for Market Rate Tariff authorization, including appropriate standards of conduct intended to preclude affiliate abuse.

NRC

The transfer of APS' share of the Palo Verde Generating Station and nuclear operations would require NRC approval.

g. APS objects to answering this question as calling for the production of proprietary, confidential and competitively sensitive information.

h. Dr. Landon believes that at the end of six years the book value of APS's generation portfolio will be greater than the market value of the assets because he believes that the Company has underestimated its stranded generation costs and because the Company has agreed to a settlement that will give it the opportunity to recover only a fraction of these costs. By ACC definition, the existence of stranded costs means that book value exceeds market value. Please see Dr. Landon's direct testimony in this docket for an explanation of why Dr. Landon believes the Company has underestimated stranded costs.

i. Non available. Please refer to response 3.d.

j. Neither APS nor its consultants have prepared any market power studies relating to the provisions of the settlement. APS did submit a market power analysis to FERC in February 1997 in connection with its application to charge market-based rates in wholesale power transactions.

k. APS intends to divest generation to an affiliate as discussed in Article IV of the Settlement. This is required by ACC rules, and thus no "study" was undertaken.

l. See response to 6.c. These costs will only relate to transferring generation items.

Attachment Q.1.b.
Commonwealth Set 1

ARIZONA PUBLIC SERVICE COMPANY

Revenue Reductions for Standard Offer Customers
Under Proposed Settlement of May 14, 1999
(All Customers Served on Standard Offer Rates)

	Revenue Reductions ($000)	
Year	Annual	Cumulative
1999	(12,161)	(12,161)
2000	(37,736)	(49,897)
2001	(65,234)	(115,132)
2002	(94,605)	(209,737)
2003	(124,130)	(333,867)
2004	(141,613)	(475,479)

06/28/99 16:39 APS FINANCIAL SERVICES → 602 3951943 NO.072 D17

ARIZONA PUBLIC SERVICE COMPANY
CALCULATION OF TYPICAL MONTHLY RESIDENTIAL CUSTOMER CHARGES
DIRECT ACCESS and STANDARD OFFER RATES
For the Year 1999

Typical Residential Usage:	1,000 kWh per month
Typical Summer On-Peak Usage:	40%
Typical Summer Off-Peak Usage:	60%

Typical Residential Customer on 1999 DA-R1 1/2/

Basic Delivery Service:	$ 10.00	/mo	$	10.00
Distribution Service:	$ 0.04158	/kWh	$	41.58
System Benefits:	$ 0.00115	/kWh	$	1.15
CTC:	$ 0.00930	/kWh	$	9.30
	Total DA-R1:		$	62.03

Typical Residential Customer on Current Standard Offer ET-1(Summer) 2/

Basic Service Charge:	$ 15.00	/mo	$	15.00
per kWh On-Peak:	$ 0.13948	/kWh	$	55.79
per kWh Off-Peak:	$ 0.04495	/kWh	$	26.97
	Total ET-1 (Summer):		$	97.76

1/ This calculation does not include:
Charge for CT's and PT's
Any credits due for metering, meter reading and billing

2/ These calculations do not include taxes or regulatory assessments

ARIZONA PUBLIC SERVICE COMPANY

CALCULATION OF TYPICAL MONTHLY GENERAL SERVICE (Under 3MW) CUSTOMER CHARGES
DIRECT ACCESS and STANDARD OFFER RATES
For the Year 1999

Typical Monthly General Service (under 3MW) Usage: 13,140 kWh
40 kW
45% Load Factor

Typical General Service Customer on 1999 DA-GS1 (Summer) 1/2/

Basic Delivery Service:	$	12.50	/mo	$ 12.50
Distribution Service: per kW over 5	$	0.721	/kW	$ 25.24
per kWh for the first 2500 kWh	$	0.04255	/kWh	$ 106.38
per kWh for the next 100 kWh per kW over 5	$	0.04255	/kWh	$ 148.93
per kWh for the next 42,000 kWh	$	0.02901	/kWh	$ 207.13
per kWh all additional kWh	$	0.01811	/kWh	$ -
System Benefits:	$	0.00115	/kWh	$ 15.11
CTC:	$	2.43	/kW	$ 97.20
Total DA-GS1 (Summer):				$ 612.49

Typical General Service Customer on Current Standard Offer E-32 (Summer) 2/

Basic Service Charge:	$	12.50	/mo	$ 12.50
per kW over 5:	$	1.85	/kW	$ 64.75
per kWh for the first 2500 kWh	$	0.11018	/kWh	$ 275.45
per kWh for the next 100 kWh per kW over 5	$	0.11018	/kWh	$ 385.63
per kWh for the next 42,000 kWh	$	0.07550	/kWh	$ 539.07
per kWh all additional kWh	$	0.04756	/kWh	$ -
Total E-32 (Summer):				$ 1,277.40

1/ This calculation does not include:
- Charge for CT's and PT's
- Any credits due for metering, meter reading and billing
- Any discounts for primary or transmission voltage level service

2/ These calculations do not include taxes or regulatory assessments

06/28/99 16:39 APS FINANCIAL SERVICES → 602 3951943 NO.072 D19

ARIZONA PUBLIC SERVICE COMPANY

CALCULATION OF TYPICAL MONTHLY GENERAL SERVICE (3MW and Above) CUSTOMER CHARGES

DIRECT ACCESS and STANDARD OFFER RATES

For the Year 1999

Typical Monthly General Service (3MW and above) Usage: 2,190,000 kWh
4,000 kW
75% Load Factor

Typical General Service Customer
1999 DA-GS10 1/2/

Basic Delivery Service:	$ 2,430.00	/mo	$	2,430.00
Distribution Service: all kW	$ 3.53	/kWh	$	14,120.00
all kWh	$ 0.00999	/kW	$	21,878.10
System Benefits:	$ 0.00115	/kWh	$	2,518.50
CTC:	$ 2.82	/kW	$	11,280.00
	Total DA-GS10:		$	52,226.60

Typical Residential Customer on
Current Standard Offer E-34 2/

Basic Service Charge:	$ 2,430.00	/mo	$	2,430.00
per kW:	$ 11.16	/kWh	$	44,640.00
per kWh:	$ 0.03288	/kWh	$	72,007.20
	Total E-34:		$	119,077.20

1/ This calculation does not include:
- Charge for CTs and PTs
- Any credits due for metering, meter reading and billing
- Any discounts for primary or transmission voltage level service

2/ These calculations do not include taxes or regulatory assessments

APS

Fax Cover Sheet

To:	Mr. Douglas Nelson, Esq.	**Date:**	June 28, 1999
Company:	Attorney for Commonwealth	**Phone:**	(602)395-1612
Department:		**Fax:**	(602)395-1943
From:	Sharon Madden	**Phone:**	(602)250-2027
Department:	Regulatory Affairs	**Fax:**	(602)250-3399
Subject:	Data Request	**Total pages including this sheet:**	26

Comments
Attached is APS's response to your data request of June 25, 1999, submitted on behalf of Commonwealth Energy Corporation.

If you do not receive all the pages, please call 250-2944 for assistance

. Thank you

Attachment Q. 3. c.

APS
Commitment. Innovation. Energy.

Barbara A. Klemstine
Manager
Regulatory Affairs

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Mail Station 9909
PO Box 53999
Phoenix, AZ 85072-3999

September 15, 1998

ARIZONA CORPORATION COMMISSION
RECEIVED
SEP 15 1998
Director of Utilities

Mr. Ray Williamson
Acting Director, Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Re: Docket RE-00000 C-94-0165
Residential Phase-In Program

Dear Mr. Williamson:

Pursuant to Decision No. 61071 all affected utilities shall file a Residential Phase-In Program proposal to the Commission for approval by the Director of the Utilities Division by September 15, 1998. Enclosed is Arizona Public Service Company's proposal. Copies of this proposal have been mailed to all parties of record in Docket RE-00000 C-94-0165.

If you have any questions, please contact me at 250-2031.

Sincerely,

Barbara A. Klemstine
Manager
Regulatory Affairs

BAK/JKD/pb

Enclosure

cc: Parties of Record RE-00000 C-94-0165
David Gallagher

ARIZONA PUBLIC SERVICE COMPANY

DIRECT ACCESS RESIDENTIAL PHASE-IN PROGRAM IMPLEMENTATION PLAN

I. GENERAL DESCRIPTION

The residential phase-in program has been developed to provide a means by which Arizona Public Service Company ("APS" or "the Company") will provide current and new residential customers with the opportunity to procure competitive services from a source other than APS. This plan describes notification procedures, selection, and tracking mechanisms necessary to meet the Arizona Corporation Commission's ("ACC" or "the Commission") requirements as set forth in A.A.C.R14-2-1604 (Rule 1604.)

II. ELIGIBILITY

General

Rule 1604 requires that a minimum of ½ of 1% of residential customers have access to competitive electric services. The number of eligible residential customers will increase by an additional ½ of 1% every quarter until January 1, 2001. In accordance with these rules, approximately ½ of 1% of APS' 685,672 residential customers (as of July 1998) or 3,500 residential customers; (the actual number of 3,428 was rounded upward) will be eligible for competitive electric service beginning January 1, 1999. Each subsequent quarter, an additional 3,500 residential customers will be eligible for direct access.

Solar

All residential customers who produce or purchase at least 10% of their annual electricity consumption from photovoltaic or solar thermal energy resources that were installed in Arizona after January 1, 1997 shall be eligible for participation in a competitive market. Customers who provide evidence of such solar or photovoltaic consumption to APS (i.e. an equipment purchase receipt or Energy Service Provider resource statement) will be declared eligible. This will be in addition to the above-mentioned residential eligibility (3,500 eligible residential customers per quarter) and will not be considered as part of the 20% of 1995 system peak demand otherwise eligible for direct access. Solar or photovoltaic customers must also identify themselves as such through their ESP for immediate processing of a service request. APS reserves the right to implement policies to verify and track eligibility of photovoltaic and solar energy resources.

Low-Income Residential Customers

To ensure that low-income residential customers (customers on Rate Schedules E-3 and E-4) have an opportunity to participate in direct access, ½ of 1% of the low-income residential customers (there are approximately 26,000 customers on E-3 and E-4) will be eligible for direct access and not counted towards the 20% of system peak demand. This results in 150 per quarter or 1,200 in total.

III. Calculation of Reserved Residential Load

Each affected utility is required to make available at least 20% of its 1995 system retail peak demand for competitive generation on a first-come first-serve basis. Twenty percent of APS' 1995 system retail peak demand of 3,725 mW is 745 mW (demands measured at the meter). To calculate the proportion of the 745 mW that must be "reserved" for residential direct access, a system peak coincident demand of 3.30 kW (as estimated from APS' ongoing load survey program) was used for each eligible residential customer. The following calculation was then used to estimate the residential "reserved" portion of the APS load available for competitive generation.

Reserved Load = Total # Residential Customers Eligible x 3.3 kW

or

Reserved Load = (3,500 x 8) x 3.3 = 92 mW

Where:	3,500	=	The number of residential customers eligible per quarter
	8	=	The number of quarters between January 1, 1999 and January 1, 2001
	3.3	=	Average residential system peak coincident demand

The amount of load available for competitive generation for non-residential customers is then 653 mW (745 mW less 92 mW).

IV. PROCESS FOR CUSTOMER NOTIFICATION OF RESIDENTIAL PHASE-IN PROGRAM

APS will implement a notification process to inform all APS residential customers concerning the residential phase-in program. This notification process is designed to inform APS' residential customers concerning the applicable provisions and eligibility requirements set forth in A.A.C.R14-2-1604(B). Based on consumer response, APS will evaluate the appropriate means of ongoing notification during the phase-in period.

Bill inserts will be sent to all residential customers upon Commission review of the Company's Implementation Plan. This bill insert will, at a minimum, contain the following information:

A. The qualification requirements for residential customers set forth in A.A.C.R14-2-1604(B).

B. Residential phase-in program direct access eligibility dates.

C. A reply card to request additional information.

D. A phone number for customers to call and ask questions or request additional information.

New residential customers (those connecting service after October 31, 1998) will be notified about direct access through the existing customer kit process used to welcome new customers.

V. CUSTOMER EDUCATION AND INFORMATION SERVICES TO BE OFFERED

Coincident with the bill insert, APS will offer customer education and information services such as online services, media relations, bi-monthly publications, public presentations/forums, direct mailings/bill communications and Spanish translations where appropriate to all APS residential customers concerning competition (including the residential phase-in program).

The information provided on the bill insert and reply form will be available on the APS Internet web site so customers can access and review the notification literature. The web site will identify locations where reply cards are available or customers can provide their name and address on-line and have an information packet sent to them.

Upon receipt of a customer reply card or customer request, a direct access customer information packet will be provided.

A separate direct access phone line in Phoenix has been established to answer questions and handle information requests. The APS Customer Solutions Center 800 number will also be provided to customers as a communication link to answer direct access questions and handle information requests. These phone numbers will be included in bill inserts, advertising, and customer information packages.

VI. SELECTION AND TRACKING MECHANISM FOR RESIDENTIAL CUSTOMERS BASED ON A FIRST-COME FIRST SERVE BASIS

Residential customers will be eligible for access on a first-come first-serve basis. Customers must actually choose an alternative energy supplier and have that supplier submit a request to switch which will be counted. The time that the request to switch is received by APS will be used to establish priority for direct access. The first 3,500 requests that are accepted will have access in the first quarter and any requests in excess will be put on a waiting list for the next quarters prioritized by time received. This selection method has several advantages: 1) it will ensure that access slots do not go unused (only customers committed to choosing an alternate supplier will have access), 2) there will not be an eligibility list that has to remain confidential, and 3) ESPs will be able to market to the class as a whole rather than only a small segment.

As a result of the ACC workshop process, APS has developed a Direct Access Service Request ("DASR") process to facilitate direct access. This process enables APS to track customer switching to and between Electric Service Providers ("ESPs"), verify customer eligibility during the direct access phase-in period, and provide a timing mechanism to place requests in a sequential order based on the time they were submitted to APS. The DASR will be the mechanism used to track customers on first-come first-serve basis.

To educate ESPs and ensure the process moves smoothly as possible the Company will have an ESP Open House in October. Additionally, an Internet site has been established were ESPs can access information.

DASR Process

Customers wishing to select direct access will contact their preferred ESP. The ESP will then prepare DASRs and submit them to APS. DASRs will be time and date stamped upon receipt by APS to track the order of receipt. APS will respond back to the ESP, on valid DASRs, a DASR status of "accepted" until the remaining slots are filled.

APS will begin accepting DASRs for the first quarter on December 1, 1998. APS will monitor both the number of customers that have effectively switched to direct access and are receiving competitive services as well as the number of DASRs that are accepted and assigned a switch date within the quarter. The quarter will be closed once APS has accepted DASRs for the total number of customers eligible in that quarter.

As the DASRs are accepted, APS will respond to the ESP confirming the change date. Once the quarterly requirements have been filled, all subsequent DASRs will be held in a pending status, establishing a waiting list, until the first business day one month prior to the proceeding quarter. On that day, APS will begin processing the pending DASRs from the waiting list in the order they were received for the next quarter. APS will respond back to the ESP, for valid DASRs, an accepted status as well as assign the next scheduled read date for the switch date.

APS will maintain a waiting list of up to 24,500 DASRs. If the waiting list is full, no further DASRs will be accepted. APS will update the newly created APS ESP Internet site with eligibility and waiting list status. If a DASR is submitted for a first time Direct Access customer and is rescinded before the effective switch date, the customer will not be given preferential treatment over other first time Direct Access customers. An ESP cannot submit changes to a DASR that is on the waiting list. The only action that can be taken by the ESP is a cancellation. Once the DASR is processed and the ESP has received an accepted status, the ESP may then initiate any appropriate changes.

Customers may elect to change ESPs during the phase-in period. The ESP acquiring the customer is responsible for submitting a DASR change. Eligibility follows the residential customer and not the site location (that is, service address.) However, if an eligible customer returns to a standard offer rate, then they must reapply for competitive eligibility through the DASR process.

VII. LOAD PROFILING

Under FERC Order 888 (Open Access Transmission), APS as a control area operator, requires hourly loads from each Scheduling Coordinator (either the ESP itself or a mutually agreed upon third party) for energy imbalance and settlement. Pursuant to R14-2-1613(J.7) residential customers with loads of 20kW (or 100,000 kWh annually) will be permitted to use load profiling to satisfy the requirements for hourly consumption data. APS will make a revised OAT filing with FERC to accommodate retail direct access. The load profiling methodology will be part of that filing and must be approved by FERC. Each scheduling coordinator's hourly-profiled and hourly-metered loads will be summed for each hour to determine its hourly responsibilities for settlement.

The load profiling process takes the retail customers cumulative kilowatt-hour (kWh) for the billing cycle and allocates it to each hour in the cycle based on a load curve developed from a statically valid sample set that is representative of the retail customer's load.

The allocation process involves:

1. Determining the representative sample set's ratio for each hour, by dividing each of its hourly loads by its total usage for the billing cycle. The billing cycle starts the hour and date that the retail customer's meter was last read and stops the hour and date of the current read.
2. The ratio for each hour is then multiplied by the retail customer's total kWh usage for the billing cycle to obtain each hourly load for that customer.

During the phase-in, APS plans to use two segment sets. These are high country residential and low country residential. Customers will be assigned one of these two profiles based upon the geographic area in which they reside.

Initially these profiles will be static. That is profiled loads will be developed based on the static profile then adjusted to reflect the profiled days system load pattern. The adjustment is needed to reflect changes in the system due to weather and other system conditions. The adjustment will be determined for each hour using the following formula:

$$\text{Adjustment} = \frac{\text{APS current system profile ratio for hour}}{\text{APS historic system profile ratio for hour}}$$

Static profiles will be provided when they are available. APS estimates that by 2001, dynamic profiles will be utilized.

Attachment Q.5.1
Commonwealth Set 1

ARIZONA PUBLIC SERVICE COMPANY

Residential Blended Rate Designs
Seasonal Flat Energy Blocks
TYE 12/31/96, 9/1/98 Rate Level

	Target Determinants & Revenues	Prices	Design Revenues
Summer			
Bills	3,667,321	$ 10.00	$ 36,673,210
Energy	4,335,429,713	$ 0.08733	$ 378,621,350
Revenue	$ 415,294,560		$ 415,294,560
Winter			
Bills	3,674,357	$ 10.00	$ 36,743,570
Energy	2,902,069,520	$ 0.07407	$ 214,961,896
Revenue	251,705,466		$ 251,705,466
Annual			
Bills	7,341,678	$ 10.00	$ 73,416,780
Energy	7,237,499,233	$ 0.08201	$ 593,583,246
Revenue	$ 667,000,026		$ 667,000,026

THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)		
Item 1: ☒ An Initial (Original) Submission	OR	☐ Resubmission No. ____
Item 2: ☐ An Original Signed Form	OR	☒ Conformed Copy

Form Approved
OMB No. 1902-0021
(Expires 7/31/98)

RECEIVED
JUL 06 1999

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
Arizona Public Service Company	Dec. 31, 1997

EXHIBIT
Commonwealth
4
Admitted

FERC FORM NO. 1 (REV. 12-95)

7. Fair Value of Financial Instruments

The Company estimates that the carrying amounts of its cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 1997 and 1996 due to their short maturities. Investments in debt and equity securities are held for purposes other than trading. The December 31, 1997 and 1996 fair values of such investments, determined by using quoted market values or by discounting cash flows at rates equal to the Company's cost of capital, approximate their carrying amounts.

The carrying value of long-term debt (excluding a capitalized lease obligation) on December 31, 1997 and 1996 was $2.04 billion and $2.16 billion, respectively, and the estimated fair value was $2.08 billion and $2.13 billion, respectively. The fair value estimates are based on quoted market prices of the same or similar issues.

8. Jointly-Owned Facilities

At December 31, 1997, the Company owned interests in the following jointly-owned electric generating and transmission facilities. The Company's share of related operating and maintenance expenses is included in utility operations and maintenance.

	Percent Owned by Company	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(Thousands of Dollars)		
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$1,830,794	$628,960	$14,498
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	572,054	213,717	9,338
Four Corners Steam Generating Station Units 4 and 5	15.0%	148,342	66,470	1,369
Navajo Steam Generating Station Units 1, 2 and 3	14.0%	182,637	82,326	33,081(a)
Cholla Steam Generating Station Common Facilities (b)	62.8%(c)	66,106	34,551	580
Transmission Facilities:				
ANPP 500KV System	35.8%(c)	62,593	19,107	4,903
Navajo Southern System	31.4%(c)	27,159	16,710	—
Palo Verde-Yuma 500KV System	23.9%(c)	11,376	3,971	—
Four Corners Switchyards	27.5%(c)	3,071	1,707	1
Phoenix-Mead System	17.1%(c)	36,418	(2,169)	337

(a) The construction costs at Navajo are primarily related to the installation of scrubbers required by recent environmental legislation.

(b) The Company is the operating agent for Cholla Unit 4, which is owned by PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.

(c) Weighted average of interests.

9. Leases

In 1986, the Company entered into sale and leaseback transactions under which it sold approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. The gain of approximately $140.2 million has been deferred and is being amortized to operations expense over the original lease term. The leases are being accounted for as operating leases. The amounts to be paid each year approximate $40.1 million through 1999, $46.3 million in 2000 and $49.0 million through 2015. Options to renew for two additional years and to purchase the property at fair market value at the end of the lease terms are also included. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated the Company's amortization of the regulatory asset for leases to an eight-year period that began July 1, 1996. The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 1997 was $53.2 million. Lease expense was approximately $42 million in each of the years 1995 through 1997.

The Company has a capital lease on a combined cycle plant which it sold and leased back. The lease requires semiannual payments of $2.6 million through June 2001, and includes renewal and purchase options based on fair market value. This plant is included in plant in service at its original cost of $54.4 million; accumulated amortization at December 31, 1997 was $46.5 million.

In addition, the Company leases certain land, buildings, equipment and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates. Rent expense for 1997, 1996 and 1995 was approximately $7.8 million, $9.7 million and $9.9 million, respectively. Annual future minimum rental commitments, excluding the Palo Verde and combined cycle leases, for the period 1998 through 2002 range between $13 million and $15 million. Total rental commitments after the year 2002 are estimated at $99 million.

10. Income Taxes

The Company is included in the consolidated income tax returns of Pinnacle West. Income taxes are allocated to the Company based on its separate company taxable income or loss. Beginning in 1995, substantially all ITCs are being amortized over a five-year period in accordance with a 1994 rate settlement agreement.

The Company follows the liability method of accounting for income taxes which requires that deferred income taxes be recorded for all temporary differences between the tax bases of assets and liabilities and the amounts recognized for financial reporting. Deferred taxes are recorded using currently enacted tax rates.

In accordance with SFAS No. 71, a regulatory asset has been established for certain temporary differences, primarily AFUDC equity, to reflect the ratemaking treatment. This regulatory asset is being amortized as the related differences reverse. In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated the Company's amortization of the regulatory asset for income taxes to an eight-year period beginning July 1, 1996. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense on the Statements of Income.

Name of Respondent Arizona Public Service Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.

2. For property having an original cost of $ 250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Cholla Stream Unit #5, Joseph City,AZ	12/31/81	12/31/09	$318,798
3	Santa Rosa/Gila Bend 230KV Line, Gila & Salt River			
4	Base, Pinal County	12/31/89	12/31/06	758,348
5	Deer Valley Data Center			
6	2122 W. Cheryl Dr., Phoenix,AZ	12/31/85	12/31/00	861,782
7	Rose Garden Substation,			
8	27th & Rose Garden Ln, Phoenix,AZ.	12/31/91	06/01/03	1,164,638
9	Raintree Substation,			
10	RaintreeDr. & Redfield Rd., Scottsdale,AZ	12/31/91	05/01/99	1,239,223
11	Cambridge (Windsor) Substation,			
12	17th Pl. and Windsor St. Phoenix,AZ	12/31/91	06/01/03	554,327
13	Roanoke Substation,			
14	35th Ave. & Roanoke Ave., Phoenix, AZ	12/31/91	06/01/02	282,772
15				
16				
17				
18	Continues-Next Page			
19				
20				
21	Other Property:			
22	West Phoenix Steam Units 4, 5, & 6			
23	51st Ave. & Buckeye Road, Phoenix,AZ			
24	(Use discontinued 1/83; Trasferred to 105 on 1/83;			
25	in use 6 months in 1985; discontinued 10/85 &			
26	trans to 105 10/85; 5/89 trans units 4&5 to 101;	12/31/83	12/31/03	14,305,516
27	in 12/89 trans back to 105)			
28				
29	WHITE TANKS/W. Phoenix 230 KV PROJECT,			
30	Phoenix & N.W. Phoenix, Maricopa County	12/31/92	12/31/04	2,168,877
31				
32				
33				
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35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			

Name of Respondent Arizona Public Service Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.

2. For property having an original cost of $ 250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Greenbriar Substation,			
3	59 th Ave. & Roanke Ave., Phoenix,AZ	12/31/93	06/01/03	1,325,099
4	MADISON SUBSTATION,			
5	11th St. & Jackson St. Phoenix, AZ	12/31/93	06/01/03	592,651
6	WHITE TANKS/W. PHOENIX 230KV LINE			
7	Phoenix & N.W. Phoenix Land Rights, Maricopa County	12/31/92	12/31/01	7,586,750
8				
9	24 OTHER PARCELS			936,459
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
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41				
42				
43				
44				
45				
46				
47	TOTAL			$32,095,240

Name of Respondent Arizona Public Service Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.

2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.

3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.

4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.

5. Minor Items (5% of the Balance at the End of the Year), for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service(line 44), or(2) other nonutility property (line 45).

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	NONUTILITY PROPERTY NOT PREVIOUSLY DEVOTED TO			
2	PUBLIC SERVICE - CONTINUED:			
3				
4				
5	LAND FOR MILLER SUB SITE, SCOTTSDALE, AZ	389,500	* (389,500)	0
6	LAND FOR LONE MOUNTAIN SUB SITE, SCOTTSDALE, AZ	617,500		617,500
7	LAND FOR SHEA SUB, SCOTTSDALE, AZ	499,089		499,089
8	LAND FOR PRESCOTT VALLEY SERVICE CENTER, YAVAPAI CNTY	770,779		770,779
9				
10				
11				
12				
13	OTHER THAN LAND:			
14				
15				
16	SUN CITY OFFICE	392,214	* (392,214)	0
17	POWER QUALITY SALES SOFTWARE	155,162		155,162
18	METER PANELS	456,266		456,266
19	NON-COMMERCIAL DWELLING	1,102,138		1,102,138
20	COMPUTER EQUIPMENT	149,181	* 1,110,900	1,260,081
21	NON-UTILITY COMBUSTION TURBINE	878,250	* 2,660,018	3,538,268
22	APS ELECTRICS		509,243	509,243
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				0
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44	Minor Item Previously Devoted to Public Service	352,037		352,037
45	Minor Items-Other Nonutility Property	263,361	(113,666)	149,695
46	TOTAL	$16,344,413	$3,778,715	$20,123,128

Name of Respondent Arizona Public Service Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	SFAS 109 Income Tax	$575,030,000	282, 283	$82,545,000	$492,485,000
2	(various: over period of book/tax difference)				
3					
4	Palo Verde Cost Deferral	419,539,661	various	60,668,729	358,870,932
5	Unit 2 (4/88 to 7/2004)				
6	Unit 3 (12/91 to 7/2004)				
7					
8	PV Sales/Leaseback Rent Levelization	62,411,690	407	9,214,167	53,197,523
9	(1/2000 to 7/2004)				
10					
11	Option II, Directors & Executives COLI	20,473,723	426	244,660	20,229,063
12					
13	PV Sales/Leaseback Refinancing	10,583,071	525, 407	1,411,076	9,171,995
14	Costs & Rent Payment				
15	(3/93 - 7/2004)				
16					
17	PV Decomm & Decont Fee	10,587,462	518	1,415,174	9,172,288
18	(1/93 to 1/2008)				
19					
20	PV Westinghouse/Everest Term Fee	9,823,377	518	2,816,711	7,006,666
21	(various: ending 6/2001)				
22					
23	Premium-Reacquired Preferred Stock	3,927,689	407, 439	536,245	3,391,444
24	(various: 10 yr period from reacquistion) 7/2004				
25					
26	TMC Term Fee	389,988	518	194,095	195,893
27	(ending 6/2001)				
28					
29	Coal Reclamation	69,065,625	407	9,208,750	59,856,875
30	(7/96 to 7/2004)				
31					
32	Pathfinder Term Fee	1,195,452	407	159,393	1,036,059
33	(ending 7/2004)				
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	$1,183,027,738		$168,414,000	$1,014,613,738

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.

3. If increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$746,937,845	$721,876,572
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr.4)	687,988,345	678,130,020
5	Large (or Ind.) (See Instr.4)	173,402,019	171,771,407
6	(444) Public Street and Highway Lighting	11,757,351	12,863,581
7	(445) Other Sales to Public Authorities	83,848	214,423
8	(446) Sales to Railroads and Railways	0	0
9	(448) Interdepartmental Sales	0	0
10	TOTAL Sales to Ultimate Consumers	$1,620,169,408	$1,584,856,003
11	(447) Sales for Resale	$137,839,266	$98,560,401
12	TOTAL Sales of Electricity	$1,758,008,674	$1,683,416,404
13	(Less) (449.1) Provision for Rate Refunds	($111,424)	$912,127
14	TOTAL Revenues Net of Prov. for Refunds	$1,758,120,098	$1,682,504,277
15	Other Operating Revenues		
16	(450) Forfeited Discounts	$3,774,131	$2,919,434
17	(451) Miscellaneous Service Revenues	6,856,057	6,632,418
18	(453) Sales of Water and Water Power	0	0
19	(454) Rent from Electric Property	7,399,258	14,042,994
20	(455) Interdepartmental Rents	0	0
21	(456) Other Electric Revenues	14,128,064	12,173,289
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	$32,157,510	$35,768,135
27	TOTAL Electric Operating Revenues	$1,790,277,608	$1,718,272,412

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

ELECTRIC OPERATING REVENUES (Account 400)(Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2,4,5,and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVG. NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
7,970,309	7,541,440	663,493	636,239	2
				3
8,524,882	8,233,762	79,754	76,708	4
3,235,646	3,161,132	3,965	3,833	5
80,870	79,098	612	574	6
5,220	5,264	245	256	7
0	0	0	0	8
0	0	0	0	9
19,816,927	19,020,696	748,069	717,610	10
4,931,333	3,367,234	59	41	11
24,748,260	22,387,930	748,128	717,651	12
				13
24,748,260	22,387,930	748,128	717,651	14

Line 12, Column (b) includes $ 3,003,000 of unbilled revenues.

Line 12, Column (d) includes 0 MWH relating to unbilled revenues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Arizona Public Service Company	(1) [x] An Original (2) [ ] A Resubmission	04/30/98	Dec. 31, 1997

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customers, average KWh per customer, and average revenue per KWh, excluding data for Sales for Resale which is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," pages 300-301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	440 Residential					
2	E-10	1,324,916	129,251,366	144,680	9,157	9.7554¢
3	E-12	2,202,706	230,652,172	281,828	7,815	10.4714¢
4	EC-1	921,186	77,983,143	41,028	22,452	8.4655¢
5	ET-1	2,520,036	227,268,315	157,768	15,973	9.0184¢
6	ECT-1R	999,165	79,285,921	38,129	26,204	7.9352¢
7	E-47	2,300	469,977	2,437	943	20.4337¢
8	E-47 Adj.	0	0	(2,437)	0	
9	Solar	0	38,947	60	0	
10	Total Residential	7,970,309	744,952,844	663,493	12,012	9.3465¢
11						
12	442 Commercial					
13	E-20	22,532	2,114,723	235	95,880	9.3854¢
14	E-21	1,577	136,949	32	49,281	8.6841¢
15	E-22	5,722	547,136	13	440,153	9.5619¢
16	E-23	12,954	1,067,493	42	308,428	8.2406¢
17	E-24	90,964	5,542,281	15	6,064,266	6.0928¢
18	E-30	13,774	1,820,872	4,867	2,830	13.2196¢
19	E-32	6,976,194	592,315,557	73,663	94,704	8.4905¢
20	E-34	636,655	36,546,826	24	26,527,291	5.7404¢
21	E-35	330,442	16,696,908	5	66,088,400	5.0529¢
22	E-40	22	11,278	11	2,000	51.2636¢
23	E-47	19,549	4,207,468	5,765	3,390	21.5226¢
24	E-51	12,729	814,349	4	3,182,250	6.3975¢
25	E-221	194,256	14,312,129	752	258,319	7.3676¢
26	E-221-TW	637	50,071	7	91,000	7.8604¢
27	E-221-8T	5,000	325,870	15	333,333	6.5174¢
28	Special Contracts	201,875	10,655,433	70	2,883,928	5.2782¢
29	E-47 Adj.	0	0	(5,765)	0	
30	Total Commercial	8,524,882	687,165,343	79,755	106,888	8.0607¢
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed					
42	Total Unbilled Rev.(See Instr. 6)					
43	TOTAL					

Name of Respondent Arizona Public Service Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customers, average KWh per customer, and average revenue per KWh, excluding data for Sales for Resale which is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," pages 300-301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	442 Industrial and Irrigation					
2	E-21	371	34,059	7	53,000	9.1803¢
3	E-22	1,119	117,657	3	373,000	10.5144¢
4	E-23	1,270	115,962	3	423,333	9.1308¢
5	E-24	62,368	3,687,759	7	8,909,714	5.9129¢
6	E-30	2	835	8	250	41.7500¢
7	E-32	770,975	60,518,720	3,136	245,846	7.8496¢
8	E-34	413,501	23,374,533	12	34,458,416	5.6528¢
9	E-35	15,402	936,707	1	15,402,000	6.0817¢
10	E-38	26,876	1,947,287	243	110,600	7.2454¢
11	E-47	867	157,267	198	4,378	18.1392¢
12	E-221	60,643	4,828,033	461	131,546	7.9614¢
13	E-221-TW	3,285	260,156	18	182,500	7.9195¢
14	E-221-8T	14,410	1,105,443	51	282,549	7.6713¢
15	Special Contracts	1,864,557	76,104,604	15	124,303,800	4.0816¢
16	E-47 Adj.	0	0	(198)	0	
17	Total Industrial & Irrigation	3,235,646	173,189,022	3,965	816,051	5.3525¢
18						
19	444 Public Street Lighting	80,870	11,775,351	612	132,140	14.5608¢
20	Total Public Street Lighting	80,870	11,775,351	612	132,140	14.5608¢
21						
22	445 Other Public Authorities	5,220	83,848	245	21,306	1.6062¢
23	Total Other Public Authorities	5,220	83,848	245	21,306	1.6062¢
24						
25	Unbilled Revenue					
26	Residential Unbilled Revenue		1,985,000			
27	Commercial Unbilled Revenue		823,000			
28	Ind. & Irrig. Unbilled Revenue		213,000			
29	Public Str Lighting Unbilled Rev		(18,000)			
30	Other Public Auth Unbilled Rev		0			
31	Total Unbilled Revenue	0	3,003,000	0		0
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed					
42	Total Unbilled Rev.(See Instr. 6)					
43	TOTAL	19,816,927	$1,620,169,408	748,070	26,490	8.1756¢

Name of Respondent Arizona Public Service Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/98	Year of Report Dec. 31, 1997

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$4,142,310	$2,984,313
5	(501) Fuel	143,550,372	166,300,895
6	(502) Steam Expenses	9,696,786	10,564,390
7	(503) Steam from Other Sources	0	0
8	(Less) (504) Steam Transferred--Cr.	0	0
9	(505) Electric Expenses	2,598,707	2,791,849
10	(506) Miscellaneous Steam Power Expenses	6,724,833	5,765,273
11	(507) Rents	393,375	394,558
12	(509) Allowance	0	0
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	$167,106,383	$188,801,278
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	$4,162,696	$3,648,544
16	(511) Maintenance of Structures	1,860,599	1,428,962
17	(512) Maintenance of Boiler Plant	19,783,517	20,596,757
18	(513) Maintenance of Electric Plant	6,024,078	4,971,270
19	(514) Maintenance of Miscellaneous Steam Plant	4,572,330	5,902,164
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	$36,403,220	$36,547,697
21	TOTAL Power Production Expenses--Steam Power (Enter Total of lines 13 and 20)	$203,509,603	$225,348,975
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	$7,962,661	$6,776,518
25	(518) Fuel	43,013,029	43,672,192
26	(519) Coolants and Water	3,498,554	3,804,210
27	(520) Steam Expenses	6,468,594	9,761,704
28	(521) Steam from Other Sources	0	0
29	(Less) (522) Steam Transferred--Cr.	0	0
30	(523) Electric Expenses	3,815,763	2,271,905
31	(524) Miscellaneous Nuclear Power Expenses	19,104,603	22,485,234
32	(525) Rents	41,663,402	41,757,744
33	TOTAL Operation (Enter Total of lines 24 thru 32)	$125,526,606	$130,529,507
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	$11,918,446	$7,950,735
36	(529) Maintenance of Structures	4,015,387	4,846,033
37	(530) Maintenance of Reactor Plant Equipment	5,422,402	10,108,145
38	(531) Maintenance of Electric Plant	4,319,593	4,302,379
39	(532) Maintenance of Miscellaneous Nuclear Plant	3,767,705	3,602,014
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	$29,443,533	$30,809,306
41	TOTAL Power Production Expenses--Nuclear Power (Enter total of lines 33 and 40)	$154,970,139	$161,338,813
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	$69,793	$68,811
45	(536) Water for power	0	0
46	(537) Hydraulic Expenses	42,759	17,061
47	(538) Electric Expenses	58,837	53,685
48	(539) Miscellaneous Hydraulic Power Generation Expenses	94,678	110,788
49	(540) Rents	0	0
50	TOTAL Operation (Enter Total of lines 44 thru 49)	$266,067	$250,345

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES(Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$12,631	$8,776
54	(542) Maintenance of Structures	50,599	10,780
55	(543) Maintenance of Reservoirs, Dams, and Waterways	70,371	141,862
56	(544) Maintenance of Electric Plant	16,388	88,412
57	(545) Maintenance of Miscellaneous Hydraulic Plant	149,684	81,089
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	$299,673	$330,919
59	TOTAL Power Production Expenses-Hydraulic Power(Enter total of lines 50 and 58)	$565,740	$581,264
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	$1,010,178	$370,838
63	(547) Fuel	14,777,755	20,420,140
64	(548) Generation Expenses	602,326	1,247,200
65	(549) Miscellaneous Other Power Generation Expenses	903,798	799,656
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	$17,294,057	$22,837,834
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	$264,827	$286,492
70	(552) Maintenance of Structures	138,607	113,917
71	(553) Maintenance of Generating and Electric Plant	682,544	1,840,433
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	728,584	657,846
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	$1,814,562	$2,898,688
74	TOTAL Power Production Expenses--Other Power (Enter Total of lines 67 and 73)	$19,108,619	$25,736,522
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	$147,686,614	$95,130,569
77	(556) System Control and Load Dispatching	(559,082)	36,102
78	(557) Other Expenses	461,985	304,132
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$147,589,517	$95,470,803
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$525,743,618	$508,476,377
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$1,643,204	$1,820,503
84	(561) Load Dispatching	1,510,609	1,267,295
85	(562) Station Expenses	80,719	38,999
86	(563) Overhead Lines Expenses	517,918	750,219
87	(564) Underground Lines Expenses	0	4
88	(565) Transmission of Electricity by Others	6,944,030	3,966,269
89	(566) Miscellaneous Transmission Expenses	2,814,394	1,790,030
90	(567) Rents	661,361	640,286
91	TOTAL Operation (Enter Total of lines 83 thru 90)	$14,172,235	$10,273,605
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$86,761	$19,329
94	(569) Maintenance of Structures	306,975	231,082
95	(570) Maintenance of Station Equipment	2,251,638	1,729,525
96	(571) Maintenance of Overhead Lines	1,182,378	1,292,542
97	(572) Maintenance of Underground Lines	5,412	27,443
98	(573) Maintenance of Miscellaneous Transmission Plant	654,176	493,336
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$4,487,340	$3,793,257
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$18,659,575	$14,066,862
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	$1,516,113	$4,203,785

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount For Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	$713,802	$634,380
106	(582) Station Expenses	61,450	91,105
107	(583) Overhead Line Expenses	227,356	653,528
108	(584) Underground Line Expenses	2,082,466	1,669,756
109	(585) Street Lighting and Signal System Expenses	743,261	1,147,484
110	(586) Meter Expenses	4,305,120	4,240,413
111	(587) Customer Installations Expenses	526,710	802,757
112	(588) Miscellaneous Expenses	7,028,758	8,277,903
113	(589) Rents	1,469,182	1,404,736
114	TOTAL Operation (Enter Total of lines 103 thru 113)	$18,674,218	$23,125,847
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	$719,364	$655,285
117	(591) Maintenance of Structures	456,457	476,124
118	(592) Maintenance of Station Equipment	1,076,553	612,739
119	(593) Maintenance of Overhead Lines	9,218,100	9,154,727
120	(594) Maintenance of Underground Lines	6,739,997	8,230,130
121	(595) Maintenance of Line Transformers	2,748,686	1,386,942
122	(596) Maintenance of Street Lighting and Signal Systems	841,115	713,592
123	(597) Maintenance of Meters	90,687	97,172
124	(598) Maintenance of Miscellaneous Distribution Plant	5,721,033	5,754,275
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	$27,611,992	$27,080,986
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	$46,286,210	$50,206,833
127	4.CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	$2,356,818	$2,705,936
130	(902) Meter Reading Expenses	5,891,416	5,476,235
131	(903) Customer Records and Collection Expenses	18,266,166	18,886,817
132	(904) Uncollectible Accounts	1,781,451	2,252,805
133	(905) Miscellaneous Customer Accounts Expenses	1,827,805	1,647,242
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	$30,123,656	$30,969,035
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	$566,796	$594,272
138	(908) Customer Assistance Expenses	5,833,360	7,025,522
139	(909) Information and Instructional Expenses	217,769	201,184
140	(910) Miscellaneous Customer Service and Information Expenses	377,469	733,145
141	TOTAL Cust. Service and Informational Exp.(Enter Total of lines 137 thru 140)	$6,995,394	$8,554,123
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	$964,809	$925,858
145	(912) Demonstrating and Selling Expenses	14,348,332	11,829,736
146	(913) Advertising Expenses	2,356,031	1,689,814
147	(916) Miscellaneous Sales Expenses	2,186,360	845,303
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	$19,855,532	$15,290,711
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	$29,209,670	$31,792,568
152	(921) Office Supplies and Expenses	15,478,190	20,004,045
153	(Less) (922) Administrative Expenses Transferred--Credit	7,679,767	9,262,227

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$7,712,149	$8,504,777
156	(924) Property Insurance	(698,870)	(145,561)
157	(925) Injuries and Damages	5,128,414	6,375,227
158	(926) Employee Pensions and Benefits	38,297,327	65,239,719
159	(927) Franchise Requirements	23,330,340	22,823,479
160	(928) Regulatory Commission Expenses	7,891,408	6,144,065
161	(929) (Less) Duplicate Charges--Cr.	1,792,269	3,408,516
162	(930.1) General Advertising Expenses	33,086	12,868
163	(930.2) Miscellaneous General Expenses	(24,344,813)	(25,578,010)
164	(931) Rents	3,428,633	3,425,120
165	TOTAL Operation (Enter Total of lines 151 Thru 164)	$95,993,498	$125,927,554
166	Maintenance		
167	(935) Maintenance of General Plant	$8,543,816	$7,294,155
168	TOTAL Administrative and General Expenses (Enter total of lines 165 thru 167)	$104,537,314	$133,221,709
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126,134,141,148 and 168)	* $752,201,299	* $760,785,650

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be dete mined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	10/22/97
2. Total Regular Full-Time Employees	5,747
3. Total Part-Time and Temporary Employees	218
4. Total Employees	5,965