0000065540

47

Arizona [illegible] of Electrical Workers

AZ CORP COMMISSION

[illegible] 28 11 37 AM '96

DOCUMENT CONTROL

DOCKETED

JUN 2 8 1996

June 26, 1996

DOCKET CONTROL
Docket No. U-0000-94-165
ARIZONA CORPORATION COMMISSION
1200 WEST WASHINGTON
PHOENIX, ARIZONA 85007
ATTENTION: GARY YAQUINTO

Dear Mr. Yaquinto:

As requested I have enclosed eleven copies of our response to Commission Staff request for Comments on Electric Industry Restructuring.

Sincerely,

William H. Turner

William H. Turner
President
Arizona State Association Of Electrical Workers
750 S. Tucson Blvd.
Tucson, Arizona

Arizona State Association of Electrical Workers

AZ CORP COMMISSION
JUN 28 11 37 AM '96
DOCUMENT CONTROL

June 26, 1996

Arizona Corporation Commission
DOCKETED
JUN 2 8 1996
DOCKETED BY

DOCKET CONTROL
Docket No. U-0000-94-165
ARIZONA CORPORATION COMMISSION
1200 WEST WASHINGTON
PHOENIX, ARIZONA 85007
ATTENTION: GARY YAQUINTO

Dear Mr. Yaquinto:

As requested I have enclosed eleven copies of our response to Commission Staff request for Comments on Electric Industry Restructuring.

Sincerely,

William H. Turner

William H. Turner
President
Arizona State Association Of Electrical Workers
750 S. Tucson Blvd.
Tucson, Arizona

ELECTRIC SERVICE QUALITY STANDARDS

PREAMBLE

Ensuring reliability of electric power in a period of electric utility restructuring is one of the most significant challenges confronting the Arizona Corporation Commission. When the deregulation of utilities threatens reliability, it is a disservice to all concerned. Widespread electrical outages are harmful and dangerous to a community:

* Businesses are shut down.
* Hospitals encounter life-threatening emergencies.
* Traffic becomes entangled when signals no longer function.
* Emergency response systems are disrupted.
* Lives of children and adults are disrupted in homes, businesses and schools.

Electric utility reliability is dependent on people. Power plant operators, maintenance workers, as well as foreman ensure the reliable production and transmission of electricity. These employees must be working 24 hours a day, 7 days a week, in order for customers to have the generally reliable power we enjoy today. Utilities must employ, coordinate, train and manage these highly skilled, stable, concerned employees. The contributions of these employees is often taken for granted, but they are at the heart of service reliability.

Adequate staffing levels in appropriate locations must be maintained to ensure the continuation of high quality, reliable electric service. Unfortunately, the prospect of deregulationn has been a driving force among Arizona utilities recently, and has been used to justify downsizing and decreasing preventive maintenance. Work loads have steadily increased while the numbers of qualified employees have declined. The eventual outcome for the utility customer will be more frequent and longer outages and an overall destabilizing effect on the quality and reliability of power.

Understaffing is endangering personnel as well as equipment. Injuries to workers can occur when equipment is not maintained properly. For example, electrical breakers, which are designed to shut down equipment under certain conditions for the protection and safety of the equipment and the customer, are now being inadequately inspected, maintained and repaired because of cutbacks. Boiler repairs, including welding, fabricating, and general maintenance, are no longer being done exclusively by skilled company personnel who have a vested interest in the outcome of their work. This has, in many cases, led to outages. Routine maintenance, calibration, and testing of equipment which ensures the proper operation of trips, alarms, and corrective response actions are not being done because of budgetary restraints and understaffing.

The supply of reliable, safe electric power will not occur without the implementation and enforcement of electric service quality standards.Unfortunately, many electric utility customers have already been forced to accept a reduction in quality, safety and reliability for their electric service without a corresponding reduction in cost. The IBEW is committed to the premise that all Arizona utility customers deserve high-quality, safe and reliable electric service.

To meet this objective, IBEW believes the Corporation Commission should focus on four distinct areas: system reliability, preventive maintenance, customer service, and public and worker safety. Time is of the essence, because in Arizona safe, reliable electric power is in serious jeopardy.

1. System Reliability

IBEW recommends the use of three indexes (See Attached) to measure system reliability. They are:

* Average Interruption Duration Index (AIDI)
* Average Interruption Frequency Index (AIFI)
* Momentary Average Interruption Frequency Index (MAIFI)

For these indexes to be useful, all utilities must employ uniform inputs or assumptions. The measurements should be undertaken and reported for each distribution circuit. If only system numbers were reported, weak areas of the system would go unnoticed and unimproved.

Terminology

Sustained and momentary outages: A sustained outage is one that lasts longer than five minutes. A momentary outage lasts less than five minutes.

Planned outages: Planned outages are those outages which the utility schedules and notifies customers of in advance.

Outage start and stop times: The beginning of an outage is recorded at the earliest indication of an automatic alarm or first report of no power. The end of an outage is when all customers have power restored.

Tracking Level: On a monthly basis each utility should compile data for each distribution circuit with regard to the three indexes

Reporting Requirements On System Reliability

Annual Report: Each utility shall file a report using the three indexes, on a distribution circuit by distribution circuit basis, for the prior 12 months. The report shall be due by September 30 and shall include data through June 30. All distribution circuits shall be ranked from the best to worst performers for each index.

Interruptions of One/Two Hours: Each utility shall file a report with the Corporation Commission any time a distribution circuit has an interruption of one hour or more and exclusively serves an urban area that is included within a Standard Metropolitan Statistical Area (SMSA). Each utility shall file a report with the Corporation Commission any time a primary distribution circuit has an interruption of two hours or more and is located in a non-urban area. The reports shall include information about the reasons for the cause of the interruption, the geographic location of the interruption, the number of customers affected by the interruption, the duration of the interruption, actions taken in response to the interruption, corrective actions to be taken by the utility in order to avoid interruptions which necessitate the filing of a report. Each circuit shall be categorized by substation.

Notice to Customers: In the event any distribution circuit, for three consecutive months, is 20% below the average for all the distribution circuits of the utility for any of the three indexes, then the utility must enclose a bill stuffer to all customers served through that distribution circuit reporting that reliability is substandard. The form and wording of the Notice shall be approved by the Staff of the Corporation Commission.

2. Preventive Maintenance Plan

There are no long-term savings from failing to perform preventive maintenance on switches, poles, lines, substations, generators and other mechanical and electrical equipment. Recently several utilities have scrapped or seriously diminished preventive maintenance programs which had been in effect for many years. Reasonable and prudent preventive maintenance plans need to be in effect for distribution and transmission utility. The Corporation Commission has recognized the importance of preventive maintenance in its Provision of service Rule R14-2-208 IBEW recommends that all utilities which own distribution, transmission, and generating facilities be required to file with the Corporation Commission a Preventive Maintenance Plan by October 1, 1996, with a 30 day period for filing comments. The Staff of the Corporation Commission shall approve, reject or modify such Plans no later than December 31, 1996. The Plan shall include overhead and underground distribution facilities as well as substations, generation and transmission facilities.

Features of the Plan

Preventive Maintenance: The Plan shall set forth a schedule for preventive maintenance for overhead and underground lines, poles, substations, and related equipment.

Replacement Schedule: The Plan shall specify the expected date for replacement of overhead and underground lines, poles, substations and related equipment.

Inspection: The Plan shall include a schedule for the inspection of poles, underground and overhead lines, substations and related equipment and appurtances. The Plan shall indicate the method of inspection (visual, oil test, infrared, mechanical, electrical, etc.) and shall include the checklist/report forms that will be used.

Guide for Inspectors: The Plan shall include the instructions given to inspectors to determine the condition of a facility or piece ofequipment.

Training: The Plan shall require all utility employees, vendors and contractors to have completed appropriate industry recognized training.

Condition Rating: Each facility inspected shall be given a rating. The criteria for such ratings shall be spelled out in the Plan.

Corrective Action: The Plan shall set forth the manner or method for corrective action implementation in the event a facility receives an unfavorable rating. The Plan shall set forth a corrective action schedule.

Recordkeeping: The Plan shall specify where the records will be kept with regard to inspections, condition rating, corrective actions, replacement of facilities and preventive maintenance. The records shall be kept for a period of five years.

3. Customer Service

To a large extent there is an information vacumn as far as customer service is concerned. Customers who have service complaints often do not know where to register a complaint or how to get it resolved. Frequently, the Corporation Commission is at the mercy of the utility to report on its level of customer service. Heavy reliance on this sort of information can prove unreliable because a utility has a vested interest in painting a rosy picture about its customer service.

Complaint Hot Line: To be able to determine the level of customer service, IBEW recommends that the Corporation Commission require each utility with distribution, transmission and generation facilities establish an easy to remember 1-800 number for the sole purpose of answering complaints about bills, service and safety concerns. IBEW recommends that on a quarterly basis each utility include a bill stuffer promoting its complaint hotline. The form of the Notice shall be approved by the Staff of the Commission. Each utility shall also prominently advertise the complaint service in each telephone directory of an incumbent local exchange company within its service territory. The complaint hot line shall be staffed so that calls can be answered by a live person within 20 seconds of iniatiation of the call except during storms or just after passage of a storm. The utility shall install enough lines so that a caller does not receive a busy signal except for major outages. A 'major outage' is constued to be an outage when 1,000 or more customers are simultaneously without service.

Commission 1-800 Number: IBEW recommends that the Corporation Commission establish a 1-800 number for electric utility customers to call about complaints with service or bills which are unresolved. The Commission should undertake a national study to determine which Commission is doing the best job in operating and publicizing such a hot line.

Performance Indicators

Establishment or termination of service: Requests for the establishment or termination of service ought to be completed within 72 hours of receiving the requests except for customer-caused delays or other delays outside the control of the utility.

Trouble Reports: Trouble reports generated by customers should be satisfactorily taken care of within 2 hours of being iniated.

Phone Center Access: Customers ought to be able to reach a live phone center operator within 20 seconds of iniating a call. Less than 5% of the calls should receive a busy signal.

Billing Process: Less than 1% of the bills should be in error as a result of not properly calclating the bill or failing to properly read the meter.

Cut-offs of Service: Adequate safeguards should be implemented to ensure that improper shut-offs of service do not occur.

4. Public and Worker Safety

There are few safeguards in place to protect against injuries to the general public and to workers which could result from the restructuring of the electric utility industry. As restructuring has occurred, utilities have attempted to provide electric service with fewer workers, especially with regard to workers who must work in and around energized power lines and substations. Some utilities have put severe stress on job performance by requiring one worker to take on responsibilities which would have been handled by two to three workers in the past. Some utilities have hired contract workers who are not highly skilled or trained to undertake job functions calling for years of experience and training. This situation has put both the public and workers at risk of serious injury. It is time that the Corporation Commission implement minimal safety requirements and appropriate reporting of accidents and injuries.

Minimal Safety Requiremens

Worker Training: Utility employees, vendors and contractors working on or around customers' equipment or property shall have completed appropriate industry recognized training to minimize hazards to the customers and the public at large.

Adherence to Safety Regulations: Utilities shall implement procedures to ensure that their employees, vendors and contractors will adhere to all Federal and State safety rules and regulations.

Bonding: Utility contractors and vendors working on or around customer or public property or equipment shall be bonded against the possible threat to customers or the public by negligent or criminal behavior by employees of such contractors or vendors.

Assume Responsibility for Damage: Utilities will be responsible for all damage to customer property and equipment primarily caused by the failure of such utilities to deliver service to their customers in compliance with the specifications set by the Commission.

Incident Reports

Reporting Criteria: Each utility shall report to the Commission all incidents where: 1. Fatality or personal injury, with inpatient hospitalization, where the incident involves utility owned electric facilities; or Estimated property damage of the utility or to others, or both, is $20,000 or more.

Written Reports: The utility shall furnish to the Commission a written report within 30 days of each incident giving a detailed and thorough account of the incident.

System Reliability Indices Definitions & Equations

AIDI

Average Interruption Duration Index: This index represents the average interruption duration for customers interrupted during a year. It is determined by dividing the summ of all customer sustained interruption durations by the number of sustained customer interruptions over a one-year period.

Equation AIDI = Sum of Customer Interruption Durations DIVIDED BY Total Number of Customers Interrupted.

AIFI

Average Interruption Frequency Index: This index depicts the average number of interruptions per customer served per year. It is determined by dividing the accumulated number of customer interruptions in a year by the number of customers served. A customer interruption is considered to be one interruption to one customer.

Equation AIFI= Total Number of Customer Interruptions DIVIDED BY Total Number of Customers Served.

Momentary Average Interruption Frequency Index: This index represents the average number of interruptions per customer interrupted per year. It is determined by dividing the number of customer interruptions observed in a year by the number of customers affected. The customers affected are counted only once regardless of the number of interruptions that they may have experienced during the year.

Equation MAIFI= Total Number of Customer Interruptions DIVIDED BY Total Number of Customers Affected.

ELECTRIC SERVICE QUALITY STANDARDS

PREAMBLE

Ensuring reliability of electric power in a period of electric utility restructuring is one of the most significant challenges confronting the Arizona Corporation Commission. When the deregulation of utilities threatens reliability, it is a disservice to all concerned. Widespread electrical outages are harmful and dangerous to a community:

* Businesses are shut down.
* Hospitals encounter life-threatening emergencies.
* Traffic becomes entangled when signals no longer function.
* Emergency response systems are disrupted.
* Lives of children and adults are disrupted in homes, businesses and schools.

Electric utility reliability is dependent on people. Power plant operators, maintenance workers, as well as foreman ensure the reliable production and transmission of electricity. These employees must be working 24 hours a day, 7 days a week, in order for customers to have the generally reliable power we enjoy today. Utilities must employ, coordinate, train and manage these highly skilled, stable, concerned employees. The contributions of these employees is often taken for granted, but they are at the heart of service reliability.

Adequate staffing levels in appropriate locations must be maintained to ensure the continuation of high quality, reliable electric service. Unfortunately, the prospect of deregulationn has been a driving force among Arizona utilities recently, and has been used to justify downsizing and decreasing preventive maintenance. Work loads have steadily increased while the numbers of qualified employees have declined. The eventual outcome for the utility customer will be more frequent and longer outages and an overall destabilizing effect on the quality and reliability of power.

Understaffing is endangering personnel as well as equipment. Injuries to workers can occur when equipment is not maintained properly. For example, electrical breakers, which are designed to shut down equipment under certain conditions for the protection and safety of the equipment and the customer, are now being inadequately inspected, maintained and repaired because of cutbacks. Boiler repairs, including welding, fabricating, and general maintenance, are no longer being done exclusively by skilled company personnel who have a vested interest in the outcome of their work. This has, in many cases, led to outages. Routine maintenance, calibration, and testing of equipment which ensures the proper operation of trips, alarms, and corrective response actions are not being done because of budgetary restraints and understaffing.

The supply of reliable, safe electric power will not occur without the implementation and enforcement of electric service quality standards.Unfortunately, many electric utility customers have already been forced to accept a reduction in quality, safety and reliability for their electric service without a corresponding reduction in cost. The IBEW is committed to the premise that all Arizona utility customers deserve high-quality, safe and reliable electric service.

To meet this objective, IBEW believes the Corporation Commission should focus on four distinct areas: system reliability, preventive maintenance, customer service, and public and worker safety. Time is of the essence, because in Arizona safe, reliable electric power is in serious jeopardy.

1. System Reliability

IBEW recommends the use of three indexes (See Attached) to measure system reliability. They are:

* Average Interruption Duration Index (AIDI)
* Average Interruption Frequency Index (AIFI)
* Momentary Average Interruption Frequency Index (MAIFI)

For these indexes to be useful, all utilities must employ uniform inputs or assumptions. The measurements should be undertaken and reported for each distribution circuit. If only system numbers were reported, weak areas of the system would go unnoticed and unimproved.

Terminology

Sustained and momentary outages: A sustained outage is one that lasts longer than five minutes. A momentary outage lasts less than five minutes.

Planned outages: Planned outages are those outages which the utility schedules and notifies customers of in advance.

Outage start and stop times: The beginning of an outage is recorded at the earliest indication of an automatic alarm or first report of no power. The end of an outage is when all customers have power restored.

Tracking Level: On a monthly basis each utility should compile data for each distribution circuit with regard to the three indexes

Reporting Requirements On System Reliability

Annual Report: Each utility shall file a report using the three indexes, on a distribution circuit by distribution circuit basis, for the prior 12 months. The report shall be due by September 30 and shall include data through June 30. All distribution circuits shall be ranked from the best to worst performers for each index.

Interruptions of One/Two Hours: Each utility shall file a report with the Corporation Commission any time a distribution circuit has an interruption of one hour or more and exclusively serves an urban area that is included within a Standard Metropolitan Statistical Area (SMSA). Each utility shall file a report with the Corporation Commission any time a primary distribution circuit has an interruption of two hours or more and is located in a non-urban area. The reports shall include information about the reasons for the cause of the interruption, the geographic location of the interruption, the number of customers affected by the interruption, the duration of the interruption, actions taken in response to the interruption, corrective actions to be taken by the utility in order to avoid interruptions which necessitate the filing of a report. Each circuit shall be categorized by substation.

Notice to Customers: In the event any distribution circuit, for three consecutive months, is 20% below the average for all the distribution circuits of the utility for any of the three indexes, then the utility must enclose a bill stuffer to all customers served through that distribution circuit reporting that reliability is substandard. The form and wording of the Notice shall be approved by the Staff of the Corporation Commission.

2. Preventive Maintenance Plan

There are no long-term savings from failing to perform preventive maintenance on switches, poles, lines, substations, generators and other mechanical and electrical equipment. Recently several utilities have scrapped or seriously diminished preventive maintenance programs which had been in effect for many years. Reasonable and prudent preventive maintenance plans need to be in effect for distribution and transmission utility. The Corporation Commission has recognized the importance of preventive maintenance in its Provision of service Rule R14-2-208 IBEW recommends that all utilities which own distribution, transmission, and generating facilities be required to file with the Corporation Commission a Preventive Maintenance Plan by October 1, 1996, with a 30 day period for filing comments. The Staff of the Corporation Commission shall approve, reject or modify such Plans no later than December 31, 1996. The Plan shall include overhead and underground distribution facilities as well as substations, generation and transmission facilities.

Features of the Plan

Preventive Maintenance: The Plan shall set forth a schedule for preventive maintenance for overhead and underground lines, poles, substations, and related equipment.

Replacement Schedule: The Plan shall specify the expected date for replacement of overhead and underground lines, poles, substations and related equipment.

Inspection: The Plan shall include a schedule for the inspection of poles, underground and overhead lines, substations and related equipment and appurtances. The Plan shall indicate the method of inspection (visual, oil test, infrared, mechanical, electrical, etc.) and shall include the checklist/report forms that will be used.

Guide for Inspectors: The Plan shall include the instructions given to inspectors to determine the condition of a facility or piece ofequipment.

Training: The Plan shall require all utility employees, vendors and contractors to have completed appropriate industry recognized training.

Condition Rating: Each facility inspected shall be given a rating. The criteria for such ratings shall be spelled out in the Plan.

ARIZONA PUBLIC SERVICE COMPANY

RESPONSE TO STAFF"s QUESTIONS ON

COMPETITION AND INDUSTRY RESTRUCTURING

ACC DOCKET NO. (U-0000-94-165)

June 28, 1996

EXECUTIVE SUMMARY

Arizona Public Service Company ("APS" or the "Company") is presenting its written response to the Arizona Corporation Commission ("ACC") Staff request for comments in its investigation of the restructuring of the electric industry (ACC Docket No. U-0000-94-165). APS supports increased competition in the electric industry as both the means to increase overall economic efficiency and to provide greater opportunities for electric utilities and their customers.

To provide for an aggressive, yet orderly transition to full and equitable competition, APS has recommended herein a phased retail access plan ("Arizona Customer Choice Plan"). The Arizona Customer Choice Plan proposes generation market access to the larger customers beginning in the year 2000 and expanding such access to smaller commercial and industrial customers, and eventually all customers, in successive steps thereafter. The implementation of this proposal would begin as soon as the new market rules and structures are in place to provide a solid foundation to support effective competition, including resolving the issues of exclusive service territory rights, obligation to serve, reciprocity and the recovery of potentially stranded costs. This solid foundation is necessary at the outset to avoid competitive chaos and potentially lose the benefits of today's reliable, vertically integrated system.

To highlight the implementation process, the Company has prepared a comprehensive "time-line" for necessary actions at both the state and federal levels that will enable retail access to begin in Arizona. Step one entails full evidentiary hearings by the ACC which should begin as soon as possible. Although it is neither possible nor necessary for the ACC to address all restructuring issues in advance, there are certain threshold issues that can and must be resolved by the ACC based on an evidentiary record. Simultaneously, a reasonable transition period can begin between the tightly regulated and legal monopoly industry structure of today and the fully competitive structure of the future. This transition period will allow utilities to bring their generating costs in line with market prices, thus mitigating a major part of potentially strandable costs, and it will allow the Commission to analyze the real world results of direct retail access both in Arizona and elsewhere to determine whether the implementation of the Arizona Customer Choice Plan will, in fact, produce net positive gains for all customers and not just reallocation of costs among "winners" and "losers". Upon implementation of the required market reforms (expected by the year 2000) direct retail access for customers can begin in accordance with the Arizona Customer Choice Plan.

SECTION I

SECTION I provides a preface to the Company's response to the Staff inquiries. The Company emphasizes that significant competition already exists in the electric utility industry, both between providers of generation and with electric energy substitutes such as natural gas, advanced demand side management technology, etc. This competition, together with the innovative performance based regulatory mechanisms ("PBR") contained in the Company's 1991 and 1994 rate settlements and the recently approved 1996 Rate Reduction Agreement, provide the Company with powerful incentives to reduce costs, improve efficiency of operations, and enhance the value and diversity of service options to customers. APS believes that ACC hearings will conclude that there are yet additional incremental economic efficiencies to be gained from direct retail competition and that such gains would exceed the likely incremental costs. These incremental costs can range from the direct costs of participation in an open marketplace (the cost of metering and telecommunications infrastructure, analyzing and obtaining market information, etc.) to indirect costs, such as the potential impact upon social and environmental programs, reduced intra-industry cooperation, tax and employment effects, etc.

This section also outlines some of the existing impediments to expanded retail customer options. Some of these issues, such as strandable costs, reciprocity and service area rights/obligations must be resolved in advance of direct access while others can be addressed concurrent with the implementation of retail competition.

Section I concludes with a description of the Arizona Customer Choice Plan and an explanation of why an orderly transition to full and equitable competition through the Company's phased approach is recommended: (1) to allow the ACC to conduct full evidentiary hearings on the many significant competition issues; (2) to incorporate the results of the special legislative study committee on retail electric competition recently created by the Arizona Legislature; (3) to achieve the prerequisite retail market structural reforms through state and federal legislative action; and, (4) to allow a sufficient period of time for stranded cost mitigation to occur. The many significant "lessons learned" from electric restructuring efforts abroad and by this country's own prior restructuring of the gas and telecommunications industries reveal that the net benefits of competition can only be achieved through a carefully considered and properly implemented process that is not based on abstract theories but is rather guided by the realities of the existing marketplace and the economic and regulatory forces which have shaped it.

SECTION II

In **SECTION II** of its response, APS addresses three of the specific inquiries identified by ACC Staff. First, the Company indicates its general agreement, subject to certain modifications, with the Staff articulation of the "objectives" of industry restructuring. APS also suggests that certain additional objectives be included to allow for a practical and effective transition, including the achievement of reciprocity and jurisdictional consistency and the need for political acceptance. Second, APS responds to the Staff request for comments on how progress in meeting the stated objectives might be measured. In general, the Company believes that the success of retail access is best measured by the net level of participant and non-participant savings, the scope of participation, customer satisfaction, the number and variety of new pricing and service options made available to customers, and the preservation of system reliability.

Third, APS has concluded that a pilot will not produce meaningful or useful results regarding the many critical restructuring issues. A review of pilot programs in other states indicates that they are either designed only to test whether customers would enjoy lower rates (rather than discover how a competitive electricity market would best work) or are merely economic development or load retention programs in disguise. By focusing attention on the pilot rather than on preparing for and implementing real retail access, a pilot will likely delay rather than promote competition. The present inability of the ACC to require actual direct access under current Arizona law, even on an experimental basis, the short duration of any likely pilot program, and the prospect of testing special market pricing packages outside the parameters of a pilot retail wheeling program all lead APS to the conclusion that the actual phase-in of permanent direct access in carefully measured steps is far preferable and should not be delayed by focusing on pilot programs.

SECTION III

In **SECTION III**, APS provides a detailed response to the 19 specific questions regarding electric industry restructuring contained in Attachment A to the Staff's February 22, 1996 letter. Because the Company does not believe a pilot program will produce meaningful results, these questions have been primarily answered as they relate to the proposed Arizona Customer Choice Plan. The major points stressed by APS in this section of its response include (references are to the specific question numbers and nomenclature used by Staff):

A1. Affected Utilities. Which utilities should open their markets to competition?

All Arizona energy utilities should be affected equally and simultaneously once the various threshold issues described previously are addressed. However, the practical impossibility of addressing all public power issues in the short term argues for excluding such entities from at least the initial stages of restructuring.

A2. d. If divestiture were undertaken, how should it be accomplished?

APS does not believe that divestiture is necessary or desirable for creation of a competitive bulk power market. At least in APS' case, such a divestiture would be prohibitively expensive and unnecessary given APS' lack of market power. In addition, a mandatory divestiture order would be beyond the ACC's legal authority. Any decision regarding divestiture of assets should be left to the individual utility's management. APS is already meeting or exceeding FERC's requirements for functional unbundling of the merchant and transmission lines of business.

A4. Services available on a competitive basis. Which services should be available in a competitive market?

APS believes that generation services, *i.e.,* the sale of power and energy, should be provided as a competitive service with all energy providers regulated equally. All ancillary transmission services can also be competitively procured if the services are both measurable and controllable. Practical limitations and costs may impede full choice for smaller customers with regard to some of these services. In most cases, retail transmission and distribution wheeling will probably continue to be regulated for the foreseeable future on a cost-of-service basis (albeit one determined through some manner of PBR rather than traditional regulation) and would not be competitively available to the customer.

A9. Recovery of stranded investment. Please indicate how the recovery (if any) of stranded investment should be accomplished.

APS defines stranded investment as "investments, costs or future obligations prudently incurred in the past, by an Arizona public service corporation for the benefit of the customers in its service territory which become non-recoverable because of changes in the regulatory compact, or because of accounting or other regulatory changes occurring in the transition from a regulated monopoly environment to a competitive market". Examples of potentially stranded costs include the excess of net book value of existing generating plant assets over the market value of the assets; regulatory assets; decommissioning, reclamation and other funding obligations associated with existing generating plants; and portions of existing fuel supply and fuel transportation contracts. Unless separately dealt with, the concept of "stranded investment" should also include an Arizona public service corporation's right to compensation for the loss of constitutionally protected property rights in an exclusive service territory as well as compensation due for use of its distribution "wires" by others.

With respect to the recovery of stranded costs, APS believes that mitigation through cost savings and expanded sales of electricity and related services should be the primary source for stranded cost recovery. However, to the extent APS customers are allowed to "leave" APS' system prior to the time these mitigation efforts can reasonably be expected to bring generation costs in line with then current market prices, they should pay a one time "exit fee" to recoup any unamortized regulatory assets attributable to such customers and an annual delivery surcharge to reflect the difference between APS' average generation costs and average market prices. The exit fee would be discontinued after regulatory assets have been fully amortized (approximately 2004 for APS). The delivery surcharge would continue and gradually decline until market prices and utility generating costs are aligned. This mechanism would allow APS to remain cost-based within the meaning of SFAS No. 71 during the transition period but still promote progressively greater customer choice of energy suppliers.

A10. Recovery of costs of Commission-mandated utility low income, DSM, environmental, renewables, and nuclear power plant decommissioning programs ("mandated programs").

APS believes in a fully competitive market, mandated demand-side management, and renewable programs should be eliminated in favor of market forces deciding which programs are adopted. During the proposed transition period, regulatory mandated programs may be desirable and even necessary to reduce and/or eliminate market barriers in order to prepare the marketplace to accept or reject the adoption of such programs on their own merits. All energy consumers should share the cost burden of funding such mandated programs during this transition period.

APS believes that steps should be taken to provide for the long term goals of affordable energy and self sufficiency for low income customers.

Environmental programs should not be mandated by the ACC independently of those other agencies specifically charged with such oversight responsibility. However, to the extent the ACC does seek to implement environmental programs on its own, they should apply equally to all certified energy suppliers.

Nuclear power plant decommissioning costs should be treated separately from other mandated program costs and should be recovered in the same manner as stranded investment costs related to generation.

A11. Encouragement of renewables.

During the transition period to a more competitive market, renewable sources of energy can be encouraged by leveraging and promoting those applications where cost effectiveness can be achieved and/or have a reasonable expectation of being achieved. Support of renewable technologies during the transition period through the continued use of goals, fully funded by all ratepayers, can assist their commercialization and create an additional tool that utilities will be able to utilize for their future operations in a fully competitive energy market.

APS supports renewables as a viable portion of our portfolio in a competitive market, but it questions whether government promotion of renewables generation resources, or any other form of technology through regulated utilities, is a practical objective in a fully competitive electric generation industry.

A12. Pooling of generation and centralized dispatch of generation or transmission.

APS strongly believes that pooling or centralized dispatch of generation or transmission should be completely voluntary. Existing voluntary industry arrangements such as sharing reserves in the Inland Power Pool or economic coordination transactions in the Western Systems Coordinating Council ("WSCC") have provided numerous efficiencies. The Southwest Regional Transmission Association and WSCC have likewise dealt with transmission planning and access issues on a voluntary basis. The generation market can be organized principally around voluntary institutions and contracts. No monolithic mandatory spot market created by a California-style POOLCO is required.

A13. Non-public service corporations.

The inclusion of such public power entities (which are not regulated by the Commission) in restructuring efforts raises important and novel legal and policy issues that have not been confronted in other industry deregulation efforts in the U.S. (where government or public ownership of assets is not prevalent) and that could delay the advent of retail competition beyond 2000. APS is also a party to contractual agreements which could prevent the parties from directly competing (e.g., the Commission-approved APS/SRP territorial agreement). Therefore, APS proposes excluding public power from at least the first phases of direct competition unless the relevant issues can be adequately resolved.

A19. Certificates of Convenience and Necessity.

APS believes competitive sellers should be appropriately supervised by the ACC through issuance of CC&Ns. Because consumers have been particularly vulnerable to fraud in other newly deregulated industries, a CC&N should require of a competitive seller adequate evidence of financial strength, proof that it is a corporation in good standing, and a commitment that it will abide by all the same ACC requirements and industry reliability standards as are imposed on incumbent sellers such as APS.

CONCLUSION

APS actively supports increasing competition in the electric utility industry. APS urges the Commission to convene evidentiary hearings as soon as practicable to properly resolve the threshold legal and policy issues within its jurisdiction, and (upon concurrent completion of other necessary state and federal action), authorize phased retail access in accordance with the Arizona Customer Choice Plan.

I. A PREFACE TO ARIZONA PUBLIC SERVICE COMPANY'S RESPONSE TO STAFF'S QUESTIONS ON COMPETITION AND INDUSTRY RESTRUCTURING

Throughout the electric utility industry, there exists a virtual frenzy of activity, discussion, argument, and concern about the effects and potential effects of introducing direct retail competition in the electric service industry. There are heated cries for regulatory and industry reform and restructuring. Arizona is no exception, as evidenced by the Arizona Corporation Commission ("ACC" or "Commission") decision to open an investigatory docket on this subject.

Arizona Public Service Company ("APS" or "Company") believes that there already exists significant competition in the electric industry, both between providers of generation and with electric energy substitutes such as natural gas technologies, and advanced demand-side management ("DSM") technologies. Such competition will intensify in the coming years regardless of the degree to which competitive retail access occurs in Arizona.

APS favors competition and views it as an opportunity, but one which also presents complex challenges. Although industry restructuring is not without its risks, APS believes that competition offers potential benefits that make such risks worth taking. However, to limit those risks, Arizona's restructuring efforts need to carefully build a solid foundation to support effective competition. The competitive world of the future requires new market rules and structures. It is important to get these right at the outset in order to avoid competitive chaos and potentially lose the benefits of today's reliable, vertically integrated system.

APS believes that the threshold legal issues of public service corporations' service rights and obligations, reciprocal opportunities, and compensation to incumbent providers for potentially stranded costs must be addressed by the Commission and the Arizona Legislature. After resolution of these issues, a phased customer choice plan ("Arizona Customer Choice Plan"), which provides for direct access to transmission level customers in 2000, customers with a load of over 3MW in 2002, customers with a load of over 1MW in 2004, and all remaining customers thereafter based on the ACC's examination of net economic benefits, offers the opportunity to proceed in the most sound and rational manner. In APS' opinion, other paths, such as initiating a pilot which consumes time and resources in defining who is eligible, how long will it run, and to establish all the other criteria to simulate a constrained and artificial market, would only distract Arizona from the most direct path to full competition.

Competition provides electric producers with powerful incentives to reduce costs, improve efficiency of operations, realign prices, and enhance the value and diversity of service options to existing and potential customers. Many of these same incentives are also provided through innovative and performance based regulatory mechanisms ("PBR") such as were authorized by the ACC in the Company's 1991 and 1994 rate settlements, and especially in the recently approved 1996 Second and Amended Restated Rate Reduction Agreement ("Rate Reduction Agreement"). See ACC Decision No. 59601 (April 24, 1996.) These incentives have already driven down APS costs and have resulted in two general rate decreases plus an ongoing mechanism to allow further rate decreases without the necessity for lengthy hearings. APS has an ongoing commitment to further reduce its prices and costs.

The Federal Energy Regulatory Commission ("FERC") is aggressively reshaping the wholesale generation market. Achievement of a competitive generation market is a necessary precursor to opening up part or all of the retail market to competition. Since the "wires" businesses of transmission and distribution are expected to remain in the foreseeable future as regulated monopolies, retail access is the access of retail customers to the competitive generation market, through the regulated wires. If the generation market is itself not competitive, then the benefits of retail competition will be minimal. Nonetheless, FERC has clearly indicated that the great majority of critical retail competition issues must be addressed at the state level.

As APS stands today, it is faced with vigorous wholesale competition in generation, and is subject to an increasing array of PBR incentives at retail. Many argue that these reforms will capture most of the possible economic efficiency gains in the electric industry. APS believes there are yet additional incremental economic efficiencies to be gained from direct retail competition--that is, efficiencies not realizable either from wholesale competition and/or PBR (which could also include competitively bidding all new resource additions). Allocative efficiency (eliminating cross-subsidies and moving prices closer to marginal cost), dynamic efficiency (accelerating the rate of technological and product line innovation), and production efficiency (more output per unit of input) should all be enhanced by increased retail competition.

Realistically, achieving these increased economic efficiencies is not without its own costs. Direct costs range from the technical (the cost of metering and telecommunications infrastructure) to the transactional (the cost to participants of obtaining, analyzing and acting upon market information, and the cost of creating and supervising the competitive market). There are indirect costs as well, such as the potential impact upon social and environmental programs, reduced industry cooperation, tax and employment impacts, etc. Finally, there are threshold legal issues that should be resolved before retail access can be implemented. These include service area rights and obligations, and potentially stranded costs. Their resolution, although necessary, will consume additional time and resources.

To better understand the cost/benefit trade-offs from retail competition, the ACC can first draw on the experience of regulators in previous industry restructuring efforts--gas and telecommunications restructuring in the United States; and electric restructuring in the United Kingdom ("UK") and in other states. Indeed, the U.S. and foreign, as well as previous Arizona experiences teach a number of lessons.

First, the need for having sufficient reliable information before acting and to anticipate problems in advance cannot be overemphasized. FERC has openly acknowledged that its failure to address "take or pay" gas supply contracts (the gas industry equivalent of "stranded costs") before requiring gas industry restructuring was a big mistake. Telecommunications restructuring in Arizona took place with many critical issues left unresolved (e.g., universal service, obligation to serve, market structure, level of regulation of incumbent providers of competitive services, interconnection, etc.). In states that are considered farther along in examining electric industry restructuring (e.g., California, New York, Pennsylvania, Massachusetts, Vermont, etc.), evidentiary hearings have either been concluded or are currently under way.

Second, the consequences of restructuring and the introduction of competition are not necessarily as predicted. Deregulation of U.S. wellhead gas prices was not intended to lead to structural reform of the role of the pipeline industry. The diversity of product offerings and the development of competition with adjacent industries (e.g., cable television) was not originally expected in telecommunications. No one foresaw the extent to which established utilities would lose customers to competitors in the U.K.

Third, restructuring is necessarily a long process. Eighteen years after deregulation began, the gas industry is only just (perhaps) completing restructuring, and full retail access has not yet been attempted, although over 26 states are beginning to examine this possibility as part of a broadly restructured energy industry. (Indeed, APS believes that the ACC should investigate retail choice in the Arizona gas industry consistent with the principle of providing greater choices to Arizona consumers.) Restructuring of telecommunications is still very much in process 14 years after the AT&T consent decree and nearly 30 years after *Carterfone*. Even if it keeps to its schedule the U.K. will have also taken many years to achieve the goal of universal retail access in electricity.

Fourth, market structure matters. Restructuring in both the natural gas and telecommunications industries entailed fewer problems than can be reasonably anticipated in the electric industry. Still, gas industry restructuring has needed multiple steps to eliminate the market dominance of pipeline merchant functions. Eliminating restrictions on dominant telecommunications companies has had to await the growth of competitors and enabling technological change. The U.K. is struggling with the consequences of an insufficiently competitive generation market.

Fifth, PBR, which gives utilities incentives to cut costs, can be very effective. In the U.K., the efficiency gains in the price-capped distribution businesses are on a par with gains in the competitive-generation sector. The same has proven true with regard to U.S. telephone utilities.

Sixth, costs stranded by the transition to competition may be very significant. There were many billions of dollars lost in the U.S. gas and telecommunications businesses. The loss in book value absorbed by the U.K. government (and, therefore, its tax paying public) in selling the electric power industry, when scaled to the U.S. electric power industry, approached $100 billion despite contractual and regulatory provisions for stranded cost recovery.

Seventh, the level and source of cost savings, the innovations in products, services and price offerings brought about by the combination of competition and deregulation are hard to forecast.

Eighth, establishing a competitive balance is important. In telecommunications, competitors have focused their efforts on luring customers that pay subsidies to other customers. A similar situation has occurred in the natural gas industry, with bypass of the local gas distribution company ("LDC") by larger customers (using interstate pipelines to directly access gas producers) exerting increasing upward pressure on rates to captive customers and greater business risk for LDC investors. The issue in electricity is compounded by the existence of a large public power segment enjoying a significant competitive advantage, and for which there was no analog in either the gas or telecommunications industries. If incumbents are disadvantaged by burdens not borne by competitors, or if new competitors are subsidized by either taxpayers or by the incumbent providers themselves, the privileged competitors will merely profit at the expense of both the incumbents and their customers.

Ninth, the drivers for deregulation have varied. In natural gas, it was the crippling gas shortages of the 1970's combined with the belief that deregulation would both improve allocative efficiency and increase domestic gas production. In telecommunications, technological breakthroughs drove change. In the U.K., the British Government desired to privatize the electric industry, to drive down the price of coal, and to use the monies from the sale of electric assets to fund other government activities. In California, even the regulators have acknowledged that the regulatory process is broken, and California customers would be facing even higher prices if the system were not radically changed. New York and New England also have among the highest priced electricity in the nation. QF bidding programs like those in California have been driving electric prices up, and restructuring has been perceived as an effective fix.

There are also important differences to consider between the process and likely results of natural gas, telecommunications, and U.K. electric industry restructuring on the one hand and the U.S. electric industry on the other hand. Differences from natural gas and telecommunications include the need for minute-by-minute integrated operation, the greater role of state regulation and overlapping jurisdictional issues, and the unique challenges presented by nuclear power and related decommissioning costs. The electric industry is far more vertically integrated and capital intensive than either natural gas or telecommunications. The industry involves many more players, with well over 100 investor-owned utilities alone, as contrasted with one AT&T or a handful of interstate gas pipelines. As compared to the U.K. experience, the U.S. electric industry has multiple, not a single regulatory jurisdiction, and has many private shareholders as owners, not the government. The U.S. industry has balkanized ownership of transmission. (Conversely, its large size and large number of utilities has already provided a better starting point for competition in generation without the need to break up individual vertically integrated firms.) Finally, bulk power has been historically regulated in the U.S. on a cost-of-service basis, unlike long-distance telephone service (priced above cost) or wellhead gas (priced below cost). This could mean that less dramatic allocative efficiency benefits may result from electric industry restructuring than from the deregulation of the other industries.

Restructuring efforts in the airline, rail, and trucking industries provide even less perfect analogies. What is clear is that these restructurings have produced varied results.

However, APS believes that the lessons learned elsewhere, although instructive (both for what they don't tell us as well as for what they do,) permit the ACC to draw only the most general of analogies and distinctions. They do not, in and of themselves, provide a sufficiently sound basis for action. In its response to the ACC Staff's questions, APS proposes a two part approach to proceeding forward on industry restructuring issues - an approach that will "reflect a deliberate process which considers the economic, financial, operational and system planning effects of such restructuring", [1] and will move Arizona down the path to a more competitive, less regulated, and more customer service oriented future.

Part one begins with evidentiary hearings by the ACC. While APS acknowledges that it is neither possible nor necessary for the ACC to address all restructuring issues in advance, there are certain threshold issues that can and should be resolved by the ACC based on an evidentiary record prior to going further. In Exhibit A to its response, the Company offers a time-line for actions at both the state and federal level. It contemplates the ACC concluding its examination of these threshold issues by the end of 1997. This is the same date by which the recently authorized special legislative study committee is to present its findings and recommendations to the Legislature. Legislative actions would follow, most likely, in the 1998-1999 Legislative Session. The coordination of efforts between the ACC and the Legislature is critical to the success of any proposed industry restructuring. That coordination is most likely to exist if the two bodies share a common factual basis for their actions and, more importantly, a common vision of the goals of restructuring.

An important outcome of these ACC hearings will be the establishment of a reasonable period to transition Arizona's utilities between the tightly regulated and legal monopoly industry structure of today and the more competitive and largely deregulated or reregulated structure (on the basis of PBR) of the future. The purpose of this period should be three-fold:

1. to both allow and encourage utilities to mitigate a major part of potentially strandable costs by bringing their generating costs into line with market prices;

2. to work through and resolve ongoing technical (metering, etc.), economic (market structure) and jurisdictional (FERC vs. ACC) issues; and,

3. to better evaluate the real world results of direct retail access, both in other jurisdictions and in Arizona.

APS has, in a sense, begun this transition by the accelerated amortization of regulatory assets. More broadly, however, the Transition Period should be that period of time between today and when existing generating costs equal the then prevailing market price. APS will thereafter refer to this as the "Transition Period". Concurrent with ACC and state Legislative actions will be ongoing Federal activity. APS will actively support efforts to provide for reciprocity and Public Utility Holding Company Act ("PUHCA") reform.

The second step involves actually instituting direct access in accordance with the Arizona Customer Choice Plan, beginning with the larger customers for which metering is readily available and for which the likely transactional costs of direct access would be low compared to their overall energy bill. The Arizona Customer Choice Plan proposes granting access to transmission level customers (69kV and above,) to be followed by individual customers over 3 MW and then individual customers over 1MW. This phased-in direct access plan would begin in approximately 2000 given

---

[1] Joint Staff and APS Statement on Restructuring Issues in Attachment 8, p.3 to the Rate Reduction Agreement (Decision No. 59601) (April 24, 1996.)

the time-line shown in Exhibit A. The third phase would be in place by 2004 and direct access would thereafter be extended to all customers as soon as practicable if no technical issues persist and if the ACC finds that such an expansion of access would provide net economic benefits. Customers granted access prior to the end of the aforementioned Transition Period would be assessed a combination of exit fees and distribution delivery surcharges to avoid any reallocation of strandable costs to other customers. The exit fee would be gradually phased out before 2004 and thereafter eliminated entirely. The delivery surcharge should also be phased out during the Transition Period and would disappear when that period ends.

The Arizona Customer Choice Plan will provide an opportunity to gather practical experience about how retail access will actually work. It will also allow policy makers to enter mid-course corrections to the path and nature of restructuring while such corrections would still affect only a relatively small number of customers. Finally, it will minimize the potential impact of retail access during the Transition Period on non-participating customers by providing for recovery of unmitigated stranded investments without cost shifting to such non-participants.

A review of pilot programs in other states indicates to us that they do not sufficiently test how electricity would be provided in a workably competitive market. Through incentives built into the pilot, they test whether customers would enjoy lower rates (rather than how a fully competitive market would work best) or are merely economic development or load retention programs in disguise. A pilot program could result in unnecessary delay in moving forward toward real competition by diverting attention away from resolution of the threshold issues that will allow APS to offer expanded choices to all its customers within the time frames outlined in the Arizona Customer Choice Plan. Any compulsory pilot conducted in this State would be limited to one in which the certificated provider would continue to act as the agent for the customer in procuring energy from the wholesale market, that is, a "virtual direct access pilot". Without resolution of the service rights and obligations conferred by existing laws, a mandatory direct access pilot would not be lawful at this time.

II. APS' RESPONSES TO ACC STAFF'S REQUEST FOR COMMENTS ON ELECTRIC INDUSTRY RESTRUCTURING ISSUES

(**ACC Objectives and Questions are in bold,** and APS' Responses, Comments, Additions, etc., are in regular type)

APS agrees with Staff, that objectives are useful in guiding our way through the process and debate to how the industry should be restructured to achieve competition. As APS highlighted above, the road to restructuring should be one which preserves the benefits of the existing system such as reliability, while encouraging the innovation and marginal cost pricing of competitive markets. The objectives should provide for a practical transition. The attributes of a practical transition include:

- Producing benefits to society and customers from each phase of reform and restructuring.
- Preparing the way for any subsequent phase of restructuring.
- Early and continuing real price reductions to customers.
- Competitive balance in regulatory and tax policies as between competitors.
- Eliminating, streamlining, or making flexible regulatory processes.
- Eliminating interclass and intraclass cross-subsidies to the degree not inconsistent with overriding public policy, using the benefits of efficiency gains to soften the short term impacts of such repricing.
- Keeping options open for any future phases of restructuring to the greatest extent possible.
- Educating customers about the prospective options and changes that industry restructuring may bring, such as increasingly variable (by hour or by day) prices, the need to make required investments in more sophisticated metering and communications services, and the allocation of risk through voluntary bilateral contracts.

Based upon the above-listed attributes, APS has, in some instances, proposed additional clarification of Staff's objectives. In others, the Company gives its initial comments concerning such objective. Finally, APS suggests that at least three (3) additional objectives be added.

Objectives

1. ***Encourage the benefits of retail electric competition.*** **Competitive markets have demonstrably resulted in economic progress and efficiency. They foster innovation and work to hold prices down. In addition, competitive markets are responsive to customer demands. They also allow consumers to choose among suppliers and products or services. These kinds of benefits may be achievable through competition in the provision of electricity.**

2. *Limit the potential harm to utilities and utility investors.* **Utilities, who have offered service as monopolies for many decades, may be at great financial risk if they are forced to compete for customers.** [APS recommended addition] - without an opportunity for stranded cost mitigation or recovery, and without an orderly and fair Transition Period.

3. *Enable a wide range of consumers to participate in a competitive market.* [APS recommended addition] - Restructuring should pay a dividend of greater efficiency and more innovation that can, and should be, shared broadly across all customers. However, the sharing of benefits should not prevent gradual elimination of existing cross-subsidies except where there exists a compelling public-policy purpose, in which case, the subsidy should be drawn from all customer classes and/or from all energy providers.

4. *Limit the potential for decreases in electric system reliability.* [APS recommended addition] - Electric power systems are complex, and their engineering limitations and safety requirements must be respected. Because of interconnection, the actions of each generator and customer affect all others, some form of central coordination must be preserved. Sufficient capacity, or the equivalent ability for instantaneous load interruption, must also be made available on a moment's notice to balance loads and eliminate the risk of system instability. New market participants can contribute to maintaining reliability by complying with all Western System Coordinating Council ("WSCC") and North American Electric Reliability Council ("NERC") guidelines.

5. ***Limit the potential for market impediments such as: a) exertion of market power by utilities which blunts competitive forces, and b) high transaction costs for market participants.***

6. *Encourage a variety of market developments.* **There is the potential for many innovative solutions to problems that will arise if regulated monopolies are partially or completely replaced by a competitive market. Our purpose is to let the market reveal these solutions rather than to assume perfect foresight and impose solutions from the outset. Areas in which innovative solutions may occur include: contract development, interconnection arrangements, spot market development, and creating or unbundling services and pricing them competitively.**

7. *Promote renewable resources.* **Renewables allow Arizona to hedge against uncertain fossil fuel prices. Further, a renewables program can help bring down the costs of renewables.** [APS comment] - During the period of transition prior to competition, the continued use of goals, fully funded by all ratepayers, can be effective in fostering the development of renewables.

APS supports renewables as a viable portion of our portfolio in a competitive market, but it questions whether government mandated renewable generation resources, or any other form of technology, through regulated utilities, is practical in a fully competitive electric generation industry. ACC mandated renewables programs should be replaced after the Transition Period by market forces, which will decide the programs adopted.

8. *Protect important public programs.* **These public programs are for environmental protection, renewable resource development, low income customer assistance, increased energy efficiency, and safe nuclear power plant decommissioning. Such programs could be jeopardized by competition, and means to protect them should be encouraged.** [APS comment] - Environmental objectives should be encouraged through strict and uniform enforcement of environmental and land use laws/regulations (including facilities siting). This places responsibility for environmental policies on those state/federal agencies having special expertise in this area and eliminates the exemptions in the existing siting law. Steps should be taken to achieve the long-term goals of affordable energy and self-sufficiency for low-income customers. Energy efficiency programs, in a fully competitive market, should be market driven and unregulated. The Company's affiliation with an ESCO evidences its belief that the market will support such programs. Nuclear power plant decommissioning liabilities and related liabilities for other forms of power generation that have already been incurred (e.g. coal mine reclamation) are very distinct from the other public programs noted above. Decommissioning and reclamation are not optional social goods but legally required safety and environmental programs. These costs have been incurred in the furtherance of the public utility's service obligation and should be addressed in that context.

9. ***Shield consumers who do not or cannot participate in the competitive market from rate increases attributable to competition.*** [APS comment] - APS agrees that both the efficiency benefits of increased competition and reduced regulation should be distributed as broadly as possible and that transition costs should not be unfairly imposed on any particular class of customer.

APS further recommends that the following two objectives be added to Staff's list:

10. *Achieve reciprocity and jurisdictional consistency.* It is important that competition not have differential access rights and rules for market participation. Moreover, competition

can only be most efficient if competitors, including natural gas competitors, are treated equally. No energy service provider in Arizona should have unique competitive advantages or disadvantages as a result of legislative policies that create differences in cost structure unrelated to efficiency and disparities in regulation inconsistent with a competitive market.

Equity, improved efficiency in competition, and the public interest also require that public service corporations be allowed the reciprocal opportunity to trade in each other's markets. APS understands that California will propose federal legislation that will explicitly recognize the ability of states to condition the entry of out-of-state power suppliers into a retail access jurisdiction upon reciprocal opportunities for that state's public service corporations. Other legislation may be introduced to authorize nationwide direct access. APS is active in this Federal debate which will require Federal action to authorize any reciprocity between the states. In addition, APS supports proposed amendments to federal laws, such as the Public Utility Holding Company Act, to remove artificial and unnecessary restraints on utilities that desire to complete in regional and national markets. The Company's efforts to remove barriers to entry into other state and regional markets will need Commission support and involvement.

11. *Achieve political acceptance.* A workable restructuring plan must be acceptable to key policy decision-makers and affected parties. If vital and legitimate interests are not respected, the result will be attempts at political sabotage and endless legal delay. Such interests include the reasonable expectations of utility investors, as well as utility competitors and utility customers. They also encompass the public policy interests of governmental bodies and advocacy groups. The public policy process used in Arizona to achieve competition in the near term is one which drives the decision makers together.

We seek comments on two sets of issues.

I. How can the objectives listed above be measured? Please propose specific methods for measuring progress in meeting these objectives.

A. How Progress in Meeting the Above Objectives Might Be Measured:

Measuring whether a program, no matter how well designed, actually meets goals as intangible as those described above is not easy. However, in the final analysis, the "success" of retail access is best measured by net increases in productive, allocative, and/or dynamic efficiency. Indicia of these greater efficiencies may be inferred by such measures as:

1. the net level of participant and non-participant savings;
2. the scope of participation;
3. customer satisfaction;
4. number and variety of new pricing and service options available to customers; and
5. maintenance of system and supplier reliability.

If participants are not saving money, the benefits of at least this manner of restructuring are obviously minimal. If participants only benefit by shifting costs onto others, the "benefits" are illusory. If few participate, the transaction costs (including loss of reliability) are just as obviously too high or perceived to be too high. If customers are confused or otherwise dissatisfied by the number and type of new services, or are otherwise subjected to unexpected and unwanted service interruptions, this ought to be a warning sign to fix the problem before proceeding further.

Possible measurement criteria:

(1) Encourage benefits of retail electric competition - percent of total Arizona retail sales based on market-priced or equivalent (e.g. PBR) generation costs.[2] The degree of direct access is less important than whether any economic benefits of increased efficiency in generation and dispatch and of more economically efficient pricing options are being passed on to consumers. Moreover, if electric prices are not lower than were otherwise

[2] Rates could include delivery surcharge (for stranded costs) such as a market exit fee and still qualify as "market-based".

forecasted in the absence of increased retail access, this may imply that the incremental benefits of direct competition were less than were anticipated.

(2) Limit potential harm to utilities and utility investors - stock market reaction to any restructuring proposal might be one measure, at least for APS and Tucson Electric Power ("TEP"). Bond ratings and earnings variability are two others. However, perhaps a better way of measuring this would be gross write-offs necessitated by restructuring, while another would be the percentage recovery or mitigation of gross stranded costs as defined by the Company (using net costs could be misleading because it might mask otherwise unreasonable levels of assumed rather than actual mitigation). All of these factors must be considered in establishing a reasonable Transition Period.

(3) Enable wide range of consumers to participate in a competitive market - percentage of total Arizona retail electric customers paying rates reflecting the market value (or its equivalent) of bulk power.

(4) Limit potential for decreases in electric system reliability -reliability is a key driver for customer satisfaction and can be measured best through customer satisfaction levels and historical trends. This data can be collected for each utility prior to and during the retail access phases and reported to the ACC annually. Regarding transmission reliability, APS will comply with *FERC Order 888*, NERC and WSCC criteria. Regarding distribution service, reliability has been traditionally measured by the system average interruption frequency index ("SAIFI") which measure outages per year, and the customer average interruption duration index ("CAIDI") which measures minutes per customer per year of outages. These measures are interpreted broadly and applied in a variety of ways across very different distribution systems. Therefore, an overall system reliability indicator is the better measure.

(5) Limit potential for market impediments such as: a) exertion of market power by utilities which blunts competitive forces, and b) high transaction costs for market participants - (a) measures for testing market power include the amount of generation owned or controlled by any one bulk power market participant as percentage of capacity available to Arizona (given transmission constraints) from both native generating units and interconnection with adjacent states; (b) the primary measurement of success in minimizing transaction costs would be level of participation, especially in the post-Transition Period.

(6) Encourage a variety of market developments - this objective is a qualitative one, but there will be new products and services and increased choice that could be identified beyond what exists today.

(7) Promote renewable resources - See APS' Response to Question A.11.b.

(8) Protect important public programs - measurement criteria would differ by program. As to low income programs, the extent to which existing programs of this kind

are maintained (or new programs are initiated) is an obvious measure. Another criterion should be the extent to which the funding base for such programs is expanded. A good example from the telecommunications industry is the Arizona Universal Service Fund ("AUSF"). The AUSF is possible in a restructured and largely competitive industry because the ACC broadened the funding base and designed a competitively neutral funding mechanism. Decommissioning or reclamation "safety" could be measured by the level of unfunded future liabilities (if any) or by the extent to which ratepayer funding of future liabilities has been made non-bypassable.

(9) Shield customers who cannot or do not participate in the competitive market from rate increases attributable to competition - real rate levels for such customers would be the first criterion. Secondarily, the degree to which mitigation efforts are successful will limit the potential harm to non-participants. Third, the ACC can provide for explicit recovery of strandable costs from customers receiving access prior to completion of a reasonable Transition Period.

(10) Reciprocity and jurisdictional consistency - degree to which APS has equivalent access outside its present service area.[3] Jurisdictional consistency is achieved when all participants in the bulk power market are subject to the same regulatory, tax, (including ad valorem taxes), and other rules. As mentioned, the Federal role in resolving this issue is critical.

(11) Political acceptance - this goal cannot be "measured" objectively, but the amount of political support for the various law changes needed to accomplish restructuring will become known as the ACC and legislative processes proceed.

B. How a Transition Period and the Arizona Customer Choice Plan Addresses the Objectives:

1. *Encourage the benefits of electric competition.*

The Transition Period would allow stranded cost mitigation to take place while allowing the full impact of wholesale competition to be felt. The ACC hearings during this same time frame could examine ongoing implementation issues, assess early results from access programs in other jurisdictions, and measure our own progress towards achieving hoped-for economic efficiency gains in Arizona.

The Arizona Customer Choice Plan provides for direct phased retail access during this Transition Period. Phased access will provide necessary information on the cost/benefit that restructuring offers and allows for time to work through financial, legal, technical, and operating issues.

[3] This does not refer simply to "bilateral" reciprocity, i.e., "you can sell to my customers if I can sell to yours". APS needs more than the right to fend off low cost producers willing to grant reciprocity; it must be able to sell in high cost markets where incumbents would naturally seek protection.

2. *Limit the potential harm to utilities and utility investors.*

The accelerated amortization of the Company's regulatory assets approved by the ACC in the Rate Reduction Agreement will clearly serve to limit the potential harm to APS and its investors from industry restructuring. However, regulatory assets are just part of the potentially stranded costs if retail access occurs prior to completion of a reasonable Transition Period.

APS believes that any restructuring plan should provide a reasonable opportunity for recovery of stranded costs as defined in its response to Question A. 9. As discussed later, recovery can come either through mitigation or explicit rate provisions (e.g., exit fees). The PBR incentives provided coupled with the Arizona Customer Choice Plan would largely accomplish cost recovery by self-mitigation efforts. If access is granted prior to completion of APS mitigation efforts, and customers thereafter obtain their generation from non-APS resources, APS would, however, seek recovery of such customers' share of the as yet unmitigated stranded costs.

3. *Enable a wide range of consumers to participate in a competitive market.*

Under the Rate Reduction Agreement and its predecessors, a wide range of APS customers have already enjoyed the benefits of both rate reductions and additional rate options. These will continue during the transition as APS adds further pricing flexibility for its customers (e.g., revised time-of-use options ("TOUs") by the end of 1996).

The Arizona Customer Choice Plan provides for direct access initially for the larger customers (greater than 1MW) and potentially for all customers after 2004. This assumes the ACC's examination of economic efficiency gains demonstrating that further net benefits can be derived from greater retail access and no technical problems exist.

4. *Limit the potential for decreases in electric system reliability.*

Electric power systems are complex, and their engineering limitations and safety requirements must be observed to maintain its integrity. To ensure system reliability is not degraded during the phase-in, new market participants will need to obtain all the ancillary services defined by FERC in Order 888 in addition to transmission services. The ancillary services include voltage support and scheduling, dispatch, reserves, regulation and imbalance. The reserves will ensure for both the customer and the Company that resources are available in the event the customer's firm supply is interrupted for any reason.

Because of the interconnection of the electric systems, the actions on all elements of the system can affect all others. Adequate interconnected system capability must be available in order for the customers' loads to be served by various resources. When the resource is an independent power producer or any new market entrant it will have to comply with NERC's and WSCC's and APS' operating guidelines and meet the same requirements as if APS had been the supplier of the customer's power.

5. *Limit the potential for market impediments.*

The Arizona Customer Choice Plan will help the ACC to assess the transaction costs for participants and can be used to evaluate opportunities to limit these market impediments.

6. *Encourage a variety of market developments.*

The Arizona Customer Choice Plan allows for and anticipates a wide range of pricing options. Undoubtedly, new products and services will be developed and offered. APS may also test customer acceptance of hourly, daily, monthly, and fixed price contracts during phase-in. Contracts could be hour by hour or for an extended period of years. Hedging or financial arrangements will develop on a competitive basis Valuable information regarding customer acceptance of and customer response to variable and fixed pricing will be gained from all eligible customer segments during the early phases of direct access and factored into future restructuring.

7. *Promote renewable resources.*

During the transition, the traditional promotion of renewable resources will continue as ratepayer-funded programs through the goals established by the utilities and agreed upon by the ACC. As a fully competitive marketplace develops in Arizona, mandated renewable programs should be replaced by market forces deciding which programs are adopted.

8. *Protect important public programs.*

See APS Comments to Staff Objectives 7 and 8, and also APS Response to Question A.10.

9. *Shield consumers who do not or cannot participate in the competitive market from rate increases attributable to competition.*

The Rate Reduction Agreement used the concept of a rate moratorium to protect core customers from rate increases. Furthermore, potential stranded costs will be mitigated through cost reductions and accelerating the amortization of regulatory assets.

The Arizona Customer Choice Plan also assumes the opportunity for recovery, largely through mitigation, of all stranded costs. To the extent access is granted prior to full mitigation, there would be an explicit stranded cost recovery from customers eligible for direct access. This protects "non-participants" from assuming the departing customers' responsibility for such costs.

10. *Achieve reciprocity and jurisdictional consistency.*

The Arizona Customer Choice Plan assumes this has been accomplished through State and Federal legislation.

11. *Achieve political acceptance.*

The evidentiary hearings proposed by APS are the first step. Once threshold issues are resolved, the Arizona Customer Choice Plan does not subsequently compromise the various parties' or utility interests, but instead proceeds on a direct course to full competition.

II. If a pilot program were implemented, how should it be implemented?

APS believes the most deliberate path to competition is by first dealing with the threshold issues -- by changing the laws granting public service corporations ("PSCs") the *exclusive right to serve,* by determining the *compensation for any lost exclusivity of this vested property right and for stranded investment,* and by changing the *obligation to plan for and serve* the electric needs of all participants and non-participants to the competitive market.[4] Without these changes, a lawful, compulsory pilot could only be one that tests "virtual" direct access. By this, we mean that APS would act as a local distribution company and purchase power in the wholesale market on behalf of its participating retail customers, as their agent. In a virtual direct access pilot, the customer may be able to select a variety of pricing options and perhaps varying degrees of interruptible service, but would not have its choice of supplier who could compete to sell power and energy into the exclusive service area of APS. Moreover, pricing options that can be offered under a virtual direct access pilot can be experimented with through innovative rate filings without the need for a formal pilot.

Whether to implement a pilot program should be determined based upon what can realistically be tested in such an experiment. The time and effort to be spent would need to focus on measurable objectives. We believe most pilot programs are likely to provide only limited answers to the issues acknowledged by Staff and APS as those to be considered in the restructuring debate and offer the following observations:

Key impediments to securing the answers to important questions about how direct retail access will work in other pilot programs being examined across the country include the fact that they:

1. are confined to operation within existing state and federal laws, which in Arizona would limit a pilot to having a public service corporation as a buying agent for a retail customer through "virtual" direct access;

[4] The competition issues previously identified by Staff in Attachment 8 to the Rate Reduction Agreement as important appear in italics through the following discussion.

2. are of short duration, typically proposed for 2-3 years, such that no long term issues can be effectively addressed (i.e. obligation to serve or reliability);

3. are conducted in artificial, constrained markets that deliberately understate the competitive price of electricity and therefore do not yield meaningful information on how a competitive market would work;

4. all start and end during a time when there is a surplus of capacity available at low prices such that the customer's willingness to accept the risks of eventual price increases in an unregulated market and the customer's tolerance for such risk are not meaningfully tested;

5. provide "safety nets" protecting customers and competing suppliers from risks which are otherwise present in a competitive market;

6. are limited to self-selected customers who have already determined they will benefit thereby leaving untested the customers who could be most adversely impacted;

7. are only applicable to new load or incremental load of an existing customer such that they are really economic development programs; and

8. are difficult to terminate once the customer has chosen a direct retail access option such that a form of Phase-in is a more practical transition.

Other legal, legislative, or jurisdictional issues identified by APS and Staff in Attachment 8 to the Rate Reduction Agreement that cannot be adequately tested in any compulsory direct access pilot include:

Jurisdictional uncertainty hinders the ability to unbundle rates and test the net efficiencies of moving toward retail competition. It is currently unclear whether FERC or the ACC or both establish rates, terms and conditions for retail wheeling over distribution and transmission lines.

Restrictions on Cooperatives cannot be removed in a pilot in order that they may compete without legislative changes or changes to the Federal Rural Electrification Act

Reciprocity cannot be tested in a pilot unless the surrounding states or intrastate public power entities voluntarily open up their territories. Only a federal law or a multi-state compact can require interstate reciprocity. Before a utility opens its territory, it should be afforded the opportunity to serve in other states/territories where its power is more competitive than the local provider.

The short duration of any retail wheeling pilot renders it unable to test the effects of the following:

Retail competition effects on the *general economy and employment* will not be noticeable over a 2-3 year period. In addition, there may be a netting of fewer electric utility jobs with the potential for more jobs if electric utility sensitive industries move or expand here -- although, few manufacturing companies' total cost of production are significantly impacted by electricity costs. Also to factor into the public interest equation is that, based upon studies performed by APS, the Southwest stands to be more adversely impacted if retail competition becomes pervasive immediately because the coal fired plants in this region have higher operating costs than many other plants located in the WSCC.

Reliability will not likely be impacted during a pilot. Supply and demand will not be short during this time frame and thus, there will be no strain on reliability. Moreover, because there are legal constraints confining the pilot to virtual direct access, APS will continue to ensure reliable power and transmission service.

The effects on *DSM, renewables, environmental protection, and integrated resource planning* are not short run issues. The long-term effect of competition on the continued existence of these programs cannot be determined in a short pilot. Customer choice of paying more for "green electricity" could be tested through a focus group or special rate outside a pilot. The impact on system planning cannot be determined in a pilot, particularly if there is a "safety net" requiring return of the customer to the utility upon expiration of the pilot.

The form of *regulation for Transmission and Distribution ("T&D")* such as PBR could be implemented in the Arizona Customer Choice Plan, but the Rate Reduction Agreement governs during this period and would have to be modified. Also, two or three years may not be sufficient time to determine the impact of PBR on T&D costs.

A workably competitive marketplace will not exist in a pilot, particularly not in a virtual direct access pilot, as would be the case in Arizona. For example, in the pilot which has begun in Illinois, Central Illinois Light (CILCO) has experienced a "dump rate" for energy of 1.6 cents/kWh in its two year PowerQuest program. The market price in the region is closer to 2.5 cents/ kWh. Competitors are selling at unreasonably low prices just to secure market share, at the expense of any margin. This constrained, artificial market, will not yield meaningful information about a workably competitive market. In fact, it may cause grossly overstated stranded costs.

The *scope of direct access* cannot lawfully be tested today in a pilot in Arizona other than through a "virtual" direct access experiment, as stated. All classes of customers could be included, or a geographic area could be chosen. Size limits could be imposed, such as a minimum MW size, a % of load or % of annual load growth could be the criteria. Again, focusing attention on these issues will distract all players from a more direct course to competition.

In a pilot, the effect of retail competition on *tax revenues* will be difficult to assess. There are many outcomes for fair tax revenue collection schemes which collect equitably from all suppliers in a competitive electric industry, but these are not testable in a pilot.

Market power concerns would not be sufficiently addressed nor the Commission's *jurisdiction over new market entrants*. As mentioned, the behavior of such entrants in the Illinois experience is that "low balling" occurs and it is not reflective of what will happen in a restructured market. The issue of affiliate participation must also be addressed. Codes of conduct would need to be in place to prevent self dealing with any parent utility. When the *public power* issues are resolved, then there may be more players in the competitive market which will change the results from what any pilot would produce.

The *transaction costs* in a limited type of pilot will not be reflective of those in a workably competitive market. This is in part due to the "safety net" issues described below. Also because *market structure* cannot be tested in a pilot of short duration, it will not represent the marketplace of the future. While the wholesale bulk power market in the WSCC is far more competitive than in the East, the West is becoming even more competitive as *FERC Order 888* is implemented and non-discriminatory open access is becoming a reality. A mandatory pool, ("POOLCO") more like that contemplated in California, cannot be tested in a pilot. However, bilateral contracting could be engaged in by the local distribution company, i.e. the franchised utility, on behalf of its customers who might participate in a virtual direct access experiment.

While participating customers could hedge the variable, or hourly price of power in a virtual direct access pilot, this would be a very limited test of their acceptance of the risk of an unregulated generation marketplace. For the next eight or more years, there will be excess supply in the WSCC which will hold down energy prices. Supply will greatly exceed demand at current tariff prices. However, as demands increase, this will put upward pressure on prices, and in times of shortage, supply could become expensive due to the relatively inelastic nature of most electric demand, at least in the short run. The pilot will not occur during a period when market prices could reasonably be expected to be moving upward, and the customers tolerance thereof will not be tested.

Other pilots which have begun or are being designed, provide significant protections for the participating customers. These "safety nets" distort the costs and effects of a workably competitive market. For example, the *affordability of service* may be maintained during a pilot that would not be sustainable in a workably competitive market unless there were government intervention. In New Hampshire, billing, metering, back up, and ancillary services are contemplated to be provided by the host utility, which would not necessarily be the case in a competitive market. This makes it simpler to move forward, but understates the complexity, cost, and consequences of retail competition. If prices for ancillary services are not unbundled, utilities cannot avoid having the other kWh suppliers lean on them without appropriate compensation. It is also difficult to unbundle without knowing which jurisdiction will be setting rates, as mentioned. Settlements among suppliers and between customers and suppliers must be addressed, but this is not tested in a virtual direct access pilot. Additionally, it remains questionable whether short-term savings to customers can be achieved without transferring costs to others. In the other pilots being proposed in the states typically with the highest electric prices, political compromises have been made to discount the price of otherwise bundled service in order to incent participation. This then is not measuring whether retail competition will enhance efficiency, i.e., reduce the resources needed to provide electricity. Moreover, the only way allocative efficiency will be tested is if prices are reset by moving prices closer to marginal costs, and this cannot be achieved in a pilot without affecting other rates of customers already set under the Rate Reduction Agreement. Whether retail wheeling will enhance dynamic efficiency, that is inducing more rapid technological change in new products and services, is doubtful given the limited duration of a pilot and the "safety nets" which could be included in an Arizona experiment. Nor can customers assess whether to make the investment in equipment required to take advantage of their load profile, such as load control devices, monitoring and synchronizing switches, in a pilot of short duration.

To understand the artificiality of the Illinois pilot, one needs to merely examine what Illinois Power ("IP") is implementing. The pilot is for 50MW or approximately one year's load growth. It will run approximately 3 years. The minimum load must be 15MW with service at 34.5 kV or above (i.e., 21 eligible customers). No less than 2MW nor more than 10MW of direct access demand per customer is allowed. IP retains at least 5MW of each participating customer's firm load. Only whole MW increments may be displaced because that is the way the wholesale interconnected system works. No more than 30MW of direct access capacity is allowed in each of three geographic regions and within those, there must be at least 8 customers. It has agreed to serve the customers under the transmission and ancillary services tariff filed with FERC and has rolled in its costs of the 34.5kV system and higher voltage into the FERC transmission tariff. IP also agreed that all energy delivered up to the direct access demand is at 100% load factor and is "first through the meter". This is not reflective of what will happen in a workably competitive market. IP estimates that the program is costing them $3.1-7.5 million in lost revenue (without fuel) and without considering the credit for resale of the displaced power. As of June 1996, only 11 of the 21 eligible customers have signed up.

APS has also reviewed the Michigan pilot. This program applies only when new supply is needed by Consumers Power and Detroit Edison. Reciprocity is required of any competing supplier and the pilot is to be terminated if the utilities prevail on appeal that the PSC has no authority to mandate retail access. Other pilots similarly apply only to new or incremental load, thereby making no real progress in the key issues. In New York, Orange & Rockland has a pilot in which eligible customers get to keep a portion of the fuel savings from market-priced power purchases. The remainder goes to the utility.

In New Hampshire, 17,000 customers are participating in its pilot. This is 3% of each utility's load (approx. 50MW total for the 6 franchised utilities, 35MW of which is in Public Service Company of New Hampshire's (PSCNH) territory). All customer classes can participate, with the class % distributed in proportion to peak load. Special contracts must be voluntarily renegotiated, however, for participation of customers under contract. Suppliers must be New

England Power Pool ("NEPOOL") members or affiliated with members. Before a retail customer's schedule is accepted, NEPOOL must have appropriate credit assurance from the new supplier. The host utility is maintaining the obligation to serve. Metering is handled in a variety of ways, including estimation. Billing depends on the agreement between supplier and host utility. Results reported thus far indicate only 8-10% of those eligible expressed interest in participating. Due to the lack of certainty about transmission jurisdiction, the tariffs were filed at both the state commission and FERC. Less than full stranded recovery is contemplated in order to incent participation. (Note that one of the six affected New Hampshire utilities, Unitil, has not filed its transmission tariffs until stranded cost recovery is resolved to its satisfaction.) There is the clear ability for a supplier to "game" this pilot by choosing a class of customers that "leans on the host utility's system". The competing suppliers are not required to secure all the services they would need in a competitive marketplace because the host utility must offer services under the FERC transmission tariff. Even though the competing suppliers may have lower costs to serve than would occur outside a pilot, none of them are expected to make significant profits, if any, from the customers they secure. Therefore, the pilot appears to be solely a case of acquiring market share and name recognition, yet delaying progress on the necessary issues that should be resolved.

Lastly, in other pilots, customers are allowed to self select within certain parameters such as, within geographic limits, a city or town, or a particular geographic area. Even if they are selected at random state-wide or utility-wide, the chosen customer may decline such that only those who agree to participate are tested. If customers self select, it means that they likely believe they will save. Thus, a pilot structured on this basis would not yield accurate information about those who did not willingly agree to participate. These will include the customers who would not fare as well under competition. A lottery may produce a better more representative test group, but again, only those willing, would participate. In a restructured, competitive market, this may not be the case.

Overall, APS believes pilots do not measure the effects of a workably competitive marketplace due to their short duration; legal, political, and jurisdictional limitations; constraints creating artificial markets; the period of surplus in which they are conducted; "safety nets" imposed by regulators; the self-selection of only those participants who believe they can benefit: they often avoid stranded cost recovery by applying only to new or incremental load; and they are difficult to terminate once an access option has been chosen. If the goal of the ACC is to adequately evaluate the benefits and cost of true competition and to resolve critical issues, the Arizona Customer Choice Plan is the better approach to moving forward.

ATTACHMENT A

III. QUESTIONS REGARDING ELECTRIC INDUSTRY RESTRUCTURING

Because APS' position is that a pilot creates delay and will not produce significantly meaningful results regarding, and will detract necessary attention from, the critical restructuring issues, APS will respond to Staff's questions in the context of the Arizona Customer Choice Plan.

A1. Affected Utilities. Which utilities should open their markets to competition?

All Arizona utilities should be affected equally and simultaneously once the threshold issues described previously are addressed. Reciprocity is a fundamental principle for restructuring. Therefore, all suppliers, be they regulated public service corporations or other types of providers, should open their markets to competition at the same time and to the same degree (subject, of course, to pre-existing contractual commitments). Reciprocity also requires that non-electric competitors, specifically natural gas, be required to allow all their customers similar competitive access.

Unbundling of local gas distribution companies (LDC) rates and services is being considered in at least 26 states. This would allow gas and electricity to compete on the basis of market criteria rather than on the basis of preferential regulatory policies. Moreover, because the population in Arizona is very mobile and transient, many are exposed to the right to choose retail gas suppliers in other states. This further motivates the marketplace to desire access to all types of energy providers in Arizona.

APS believes that any market entrant allowed into a previously exclusive territory of a regulated electric public service corporation should be able to do so only when it becomes a regulated public service corporation subject to whatever appropriate oversight and related obligations as are imposed on comparable services provided by APS. Special legislation (or if absolutely necessary, a Constitutional amendment) will need to be enacted to accomplish this. Other advantages enjoyed by non-IOUs would require additional legislation, both state and federal, to address their impact.

The same arguments against allowing non-public service corporations to compete against PSCs may well apply to cooperative electric suppliers. APS recognizes that the unique historical development of such entities and their relationship to the federal government may require granting them some manner of exemption from certain aspects of industry restructuring.

The Arizona Customer Choice Plan is designed such that these principles can be resolved prior to the first phase of direct access. As shown on the attached time-line, there are a number of issues that will require a cooperative effort of a number of agencies to resolve.

Several hearings are contemplated before the ACC, in conjunction with necessary legislative changes. A bill has been passed to mandate a legislative study of competition issues, with a report due in December 1997. A potential sequence and priority of subjects for these ACC hearings is laid out in said Exhibit. As discussed in the Preface, APS believes the first of these evidentiary hearings can be completed before the end of 1997 and the ACC's findings incorporated into the legislative study committee's report and recommendations.

A2. Scope of Restructuring.

a. How much of the utilities' markets should be opened to competition?

In evaluating any proposal for change or restructuring of the electric service industry in Arizona, our focus should be on whether we can confidently rely upon direct retail access to create additional net economic efficiency benefits, not merely reduced rates for a select few. An evaluation of any proposed restructuring plan is required before we affect the lives of millions of Arizona consumers, taxpayers, and shareholders. Most of the near term benefits that could be attained by a transition to competition may be achieved through a combination of vigorous wholesale competition (the full development of which is nearly universally believed to be a necessary precondition to efficient retail competition,) competitive bidding for incremental resource additions, and PBR at the retail level. Today, for instance, APS has a PBR plan in place and is complying with FERC's open access requirements to achieve wholesale competition.

The Arizona Customer Choice Plan should capture the bulk of incremental economic efficiency gains in its early years of operation. Retail transmission customers receiving power at 69kV or above would be eligible for direct access in the year 2000 assuming the legal and other regulatory reforms outlined herein have occurred. In 2002, all customers greater than 3MW would have similar access and in 2004, customers with (non-aggregated single premises) demand in excess of 1MW would be included. Direct access for all remaining customers would be implemented as soon thereafter as possible if evaluation of the initial phases of phased direct access leads the ACC to the conclusion that additional economic efficiency benefits would result and assuming all technical metering and control issues have been answered and the rules for restructuring are in place.

b. Which consumers should be allowed to shop around for power and energy? Consider both geographic areas and consumer classes.

In the long run, APS does not believe that geographic restrictions on the scope of any direct access is appropriate (although the exclusion of non-PSCs and perhaps cooperatives from any such program may effectively result in some areas of the state having fewer competitive options). Direct access should be pursued to the point where incremental costs exceed incremental benefits.

c. Should utility customers served under existing contracts be eligible to participate in the competitive market prior to expiration of the existing contracts?

Only if both parties to the contract agree. The legal sanctity of contracts should be preserved no matter what form restructuring takes.

d. If divestiture were undertaken, how should it be accomplished?

Before even considering the "How", the ACC must first answer the "If" and "Why" of this issue. These answers will render moot any further discussion of "How".

Any divestiture of assets should be left to the determination of each individual utility's management for three reasons:

1. it would be prohibitively expensive;
2. it is not necessary after examination of APS' lack of market power; and
3. it would be beyond the ACC's legal authority to order mandatory divestiture.

As indicated in the pleadings of the three investor-owned utilities in California, divestiture or disaggregation of their companies into separate companies would entail very significant expense if the mortgage indentures were re-collateralized.[5] APS has similar covenants and mortgage issues. The benefits from divestiture, if any, could be significantly dwarfed by the cost of such a process. Moreover, with the accomplishment of FERC's final Order 888, open access of the transmission systems should be ensured. APS has separated the merchant from the transmission operation and system reliability functions beyond that required by FERC. This effectively accomplishes the disaggregation of the ownership of generation from transmission and will go a long way toward creating a truly competitive bulk power market. APS' adoption of discrete business units also provides functional separation that should likewise mitigate any concerns which would otherwise prompt calls for divestiture.

Any benefits of divestiture are dependent upon a finding that such divestiture is necessary for creation of a competitive bulk power market. This, in turn, requires an understanding of both the alternatives available to divestiture and the degree of market power exercised by the existing vertically integrated electric utilities.

---

[5] In comments dated March 19, 1996, filed with the CPUC, both Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") noted that even partial divestiture would take many months if not years to accomplish, even under the most optimistic assumptions, and would significantly increase transition costs to secure necessary lender, vendor, governmental and other approvals, conduct the requisite appraisals, negotiate terms of any sale and/or auction, etc. For example, SCE estimated that mortgage bondholder refinancing alone would cost $220 million.

APS agrees that deregulation of the bulk electric power market will result in competitive prices only if the market itself is competitive. A competitive generation market requires:

1) Transmission access on comparable terms that assure that all full and equal access to the market; and
2) A generation market structure that assures that prices paid to generators and by wholesale market customers are at competitive levels.

Comparable transmission access is required to assure that utilities do not exercise "vertical" market dominance, using control over transmission and dispatch to benefit affiliated generation operations to the disadvantage of competitors and customers. The purpose of FERC comparable-access tariff requirement is to assure that vertical market dominance will not be exercised. Through the separation of transmission from the power sales merchant function, described above, vertical market power is mitigated.

Competitive pricing in a wholesale bulk-power market also requires that the generation sector be workably competitive. If there is "horizontal" market dominance in generation, a firm with market dominance can increase prices above competitive levels to the detriment of customers. Conversely, an attempt by a firm lacking market dominance to increase prices, e.g., by increasing its prices offered to the market, will not be profitable.

Market dominance should not be an issue in the properly defined subregion relevant for assessing whether APS possesses market power, even if this subregion is defined to be as narrow as Arizona or more likely, the Arizona-New Mexico subregion. The main reason is that while these are "marketplaces", they are not markets necessarily in any legally or economically meaningful sense. Whether defined in terms of generation or in terms of load, the Arizona-New Mexico subregion is a small portion of the WSCC. The Arizona-New Mexico area has a peak load of about 13,489MW and resources of about 16,529MW. In contrast, the WSCC comprises about 115,826MW of load and about 153,000MW of resources.

Further, while parts of the WSCC may not be strongly interconnected, and therefore arguably separate submarkets, this cannot be said of the Arizona-New Mexico subregion. Arizona's geographic placement in the WSCC's transmission links permit up to 4,500 MW of power to be transported into the region and up to 8,900 MW to be transported out of it. The utilities serving load in the Arizona-New Mexico region control only a small portion of this capacity.

Transmission into the subregion is important because an attempt by one or more utilities within the subregion to raise prices would attract substantial power flows into it. Since any party who can physically reach the area is entitled to sell at wholesale in it under comparable-access provisions, this is an effective barrier to any potential exercise of market dominance in the subregion.

The transmission capacity out of the subregion also is relevant. Experience in the interchange and contract markets, as well as APS' preliminary analysis of future markets, demonstrates that much of the time the price of spot power in the exporting regions of the WSCC (including Arizona, New Mexico, Utah, and Texas) is determined by prices in the California marketplace. These, in turn, are set by vigorous competition among producers in California, Arizona, New Mexico, the Pacific Northwest, "coal by wire" regions of the central West and other WSCC producers, including those in Canada and Mexico. This WSCC-wide competition also assures that no utility in the subregion can exercise monopsony (i.e. limited to one buyer) power. In this context, it is relevant that the utilities with the largest loads all have sufficient capacity to meet native load requirements. They are not dominant purchasers of power; indeed, with the exception of San Diego Gas & Electric Company, they are all net sellers.

Even if the Arizona-New Mexico region were isolated, it is not likely that a single utility would have market power. APS is among the largest generating utilities in the subregion but owns only 21 percent of the capacity located in it.

There is significant operating margin in the Arizona-New Mexico and Southwest areas in particular, and in the WSCC in general. Even when this capacity margin ceases to be sufficient, sometime in the next century, it is clear that the market for new capacity is highly competitive, with dozens of firms typically competing for any new requirement. This competitively priced new capacity sets a ceiling on the wholesale prices that can be charged for existing generation.

Finally, transmission services provided to others and to APS itself will be posted on the Open Access Same-Time Information System ("OASIS") pursuant to *FERC Order 889.* Rates and definitions of these services will be in tariffs filed with FERC. Agreements for transmission services will be initiated using OASIS and finalized off line. This will all be available to anyone with the ability to look at the OASIS.

A3. Term of Restructuring.

a. When should competition start?

Once the ACC finished its evidentiary hearings on the threshold issues identified herein, and the necessary Legislative and/or Congressional actions are complete, direct retail competition under the Arizona Customer Choice Plan would be able to begin, which APS believes will be approximately in the year 2000.

b. If competition is in the form of a pilot or phase-in, how long should the pilot or phases run? Please describe the phases of a phase-in. Please consider that many larger customers of utilities are currently under contract and may not be able to shop around until those contracts expire.

APS has previously described the phases of the Arizona Customer Choice Plan for direct access. Although APS believes that the first three (3) phases can be implemented every other year once the critical issues of exclusive service territory, obligation to serve, compensation for stranded costs, and reciprocity have been resolved, the expansion of retail access to customers below 1MW must also be considered. Again, net benefits are those which accrue to customers only as a result of retail choice of energy supplier. These are net of transaction costs and do not include the benefits which will be realized as a result of greater competition for wholesale power and PBR for transmission and distribution services. Bulk power (that is the costs of generation, transmission, including fuel and all associated capital costs and return) comprise about 75% of APS' costs. Wholesale competitive markets will put great pressure on utilities to reduce these costs.

Distribution and customer-related services comprise most of the remaining 25%. Distribution is unlikely to become a competitive business. Therefore, one cannot readily conclude that retail access to smaller than 1MW customers will create any added efficiencies, but this is what needs to be analyzed in determining how access to these customers can be achieved.

Currently, there are not a significant number of APS customers under long term contracts. However, even if that were not the case, APS would not propose a more/less accelerated direct access plan. APS' first phase is tied to the critical need to resolve high priority, legal, and structural issues prior to adopting wide-scale direct access - not to the individual circumstances of a particular customer or utility. Certain issues can be resolved concurrent with access as indicated on Exhibit A. As the number of direct access retail customers increases, technical issues such as installation of meters, communications equipment, complexity of scheduling and billing could limit the speed of implementation.

c. If competition is in the form of a pilot, how can the term of the pilot be set so as to avoid discouraging long term contracts signed under the pilot?

Although APS does not support a pilot program, a pilot could allow for agreements whose contractual provisions would survive the term of a pilot. In addition, the ACC should allow for long-term agreements based on competitive alternatives outside any pilot program.

A4. Services Available on a Competitive Basis. Which services should be available in a competitive market?

Absent market power, generation services, i.e., the sale of power and energy, should be available from competitive suppliers, with the energy sales of all providers regulated equally.. Whether the energy sale is regulated in a "light-handed manner" or is priced in the market, all energy sales by <u>any</u> suppliers should be regulated in the identical manner. Ancillary transmission services can be competitively procured <u>if</u> the services are measurable and controllable. Transmitting the power from the provider to the customer's load will in most cases require transmission and distribution wheeling. These will probably continue to be regulated on a cost of service basis (albeit one determined through some manner of PBR rather than traditional regulation) and not be competitively available to the customer.

APS will file rates for transmission and certain ancillary services July 9, 1996 in response to the *FERC Order 888.* They are listed below. Other distribution-related services will be unbundled during phased access as required. For unbundled services to be competitively provided, they must be both measurable and controllable, as state of the art telemetering and communications equipment, (computers and computer software)are required if real time pricing is desired. In this case, the customer's real-time requirements need to be known by both the Company's and the generation supplier's control centers. Each system must be able to respond to meet the customer's needs instantaneously if, for example, regulation/load following is to be provided by other than the load-control area utility. Industry standards for both system and generation control are metered and measured in whole megawatts. APS adheres to this standard. It is required because large generating units cannot increase generation instantaneously to respond to very small fluctuations in load. For a customer to choose load following to be provided by an alternative supplier, the more expensive communications equipment and real time metering would need to be installed in order for APS to measure and bill for the alternative service. APS believes smaller customers will not benefit from direct access, i.e., choice of alternate suppliers of all unbundled services, until procedures and infrastructure are in place to accommodate their smaller demands.

- **Distributed energy services at market based rates (serving multiple consumers located in proximity, and not requiring transmission service from others); this is distinct from on-site self generation for just one consumer.**

  Distributed energy services (other than self-generation) could be competitively provided by third parties subject to the requirement that these services be regulated by the ACC on the same basis as APS is regulated with regard to those services. If inter- connected to APS' system, certain rules for operation and interconnection would need to be followed. There should be no distinction in treatment between the regulation of such distributed energy services and central station generation services.

- **Central station generation services at market based rates (generation serving one or more consumers located at a distance from consumers and requiring transmission service).**

  APS' existing central station generation services were built under the historical regulatory compact in Arizona. APS should be compensated for said plant based on cost. That does not mean that energy from such plants may not be provided at market based rates, but only that there must then be an alternative opportunity for recovery if plant costs are above market rates. This also assumes that at least some customers have market access before APS can reduce its unit costs to market levels..

- **Other services described in Sections A5, A6, A7, and A8.**

The ancillary services described below are those which APS anticipates filing with FERC on July 9, 1996 for use by wholesale customers. These can be provided at competitively-based rates if they can be competitively procured in the marketplace; however, some must be provided by local control area utilities unless and until the proper metering, protocols and communications infrastructure exists. This is an area where jurisdictional uncertainty clouds whether the ACC or FERC will establish the rates, terms and conditions for these services if provided to retail, and not wholesale customers. Note, that while FERC defines these services as ancillary to the provision of FERC-jurisdictional transmission service, they are provided by generation resources. It is contemplated that after *FERC Orders 888 and 889* are implemented, these services can be provided at market based and not cost of service based rates. During the Transition Period, APS will develop ancillary service rates applicable to the provision of these services to retail customers. The cost to provide (or market value of) these services to retail instead of wholesale customers may differ. Moreover, to ensure that non-participating customers are not harmed and that the utility is kept whole for the services it provides, traditional transmission or distribution rates need to be unbundled in a manner to ensure that those provided by the host control area utility are not under-priced.

1. Regulation and frequency response service - Regulation is the moment to moment matching of the resources to the load. This is a service that can be available on the competitive market if the customers requirements are <u>measurable</u> and proper metering, communications, computer interface and software are in place. This is needed in order for the Company's and the suppliers' systems to respond appropriately to the load changes.

2. Energy imbalance services - This service is provided when the customer's load does not meet its schedule. When imbalance does not exceed a plus or minus 1.5% band, this service can be purchased competitively, so long as the quantity is measurable. This can be achieved by deviation accounting. During times that the imbalance is outside the band there is unauthorized use of the Company's system by the customer. Unauthorized uses can be discouraged by the customer's payment of an unauthorized use charge. This however will be made up from APS' generation, thus this portion of the service should not be available competitively. If excess power is scheduled into APS' system, its generation could operate uneconomically. To compensate for the uneconomic costs, APS proposes to return only 85% of the excess power to the customer at the end of the month. This will require metering to inform the customer and the Company when an imbalance is occurring

3. Spinning reserve service - This is unloaded generation that is connected to the grid and ready to accept load. This is a service that the customer can procure in the competitive market, if the customer's requirements are measurable, and if the Company is able to confirm that the resource is available to respond.

4. Supplemental reserve (ready reserve) service - This is unloaded generation that can be loaded within 10 minutes. This is a service that the customer can procure in the competitive market, if its requirements are measurable.

5. Losses should be a separate required service. This service would include energy and capacity to provide for the loss of kW and kWh over the system in order to deliver the customer's power and energy. This should not be included with the imbalance, in that this naturally occurs whenever there is transmission of power. Imbalance only occurs when the schedule does not match the actual requirement. If losses are measurable, the customer could procure these in the competitive market. See discussion below.

6. See also the description below of scheduling reactive supply and standby which services are less likely to be competitively supplied to smaller customers.

- **Other services (please describe).**

  See the above as well as APS' Response to the next question.

A5. Necessary Services. Utilities and perhaps other parties will have to address the services listed below. Please indicate how these services should be offered, measured (metered), and priced on an unbundled basis.

Necessary services to be provided by the host control area utility will include scheduling and reactive support whenever the customer does not maintain a required power factor, nor has the ability to control and measure the service.

- **distribution service -** This is the use of the distribution facilities to move the electric power from the transmission system to the customer's load. The amount available to the customer will be based on the capacity of the local distribution system used or reserved by the customer. Use of the distribution system will be based on the customer's load requirements which are metered. Rates for wheeling to a wholesale customer who takes service at the distribution level will be based on the cost of the facilities required to provide the service and today are regulated by FERC. In the case of retail customers using the distribution system, there may be great difficulty and cost to unbundle a price based on the system used to serve them. Significant costing work would need to be accomplished before appropriate distribution rates could be set. They may vary by geography and may be more costly in less dense, or mountainous areas. The jurisdictional line between FERC and the ACC must also be resolved to know what costs are subject to whose jurisdiction and how they will be allocated to wholesale versus retail distribution level customers before unbundled rates can be set. These are among the many issues arising in the Capacity Reservation Tariff NOPR ("CRT") just issued by FERC and which will be resolved over the next year and one-half.

APS anticipates it would provide all unbundled distribution (defined as operation and maintenance of wires) and related necessary services over local distribution facilities, such as wires below 69kV (with a few exceptions for larger voltage radial lines) under rates approved by the ACC.

- **transmission service** - The use of the transmission system to bring the electric power from the source to the distribution substation. This service will be offered on a firm or non-firm basis with network or flexible point-to-point service (unless and until replaced by the flexible point to point CRT or some other method). In most cases this will <u>not</u> be metered. Usage will be based on schedules for the customer across the path. Payment for this service will be based on the type of transmission the customer has. If the customer has firm transmission, it will pay for the service even if it is not used. A non-firm transmission customer will pay only when the service is available and is used. Under the *FERC Order 888* proforma tariffs, when the customer has a point-to-point agreement, it can use only the identified paths for firm service but has non-firm rights at no additional cost. The customer will pay a postage stamp rate for the service initially under APS' transmission rates filed in response to the *FERC Order 888*. A network transmission customer has the rights to use the network transmission system similar to the way APS uses it. A network customer will pay based on its proportionate usage of the network until superseded by the CRT. The CRT would require some form of flexible point to point reservation of use. APS would be required to reserve peak capacity for its native load and firm transmission obligations, but the details are less than clear under the CRT NOPR.

  There currently is no well developed model of transmission pricing in a retail wheeling market. For expediency, Public Service Company of New Hampshire, and a few other utilities, have amended their FERC-filed open access transmission tariffs to voluntarily allow retail customers who have direct access under the New Hampshire pilot, or other states pilots, the ability to take transmission service under such tariff. It is not clear how the fixed costs of the transmission system will be recovered in the future. APS is reviewing various methods which might one day supersede APS' postage stamp method of pricing the transmission system.

- **supplemental generation service** - APS is not certain what is contemplated by this term beyond "back-up service". See APS' Response to "back-up (standby) service".

- **imbalance service**[6] **(including accounting for losses)** - This service is to cover a mismatch between the customer's actual load and its schedule, but this service should not include losses as Staff suggests. This service is described above..

- **back-up (standby) service** - This service covers the customer's power and required ancillary services if its source of power is lost for more than a short period of time. It should not be required to be provided by the host, control area utility. Appropriate metering would be required and the ability for the customer to separate from APS' system, to ensure APS is not the provider of last resort. This service should be competitively-priced.

- **voltage control** - This is maintaining the customer's voltage at a predetermined level. Generally, the host utility will provide this service. However, voltage control could be provided by a third party provider, if the service can be unbundled and priced separately, if it can be measured, and if the third party can provide it within the customer's local load. The price for this service will be included in both the transmission and distribution wheeling cost. The customer will be required to maintain its power factor within an acceptable band and either APS, or the customer, will install the equipment to achieve this.

- **other ancillary services necessary for maintaining system reliability-** These services would include:

  Regulation and frequency response - This will insure that the moment to moment change in the customer's load is matched by a resource. It will be priced based on the resources used to supply this and the magnitude of load changes. Telemetering of the customers load to the Company's and the supplier's control centers will be required to competitively provide this. This will include meters, remote terminal units ("RTUs") and communications between the customer and the two control centers. See also Response to Question A16.

  Operating reserves (spinning and supplemental) - These services are to provide reliability to the customer in the event that it loses its source of power. This service will be available to the customer for a short period until it can arrange to return its resources to normal. This service should be market based.

It is imperative that all market players abide by NERC, WSCC, and APS' reliability criteria. As described in the 1996 WSCC Reliability Criteria, "The reliable operation of the interconnected bulk power system of North America requires that all systems observe, and subscribed to certain minimum operating reliability criteria. Continuity of service to loads is the primary objective..." Criteria for transmission system planning, power supply design and

[6] **Imbalance service applies in cases where the consumer takes more or less power or energy than scheduled.**

minimum operating reliability criteria are established. System operators are required to maintain power plant outposts and transmission line loadings within the system's ability to handle a "single contingency outage". If there is a single or multiple outage, the system is in jeopardy of cascading outages, islanding or even collapse to blackout. Today, generally, the operators can restore service. However, as the number of suppliers and direct access customers increase, it becomes difficult to contact enough parties to implement schedule changes to return the system to normal within the required 10 minutes, for example if a generator trips. Depending on the number of direct access transactions, some form of centralized scheduling may be needed in the future and certainly new, internet type of computer systems that handle millions of transactions per day will be required

- **scheduling of supplies and demands** - Scheduling, system control and dispatch - This service is the arranging and accounting for transactions that occur on the system. It is a service provided by each system that provides transmission for the transaction. Schedules are in whole megawatts. Both FERC and NERC recognize, to maintain the interconnected system reliability, this service must be performed by all control areas that the transaction impacts. Therefore this service will <u>not</u> be offered in the competitive market and is a necessary service. While a customer can hire a private firm to submit schedules of the customer's anticipated use, the control area operator will be the only one to dispatch the system and implement real time schedules.

  The cost for this service will be included in APS transmission cost filed on July 9, 1996 in response to *FERC Order 888*, as will system control and dispatch costs. At this time they will not be separately unbundled because they are necessary and physically are provided by the host control area utility.

- **repairs/consumer complaints** - This will be dependent on where the customer has a complaint (transmission, distribution or generation) or where the repairs are needed. Because the cost of repairs or the correction for complaints are operations and maintenance expenses, they would be included in the price for transmission or distribution. This should not be classified as a separate service.

- **other necessary services -- please describe** - Refer to above discussion.

A6. Market Center Services. The market may benefit from the services listed below. Please indicate how these services should be offered and priced.

NERC requires that schedules and transfers of power be made between control areas. Presently, APS has about 40 inputs to scheduling as a result of this requirement. Energy billing and accounting will significantly increase in complexity if all of the customers eligible for access submit separate energy and separate ancillary services schedules. This is described further in response to A.12.

- **title transfer** - The title transfer, transaction confirmation and establishment of credit standards will be performed by the control area operator or by private entities who are beginning to offer these services. For example, Thule, Inc. currently offers such services at the California-Oregon Boarder ("COB") hub. These should be competitively offered and priced.
- **transaction confirmation** - see above answer
- **establishing credit standards** - see above answer
- **invoicing** - Invoicing is contemplated to be performed by the control area operator who will deal directly with the open access retail customer. The cost for this service will be included with the transmission service charge.
- **dispatching of transmission/generation** - Dispatching of transmission will be scheduled by the control area operator. Dispatch of generation will also. This will be priced and offered as described in the sections above.
- **exchanges/swaps** - Swaps may be necessary risk management tools to be used if fixed pricing options are to be offered to customers in a restructured environment where price and revenue volatility are significant. These should be competitively offered and priced to retail or wholesale customers. If a utility utilizes such instruments to hedge its cost of production to offer a certain price to a retail customer, then it will be a legitimate cost of doing business.
- **interruption notification** - If the customer has interruption notification services, it will either have supervisory control devices installed so that APS can interrupt remotely or a rate should be established where the customer pays a significant penalty for not interrupting when requested.
- **imbalance trades** - As described under invoicing, the customer will deal with the control area operator. See also response to A.5.

A7. Spot Market Services. The market may benefit from the services listed below. Please indicate how these services should be offered and priced.

The services listed below could benefit the customer, but to supply them will require computers, computer programs and personnel trained in the areas listed below. These services would all have to be included in the price that the customer pays. Benefits from this would have to be determined by the customer.

- **electronic bulletin boards for spot transactions/prices** - Electronic Bulletin Boards (OASIS) are being established for transmission services and availability in response to *FERC Order 889*. Currently, Electric Commerce Clearinghouse provides a spot power bid/offer matching service. Several other services post after the fact prices, such as Dow Jones and NYMEX at the Palo Verde and COB delivery points. These are being developed in the marketplace and no ACC involvement is required.

  This service could be made available to any customer large enough for its requirements to be measured and controlled. Charges for this service could be a combination of fixed costs for the right to use the bulletin board and a variable cost based on the amount of time the service is used.

- **power pooling services -** Power pools have developed in the industry to share reserves and meet NERC criteria. If what is meant by this question is the service of aggregation, we think this will occur in the marketplace. The pricing of these services may not be regulated under traditional cost of service ratemaking. Any aggregators doing business in Arizona should be certified pursuant to the Commission's requirements, discussed below, and energy sold by them should be regulated in the same manner as are APS' energy sales.

- **coordination with futures/options markets -** The NYMEX electricity futures contracts began trading recently at the Palo Verde and COB delivery points. While the number of trades are not large enough to make for a liquid market yet, it is anticipated that in time the futures contract will be a necessary and useful instrument to manage energy price risk. In order to manage this price risk, particularly in a market with declining margins, the use of these instruments will be needed. Moreover, competitors may employ the use of such instruments to fix the price to customers, so regulated utilities must have the same capability. In a competitive generation market, prices can be very volatile.

  The ACC should not regulate this activity. The FERC has already disclaimed jurisdiction over futures since it is not defined as a security. Only if power is actually delivered under a futures contract, would FERC have jurisdiction.

A8. Transmission Service. For a competitive market to work, utilities owning transmission facilities must provide transmission service. Please indicate how the following objectives would be met:

- **services must be provided consistent with FERC tariffs -** the filings by regulated utilities on July 9, 1996 should satisfy this requirement. The *FERC Order 888* will open the area's transmission and non-discriminatory access. Thus, all suppliers will be able to participate in the supply market with the same opportunities as transmission independent utilities. The FERC Order 889 provides "same time" transmission information such as, transfer capacity, available transmission capacity and pricing. This will be accomplished via electronic communications on the Open Access Same-Time Information System (OASIS). In addition, FERC Order 889 provides for a "Standards of Conduct" which prohibits the merchant function personnel from any knowledge on transmission operations/reliability before any other transmission user. In the WSCC, most non-regulated utilities will be making similar filings with the established regional transmission groups of Southwest Regional Transmission Association ("SWRTA"), West Regional Transmission Association ("WRTA"), or Northwest Regional Transmission Association ("NWRTA"). SRP, as a member of SWRTA, has agreed to file comparable open access tariffs as a condition of membership.

- **utilities must accept power delivered to their transmission systems by other suppliers and offer wheeling services comparable to services they provide to themselves** - most utilities are included within the definition of "transmitting utilities" who are subject to Section 211 of the Federal Power Act (FPA). If the utilities are not complying with the comparability standards, FERC can order access pursuant to a Section 211 complaint. However, the reciprocity provisions of *FERC Order 888* are inadequate because they are only bilateral and not self-executing (i.e., APS would have to request and possibly even file a complaint to get access).

- **all sellers supplying consumers must have interconnection agreements with owners of necessary transmission facilities** - interconnection orders can be sought by wholesale suppliers under Section 210 of the FPA.

A9. Recovery of Stranded Investment. Please indicate how the recovery (if any) of stranded investment should be accomplished. Address each of the following issues:

Arizona public service corporations have constitutional and equitable claims for compensation in addition to what is ordinarily thought of as "stranded investment", or stranded costs. These include its vested property right in its exclusive Certificate of Convenience and Necessity ("CC&N") and the compensation due for services provided competitors in order to provide access to APS customers and other ancillary services.

With the understanding that stranded costs are just one element of overall transition costs, APS believes that the following list of principles should be applied to the resolution of the stranded cost recovery issue in Arizona:

1. Arizona public service corporations should have a reasonable opportunity to either mitigate or recover all stranded costs, and a decision in this regard should be issued <u>before</u> any phase of restructuring has begun.
2. Every opportunity and incentive for mitigation of stranded costs should be provided so as to obviate the need for explicit recovery mechanisms.
3. Any additional stranded cost recovery mechanism must be non-bypassable.
4. Stranded cost recovery should attempt to prevent cost shifting between customer classes.
5. The stranded cost recovery mechanism must avoid creating situations in which a customer (or class of customers) can physically leave the system (or avoid paying stranded costs in some other way).
6. The structure for stranded cost recovery should minimize market distortions.

7. Stranded cost recovery should rely on market-based approaches (tracking market price through the Transition Period rather than using point in time estimates) to the maximum extent possible to minimize risks to both utility shareholders and customers of over/under recovery.
8. The recovery mechanisms should not create incentives for uneconomic generating plants to continue to operate.

a. The definition of stranded investment.

APS believes that the term "stranded costs" is a more appropriate description than "stranded investment" because this issue includes more than simply a utility's past investments in capital assets. Stranded costs can be defined as follows: "Investments, costs or future obligations prudently incurred in the past, by an Arizona public service corporation for the benefit of the customers in its service territory which become non-recoverable because of changes in the regulatory compact, or because of accounting or other regulatory changes occurring in the transition from a regulated monopoly environment to a competitive market." As a basic principle, stranded costs should include only investments, and costs or future obligations incurred in the past which cannot be avoided in the future. To the extent that a cost can be avoided in the future (an example could be a coal supply contract with a termination option,) the avoidable costs should not be considered to be stranded. Examples of potentially stranded costs are listed below.

1. The excess of net book value of existing generating plant assets over the market value for the assets.
2. Lease obligations for existing generating plants.
3. Existing purchased power contracts, including termination fees.
4. Existing fuel supply and fuel transportation contracts, including termination fees.
5. Regulatory assets.
6. Decommissioning, reclamation and other funding obligations associated with existing generating plants.
7. Existing general utility plant allocable to the generating function.
8. Current administrative and general expenses allocable to the generating function.
9. Corporate restructuring/reorganization costs which could include legal, financial and employee transition costs.
10. Non-avoidable generating plant operating costs and capital additions (these costs could arise from capital improvement projects which are already underway or contractually committed or from specific generating plants which are required to operate in a restructured market during the transitional phase both to assure adequate levels of reliability and to discharge continued service obligations during such period).

b. The fraction of stranded investment which should be recovered.

APS believes that all Arizona public service corporations should have a reasonable opportunity to mitigate or, if necessary, explicitly recover all of their stranded costs. Indeed, a reasonable Transition Period during which retail access could be phased in should provide sufficient time to allow full mitigation of strandable costs. (APS has used this definition of "Transition Period" whenever this term is used in this response.) Arguments against full recovery that are often made, e.g., that it does not mirror the competitive world or that paying off prior obligations is itself anti-competitive, simply do not withstand closer analysis.

First of all, to apply a competitive industry cost recovery paradigm - a paradigm in which there is no obligation to serve, no government oversight of or involvement in investment decisions, no profit or price regulation, and no legally protected service area rights - to costs incurred under a cost-based regulatory regime is both illogical and unfair. Second, even in the most competitive markets, one cannot switch to a new supplier to avoid obligations already owed to the old supplier.

If the only or even primary benefit to be gained from retail competition is the avoidance by certain customers of sunk costs, the transaction costs for this transition to competition would clearly exceed the marginal benefits. It is not anti-competitive to expect current market participants to honor past commitments any more than it is anti-competitive for a tenant to have to settle current lease obligations before moving or for a homeowner to pay off a prior lender before refinancing his mortgage.

APS believes that competition provides benefits beyond merely shifting costs on to either other customers or utility shareholders. In this respect, APS has more faith in competition than many of its more vocal proponents.

c. How the Commission will determine the amount of stranded investment, taking into account: revenues under traditional tariffed rates (or existing special contracts); actual utility revenues from customers who obtain discounted rates or obtain service from others; increases in net revenues from wholesale sales and additional retail sales, including the effects of price elasticity of demand; increases in the value of assets due to new pricing or competition; mitigation of stranded investment; and other relevant factors.

During the Transition Period (before which the Company cannot reasonably be expected to reduce embedded average generation costs to market level,) potentially stranded costs are, by definition, the difference between the market price of generation and average embedded generation costs (including decommissioning/reclamation costs and amortization of regulatory assets). The latter implicitly reflects any cost mitigation. To the extent APS customers are permitted to receive market-based generation during this period, the potentially stranded costs become actual stranded costs, assuming transmission/ distribution services remain cost based. Stranded costs can be determined on an annualized basis or by projecting market prices for the remaining years of the Transition Period and comparing the present value of the revenue streams (market vs. cost).

d. Preliminary estimates of the magnitude of stranded investment (please provide supporting analyses).

The magnitude of potentially stranded costs is extremely dependent upon (1) market prices for energy; and (2) the timing, scope, and terms of retail access. Market prices are difficult to forecast and depend upon such factors as natural gas prices, hydroelectric energy availability, demand for energy, supply conditions (amount of existing power plants that remain viable and new market entrants) taxes, and transmission constraints. Market price is itself also time dependent. For these reasons, it is not possible to provide a definitive response to Staff's Question without further delineation of the parameters subsumed in it. This is one of the many issues that the full evidentiary hearings proposed by APS could more fully determine. Suffice it to say, if APS' prices were capped at today's market prices, the revenue shortfall would be very large. This amount would be expected to decline as APS depreciates existing generating and regulatory assets and the market price for energy rises due to an expected reduction in the amount of generating capacity in excess of demand requirements.

Stranded costs are also increased if retail access is allowed before mitigation efforts are given a reasonable opportunity to succeed. The Rate Reduction Agreement provided for mitigation of regulatory assets by 2004. If mitigation measures are allowed to continue throughout the Transition Period, as defined herein, and depending upon future market prices, APS believes its potentially stranded costs will be mitigated. In any event, at the end of the designated Transition Period, all explicit rate recovery of any potentially stranded costs through either exit fees or delivery surcharges would cease.

e. The proper ratemaking treatment of negative stranded investment.

Negative stranded investment, to the extent there is any, should be offset against positive stranded investment as partial mitigation. This is done automatically if PBR cost targets are employed in measuring potentially stranded costs.

f. From whom stranded investment should be recovered.

As discussed above, APS believes that mitigation through cost savings and expanded sales of electricity and related services should be the first source for stranded cost "recovery". If APS customers are allowed to "leave" its system prior to the time these mitigation efforts can reasonably be expected to bring APS generation costs in line with then current market prices, APS believes these customers should pay for as of yet unmitigated costs that are stranded by their departure.

g. The mechanism for recovery of stranded investment.

APS proposes that mitigation be the primary mechanism for stranded cost recovery. This requires that a reasonable Transition Period be established during which the utility would be given an opportunity to bring its generation costs (as defined earlier) into parity with the market.

During this period, the initial three (3) steps of the Arizona Customer Choice Plan could be implemented (assuming timely resolution of the critical issues identified in these responses). To the extent any eligible APS customers chose direct access prior to the end of the transition, APS would propose an "exit fee" to recoup any unamortized regulatory assets attributable to such customers, and an annual delivery surcharge to reflect the difference between APS' average generation costs and average market price. This would allow APS to remain cost-based within the meaning of the Statement of Financial Accounting Standards ("SFAS") No.71 during the Transition Period but still permit progressively greater customer choice.

h. The time period over which stranded investment is to be recovered.

If the ACC agrees that mitigation ought to be the primary means of stranded cost recovery, then the period over which stranded costs would be recovered would be that Transition Period necessary to provide a reasonable opportunity to bring generation costs down to market levels.

Given the current incentives applicable to APS under the Rate Reduction Agreement, full mitigation of potentially strandable costs would require no fewer than eight (8) years even under favorable assumptions. However, the Transition Period can be affected by many factors. For example, this period may be shortened by one or more of the following:

1. use revenues earmarked for amortization of regulatory assets to accelerate depreciation of generating assets post-July 1, 2004;

2. use cost reductions to accelerate depreciation of generation assets;

3. higher than expected market prices for generation; or

4. lower than expected generation costs.

The Transition Period may be further lengthened by:

1. imposing new cost burdens on incumbent providers;

2. providing perverse regulatory incentives for the continued operation of uneconomic generation;

3. requiring that most or all of cost savings be reflected in rate decreases during the Transition Period; or

4. lower than expected market prices for generation.

Minimizing the Transition Period is a worthwhile objective regardless of the eventual end state of industry restructuring. The Arizona Customer Choice Plan would, at the same time, allow limited direct access to begin.

i. How utilities can mitigate stranded investment.

APS believes that the use of performance-based mechanisms and a limited Transition Period will provide utilities with ample incentive to mitigate stranded costs. The advantage of this approach is that it provides the utilities with the appropriate incentives without specifying the mitigation measures. The utilities can utilize their creativity and innovation to reduce costs below the performance target and use the savings to accelerate the recovery of stranded costs. This method also avoids unnecessary debate about whether any increased sales is due to natural load growth or to utility efforts, and if the former, whether it is or is not counted as mitigation. In the meantime, all customer groups enjoy stable or even declining rates.

A10. Recovery of Costs of Commission-Mandated Utility Low Income, DSM, Environmental, Renewables, and Nuclear Power Plant Decommissioning Programs ("Mandated Programs").

a. How shall costs of mandated programs be recovered from participants in the competitive market?

APS believes that in a fully competitive marketplace, ACC mandated demand-side management, and renewables programs should be eliminated in favor of market forces deciding which programs are adopted. Ratepayer funded programs simply are inconsistent with the principles of a competitive energy marketplace. In such a competitive market, customers should adopt DSM measures, and purchase or fund renewables without utility subsidies. They will do so if and only if they see value in such products and services. Likewise, energy service providers will offer such product and services if they can profit from them.

Notwithstanding the Company's belief in the efficiencies of a competitive marketplace, APS recognizes that such a competitive energy marketplace does not currently exist and a period of transition will, therefore, be necessary before it is fully developed. APS has proposed a phase-in approach to a competitive, open access marketplace, giving broad generation market access to Arizona's larger customers beginning in the year 2000 and expanding such access to smaller commercial and industrial customers in successive steps in the years 2002 and 2004. During the period of transition, regulator-mandated programs may be desirable and even necessary to reduce and/or eliminate market barriers in order to prepare the marketplace to accept or reject the adoption of DSM and renewables on their own merits. APS believes it appropriate that all ratepayers share the cost burden of funding such mandated programs during this period of transition.

As the industry moves towards a more competitive environment, APS believes that steps should be taken to ensure that the long term goals of affordable energy and self-sufficiency for low income customers are met. The Company further believes that these social services can best be provided through legislative and regulatory policies which recognize the long term goals of equity and universal benefits for this special class of customers. To the extent that such social services are provided through regulatory policy, such programs should be funded by all ratepayers.

To fund mandated DSM and Renewables programs (only during the Transition Period) and low income and other social service programs as deemed appropriate by the ACC, APS proposes that a non-bypassable uniform fee on all energy sales be collected from all customers served in Arizona. APS also proposes that mandated programs be implemented by the distribution utility. This proposal is intended to ensure equity in the distribution of the cost burden imposed by such mandated programs, that the program benefits those that pay, that a competitive balance is maintained, and that maximum use is made of competitive market forces.

The ACC should not mandate environmental programs independently of those other agencies specifically charged with that responsibility. However, the ACC should seek to have all generators comply with transmission line and plant siting requirements. In addition, to the extent the ACC does seek to implement environmental programs of its own, they should apply equally to all certified energy suppliers.

In regard to nuclear power plant decommissioning costs, it is APS' position that such costs be treated separately from other mandated program costs. We believe it is more appropriate to recover such costs in the same manner as other stranded investment costs related to generation. Just as generating plant represents an element of sunk costs, nuclear decommissioning costs are largely fixed once the plant begins operation and completes a fuel cycle. Beyond the cost of spent fuel disposal, subsequent years of operation produce few additional liabilities for decommissioning costs. However, in a less regulated environment, there are increasing concerns about the financial ability of utilities to fully fund decommissioning.

b. How shall the magnitude of the costs of mandated programs be determined?

Expenditure levels should be established based upon desired objectives and the development of strategies and tactics needed to meet those objectives. The principal driver will be the establishment of reasonable objectives, an exercise which should endeavor to balance social benefits against social costs. Estimating the magnitude of expenditures then becomes a matter of pricing out the least cost options available to meet the established objectives.

A11. Encouragement of Renewables.

a. How shall renewables be encouraged in a competitive environment? Please discuss such mechanisms as a requirement that x percent of energy sold in the competitive market must come from solar resources.

As stated in its response to A.10, APS believes that in a competitive energy marketplace, market forces themselves will decide whether or not renewables are adopted as a sustainable portion of the energy supply. APS also recognizes that the renewable marketplace is, today, in its infancy and that a period of transition to the fully competitive marketplace is necessary to develop the renewables market to a state of maturity in which it can survive and flourish in the competitive energy arena.

Renewable sources of energy can be encouraged during the transition to a competitive market by leveraging and promoting those applications where cost effectiveness can be achieved and/or have a reasonable expectation of being achieved. Specifically, renewables can be encouraged and the development of a viable renewables market can be assisted by continuing to support applications such as off-grid single and multi-customer installations and providing an option for all grid-connected customers to access renewably generated energy. It must be recognized that these are non-traditional applications for both utilities and customers alike. It is only through continued support of such applications during the Transition Period that the market will develop as the expectations of customers, the experience of utilities and capabilities of manufacturers mature.

Additional utility applications of renewables are envisioned in the form of distributed generation systems when some of the newer technologies with the potential for low cost installation become commercially available. Again, support of these technologies during the Transition Period will assist their commercialization, and create an additional tool that utilities will be able to utilize for their future operations in a fully competitive energy market.

APS supports renewables as a viable portion of our portfolio in a competitive market, but questions whether government mandated renewable generation resources, or any other form of technology, through regulated utilities, is practical in a fully competitive electric generation industry.

During the period of transition prior to competition, however, the continued use of goals, fully funded by all ratepayers, can be effective in fostering the development of renewables. Goals, if they are realistic and achievable, can be a significant incentive to perform. Following the Transition Period, market forces should provide the only appropriate encouragement required to promote renewables.

b. How could progress in encouraging renewables be measured?

A number of parameters could be tracked to indicate the degree of penetration of renewables into the energy market. Among them are:

1. Installed capacity as a percentage of total capacity.
2. Number of off-grid customers with installed renewable systems.
3. kWh of energy produced as a percentage of total energy sales.
4. Average cost per kW to install.

c. How could a renewables program be enforced by the Commission?

Beyond the Transition Period, APS believes that any form of "enforcement" is inconsistent with the idea of a fully competitive, market-driven environment.

A12. Pooling of Generation and Centralized Dispatch of Generation or Transmission.

a. Should pooling of generation or centralized dispatch of generation or transmission be mandatory or voluntary?

There are a number of different pooling concepts, including traditional joint economic dispatch, such as the PJM "tight" pool, the sharing of reserves in the Southwest under the Inland Power Pool, of which APS is a member, economy energy transactions, such as the Western Systems Power Pool, and the much-discussed California versions of "POOLCO" which rely on competitive bidding of resources into and out of a common pool to reduce energy costs. Although not a "pool", multiple participants in jointly owned and operated transmission lines and power generating plants have also produced efficiencies similar to pooling. APS has secured many efficiencies through its pooling arrangements and they have all been achieved voluntarily. Any pooling the ACC may be contemplating in this question, or centralized dispatch of generation or transmission should be completely voluntary. Voluntary programs have been proven to work best. Consider also, for example, the formation of SWRTA, and the formation years ago of the WSCC. Moreover, pooling is not required to accomplish the Arizona Customer Choice Plan. APS currently uses least cost dispatch. APS purchases power in the market whenever it is the least cost resource. Additional efficiency gains by centralizing dispatch of all Arizona resources save no more than 1-2% based on past studies, and will not produce any significant savings beyond today's practices.

This unique degree of cooperation, such as the pooling of reserve requirements and joint venture transmission and generation projects, among competitors in the electric industry is essential to achieving current levels of efficiency and enhanced efficiency in the future.

Retail access will create disincentives for utilities to cooperate to lower one another's costs and this must be factored into the restructuring debate. Although resource planning will reside with the individual utility so long as it has the legal obligation to serve, market forces will greatly shape how planning for such resources will be dealt with in the future.

A mandatory pool can be seen as an unnecessary monopoly. It would limit the benefits that competition might bring in terms of creative pricing that provides choice to contracting parties. The mandatory nature of a pool like that originally proposed in California, invites more regulation. Less experienced participants in the U.K. pool complain of complex bidding and price formation rules that advantage experienced participants and have been "gamed" by some generators. This gaming is a main reason why the U.K. regulator has intervened to re-regulate generation pricing with increasing frequency. Imposition of a mandatory pool that governs the pricing of all the wholesale market will require the participation of all affected parties in creating its rules. This could delay progress toward a competitive market. The common theme of these criticisms is the involuntary nature of the original POOLCO proposal. Most of these can be circumvented by making participation in any type of pool voluntary.

The generation market can be organized principally around voluntary institutions, as stated above, and contracts between the parties.

Regarding the operation of the transmission system and reliability of the system, APS has reviewed the Independent System Operator proposal in California. APS is familiar with Midwest and PJM proposals for more coordinated operation of the region-wide transmission systems. These proposals have very different institutions to achieve these functions. The California ISO operates the integrated transmission systems in California and maintains reliability, while the Midwest proposal will leave in tact the seven load control areas and the existing dispatch centers of the utilities will continue its reliability function. The ISO will only perform scheduling and dispatching of the systems. There are many variations depending on the objectives.

Regarding the coordination of the planning and expansion of transmission, SWRTA is expected to fulfill this role for the region's utilities. FERC has asserted jurisdiction under the *FERC Order 888* for requiring transmission expansion to meet market requirements; however, the states retain siting authority and, hence, retain the ultimate decision-making over whether planned transmission can be constructed.

b. What technical requirements will be necessary to ensure reliable and efficient use of generation and transmission resources? Please propose specific requirements, if possible.

All participants will need to abide by the NERC, WSCC, and APS operating criteria. In addition, system operation requires an efficient mechanism for matching loads and resources where contracts do not balance or cannot be accommodated due to transmission constraints. This creates a significant energy billing and accounting issue which increases in complexity with the number of retail customers/accounts with the choice of an energy supplier and potentially a separate ancillary services supplier. Each hour there will be energy imbalances because no customer ever takes and uses the exact amount of energy which it will schedule in advance. Pricing, payment, and accounting for this difference could become unmanageable if the number of customers with choice exceed those set forth in The Arizona Customer Choice Plan. There will need to be rules established for settling the payment amount of imbalances.

At this point, APS intends to account for imbalances as described in APS' response to A.4.

A13. Non-Public Service Corporations. How shall non-public service corporations such as municipal utilities be involved in a competitive market? For example, the service territories of Arizona utilities not regulated by the Commission may not be open to competition and Arizona utilities not regulated by the Commission may not be able to compete for sales in the service territories of the utilities identified in Section A1. Alternatively, an Arizona utility not regulated by the Commission may voluntarily participate in a competitive program if it makes its service territory available to competing sellers and if it agrees to all of the requirements of the Commission's competitive program.

APS has excluded municipal utilities, including SRP, from its restructuring proposal. Addressing all the important and novel legal and policy issues with public power entities that have not been confronted in other industry deregulation efforts in the U.S. (where government or public ownership of assets is not prevalent) is a formidable task - one that likely cannot be accomplished before 2000. Second, APS and SRP have a Commission-approved territorial allocation agreement in place, and APS must necessarily assume that this agreement will remain in force for the foreseeable future. However, should SRP or any other public power entity propose a means of competing that does not give it an unfair advantage and does not violate existing obligations, APS would certainly be willing to reconsider this point.

A14. Conditions for Returning to Utility Service After the Conclusion of a Pilot Program. If a pilot were adopted, please indicate what conditions are appropriate for returning to utility service after the conclusion of the pilot.

If a pilot is defined as a limited term experiment, then customers could generally return to bundled tariffed rates at any time after the conclusion of the pilot, provided that any specific costs directly attributable to that customer's participation in the pilot are collected from it prior to its return. This has practical limitations as mentioned in APS' response to Part II. If the pilot is another term for the first phase of restructuring, then the obligation to accept the customer desiring to return to its former provider, should be required only if the customer pays the full incremental market costs caused by its return.

A15. Conditions for Returning to Utility Service. Please indicate what conditions (if any) are appropriate for returning to utility service if a competitive market is on-going.

Once a fully competitive and deregulated market exists, the only condition for returning to fully bundled utility service should be the obligation to pay the full market costs incurred by the utility on account of such return. This prevents the returning customer from burdening either the utility or other customers.

Modifying an electric utility's obligation to serve in the manner described above is the "flip side" of allowing multiple suppliers. Currently, in return for exclusive territorial rights, public service corporations are generally required to serve all customers requesting service (whether profitable or not) in accordance with rules and regulations established by the Commission. This obligation to serve is an essential part of the regulatory compact and has required Arizona's electric utilities to anticipate customer growth, demand and usage and prudently invest in generation, transmission, distribution, and other utility assets. Unlike an enterprise in a fully competitive market, Arizona's electric public service corporations cannot decide unilaterally which markets they wish to serve, set the terms for providing such service, or determine whether or not to expend the capital funds necessary to meet future demands.

As customers gain access to other generation suppliers, this will require a symmetrical change in the obligation of incumbent suppliers so that the incumbent utility is not unfairly burdened with "provider-of-last-resort" status. A clear breach of the regulatory compact will occur if the obligation to serve (and associated cost burdens) remains on a particular utility, while its competitors are free to pick who, how, and when they wish to serve. Accordingly, APS will support appropriate modifications to service obligations of Arizona public service corporations that recognize increasing customer options (at least with respect to generation) while still preserving the availability of reliable and affordable service.

A16. Administrative Requirements.

a. A utility may require consumers obtaining generation from another entity to adhere to reasonable scheduling notification requirements, accept reasonable delivery points, adhere to reasonable metering requirements, and accept reasonable remote control requirements for interruptions of other purposes. Please specify what you consider to be reasonable.

The extent of infrastructure modifications and enhancements required to facilitate open access will depend on at least two major assumptions: (1) the degree of customer participation in open access and (2) the types of ancillary services to be competitively provided. The expected cost can vary by an order of magnitude depending on the answers to these two assumptions. At the very least, restructuring the electricity market will require an enhanced communication infrastructure to enable the necessary pricing signals to flow from the marketplace to the customer.

True customer choice requires two-way communication capability and different metering than is commonly in place today. A communication system must be in place to deliver pricing signals to those customers wishing to take advantage of spot pricing (i.e., real time pricing) and to verify and reconcile hourly energy consumption for billing purposes on a daily basis. Such market operations will require the provision of hourly demand meters as well as the possible provision of Var meters for those customers large enough (over 1 MW in size) to have the provision of such a service unbundled. The required communication capability could be provided by the same communication network employed in less data-transfer intensive Automatic Meter Reading ("AMR") systems.

For those customers large enough to have the choice of who supplies their regulation and back-up ancillary services, an instantaneous communication system is necessary. Because the system controls regulating the second by second response of large generators are too insensitive to respond to "instantaneous" load demand changes of less than 1MW, it is impractical to allow customers incapable of experiencing load swings of less than 1MW, the choice of purchasing their regulation service from an alternative supplier. If a third party provides regulation services to a customer, APS must be able to monitor their load fluctuations (every 2 to 4 seconds) to ensure the third party supplier, and not APS, dispatches its generating resources in response to the customer's load changes. The frequency and amount of data being transmitted would require broad band communication media such as dedicated microwave, cable or fiber optics. The existing metering and communication channels available on all but the largest customers do not have this "instantaneous" communication capability, nor do AMR systems, which typically use wireless communication.

Customers opting to contract with an alternative power provider for back-up services or opting to install their own back-up generation will also require the same instantaneous communication system needed to provide system regulation services. In addition, they will need to provide the necessary load control devices to drop load or switch over to their back-up generators when required to do so.

The customer without an instantaneous communication system or customer of insufficient size, must take regulation (load following) service from APS and APS must be adequately compensated for such service. APS will need to develop an unbundled rate for such service. Similarly, only customers above 1 MW could purchase unbundled reactive power (i.e., Var) support which is needed to maintain proper voltage and operating power factor. Smaller customers will receive voltage control (Var) service from APS on a bundled service basis or put in their own capacitor banks to meet voltage and/or power factor requirements. The cost of this service provided to a retail customer could vary from the FERC filed wholesale rate, but there is no unbundled retail rate for this service today.

If measuring Var consumption is required for small customers for billing purposes, the only practical solution is to measure Vars at the 12kV feeder level. It is not practical to install Var meters on small individual customers. Approximately 50% of APS' 12kV substation feeders do not have Var metering. This equipment would need to be installed to accomplish choice of alternative sources of Var support other than the host utility for smaller customers.

Administrative requirements can be as specific as the customer being required to notify the Company no later than 9:00 a.m. MST or at a mutually agreed to time, on the last business day prior to schedule implementation of (1) anticipated loads, (2) the power source, and (3) the delivery points. In the event that there are constraints on the APS system that would preclude a transaction, APS will notify the customer immediately. Procedures will be developed for performing these functions.

Under the Arizona Customer Choice Plan, accommodating choice for customers above 1MW will require all billing locations to have hourly load meters, Var meters (if a bundled service is not desired), communication links with the system operator, and special software to communicate pricing information, monitor loads and facilitate more complex billing. The costs of remetering are intended to be passed on to participating customers. Depending upon the degree of customer participation levels, the quantity of meters that would have to be changed out, and the improvements or additions to the APS system communication network, such changes could take several years to implement.

Furthermore, we should recognize that in addition to the system requirements described in the preceding discussion, there will be additional costs incurred by customers for equipment and services needed to take advantage of open access offerings. Such costs could include the provision of load control devices which automatically respond to real time pricing, customer displays and smart terminals, synchronizing hardware, etc. At the present time a number of issues remain unresolved relative to the establishment of communication services with the end-customer. No universally adopted standards and installation protocols have been adopted. Likewise, while emerging rapidly, not all of the hardware which will enable a customer to take advantage of spot price offerings or unbundled services are fully developed and available today.

A17. Impacts on Other Utility Customers. Please indicate how adverse impacts on rates or service quality for utility customers not participating in the competitive market could be minimized.

Regarding impacts on rates for non-participants, they will be minimized through no planned stranded cost shifting to non-participants. Departing customers will pay a non-bypassable charge to recover stranded costs if they have choice of supplier prior to the end of the Transition Period, plus an exit fee based on the remaining balance of regulatory assets at the time of exit. Moreover, during the Transition Period, APS will be attempting to mitigate stranded costs through expanded sales and non-stranded cost reductions.

Regarding impacts on service quality, they can also be minimized. APS has agreed to several internal benchmarks for the maintenance of service quality. Service quality is key to APS' competitive success. APS will not lower service quality for those not participating in the competitive market. The ACC has ample authority to respond to increased customer complaints of poor quality service such that no additional measures are needed. Moreover, experience in other competitive markets shows that competition creates strong incentives to maintain quality to retain customers - at least as strong an incentive as one to cut prices.

APS will continue to focus on building customer loyalty, enhancing an already high level of customer service and reducing its costs. APS is positioning itself now as the provider of choice and building the customer's expectation of high service levels.

A18. Reporting Requirements for All Sellers of Electricity to End Users. Please indicate what reporting requirements (to the Commission) are appropriate and who should file reports.

The distribution and transmission functions are presumably fully regulated on either a traditional cost of service basis or through some manner of PBR. They would report to the ACC and FERC the same sort of transmission and distribution data as before. However, there should be no public reporting of competitive generation data (by either buyers or sellers,) whether from independent generators or by vertically integrated utilities (functionally unbundled) except perhaps gross generation and/or gross generation sold in Arizona.

Public reporting is not contemplated for any competitively sensitive data.

A19. Certificates of Convenience and Necessity. Please comment on whether competitive sellers who supply electricity to an end user must obtain a Certificate of Convenience and Necessity from the Commission (unless the seller already has an applicable Certificate). Please describe whether any conditions on the certificate would be necessary.

Appropriate legislation should both enable and require that competitive sellers obtain a CC&N from the ACC. Conditions to securing a CC&N should include adequate evidence of financial strength; evidence that it is a corporation in good standing where incorporated; and that it will abide by all the same ACC requirements and limitations and industry reliability standards, as are imposed on incumbent sellers such as APS.

Consumers have been particularly vulnerable to fraud in other newly deregulated industries. The role of the Commission may shift through the transition to protect the public interest in new ways. This will include providing consumer protection, safety and information to consumers to make knowledgeable choices. Both operational rules (metering, reserves, rules for aggregation) and consumer protection measures will need to be established.

In conclusion, APS embraces competition and looks forward to a constructive process to resolve all issues in a timely manner to implement retail choice.

Time-Line for Resolution of Issues Required for Arizona Customer Choice Plan by 2000

	1996	1997	1998	1999	2000
Arizona Corporation Commission	**Competition Docket Workshops and Hearings on Restructuring** • Modify service area rights & obligations • Provide for compensation including stranded investments • Provide for reciprocity		• Establish scope of ACC jurisdiction and regulation of all generation market suppliers and PBR for transmission & distribution • Examine costs & benefits of direct access to determine net benefits • Transition plan for energy efficiency, renewables & social programs • Modify IRP • Assess market power • Implementation issues (metering, unbundling & pricing)		Phased retail access begins
Arizona Legislature	**HB 2504** Joint Competition Study		Consider Legislative Proposal: Modify statutes for rights and obligation to serve, provide for reciprocity and competitive balance, and non-PSC matters such as taxes and line siting		
Arizona Constitution			Only if required, Constitutional amendments considered at next general election		
FERC	Order 888 (Open transmission access) OASIS (Real time transmission information) Decision implementing California restructuring filing	Capacity Reservation Tariff Filing		Any required filings and approvals to implement retail access in Arizona	
Congress		• PUHCA • Reciprocity • Establish jurisdictional authority between State & Federal levels of government			

Exhibit A