0000071440

RECEIVED
AZ CORP COMMISSION

Nov 3 4 45 PM '97

DOCUMENT CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. U-0000-94-165

NOTICE OF FILING

Staff of the Arizona Corporation Commission hereby files a report submitted by the Unbundled Services and Standard Offer Working Group, in the above-captioned matter.

RESPECTFULLY SUBMITTED this 3rd day of November, 1997.

ARIZONA CORPORATION COMMISSION

By: Christopher C. Kempley
Christopher C. Kempley
Assistant Chief Counsel
Legal Division
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Arizona Corporation Commission
DOCKETED

NOV 03 1997

DOCKETED BY JH

I:\JOAN\WP60\LINDY\ISSUES.LGL\NOF.USS

Original and ten copies of the foregoing filed this 3rd day of November, 1997.

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing mailed this 4th day of November, 1997 to:

All parties on the service list for Docket No. U-0000-94-165

Joan Sells

I:\JOAN\WP60\LINDY\ISSUES.LGL\NOF.USS

REPORT TO THE

ARIZONA CORPORATION COMMISSION

RECEIVED
AZ CORP COMMISSION
Nov 3 4 45 PM '97
DOCUMENT CONTROL

IN THE MATTER OF THE COMPETITION
IN THE PROVISION OF ELECTRIC SERVICE
THROUGHOUT THE STATE OF ARIZONA
DOCKET NO. U-0000-94-165

Submitted By

The Unbundled Services and Standard Offer Working Group

November 3, 1997

CARL J. KUNASEK
CHAIRMAN
JAMES M. IRVIN
COMMISSIONER
RENZ D. JENNINGS
COMMISSIONER

JACK ROSE
EXECUTIVE SECRETARY

ARIZONA CORPORATION COMMISSION

November 3, 1997

To The Commissioners:

Decision No. 59943, issued by the Commission on December 26, 1996, contained rules ("Rules") providing for a phased-in transition to retail electric competition in Arizona, beginning on January 1, 1999. Such Rules required the creation of special Working Groups to address several key issues related to the introduction of competitive power markets in this State. One such group was the Working Group on Standard Offer and Unbundled Services.

Consensus was achieved on some issues. In certain cases, the Working Group consensus was to modify the existing Rules; in other instances, changes to the Rules are not needed. Some implementation issues remain unresolved. This reflects both the complexity of the issues and diversity of competing stakeholder interests. Also, for this reason, among the recommendations of the Group were those advocating a continuation of the labors of various subcommittees. Certain of these can probably be resolved in the process of reviewing company tariffs as they are filed.

Respectfully submitted,

David P. Jankofsky
Assistant Director-Utilities Division
Working Group Leader
Arizona Corporation Commission

DPJ:cmt

1200 WEST WASHINGTON, PHOENIX, ARIZONA 85007-2996 / 400 WEST CONGRESS STREET, TUCSON, ARIZONA 85701-1347

UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP

REPORT TO THE COMMISSION

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This Section of the report summarizes the findings and recommendations of the Working Group assembled pursuant to R14-2-1601.I. to explore the issues inherent in the offering of "unbundled" electric services and in the offering of traditional "standard offer" service. Additionally, R14-2-1608 added the issues surrounding System Benefits Charges and Staff added the Solar Portfolio Standard established in R14-2-1609 to this Working Group's considerations.

Issues identified by the Working Group for consideration were grouped into the following categories: Standard Offer Service; Unbundled Services; System Benefits Charge; Measurement and Cost; Solar Portfolio Standard; Metering and Meter Reading; Billing and Collection; Customer Requirements; and Administrative Requirements. Three subcommittees (Solar Portfolio Standard, Metering, and Billing and Collection) were formed to analyze certain specific issues and submitted reports to the full Working Group. The full Working Group evaluated all other issues.

Three types of conclusions were reached by the Working Group: 1) Consensus items, where the Group agreed on the meaning of the existing rules relative to a given subject; 2) Recommendations, in which the Group agreed that a change to the rules was needed in a given area; 3) Recommendations for further work. Additionally, Staff itself made some recommendations.

The highlights of each of the four categories are contained in this report summary.

I. THE WORKING GROUP CAME TO CONSENSUS ON THESE ISSUES:

Standard Offer Service

- **Can New Entrants Provide Standard Offer Service?** Under the existing Rules, only incumbent utilities could offer a Standard Offer Service as defined in R14-2-1606.A. However, new providers could offer a package of unbundled services that is similar to Standard Offer Service.

- **May a New Provider Offer Service to Those Customers not in the Competitive Market During the Transition Period?** New providers could not offer service to non-participants under the current Rules. This does not apply to buy-through transactions as authorized in R14-2-1604.G.

Unbundled Services

- **What Unbundled Services May Be Offered?** While not specifically articulated in the Rules, there seems to be no prohibition to incumbent utilities and new providers alike "rebundling" various unbundled service elements and offering those in the competitive market, subject to approval of tariffs by the Arizona Corporation Commission.

- **What is the Extent of State Jurisdiction in Transmission Services?** Unbundled transmission is effectively under FERC jurisdiction, however, if it is found that an Affected Utility's current FERC open access tariff requires modification to fully accommodate retail access, then the Arizona Commission may have to cooperate or concur with the incumbent utilities for an unbundled retail transmission tariff to the FERC. Additionally, the Arizona Commission would have to be involved in the "jurisdictional bright-line" that is proposed to the FERC for the jurisdictional separation of distribution and transmission facilities.

- **Are Existing Line Extension Policies Still Valid?** The traditional theory remains unchanged, that cost-causers will pay the costs of line extensions, perhaps with a certain free allowance.

- **What Types of Ancillary Services May Be Offered**? The unbundled ancillary services that could be offered would depend, at least in part, on the provisions of FERC Order 888. One aspect of the system that the Group agreed was not an ancillary service was operation and maintenance of the distribution system.

- **Should Load Management/Energy Management Services Be Regulated?** This type of service should be unregulated and left to the competitive market.

- **Should the Sum of the Prices of Unbundled Network Elements Always Equal the Price of Traditional, Bundled, Standard Offer Service?** Since unbundled elements can be bought from various sources, the consensus answer to this question was no.

<u>System Benefits Charge</u>

- **DSM Portion of the System Benefits Charge.** The Working Group agreed that DSM measures that are already market driven should not be included in programs that are funded by the System Benefits Charge. The Working Group agreed that the DSM portion of the System Benefits Charge should include those programs that are designed to reduce or overcome market barriers to market driven energy efficiency that are not otherwise addressed adequately in competitive or regulated markets.

- **Nuclear Decommissioning Portion of the System Benefits Charge.** The Working Group agreed that nuclear decommissioning charges should be entered as a separate line item of the System Benefits Charge. Whether the costs of nuclear <u>disposal</u> should be included was not resolved.

<u>Metering and Meter Reading</u>

- **Meter Ownership.** Meter ownership and control of the metering equipment would be limited to the Electric Service Provider or the Local Distribution Company at the customer's choice.

- **Who Installs the Meters?** Responsibility for the installation of meters rests with either the Electric Service Provider or the Local Distribution Company.

- **What Part, if any, of the LDC's Metering Infrastructure (i.e., PTs and CTs, Meter Socket, etc.) Will Be Made Available to Facilitate Third Party Installation of an Hourly Meter?** The metering infrastructure (PT, CT, socket) would be transferred to the Electric Service Provider with appropriate compensation to the Local Distribution Company.

- **If Metering is a Competitive Service, What Becomes of the Meter and Communication System Installed by an ESP When its Contract Expires with the Customer? Is it Removed? How Does the LDC Get its Metered Data then?** Any transaction between two parties is a commercial (market) transaction. A timely procedure must be in place to ensure an orderly transition.

- **Should There Be a Provider of Last Resort for Metering and Meter Reading Services?** There should be a provider of last resort for metering services. The energy provider of last resort should be the metering provider of last resort.

- **Metering Data Exchange.** A statewide standard data file format must be implemented. A workshop should be held to help develop a statewide standard data file format.

- **What Are the Minimum Metering Requirements to Accommodate Direct Access?** Minimum metering requirements for direct access customers over 20 kW (or an annual equivalent kWh for 20 kW demand) should consist of hourly consumption measurement meters.

- **Should Load Profiling Be Allowed?** There was consensus that load profiling should be allowed as an economic alternative to hourly metering. However, certain details remain to be resolved.

- **Meter Data Access Rights.** Access to end-use data should be available to the LDC, the ESP, and their designated metering and billing agents who require the data for operations and billing. No other party may have access to such data without specific authorization from the end-use customer.

- **Metering Certification Process.** In the CC&N process, the qualifications and certification programs for the personnel of companies applying for a CC&N will be evaluated.

<u>Billing and Collection</u>

- **What Billing Options Are Available?** The Working Group identified three billing options: two separate bills, a combined bill from the LDC, or a combined bill from the ESP.

- **Who Is the Responsible Paying Party?** The responsible paying party is the end user or customer of record.

- **Who Should Have the Authority to Order a Disconnect, Connect or Reconnect?** Functionally, disconnects and connects should be handled by the LDC. Only the LDC should order connects, disconnects and reconnects.

- **What Minimum Information Needs to Be Included on the Bill?** The consensus of the Working Group was that certain minimum information needs to be included on residential customers' bills for customers who take other than standard offer service. However, the billing agent may customize a residential bill and include less information upon receiving a written request by a residential customer stating what information should appear on his/her bill.

- **What Consumer Protection Standards Need to Be in Place, Including Confidentiality of Billing Data, etc.?** Customer specific billing data will only be released to parties with whom the customer has given authorization for the disclosed purpose.

II. WORKING GROUP RECOMMENDATIONS.

The following summarize the major recommendations to the Commission from the Unbundled Services and Standard Offer Working Group that would require modifications to the existing rules.

<u>System Benefits Charge</u>

The Commission should amend the wording in R14-2-1608.A. to establish a mechanism in which affected utilities file for a review of the System Benefits Charge every three years.

<u>Solar Portfolio Standard</u>

- The revised objectives of the Solar Portfolio Standard should be included in the Rules.

- The Solar Portfolio Standard penalty should be changed to a mechanism whereby the penalty funds are utilized to install solar electricity systems in Arizona.

- The Solar Portfolio Standard should include incentives of some type to encourage the electric service providers to take actions which will better meet the objectives of the solar portfolio standard.

- Electric Service Providers should be allowed to "bank" solar kWh for use in later years.

- Excess solar kWh should be tradable commodities that may be sold to other interested parties.

<u>Metering and Meter Reading</u>

- A definition of metering and meter reading services should be added to the Rules.

Billing and Collection

- The existing rules should be amended such that, assuming the data communications interface between the LDC and ESP have been established and the metering requirements are met, a customer or its authorized agent must provide 15 days advance notification to the LDC and existing ESP of his/her intent to switch suppliers.

Customer Requirements

- The existing rules should be amended to require that any tariffs submitted for competitive unbundled services include information about any additional elements necessary for the consumer to receive full electric service.

- The existing rules should be augmented for customers in the competitive environment, to indicate that the telephone numbers of the Electric Service Provider, the Local Distribution Company, and the Arizona Corporation Commission should be included on the bill.

III. STAFF RECOMMENDATIONS.

The Staff, in the course of drafting the report, developed certain recommendations for Commission consideration:

Standard Offer Services

- Staff recommends that the issue of provider of last resort be addressed by the Commission at the same time as the Commission makes a determination whether competition has been substantially implemented, pursuant to R14-2-1606.

System Benefits Charge

- Staff recommends that, if the Commission decides to allow an independent SBC administrator, that the Commission relieve the affected utilities from the existing, related Commission requirements to perform such programs and provide such services.

- Staff recommends that if the Commission decides to move to an independent SBC administration, that it be done over a reasonable transition period, to allow the affected utilities to efficiently transfer existing programs to the new, independent administrator.

- Staff recommends that, if the Commission opts for an independent SBC Administrator, the party making the triennial filing should change from the affected utility to the administrator, for certain of the programs mentioned.

IV. RECOMMENDATIONS CONCERNING FURTHER WORK

- The Working Group recommends that the Metering Subcommittee be allowed to continue meeting until the following issues are resolved:

  1. The Load Profiling methodology details are developed.

  2. Minimum metering requirements are drafted.

  3. The universal metering identifier that should be used is determined.

  4. Proposed Performance Metering Specifications and Standards are finalized.

  5. A set of validating, editing, and estimating (VEE) standards are developed.

  6. The details of open architecture for metering are finalized

- The Working Group recommends that the Billing and Collection Subcommittee continue working to review the billing and collection standards and consumer protection issues.

- The Working Group recommends that a workshop be held on Metering Data Exchange so that a statewide data format can be developed for exchanging data.

- The Working Group recommends that the Commission require Staff to form a Customer Education Working Group to develop a specific customer education program.

- The Commission should establish a mechanism to develop a cost-impact cap to be used by the Commission to determine if the Solar Portfolio Standard percentage should change in the future.

- Low-income issues should be addressed by a Task Force or Working Group in the coming months.

I. INTRODUCTION

The purpose of this report is to present the findings and recommendations of a special Working Group assembled to explore the issues inherent in the offering of "unbundled" electric services and in the offering of traditional "Standard Offer" Service.

On December 26, 1996, the Arizona Corporation Commission issued Decision No. 59943, which established rules (Rules) designed to provide for a phased transition to a competitive retail power market. These rules provided *inter alia*, for incumbent electric utilities to make at least 20% of their 1995 system retail peak demand available for competitive generation supply to all customer classes on January 1, 1999. The required eligibility will increase to 50% on January 1, 2001. Full competitive generation is scheduled to occur no later than January 1, 2003.

During this transition to a more competitive environment, incumbent utilities will still be required to offer traditional, Standard Offer Service to those customers that are not part of the competitive market, in addition to offering unbundled service to those customers that are part of the competitive market. The issues that arise for both incumbent utilities as well as new entrant electric service providers are discussed below.

Rule R14-2-1606.I. required the creation of a Working Group comprised of all stakeholders in the electric restructuring process to evaluate certain key items, including:

- Unbundled Services Tariffs
- Standard Offer Tariffs

Rule R14-2-1608 added the issues surrounding System Benefits Charges to the task of this Working Group. (System Benefits Charges are explained elsewhere in this report.)

Finally, Staff determined that the Solar Portfolio Standard established in R14-2-1609 should also make up a part of this Working Group's considerations.

By the Rules, the Working Group was charged with making its recommendations to the Commission by November 1, 1997.

The first meeting of the Working Group took place on April 9, 1997. A list of those Working Group participants and their representatives are appended to this report.

At the first meeting, a list of questions to be addressed was developed by the Working Group. Those questions were categorized into the following groupings, each of which is the subject of a section of this report:

- Standard Offer Service
- Unbundled Services
- System Benefits Charge
- Measurement/Cost Issues

- Solar Portfolio Standard
- Customer Requirements
- Administrative Requirements

Procedurally, the Group addressed each issue individually, over the subsequent five months. At the outset, the only Subcommittee established to address a particular area of concern was for the Solar Portfolio Standard. Subsequently, Subcommittees were established to address metering issues, and to address billing and collection issues. The full Working Group discussed all other issues.

Each of the Subcommittees submitted a report to the full Working Group containing their analyses, that constitute the basis for the Sections of this report on Solar Portfolio Standard, Metering and Meter Reading, and Billing and Collection.

No formal voting mechanism was established for the Working Group as a whole. When questions/issues were addressed, consensus was sought. In those instances where consensus was reached, it does not necessarily mean that there was unanimity among the members of the Working Group present at that particular meeting, but simply that the vast majority of those present were in agreement with the conclusion.

Throughout the remainder of this report are found the various issues analyzed by the Working Group, along with any recommendations. When analyzing each issue, the paramount question that the Group tried to answer was "Does a particular rule need to be modified?" While consensus was reached on some issues, there remains substantial disagreement on others. In those cases where no consensus was reached, the various positions and the differences between them have been crystallized to the extent possible.

Additionally, appended to this report are the unedited comments of the parties with respect to any issue a given party cared to address. These comments are intended to speak for themselves, and serve to further point out the overall complexity of the issues involved in transition to retail competition, and the importance of these issues and their resolution to the various stakeholders. As in most of the other states considering retail competition, the Commission will likely have to decide among competing interests on many key issues. Due to time constraints, the Working Group and Subcommittees focused on larger issues first, moving to operational details as time permitted. Additional details will require resolution prior to the beginning of the partial competitive market on January 1, 1999.

II. STANDARD OFFER SERVICE

Standard Offer Service is the traditional "bundled" service offering that electric utilities have historically provided customers in designated monopoly areas at regulated rates. Pursuant to the Rules, existing incumbent utilities **may** file new tariffs to offer Standard Offer Service. If they chose to do so, they must file such tariffs by December 31, 1997. According to the Rule, if the incumbent utility chooses to not file new Standard Offer tariffs then the tariffs in effect on that date will constitute the Standard Offer Service. The rules further state that the rates for this service must reflect costs. Finally, the Rules state that if an incumbent utility chooses to file a new Standard Offer tariff, that it is not expected that the rate for the service would increase (R14-1606.B.2).

Pursuant to the Rules, Standard Offer Service is required to be offered by incumbent utilities until the Commission has decided that competition has been substantially implemented for a particular class of customers and all stranded costs for that affected class of customers has been recovered. This determination may be made by application of an incumbent utility, or upon the Commission's own motion.

A. AREAS OF AGREEMENT

1. ISSUE: **Definition of Standard Offer Service.** The first question the Working Group evaluated was whether the definition of Standard Offer Service was adequate. The consensus of the Group is that the definition is adequate, and that the mechanism is fairly clear insofar as incumbent utilities are concerned. Incumbent utilities understand that they will be required to offer this service at cost-based rates, set pursuant to traditional ratemaking principles, to consumers during the transition period. When competitive conditions exist, pursuant to R14-2-1606.A, the market will determine whether a provider offers what has traditionally been known as Standard Offer Service.

2. ISSUE: **Can New Entrants Provide Standard Offer Service?** One question raised by potential new providers into the market is whether they, in seeking to maximize their market share of the load open to retail competition (20% in 1999, and 50% in 2001), would be eligible to offer Standard Offer Service. The Working Group concluded that under the existing Rules, that only incumbent utilities could offer a Standard Offer Service as defined in R14-2-1606.A. However, new providers could offer bundled services pursuant to R14-2-1606, by obtaining and bundling together the various service elements (e.g. generation, transmission, distribution, metering and meter reading, billing and collection) and offering the service to any eligible competitive customers that wanted to change from their traditional supplier, but wanted "one stop shopping" for electric service. In other words, new entrants could offer a package of services that is similar to Standard Offer Service except the name that is used to describe it under the Rule. Pursuant to R14-2-1606, new entrants would have to file tariffs to offer any service and documentation for its proposed rates.

3. ISSUE: **May a New Provider Offer Service to Those Customers not in the Competitive Market During the Transition Period?** Another question discussed by the Group was whether a new energy provider could offer Standard Offer Service (or a package of service elements that resembles Standard Offer Service) to the 80% (or 50%) of the load not offered retail competition during the transition. While the Group, as mentioned above, felt that the existing Rules allowed for new providers to offer what is essentially Standard Offer Service to those consumers in the competitive market, permitting new providers to offer such a service to those (80% or 50%) not yet in the competitive market would essentially amount to an immediate "flash-cut" (i.e., moving to 100% competition all at once) to competition. This is a

scenario not currently contemplated by the Rules. Accordingly, there was a consensus that new providers could not offer this service to non-participants under the current Rules. This does not apply to buy-through transactions, as authorized in R14-2-1604.G.[1]

B. UNRESOLVED AREA

ISSUE: **Provider of Last Resort in a Competitive Market.** Finally, there was some discussion of who should serve those eligible to choose an alternative provider, but not choosing one. Pursuant to the current rule, the incumbent utilities have the obligation to serve and are the energy providers of last resort during the transition period to a fully competitive market. Potential new providers felt that they should have the opportunity to provide service to those "non-choosers" either on a random assignment basis, or perhaps through a bidding process to be a "default provider" of sorts. The answer to this question depends, though, on how the Customer Selection Working Group recommends, and how the Commission decides on the methods of selecting participants in the competitive market during the transition. If the selection method is one in which potential participants are contacted until the requisite number make a choice of supplier, the issue becomes moot. If, on the other hand, 20% (in 1999) of the universe of customers are selected as being eligible for alternative suppliers, and a certain portion of that 20% does not choose another supplier, potential new providers felt that they should have the opportunity to provide service to those "non-choosers" either on a random assignment basis, or perhaps through a bidding process to be a "default provider" of sorts. Incumbent utilities, on the other hand, argue that customers that do not choose to exercise their option to enter the competitive market **have** made a choice, that is, to stay with the incumbent utility. Further, there was discussion that customer dissatisfaction and complaints could result if customers were involuntarily removed from their existing provider.

However, the discussion on this issue, while not relevant to this Working Group for the moment, did serve to raise the question of who would be a provider of last resort in a competitive market, and how that entity or entities would be selected/designated. That is, if a market were considered to be competitive such that Standard Offer Service need no longer be offered by incumbent utilities, would the incumbent utility be obligated to serve those in their historic service territory, or could it "pick and choose"? If no obligation to serve existed, how would those who would otherwise be left unserved be handled? Presumably in a competitive environment the only customers left unserved would be those that are bad credit risks. Would some form of public/general ratepayer assistance be required to allow a competitive provider to profitably serve? It would be at that time that the problem would come to the fore since Standard Offer Service would no longer be required to be offered. To ensure that this obligation is not forgotten with the passage of time, Staff would recommend that the Rules be modified

[1] Discussion of this issue led to a discussion of whether a "flash-cut" to competition was desirable. While there was some sentiment in favor of such a position, there was also agreement that January 1, 1999, would be an unreasonable date for such an action. Others believe a flash cut has merit, however, they are opposed to any delay in the implementation date, and therefore, prefer a phase-in starting January 1, 1999, over a flash cut at a later date. Moreover, it is more within the purview of the Customer Selection Working Group to evaluate this issue and present any recommendations for changes in Rules to the Commission.

III. UNBUNDLED SERVICES

The Rules provide that no later than December 31, 1997, each incumbent utility must file tariffs offering unbundled services. The services that are required to be "unbundled" and offered separately pursuant to tariff include:

- Distribution Service.
- Metering and Meter Reading Services.
- Billing and Collection Services.
- Open Access Transmission Service (as approved by the Federal Regulatory Energy Commission, If applicable).
- Ancillary Services in accordance with FERC Order 888.
- Information Services, such as provision of customer information to other Electric Service Providers.
- Other ancillary services necessary for safe and reliable system operation.

With electric competition, incumbent utilities will essentially transform their transmission and distribution services into common carrier type services. This means that any eligible supplier (or consumer) will have access to transmission, distribution, and ancillary services at comparable, nondiscriminatory rates. The Commission would set rates for unbundled distribution and other services (where it has jurisdiction). The Rules provide that these rates be cost-based and may be downwardly flexible. Cost support information would have to be provided along with the proposed tariffs for Commission analysis.

A. AREAS OF AGREEMENT

1. ISSUE: **What Unbundled Services May Be Offered?** While the Rules specify the list of services that are required to be unbundled, much of the discussion of the Working Group centered on the additional services that could be offered. The group did agree that while not specifically articulated in the Rules, there seemed to be no prohibition to incumbent utilities and new providers alike "rebundling" various unbundled service elements and offering those in the competitive market. Of course, tariffs would have to be filed for these services and Commission approval granted. These services would be optional. No change to the Rules would be necessary to accomplish this.

2. ISSUE: **What is the Extent of State Jurisdiction in Transmission Services?** A second issue discussed in the context of unbundled services involved the jurisdictional issues involved in unbundled transmission services. Unbundled transmission is effectively under FERC jurisdiction. However, if it is found that an Affected Utility's current FERC open access tariff requires modification to fully accommodate retail access, then the Arizona Corporation Commission may have to cooperate or concur with the incumbent utilities for an unbundled retail transmission tariff to the FERC. Additionally, the Arizona Commission would have to be involved in the "jurisdictional bright-line" that is proposed to the FERC for the jurisdictional separation of distribution and transmission facilities. There was a suggestion

that FERC standards could be evaluated as a model for retail suppliers' standards of conduct, effectively providing procedures for dealing among all players in the market. However, the standards were not discussed or made available for review to the Working Group.

3. ISSUE: **How is the Price for Distribution Wire Charges Set?** A third issue discussed on which consensus was reached was the methodology for determining distribution "wire charges", in essence the price for distribution service. While this question was raised specifically in the context of distribution pricing, it could have just as easily been discussed in the context of any proposed unbundled service offered in the competitive portion of the market. The Working Group's consensus was that the Rules provide that pricing on these services is approved by the Commission. The rates are based on traditional cost of service regulation and may be downwardly flexible. Accordingly, no change to the Rules is required in this instance.

4. ISSUE: **Are Existing Line Extension Policies Still Valid?** The issue of line extension policies was discussed, the essential question being: In the competitive portion of the market, are existing policies still valid? The Working Group consensus on this issue is that the traditional theory remains unchanged, that cost-causers will pay the costs of line extensions, perhaps with a certain free allowance. Actual costs would vary based on the particular requirements of a given line extension.

5. ISSUE: **What Types of Ancillary Services May Be Offered?** In the matter of ancillary services, the essential question was the types of services that could be offered and, implicitly, whether the Rules needed modification in this regard. The consensus of the Working Group was that the unbundled ancillary services that could be offered would depend, at least in part, on the provisions of FERC Order 888. FERC has identified six ancillary services: scheduling; system control and dispatch, reactive supply and voltage control, regulation and frequency response, energy imbalance, spinning reserve and supplemental reserve. These services are contemplated by the Rules in R14-2-1606.C.5. Other ancillary services that were identified by the group that could be offered pursuant to R14-2-1606.C.7 (related to safe and reliable system operation) included local backup generation, distribution voltage control, title transfer, transaction confirmation, invoicing, interruption notification, and/or power factor correction. The Group agreed that operation and maintenance of the distribution system was not an ancillary service. Some of these matters are further discussed in the sections of this report dealing with metering and billing and collection. In any event, the consensus of the Working Group was that, since the definition of ancillary services was not exclusive, no change to the Rule is necessary.

6. ISSUE: **Should Load Management/Energy Management Services be Regulated?** Finally, the specific service of load management/energy management services was also discussed. It was agreed that this type of service should be unregulated and left to the competitive market.

7. ISSUE: **Should the Sum of the Prices of Unbundled Network Elements Always Equal the Price of Traditional, Bundled, Standard Offer Service?** Finally, the question was raised as to whether the sum of the prices of unbundled components would equal the price of traditional Standard Offer Service. Since unbundled elements can be bought from various sources, the consensus answer to this question was negative.

B. UNRESOLVED AREA

ISSUE: **Deaveraging of Distribution Rates.** One important issue discussed by the participants was what might occur if distribution rates were deaveraged and the integrity of existing distribution service territory were not maintained. In such a scenario, the Cooperatives, and low-income advocates were concerned about how the disparity of distribution costs and rates between two competing – and possibly contiguous – companies could result in customers ultimately buying from a company that did not provide the lowest generation costs. That is, a vertically integrated utility serving an urban area would generally have a lower distribution cost than a rural utility with relatively few customers per mile of distribution. If the urban utility is permitted to collect distribution costs on a "rolled-in" basis from all of its customers, it can offer the full package of services (generation, transmission, and distribution) at a lower total price per kWh than can its rural counterpart, even if the rural utility was "made whole" by the urban utility paying the rural utility the full costs of the rural utility's unbundled distribution. This could even be the case despite lower generation costs on the part of the rural utility, depending upon the extent of the disparity in average distribution costs.

One solution that was discussed was requiring the competitive supplier (in this case the urban integrated utility) to charge the customer it is servicing in the rural utility's service territory the full distribution rate that the rural utility had historically charged. This solution could work provided that the urban utility's native customers do not absorb any of the distribution costs of the rural utility, essentially maintaining the integrity of each existing service territory. This solution would require strong segregation of costs, and records that maintain the segregation of customers by existing service territory.

A related issue is the geographic deaveraging of rates (an emerging trend in the telecommunications industry) within a utility's existing service territory. Presently, with average distribution costs and pricing, the more rural customers in a service territory are effectively subsidized by the more urban customers. Deaveraging geographically could result in rural customers seeing higher rates (to an unknown extent) as the subsidy from the more urban customers is lost.

IV. SYSTEM BENEFITS CHARGE

Through various rate cases and through the Integrated Resource Planning decisions, the Commission has required incumbent utilities to conduct a series of low-income, environmental, demand-side management (DSM), and renewables programs. For those utilities with nuclear plants, the Commission has required nuclear power plant decommissioning programs. These programs will, at least in the short run, increase these utilities' costs, thereby driving their prices up at the margin.

With the advent of retail electric competition, it is likely that the incumbent utilities will be unable to meet the Commission-mandated requirements and still remain competitive as customers select new electricity providers. The System Benefits Charge was developed to ensure that customers who select a new electric service provider will continue to contribute to these public interest programs, thereby allowing their distribution utility to meet mandated requirements and to fairly compete for customers as Arizona transitions into a competitive market. Staff asserts that the original intent of the System Benefits Charge was to ensure that departing customers will pay the same amount (on a per kWh basis) for these programs as the customers who remain with the incumbent utility.

A. AREAS OF AGREEMENT

1. ISSUE: **DSM Portion of the System Benefits Charge.** The Working Group agreed that DSM measures that are already market driven should not be included in programs that are funded by the System Benefits Charge. Which programs are market driven can be determined during review of the triennial System Benefits Charge filings discussed elsewhere in this section. The Working Group agreed that the DSM portion of the System Benefits Charge should include those programs that are designed to reduce or overcome market barriers to market driven energy efficiency that are not otherwise addressed adequately in competitive or regulated markets.

2. ISSUE: **Nuclear Decommissioning Portion of the System Benefits Charge.** The Working Group agreed that nuclear decommissioning charges should be entered as a separate line item of the System Benefits Charge. However, one issue that was presented in the Stranded Cost Working Group and not discussed by the Unbundled Services Working Group was the issue of nuclear waste disposal and whether that should also be part of the System Benefits Charge. To the extent that it is, a change to the rule would be necessary.

3. ISSUE: **Amounts Collected Annually through the System Benefits Charge.** The present language in the rule lends itself to differing interpretations. The sentence in question says (R14-2-1608.A):

> "The amount collected annually through the System Benefits charge shall be sufficient to fund the Affected Utilities' present Commission-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning programs."

One way to interpret the language is that it means the actual dollar amounts presently (i.e., at December 26, 1996, the date the rule was approved) included in regulated rates are sufficient to fund the programs covered by the System Benefits Charge language. The rules clearly state that the System Benefits Charge should be enough to fund the "present Commission-approved" programs. If the Commission approves additional programs in the future, R14-2-1608.A. says "the Affected Utility may file for a change in the System Benefits charge at any time."

It was observed that it will be difficult, if not impossible, for the State's two largest utilities to achieve the renewable resource goals identified in the Integrated Resource Planning (IRP) at present funding levels. Moreover, there are several DSM programs under way that had not been submitted to the Commission for approval until after the Retail Electric Competition Rule was approved in December 1996. These examples conflict with the first interpretation.

Accordingly, a second interpretation of the language is that amounts collected by the System Benefits Charge should be sufficient to fully fund the programs supported by the SBC, regardless of the December 1996 funding level. This interpretation addresses the adequacy of amounts presently included in regulated rates. It may result in amounts collected on a per kilowatt-hour basis through the System Benefits Charge, applicable to retail customers in the competitive market, greater than those collected through regulated rates.

After much discussion, the Working Group concluded that the ambiguity might be resolved by adding new wording to the rule to set up a mechanism for establishing the proper level of the System Benefits Charge. The following wording change was suggested as a way to clarify the wording in the rule. (New wording is underlined twice.)

> ~~In addition, the Affected Utility may file for a change in the System Benefits Charge at any time~~. Affected Utilities shall file for a review of the System Benefits Charge every three years. The amount collected annually through the System Benefits Charge shall be sufficient to fund the Affected Utilities' ~~present~~ Commission-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning programs in effect from time to time.

This rule change, if adopted, would establish a mechanism by which the level of SBC funding is reevaluated. Through this mechanism, advocates of a set level of funding as well as those who argue that funding should correspond to a set need will periodically have the opportunity to make their case to the Commission.

4. ISSUE: **Low Income Portion of SBC.** The Rule provides for low-income programs under the System Benefits Charge. Utilities currently provide low-income programs designed to make electricity more affordable and accessible for low-income consumers.

These programs include rate discounts, bill assistance, weatherization and energy education and vary from utility to utility in type and funding level.

The Working Group was unable, due to time restraints, to determine how low income programs should be provided for during the phase-in period or under full competition including:

- Uniform menu of types of programs.
- Statewide versus local distribution territory administration of programs.

Therefore, the Working Group recommends that low-income issues be addressed in the coming months.

A. AREA OF DISAGREEMENT

ISSUE: **Administration of System Benefits Charge.** One significant area of disagreement among the Working Group members concerned administration of the System Benefits Charge. The two alternatives presented were for an independent system administrator and for incumbent utilities to administer the funds.[2]

[2] At the final meeting of the Working Group, it became clear that there may have been a misunderstanding of the suggested "independent administrator." Those who have proposed an "independent administrator" indicated that this entity would not provide SBC services or implement programs, but rather, merely administer the SBC funds. Those interested in pursuing possible independent administrator approaches can raise this issue as the Commission considers the appropriateness of System Benefit Charge filings by Affected Utilities.

Those advocating an independent Systems Benefits Administrator assert that an independent administrator could more effectively manage System Benefits Charge money. They contend that utilities have high overhead costs and inherent conflicts of interest. They believe that such an administrator could reduce overhead costs and would operate without conflicts of interest.

Those arguing for utility administration of programs say that if System Benefits Charge money is diverted to another organization, there will be a shortfall of funding for Commission-ordered programs. They contend that utility programs are well-established and far along the "learning curve." A new provider of services would have to start anew. Utilities assert that there are inherent benefits to customers by the management of distribution costs through DSM. Finally, there is a concern that the Commission may have difficulty controlling independent organizations which are not subject to the Commission's regulatory authority.

Staff recommends that, if the Commission decides to allow an independent SBC administrator, that the Commission relieve the affected utilities from the existing, related Commission requirements to perform such programs and provide such services. Further, Staff recommends that if the Commission decides to move to an independent SBC administration, that it be done over a reasonable transition period, to allow affected utilities time to efficiently transfer existing programs to the new independent administrator.

If the Commission were to opt for an independent SBC Administrator, the party making the triennial filing would change from the affected utility to the administrator, for certain of the programs mentioned.

The question of new programs under the System Benefits Charge was raised. Those in the minority position on including solar thermal water heating in the Solar Portfolio Standard Subcommittee have been told that solar water heating was not forgotten when Staff drafted the Rules, but was meant to benefit under the System Benefits Charge. The Working Group generally agreed that solar thermal water heating should be allowable under the System Benefits Charge. Since there are not currently any programs that benefit solar thermal water heating, new programs will need to be developed and a mechanism to approve these programs needs to exist.

V. MEASUREMENT/COST ISSUES

How costs are handled in the new competitive environment will have an important impact on the success of competition and on the limitation of potential anti-competitive abuses. The Working Group discussed numerous aspects of measurement and cost issues.

A. AREAS OF AGREEMENT

1. ISSUE: **Categorization of Costs.** When tariffs are filed for Standard Offer and Unbundled Services, it is Staff's responsibility to ensure that the rates (for non-competitive services) are cost based, and that such rates do not include costs associated with the provision of competitive services. In this regard during

the transition to retail competition, Staff should guard against the shifting of costs from competitive generation to distribution, transmission or standard offer generation.

There should be no incentive for companies to load additional costs into competitive service offerings since that would cause the pricing to increase and thereby make the offeror's unbundled service or service elements less competitive. When reviewing those tariffs, Staff will also look to ensure that rates cover costs to prevent predatory pricing by any firm with market power.

Finally, it is important to note that interested parties may petition to intervene in tariff filings. Even without intervention, interested parties may file comments on any tariff filing. With intervention, if a particular tariff filing went to hearing, intervenors would have the same rights as parties and could present their own evidence and cross-examine witnesses.

2. ISSUE: **Cost Basis: Historical or Marginal.**

- Standard Offer Service - Tariffs for Standard Offer Service are not required to be filed under the Rules; Affected Utilities may leave their existing tariffs in place. To the extent that an Affected Utility chooses to file new tariffs for Standard Offer Service, the same costing principles would apply to that filing as have historically applied to the other filings of monopoly utilities.

- Unbundled Services - For unbundled service offerings, where a measure of competition will exist, rates should approach cost, and marginal cost pricing will probably be used.

3. ISSUE: **Functional, Direct Costs.** Direct costs are determined from FERC accounts.

4. ISSUE: **Functional, Indirect Costs.** Indirect costs are determined from FERC accounts.

5. ISSUE: **Administrative and General Costs.** Administrative and general costs are determined from FERC accounts.

6. ISSUE: **Preventing Cost-shifting.** In the review of any tariff or in a rate case, part of the Staff's analysis is to ensure that the rates for noncompetitive services should be cost-based and such rates should not include costs associated with the provision of competitive service. Affected Utilities are, however, free within the parameters set forth in the previous sentence to file to rebalance their rates.

7. ISSUE: **Predatory Pricing.** Predatory pricing[3] is offering a service below cost to obtain market power. Predatory pricing is not an issue if the rates charged for a service or product cover costs. That will be part of the Staff's review of any tariff. If competitors believe that a predatory pricing situation is taking place, they may file a complaint with the Commission, and that well-developed process will be followed.

[3] Predatory pricing is reducing prices below cost in order to drive a rival out of business or prevent new rivals from emerging with the intention of raising prices afterward to recoup all losses.

8. ISSUE: **Non-Discriminatory Pricing.** R14-2-1606.C. states that the Unbundled Service tariffs must be offered on a non-discriminatory basis. That is, the price, of services such as distribution and transmission should be comparable for similarly-situated customers, irrespective of whether the customer purchases competitive services from the utility as part of Standard Offer Service, a utility affiliate, or a third-party provider. Failure to require non-discriminatory treatment could result in the creation of market power for utility-provided or affiliate-provided generation, as the price of non-competitive services could conceivably be set at a higher level for customers purchasing generation from third parties.

B. AREA OF DISAGREEMENT

ISSUE: **Marketing Costs.** There was significant discussion in the Working Group concerning marketing costs. Some felt that Affected Utilities should cease competitive marketing activities at the end of 1997. Some potential competitors felt that Affected Utilities should be required to clearly demonstrate, in their December 1997 filings, that marketing costs associated with competitive services have been removed from regulated rates. It was also suggested that Affected Utilities should be required to file information about establishment of an affiliated, competitive marketing entity. Finally, it was suggested that the Commission should adopt guidelines concerning the relationships between the Affected Utilities and their affiliated, competitive marketing entities.

Staff believes that the existing process is adequate and that no change to the rules are necessary. Staff will review tariffs filed for Standard Offer Service and noncompetitive unbundled services to ensure that marketing costs that support competitive services are not included in the pricing. There is no incentive to put excessive marketing costs into competitive service offerings since that may make an offering noncompetitive in the market. Additionally, establishing an affiliated entity would require compliance with the interest rules where the general standard for allowing a utility to establish an affiliate is that it causes no materially adverse impact on the utility.

VI. SOLAR PORTFOLIO STANDARD

A. BACKGROUND

The Commission has supported development of renewables by utilities in Arizona for a number of years. In the first two cycles of Integrated Resource Planning (IRP), the Commission encouraged Arizona utilities to diversify their generation mix by adding renewable resources. Very little in renewable resource generation has resulted from the IRP orders. Now, through the Retail Electric Competition Rule, the Commission has required that all Electric Service Providers must provide part of their competitive electricity from solar.

1. Staff Analysis of the Solar Portfolio Standard

Solar electric technologies are the most applicable renewables in Arizona. The phase-in program extends the Commission's interest in renewables by requiring that suppliers in the competitive market obtain at least one half of one percent of the total retail electric energy sold competitively from solar resources, whether that solar energy is purchased or generated by the seller. Solar resources include photovoltaic resources and solar thermal resources (for example, dish-Stirling generation). After December 31, 2001, the Commission may change the solar portfolio percentage; if it does not act, the percentage increases to one percent of electric energy sold competitively.

Solar resources may be built and operated by sellers of electricity in the competitive market. However, it is expected that some of the solar energy will be supplied by firms specializing in solar resources that sell their electric output to competitive suppliers under contract. The rule indicates that the solar resources must be new, i.e., installed on or after January 1, 1997. The purpose of the requirement is to foster advances in technology, encourage economies of scale in manufacturing, and gain greater experience with applying solar resources. Sellers must report regularly on their compliance with the standard; they must clearly demonstrate the output of solar resources, the installation date of solar resources, and the transmission of energy from those solar resources to Arizona consumers.

The rule encourages early development of solar resources through a "double credit provision." Any company certificated under the provisions of the rule can credit two times the electric energy generated before January 1, 1999 using solar electric resources installed in Arizona on or after January 1, 1997 to the percentage requirement cited above.

Competitive market consumers and suppliers will pay for the solar portfolio standard. The costs will be shared by both consumers and suppliers reflecting the price elasticities of demand and supply. Further, among consumers, a large share of the costs are likely to be borne by those competitive market consumers who desire "green power." That is, those consumers who value solar power the most are likely to bear a large fraction of the costs of the Solar Portfolio Standard and they will satisfy their demand for solar electricity. In another section of the Retail Electric Competition rule (R14-2-1604 E3) there is a provision that allows customers who receive at least 10% of their electricity from solar resources to be automatically eligible for competitive electric service.

The percentage standard was selected in order to balance the interest in encouraging solar power and the higher costs of solar power relative to conventional generation. The cost impact of the solar portfolio standard is expected to be smaller than the savings which can occur through competition, especially as stranded cost recovery concludes.

With a solar portfolio standard of 0.5 percent and with 20 percent of the market served competitively, about 21 MW of solar generation capacity would be needed if SRP is included; if SRP were excluded, solar generation requirements would be about 13 MW.

The percentage standard is consistent with the utilities' planned generating capacity additions, as reported in the 1995 Resource Planning filings. By 2003, the year full competition is to start, the utilities have planned to add 377 MW of generating capacity; by 2004 they have planned to add 602 MW of generating capacity. These figures should be regarded as estimates. Including SRP, a solar portfolio standard of 1 percent of competitive kWh sales would result in solar capacity additions of 256 MW by 2004. The solar generating capacity would be in addition to the renewable goals established for utilities in the most recent Integrated Resource Planning order.

There are four solar technologies that could meet the needs of competitors in the Arizona phase-in: photovoltaics, solar dishes, solar troughs, and solar central receivers.

2. Staff Objectives of the Arizona Solar Portfolio Standard

In developing the details of the Solar Portfolio Standard, the Corporation Commission Staff was guided by the following objectives:

- Encourage the use of solar electric technologies to increase the fuel diversity in the electricity generation mix.
- Increase utility and electric service provider expertise and experience in the procurement, installation, and operation of solar electric systems or in the purchase and transmission of solar electricity from other sources.
- Encourage new solar electric technologies as a reasonable percentage (1/2 to 1% of competitive retail electric sales) that is significantly less than the annual growth (2-3% per year) of demand for electricity. (This allows utilities and other electric service providers free choice of the technologies for 99-99.5% of electricity generation.)
- Encourage the use of modest-sized, distributed solar generators to reduce the loading on existing transmission lines and also reduce the need to build new, expensive transmission lines as the demand for electricity increases in the future.
- Contribute to the commercialization of solar electric technologies, which will decrease the cost of solar electricity to Arizona customers in the future.

B. ACTIVITIES OF THE SOLAR PORTFOLIO STANDARD SUBCOMMITTEE

The Solar Portfolio Standard Subcommittee had its first meeting on May 8, 1997. The second meeting, on June 2, 1997, included a morning workshop and an afternoon meeting. Follow-up meetings were held on July 9, August 1, August 27, and September 12, 1997.

Prior to the first meeting, subcommittee members submitted 27 major issues of concern. At the first meeting, an additional 27 issues were identified. The subcommittee then grouped the 54 issues into eight major issue categories:

1. Major Issue Categories Related to the Solar Portfolio Standard:

- Goals and objectives of the SPS
- Technology choice (definition of equipment allowed in the Solar Portfolio Standard)
- Costs/timing
- Incentives (reward intended results, discourage unintended results)

- Economic development/solar industry development
- Administration
- Level playing field
- Technical details

2. Objectives. The Subcommittee discussed objectives developed by Staff and, at the August 1 meeting, the Subcommittee developed additional objectives for the Solar Portfolio Standard and slightly modified the wording of the original Staff objectives:

- Encourage the use of solar electric technologies to increase the fuel diversity in the electricity generation mix.

- Increase utility and electric service provider expertise and experience in the procurement, installation, and operation of solar electric systems or in the purchase and transmission of solar electricity from other sources.

- Encourage new solar electric technologies as a reasonable percentage of competitive retail electric sales that is significantly less than the annual growth of demand for electricity.

- Encourage the use of modest-sized, distributed solar generators to reduce the loading on existing transmission lines and also reduce the need to build new, expensive transmission lines as the demand for electricity increases in the future.

- Contribute to the commercialization of solar electric technologies, which will decrease the cost of solar electricity to Arizona customers in the future.

- Contribute to economic benefits throughout Arizona.

- Encourage environmental benefits.

- Encourage a market-based solar electric industry.

- Increase public information/awareness of solar electricity.

- Reach an acceptable cost/benefit point.

- Encourage solar resource development, rather than payment for non-compliance.

3. Suggested Changes to the Solar Portfolio Standard:

Subcommittee members were asked to suggest ideas for changes to the Solar Portfolio Standard. The following suggestions were made by various Subcommittee members:

Arizona Electric Power Cooperative, Inc. (AEPCO) said that the Solar Portfolio Standard is unduly burdensome and that both AEPCO and its members should be excluded from the requirements. AEPCO and its members do not need any new generation until after the turn of the century. The cooperatives are non-profit and member-customer owned who have no shareholder venture capital to invest in expensive excess capacity. AEPCO does not believe an investment in solar resources according to the SPS timetable would benefit the member-customers that the member-owner cooperatives serve. AEPCO proposed, as an alternative, a portfolio standard that could be phased in as new generation resources are needed to serve the retail competitive load. It should also be noted that, as a precedent, the Nevada Legislature in its competition rules exclude cooperatives from its SPS.

Arizona Public Service Company (APS) suggested that the Solar Portfolio Standard should encourage the local economic development of the solar industry. APS suggests the establishment of a "wires" charge of 30 cents for each solar kWh required for the solar standard, which can be offset, i.e., reduced, by 30 cents for each solar kWh actually provided by the ESP. This avoids the problems with penalties, and assures that the money will be spent on solar and encourage competition to purchase solar energy in the market at the least price available below 30 cents. The charges for solar kWh requirements that are not offset by the ESP would be paid to the regulated "wires" companies for them to purchase solar kWh, or install solar to meet the kWh requirement. If the cost of solar kWh to the "wires" companies exceeds 30 cents, the companies would obtain the maximum kWh possible with the funds. The wires companies would resell the solar kWh and use the revenues to offset or reduce wires charges in the future. This approach would also provide a limit to the cost of the SPS. The .5% portfolio requirement should be kept until 2003 and increased by .1% each year thereafter, until reaching 1% in 2008. A 2-times credit should be given for solar kWh from equipment manufactured and installed in Arizona. The double credit should be good for five years and apply to plants installed through 2008.

ElectriSol Ltd. recommended minor modifications in the gradation of the Solar Portfolio Standard over time to produce (in conjunction with the major step increases in eligible customers in 1999, 2001, and 2003) a more gradual solar increase over years and increasing above 1% in later years. SPS % suggestions were: 1999: .5%; 2000: .75%; 2001: .5%; 2002: .75%; 2003: .5%; 2004: 75%; 2005: 1%; 2006: 1.25%; 2007: 1.5%.

The Arizona Solar Energy Industries Association (ARISEIA) recommended that solar water heaters be included in the Solar Portfolio Standard.

KJC Operating Company recommended that the Solar Portfolio Standard not be limited to modest-sized solar installations. KJC feels that the SPS % should be increased to 1% in 1999 and, after that, increased by at least .5% per year for at least five years.

The Land and Water Fund of the Rockies suggested that a way needs to be found to allocate penalty monies to the installation of solar equipment, possibly in conjunction with the System Benefits Charge programs, rather than having the penalties go back to the General Fund.

Solel Solar Systems Ltd. said that there is a minimum "critical mass" for solar projects of 30-35 MW.

Entech, Inc. suggested rule clarification that would "grandfather" solar systems already installed or solar electricity already contracted for, if the Commission decided at a later date to drop the SPS requirement. This would avoid stranded solar investment.

A Tucson Electric Power Company (TEP) representative suggested starting with a lower SPS% of 1/4 of 1%, increasing to 1/2 of 1% in 2003, 3/4 of 1% in 2005, and 1% in 2007, assuming that the competitive phase-in currently contemplated by the Rules were to be changed in favor of a flash-cut (i.e., 100% competition starting at once) in 2001. TEP suggested adding a credit for solar "Competitive Suppliers" who own or invest in solar manufacturing, system integration, or similar businesses in Arizona. TEP also suggested double credit for early installations.

Enron presented a detailed proposal that would incent parties to enter into power purchase agreements of various terms. To hedge pricing risk associated with such contracts, Enron outlined a series of incentive credits for generated kWhs with larger credits for longer power purchase agreement terms. To the extent that the market share fluctuations and incentive credits create shortages/surpluses of kWh credits, Enron proposed allowing the trading of credits. Enron also recommended that the penalty should be increased to 50 cents per kWh to discourage participants from simply deciding to pay the lower 30-cent penalty. Given the reluctance of energy providers to enter into long-term agreements, the higher prices of "spot" or short-term solar energy make the current penalty more appealing than a penalty should be. Enron further recommended that any penalty funds be used to buy down the consumer cost of purchasing distributed solar generation, including solar rooftop systems. To enhance the economic appeal of these rooftop systems, Enron proposed that legislation promoting net metering at retail rates be implemented. Enron believes that the Solar Portfolio Standard should not include DSM, energy efficiency, or other renewable technologies. Enron also recommended that certain technical solar standards and a certification of solar facilities be met by all solar providers.

Both Boeing and York Research Corporation recommended keeping the Portfolio Standard as originally adopted.

Stirling Energy Systems, Inc. recommended that the 1% requirement should be gradually increased to 5% by January 1, 2008.

ASARCO, BHP Copper, Cyprus Climax Metals, Phelps-Dodge, and the Public Interest Coalition on Energy (the Mines and the Coalition) object to the imposition of the solar portfolio mandate. The Solar Portfolio mandate will hamper the implementation of retail competition by increasing retail prices and by adding supply-risk to the provision of competitive resources.

4. Spreadsheet Analyses of Solar Options. Thanks to funding from the National Renewable Energy Laboratory (NREL), a consultant to NREL, Pacific Energy Group, was able to develop a sophisticated spreadsheet tool to evaluate five options that had been suggested for the Solar Portfolio Standard. A representative of Pacific Energy Group (PEG) made a presentation to the Subcommittee at the August 27 meeting. Based upon input from the Subcommittee, PEG refined the spreadsheet and it was e-mailed to Subcommittee members on September 4, 1997.

5. Energy Efficiency and Renewable Energy Economic Development Impact Study. Several Subcommittee members attended a workshop presented by Economic Research Associates that described the results of a study jointly funded by the National Renewable Energy Laboratory, the Land and Water Fund of the Rockies, and the Arizona Department of Commerce Energy Office. The Study, called "Arizona Energy Outlook 2010: Energy Efficiency and Renewable Energy Technologies as an Economic

Development Strategy," presents a scenario that recommends a $4.8 billion cumulative investment for energy efficiency and renewables for years 1998-2010. Such an investment, representing less than .3% of Arizona's cumulative GSP for the period, would result in energy bill savings of almost $2 billion, generates a positive benefit-cost ratio of 1.92 and creates 11,100 new jobs.

C. AREAS OF AGREEMENT

In its deliberations, the Solar Portfolio Standard Subcommittee developed some areas of agreement.

1. ISSUE: **Changing the Penalty Provision in the Standard.** The Subcommittee agreed that the penalty provision in the rule was inappropriate, as written. As written, the penalty funds would not ensure the installation of any new solar electricity projects. The penalty funds would return to the General Fund of the State of Arizona. This would not promote the widespread use of solar electric technologies by electric service providers as intended by the Solar Portfolio Standard. The Subcommittee agrees that the penalty wording should be changed to a mechanism whereby the penalty funds are utilized to install solar electricity systems in Arizona.

2. ISSUE: **Incentives.** The Subcommittee agreed that the Solar Portfolio Standard should include incentives of some type to encourage the electric service providers to take actions which will better meet the objectives of the Solar Portfolio Standard. There is general agreement that the incentive in the existing rule is not substantial enough to encourage a significant number of early solar installations.

3. ISSUE: **Banking and Trading of Solar kWh.** The Subcommittee agreed that Electric Service Providers should be allowed to "bank" or save up any extra (that is, above the annual portfolio requirement) solar kWh produced in a year for use in later years. The Subcommittee agreed that excess solar kWh should be tradable commodities that may be sold to other interested parties.

4. ISSUE: **Cost Reduction Incentive.** The Subcommittee agreed that the cost of the Solar Portfolio Standard should be limited to an acceptable cost/benefit point, and a cost-reduction incentive should be provided to protect Arizona consumers from increasing solar purchases if lower-price objectives are not met. A kWh cost-impact cap could be set to insure that costs must decline in order for solar installation rates to increase. If the kWh cost-impact cap is broadly accepted and achieved, it could help provide a reasonable expectation for the solar industry that the Solar Portfolio Standard requirement would remain or could even increase. This range and the related assumptions and uncertainties would need to be considered in determining an acceptable cost-impact cap. Other measures such as the average solar installed cost and performance should be monitored as well. The Subcommittee agreed that the Commission should establish a mechanism to develop the cost-impact cap and decide on a date when the costs of solar electricity is to be compared to the cost-impact cap. This "decision point" would be used by the Commission to determine if the Solar Portfolio Standard percentage should change.

D. AREAS OF DISAGREEMENT

1. ISSUE: **Allowable Technologies in the Solar Portfolio Standard Definition.** The issue is whether the Solar Portfolio Standard definition should be expanded to include renewables other than solar electric systems. Some Subcommittee members suggested including other renewable technologies, such as wind, biomass, or geothermal, in the definition. Representatives of the Arizona Solar Energy Industries Association suggested expanding the definition of solar equipment eligible for the Solar Portfolio Standard by adding the following wording to the definition: "or displace electricity by active or passive solar thermal energy technologies."

- Majority Opinion: The Solar Portfolio Standard definition should stay as it is: requiring the use of solar electric technologies. This will increase fuel diversity in the electricity generation mix. It will increase electric service provider expertise in using solar electricity systems. By concentrating on four solar electric technologies, the Solar Portfolio Standard will contribute to the commercialization of those four technologies in a major way. This concentration will lead to manufacturing expansions which will reduce the future costs of electricity produced by solar. Focusing on solar electric technologies is more consistent with the business in which electric service providers operate. The "portfolio" to which the standard refers is the provision of electricity. Adding a long list of other "renewable" technologies would dilute that commercialization effort.

  Renewables other than solar electricity, such as wind or solar water heating (SWH), should not be included in the SPS. Wind resources are not widely available in Arizona, and are poorly matched in time and location to the daily and seasonal electric load of the state. Wind is already in large-scale use and is well supported in other states that have more wind resources. Water heating provides thermal energy, which is a totally different product than electricity, measured in thermal BTUs, which have a much lower value and cost than electric kWh. Solar water heaters are devices that normally must be installed as part of a customer's water plumbing and heating system and their cost-benefits are better handled by companies that sell equipment and services for energy savings. Finally, it was recognized that there was another mechanism in the rules, the System Benefits Charge, which allows the use of all other renewable technologies that were suggested for inclusion in the definition. The majority felt that the System Benefits Charge was the proper mechanism to encourage solar water heaters and other renewables. Any incentives for wind, solar water heating or other renewables should be considered separately, under the System Benefits Charge. **(ElectriSol, Tucson Electric, R. Annan, Boeing, LAW Fund, Enron, Stirling Energy Systems, Arizona Public Service Company, USSC, KJC Operating Company, PVRI, PowerMark, City of Tucson, American Hydrogen Association)**

- Dissenting Opinion(s): Solar water heating should be included as part of the Solar Portfolio Standard. Solar water heating does produce BTUs, which can be expressed in electric terms by the following simple formula: 3250 BTUs = 1 kWh. Meters are available that make this calculation. Like other solar technologies, the cost of solar water heating would decrease significantly if used on the scale expected to be created by the SPS. Unlike other solar technologies, solar water heating panels are presently manufactured in Arizona and other manufacturers have indicated that they would open facilities here if solar water heating were included in the SPS. Solar water heating is by far the most economical solar technology. A standard solar water heater, which costs approximately $2,500 offsets as much electricity in a year as $20,000 photovoltaic would. That is obviously a substantial difference.

Unlike the other solar technologies, such as central receiver, Stirling dish, or central station photovoltaic, solar water heating will be located at the home of the residential user instead of a remote location. At this home location, it will produce a direct observable benefit to that consumer immediately. In addition, the "majority opinion" is seriously compromised since those who comprise the majority stand to lose financially if it is included. The only winners would be residential users. It gives them five to ten times the amount for their money. The only state with similar conditions with a Solar Portfolio Standard, Nevada, included solar water heating in its renewable standard. **(Arizona Solar Energy Industries Association, Entech, York Research Corporation, AEPCO, Conservative Energy Systems, SAIC, Solar Energy Industries Association, Bechtel)**

- Individual Dissenting Opinion(s):

  a. A provision for solar water heating and other renewable technologies could be incorporated after the year 2003, assuming there is an increase of an additional 4% of the total electrical power generation for renewables in Arizona. **(Stirling Energy Systems, American Hydrogen Association)**

  b. Pacific Energy Group joins with the dissenting opinion under the following conditions: If solar water heating were allowed in the SPS, then:

     (i) It should be allocated a maximum percentage of the SPS to address concerns of diluting commercialization efforts of competing solar electric technologies. We suggest a maximum percentage of 15%. This does not mean that 15% of the SPS is reserved for solar water heating, it means that solar water heating is eligible to fulfill up to 15% of the SPS on a per Energy Service Provider basis;

     (ii) The definition of eligibility should be more strictly defined. For example, replace the dissenting opinion language to read, *or solar hot water systems that directly displace electricity used to heat water*; and

     (iii) Solar hot water systems that qualify under the SPS shall not be eligible for other funds resulting from restructuring, such as a system benefits charge, only if other technologies such as troughs, towers, dishes, and PV are similarly ineligible. **(Pacific Energy Group)**

2. ISSUE: **Solar Portfolio Standard Percentage and Timing.** The issue relates to the size of the Solar Portfolio Standard percentage and how that should change over time. Some feel that the percentage is too high in the early years, when solar is more expensive. Others feel that the timing of the phase-in should be extended.

- Majority Opinion: The majority of the Subcommittee members believe that either the percentage should be changed, or, by the use of multiple-credit incentives, the "effective percentage" should be reduced. (The "effective percentage" idea relates to the idea that a double credit, for instance, will effectively temporarily reduce the percentage to one-half of the required amount, though the full amount would be built after the credit expires.) **There is no majority agreement on what the percentage should be. There also is no majority agreement on when the percentage should be increased.**

Some of the suggested changes mentioned are:

- Mixed Opinions:

  a. The .5% portfolio requirement should be kept until 2003 and increased by .1% each year until reaching 1% in 2008. **(Arizona Public Service Company, AEPCO, Tucson Electric)**

  b. If there is a delay in the percentage increase, there should be a commensurate increase in the percentage above the 1% amount to compensate for the resulting delay in adding new solar resources. There should be minor modifications in the gradation of the Solar Portfolio Standard over time to produce (in conjunction with the major step increases in eligible customers in 1999, 2001, and 2003) a more gradual solar increase over years and increasing above 1% in later years. SPS % suggestions were: 1999: .5%; 2000: .75%; 2001: .5%; 2002: .75%; 2003: .5%; 2004: .75%; 2005: 1%; 2006: 1.25%; 2007: 1.5%. **(ElectriSol, Bechtel)**

  c. The SPS % should be increased to 1% in 1999 and increased by at least .5% per year for at least five years. **(KJC Operating Co.)**

  d. Starting with a lower SPS % of 1/4 of 1%, increasing to 1/2 of 1% in 2003, 3/4 of 1% in 2005, and 1% in 2007, assuming that the competitive phase-in currently contemplated by the Rules were to be changed in favor of a flash-cut in 2001. **(Tucson Electric, AEPCO)**

  e. The 1% requirement should be gradually increased to 5% by January 1, 2008. **(Stirling Energy Systems, Inc., American Hydrogen Association)**

  f. The percentage requirements, as stated in the Solar Portfolio Standard, should remain in place although effective percentages would be adjusted by any approved credit incentive. **(Enron)**

  g. Changing the effective SPS percentage phase-in and/or the ultimate percentage appears to be prudent to optimize the success of the Solar Portfolio Standard. However, it is not prudent to change the SPS percentage and timing until it is known whether or not Salt River Project is a full participant of the SPS. **(Pacific Energy Group)**

  h. The SPS percentage should be increased and ramped up to respond to national renewable portfolio standards. **(Science Applications International Corporation)**

- Dissenting Opinion(s):

  a. Some members of the Subcommittee felt that the Solar Portfolio Standard percentage and timing should remain as written in the rules. No change is needed. **(Boeing, York Research Corporation, R. Annan, LAW Fund, Solar Energy Industries Association, USSC, City of Tucson)**

  b. The Mines and Coalition do not support the mandate of the Solar Portfolio Standard; but if the Solar Portfolio Standard is implemented, we do not support any increase in the SPS percentage requirements currently mandated by the ACC rule. **(Mines and Coalition)**

3. ISSUE: **Incentives.**

- Majority Opinion: The majority of the Subcommittee members agree that some sort of incentives should be incorporated into the Solar Portfolio Standard. The majority agree that two different incentives should be offered: one incentive to encourage early installation of solar electric systems and another incentive to encourage solar economic development in Arizona:

  a. Early Installation Extra Credit Multiplier: For new solar electric systems installed and operating prior to December 31, 2003, electric service providers would qualify for multiple extra credits for kWh produced for five years following operational start-up of the solar electric system. The five-year extra credit would vary depending upon the year in which the system started up, as follows:

YEAR	EXTRA CREDIT MULTIPLIER
1997	.5
1998	.5
1999	.5
2000	.4
2001	.3
2002	.2
2003	.1

The Early Installation Extra Credit Multiplier would end in 2003.

  b. Solar Economic Development Extra Credit Multiplier: There are two equal parts to this multiplier, an in-state installation credit and an in-state content multiplier.

    (i) In-State Power Plant Installation Extra Credit Multiplier: Solar electric power plants installed in Arizona shall receive a .5 extra credit multiplier.

    (ii) In-State Manufacturing and Installation Content Extra Credit Multiplier: Solar electric power plants that are installed in Arizona shall receive up to a .5 extra credit related to the manufacturing and installation content that comes from Arizona. The percentage of

Arizona content of the total installed plant cost shall be multiplied by .5 to determine the appropriate extra credit multiplier. So, for instance, if a solar installation included 80% Arizona content, the resulting extra credit multiplier would be .4 (which is .8 X .5).

All multipliers are additive, allowing a maximum combined extra credit multiplier of 1.5 in years 1997-2003, for equipment installed and manufactured in Arizona. So, for example, if an Electric Service Provider installed a solar power plant in 1999 in Arizona, using 100% Arizona content, which produced 1 million kWh, the ESP would receive credit for 1 million kWh plus extra credit of 1.5 million kWh, totaling 2.5 million kWh.

(Pacific Energy Group, Bechtel, SAIC, USSC, Enron, Solar Energy Industries Association, KJC Operating Company, Stirling Energy Systems, American Hydrogen Association)

Some of the suggested incentives are:

- Mixed Opinions:

  a. The Solar Portfolio Standard should encourage the local economic development of the solar industry. A 2-times credit should be given for solar kWh from equipment manufactured and installed in Arizona. The double credit should be good for five years and apply to plants installed through 2008. Economic development incentives are fully described in Issue 4. **(Arizona Public Service Company, Tucson Electric, AEPCO, R. Annan, City of Tucson)**

  b. Double credits for early installations and credit for competitive suppliers who invest in solar manufacturing, systems integration, or similar businesses in Arizona. **(Tucson Electric)**

  c. Recommends a combination of incentives, such as incentives that encourage economic development and longer-term agreements. The development of these incentives should be in concert with the development of the SPS Percentage and Timing. **(Pacific Energy Group, LAW Fund)**

- Dissenting Opinion(s): Some of the Subcommittee members feel that no changes to the Solar Portfolio Standard are needed. **(Boeing, ElectriSol, and York Research Corporation)**

4. ISSUE: **Economic Development Incentives.**

- Majority Opinion: A majority of the committee agreed that the SPS should be modified to enhance its economic benefits for Arizona consumers. The present rule does not contain a mechanism to specifically encourage the long-term development of the Arizona solar industry, or for installations of solar in Arizona. Arizona consumers who subsidize solar under the SPS are likely to expect substantial economic benefits from the resulting development of the solar industry. The majority agreed to a two-part economic development incentive (as shown in Issue C.) that offers incentives for in-state power plant installation and in-state solar equipment manufacturing. **(Arizona Public Service Company, ElectriSol, Bechtel, Tucson Electric, R. Annan, York Research Corporation, AEPCO, Stirling Energy Systems, SAIC, USSC, Enron, City of Tucson, KJC Operating Company, American Hydrogen Association)**

- Additional opinion(s):

  a. Credit for competitive suppliers who invest in solar manufacturing, systems integration, or similar businesses in Arizona. TEP suggests that a Competitive Supplier should be entitled to receive a credit against the Solar Energy Requirement if the Competitive Supplier owns or otherwise makes an investment in any solar energy-related manufacturing, systems integration, or other similar business enterprise for which physical facilities are located in the state of Arizona. TEP proposes that any such credit against the Solar Energy Requirement will be equal to the amount of nameplate capacity produced in a calendar year times 2,190 hours (based on an assumption of 25% capacity factor for solar energy generation). Any assumptions and standards related to the determination of the Solar Energy Requirement could be adjusted by the Commission from time to time to reflect changes in the cost and operation of solar technology and related market conditions. **(Tucson Electric, Bechtel)**

  b. Pro-rata credit for Arizona content. Allow a credit to apply toward Arizona construction content for central station. **(Bechtel)**

  c. The SPS should be modified to provide economic development incentives that will more directly benefit Arizona. Particularly, incentives that promote the installation of systems in Arizona are viewed favorably. The approach proposed that includes a determination of Arizona content merits consideration, however, there is concern that it may prove to be overly burdensome to administer. The development of these incentives should be in concert with the development of the SPS Percentage and Timing. **(Pacific Energy Group, LAW Fund)**

- Dissenting Opinion(s): Some Subcommittee members believe that the Solar Portfolio Standard is not an appropriate place to have economic development incentives. Manufacturers will make plant location decisions based on other considerations and not on market issues such as those in the Portfolio Standard. **(Boeing, Solar Energy Industries Association)**

5. ISSUE: **Protection for Electric Service Providers in Case of Future Commission Changes in the Portfolio Standard Requirement.** One of the major barriers to the Affected Utilities and Electric Service Providers meeting the Solar Portfolio Standard is that, in the future, the Commissioners may decide to change or eliminate the Solar Portfolio Standard. This might leave the early participants at a competitive disadvantage.

- Majority Opinion: A rule clarification was suggested that would "grandfather" solar systems already installed or solar electricity already contracted for, if the Commission decided at a later date to drop the SPS requirement. The majority agreed that some wording should be added to the rules to protect the participants from the adverse affects of a future change in Commission rules to reduce or eliminate the Solar Portfolio Standard. **(ElectriSol, Tucson Electric, R. Annan, AEPCO, York Research Corporation, Bechtel, Boeing, LAW Fund, Stirling Energy Systems, Solar Energy Industries Association, SAIC, USSC, KJC Operating Company, American Hydrogen Association)**

- Dissenting Opinion(s): The ACC Rule clearly presents the definition of stranded cost "as the value of all the prudent jurisdictional assets and obligations necessary to furnish electricity...acquired or entered into prior to the adoption of this Article, under traditional regulation of Affected Utilities..." Alone, this definition should provide reason to reject any proposal to recover future stranded solar investment.

  Additionally, the current amount of stranded cost recovery imposed by the ACC Rule is burden enough to customers. Imposing future increases in stranded cost recovery will continue to impede pure competitive pricing for customers. Furthermore, the assurance of future recovery of stranded costs associated with solar investments can lead to imprudent solar investment on the part of the ESP's, which the customers will be responsible for subsidizing if stranded costs are imposed.

  Ultimately it will be all customers that will be negatively impacted if future solar stranded investments. will allow for recovery. We do not support a mechanism will impose additional costs to competitive electricity prices as a result of stranded investment in solar facilities. **(Mines and Public Interest Coalition on Energy, Enron)**

6. ISSUE: **Details of the Penalty in the Standard.** Although there was majority agreement that the penalty wording in the rule should change, there was no general agreement in how the penalty monies should be used or what the penalty level should be. Some of the ideas suggested were:

- Mixed Opinions:

  a. Increasing the penalty to 50 cents per kWh to discourage participants from simply deciding to pay the lower 30 cent penalty deserves consideration since energy providers are unlikely to enter into long-term contracts that would offer energy pricing well below the current penalty level. While it is understandable that the Commission would like to set limits on solar power pricing in order to minimize the rate impact on consumers, the penalty is not the optimal mechanism to achieve this goal. Instead, the Commission should evaluate the various pricing scenarios that may occur if energy service providers buy spot solar power versus if they enter into longer term contracts and establish target prices for solar power over time.**(Enron, ElectriSol, Boeing, LAW Fund)**

  b. The penalty funds should be allocated to the System Benefits Charge to be used to purchase solar electricity for public schools or other public facilities. **(LAW Fund, City of Tucson)**

  c. The funds should be given to "wires" companies to be used to purchase solar electricity or install solar electric systems. **(Arizona Public Service Co., Tucson Electric, York Research Corporation, AEPCO, SAIC, LAW Fund)**

  d. The penalty funds go into a "solar fund" to be used for a consumer-based program to foster the development of solar technologies in small-scale, distributed generation applications. The fund approach could be similar to California's emerging technology fund that is resulting from restructuring. The fund should provide monetary rebates, buydowns, or equivalent incentives, to purchasers, lessees or lessors of eligible solar electric systems. **(Pacific Energy Group, LAW Fund)**

e. SEIA agrees with the concept that penalty funds should be used to fund a solar deployment trust fund. SEIA does not agree with any of the mixed options. **(Solar Energy Industries Association, KJC Operating Company)**

- Dissenting Opinion(s):

a. Some organizations are firmly against increasing the penalty levels. **(Mines and Public Interest Coalition on Energy, Bechtel, Stirling Energy Systems, American Hydrogen Association)**

b. Leave the penalty as written in the rule. **(R. Annan)**

VII. METERING AND METER READING ISSUES

A. INTRODUCTION

On December 26, 1996, the Arizona Corporation Commission adopted Article 16, the rules for Retail Electric Competition in Decision No. 59943. In Rules R14-2-1605 and R14-2-1606(c).2, it was ordered that metering and meter reading services were to become competitive services. In Rule R14-2-1606(I), it was ordered that the Commission Staff should explore issues in the provision of Unbundled Service and Standard Offer Service. Staff was also ordered to submit a report to the Commission on the activities and recommendations of the Unbundled Services and Standard Offer Working Group (Working Group) sixty days prior to the end of the year.

On April 9, 1997, the first meeting of the Working Group was held. The Objectives of the Working Group and the Key Issues were developed at this first meeting. At the next meeting of the Working Group on May 9, 1997, the participants began discussing the Key Issues. During these discussions, it became apparent that the implementation of the metering and meter reading issues would involve much more discussion. Thus, the participants agreed to establish a Metering Subcommittee. Representatives from Arizona Public Service (APS), Enron, Tucson Electric Power (TEP), Citizens Utilities, Sulphur Springs Valley Electric Cooperative (SSVEC), and the City of Tucson volunteered to be on the subcommittee. It was suggested that a consumer group such as the Residential Utility Consumer Office be invited to be a participant in the subcommittee. In addition, representatives from Salt River Project (SRP), Arizona Community Action Association (ACAA), Navopache Electric Cooperative (Navopache), CellNet Data Systems (CellNet), PG&E Energy Services, Energy Strategies, Inc. (ESI), Trico Electric Cooperative (Trico) and the City of Mesa joined the Subcommittee. David Jankofsky, chairman of the Working Group, appointed Commission Staff member Ron Franquero to head the Subcommittee.

B. ACTIVITIES OF THE METERING SUBCOMMITTEE

The first meeting of the Metering Subcommittee was held on May 28, 1997. The Subcommittee's objectives were to identify, discuss, and resolve metering and meter reading issues for the purpose of making recommendations to the Commission for incorporation in appropriate rule making. An initial list of 45 key issues regarding metering and meter reading was developed. The Subcommittee then summarized these key issues into ten major issue categories:

1. Meter Ownership
2. Who is responsible for what?
3. Protocols, Standards, and Procedures
4. Metering Requirements
5. Metering Services
6. Data Security
7. Data Communications
8. Data Management
9. Performance Standards
10. FERC Issues

After this first meeting, subsequent follow-up meetings were held on July 1, July 30, August 21, September 11, and September 26, 1997.

C. DEFINITION OF METERING AND METER READING SERVICES

At the August 21 meeting, a discussion was held on what part of metering and metering services should be open to competition and what part should remain regulated. This issue was further discussed at the September 11 and 26 meetings and the Subcommittee decided on the following definitions:

The following functions are included under the general heading "Metering and Meter Reading Services" (i.e., these functions would be open to competition under the existing rules).

1. Installation of meters.

2. Installation of instrument transformers, test switches, and wiring.

3. Maintenance and troubleshooting of all the above.

4. All other equipment (RTUs, recorders, communications) necessary to meet the requirements of specific customers' applications, when used primarily as billing/energy accounting tools.

5. Coordinate replacement and return of existing metering equipment.

6. The timely communication of all required metered data to all "authorized" parties.

7. Making customer data available to customers upon request.

8. Liability for "mis-metered" customers.

9. Automated Meter Reading systems including communication system.

10. Programming of solid-state meter registers.

11. The validation, editing, and estimation process to convert "raw data" to billing and settlement ready quality.

12. The provision of data storage and other data management services.

13. Maintaining security of metered data access.

14. Meter testing.

15. Provision of diagnostic services.

16. Physical disconnects and reconnects in the field.

17. Load research meters (Note: load research will be done by both the ESP and the LDC.)

Functions which DO NOT fall under this heading (these functions would continue to be regulated under the current rules):

1. Substation panel meters

2. Digital Fault Recorders

3. Remote Terminal Units used primarily for the operation, planning, and maintenance of transmission and/or distribution systems.

4. Any metering/monitoring equipment not specifically and primarily installed for billing and/or energy accounting functions.

5. Load research meters

CellNet and Enron did not concur with the Subcommittee that competitive item #2 (installation of instrument transformers, test switches, and wiring) should be competitive. This equipment would only be needed for 400 amp service entrances and above or for 75 horsepower motors and above. CellNet and Enron were concerned that the high cost of this metering equipment would be a barrier for entry into the competitive market. At the September 26, 1997 meeting, it was mentioned that this metering equipment would only be installed for new customers. For existing customers, a service agreement could be made between the electric service provider (ESP) and the local distribution company (LDC) for use of the existing metering equipment.

CellNet and Enron also did not concur with the Subcommittee that item #16 (disconnects and reconnects) should be competitive. They felt that the LDC's should perform this activity to ensure consumer protection and because the Billing Subcommittee decided that LDCs would be the only one able to authorize physical disconnects and reconnects.

D. COMPETITIVE VERSUS REGULATED METERING AND METER READING SERVICES

Since the first meeting, considerable debate has occurred on whether metering and meter reading services should be made competitive. Rather than take too much of the Subcommittee's time, it was decided to have the participants present two "white papers" on this issue. TEP, then later APS, agreed to take the lead on preparing the paper on why metering and meter reading services should remain regulated. This paper is included as Appendix C. Enron agreed to take the lead on preparing the paper on why metering and meter reading services should become competitive. This paper is included as Appendix D.

E. AREAS OF AGREEMENT

In its deliberations, the Metering Subcommittee developed some areas of major agreement.

1. ISSUE: **Meter Ownership.** Initially, there was total consensus on this issue, but subsequently, some of the parties dissented. The original consensus was that the ownership and control of the metering equipment would be limited to the ESP or the LDC at the customer's choice. The LDCs such as APS and Navopache advocated this position. TEP indicated that the LDC or the customer could own the meter and Enron's position was that the ownership of the meter should be governed by the commercial agreement that is struck in the marketplace. This could include ownership by the customer, the ESP, or the Metering Agent (MA). CellNet and the Mines and Coalition indicated that anyone could own the meter, but the LDC or ESP should control the meter. In the United Kingdom, CellNet said the customer signs a service agreement with the LDC or the ESP. Problems could develop if the customer could own the meter, so the United Kingdom will require, beginning in 1998, that the energy provider be fully responsible for the meter, including its accuracy, integrity, data timeliness, and so on, regardless of who owns the meter. APS stated that certain problems of customer ownership, such as meter tampering and who is responsible for the operation and maintenance of the meter, could pose legal barriers to the customer ownership, or at the very least could involve added complexity. Despite these concerns raised by various entities, there was a consensus that meter ownership should be by the ESP or LDC.

2. ISSUE: **Who Installs the Meters?** The consensus was that the responsibility for the installation of meters rests with either the ESP or the LDC. It is a possibility that a metering agent (MA), a company who is hired by the ESP or LDC could handle the metering requirements, could perform meter installations.

3. ISSUE: **What Part, if any, of the LDC's Metering Infrastructure (i.e., PTs and CTs, Meter Socket, etc.) Will be Made Available to Facilitate Third Party Installation of an Hourly Meter?** Initially, there was complete consensus that the metering infrastructure (PT, CT, socket) would be transferred to the ESP with appropriate compensation to the LDC. Enron and CellNet changed their position and maintain that this metering equipment should remain as part of the LDC, notwithstanding that the PTs and CTs are an integral part of the meter and contribute to its accuracy. If the ESP takes over

service to an existing LDC customer, it would be uneconomical to replace the existing metering infrastructure. Reimbursement for equipment will be worked out between the ESP and LDC based on an evaluation of the compensation process that must be developed.

4. ISSUE: **If Metering is a Competitive Service, What Becomes of the Meter and Communication System Installed by an ESP When Its Contract Expires With the Customer? Is it Removed? How Does the LDC Get Its Metered Data Then?** The consensus was that any transaction between two parties is a commercial (market) transaction. A timely procedure must be in place to ensure an orderly transition. Enron proposed that the customer could change his provider at any time of the month. APS was agreeable to this as long as there was enough time to change providers.

5. ISSUE: **Should There Be a Provider of Last Resort For Metering and Meter Reading Services?** The consensus was that there should be a provider of last resort for metering services. Today, electricity is a necessity of life, and there cannot be any point in the line of the generation, transmission, or distribution systems where a consumer could be left without service. At least three conditions will result in the need for a provider of last resort for metering and meter reading services:

- The responsible ESP fails to provide metering services under the agreed-to terms and conditions for such services and simply walks away from its obligations.
- The end-use customer fails to select an MA upon inception of mandatory direct access.
- The end-use customer wishes to participate in direct access, but is unable to find an MA willing to provide metering services (i.e., customer default).

There was consensus that the energy provider of last resort should be the metering provider of last resort. The Subcommittee deferred to the Working Group to determine who should be the energy provider of last resort. (See discussion in Chapter II.)

6. ISSUE: **Metering Data Exchange.** The delivery of data from the responsible MA to authorized recipient(s) of such data should be through a "connect to" server. The MA will maintain a database with validated and/or raw data in such a way that authorized parties can connect to the server and access the data. Whether or not two servers will be required, one for validated data and one for raw data, will require further analysis. The server will be constructed such that each authorized party will have access only to the data it is authorized to have. Access will be protected by password clearances to authorized data and the development of "firewalls" between communication and data servers. Other issues related to metering data exchange include the format of data, frequency of transferring data, and the method of communicating data to appropriate parties.

The consensus was that a statewide standard data file format must be implemented. Much discussion was held regarding the format to be used, but this issue will not be resolved until next year. A workshop should be held to help develop a statewide standard data file format.

Another consensus reached was that Arizona should adopt existing national standards. There is no need for the LDC's and the ESP's to invest in developing data communication systems and transaction sets when national standards already exist. There was no consensus reached on what national standard to use; however, Enron suggested use of an existing national standard (ANSI X.12) that was developed by the Utility Industry Group. These standards are called the Electronic Data Interchange (EDI). EDI is an off-the-shelf product that can be purchased for as little as $5,000 to $10,000. In addition, Arizona will benefit from the development and implementation of EDI in the California market.

There was also consensus for using the Internet as the preferred method of communications. TEP suggested that there are many reliability issues concerning the Internet and that the Internet is not reliable enough to trust it for critical real-time information.

7. ISSUE: **What is the Minimum Metering Requirements to Accommodate Direct Access?** Minimum metering requirements for direct access customers over 20 kW (or an annual equivalent kWh for 20 kW demand) should consist of hourly consumption measurement meters. This requirement is principally driven by the energy scheduling and settlement process (transmission ancillary services) which requires that hourly consumption data be accurately determined after the fact in order to assign transmission demand and ancillary services costs to those parties incurring such costs. All customers desiring direct access must have their loads pre-scheduled with the system operator. At a minimum, a day-ahead schedule of 24-hourly loads is required. Energy prices in a real time pricing market are also based upon hourly data. Most participants agreed that metered data for customers over 20 kW shall consist at a minimum of hourly demand (kW), and energy (kWh). Enron's position was that metering requirements would be determined by the filed tariffs.

The need for reactive metering would be consistent with the existing tariffs which provide that, at its sole discretion, the LDC will determine the need for reactive metering on a case by case basis to insure least cost system operations and effective cost allocations, and or compliance with any FERC requirements.

The reactive metering costs will be borne by the direct access customer. Yet to be determined are the minimum data which must be maintained and provided by the responsible MA (e.g. read dates, whether the data is actual or estimated, time stamps, adjustment flags multipliers, LDC/ESP identifiers etc.).

8. ISSUE: **Metering Identifiers.** As a result of direct access implementation in the restructuring of the electric industry, participants are scheduled to have access to critical customer information. This information exchange can be facilitated by the institution of common data identifiers. One such concept is the institution of common data identifiers for customers, premises, and delivery points. A universal identifier acceptable to all affected parties will provide the basis to establish an open architecture for information exchange. Key to successful implementation of universal identifiers is agreement on a set of definitions for customers, premises, and delivery points. Today, a variety of terms and definitions are in use, such as meter, account and SIC to identify customer related information. To optimize the information exchange process, the universal identifier must be non-intelligent, permanent, and simple. An example of an identifier that meets these characteristics would be a sequential 10-digit number, which could accommodate the existing LDC identifiers.

A universal identifier will provide immense benefits in the identification and consistent definition of customers, premises, and delivery points. Once a unique identifier is established, it is rather simple to consistently associate the relationship of the data entities under consideration. For example, a customer may have one or more premises. A premises may have one or more delivery points. There may be multiple accounts associated with identified customers, premises, and delivery points. The use of universal identifiers will facilitate access to energy consumption and related data on a consistent basis. Any identifier ultimately accepted must be consistent with current existing LDC identifiers. Changes to these existing identifiers could result in higher costs to the LDCs.

While there was consensus regarding the need for a universal metering identifier, no such identifier was addressed at the meetings and this issue must be resolved in the future.

9. ISSUE: **Meter Data Access Rights.** Access to end-use data should be available to the LDC, the ESP, and their designated metering and billing agents who require the data for operations and billing. No other party may have access to such data without specific authorization from the end-use customer. In the case where the LDC is the MA, the LDC will be required to make validated meter data available to the authorized ESP to satisfy the ESP's billing requirements. Any other authorized party will also be provided such data under similar terms and conditions. If the ESP is the MA, the ESP must provide the LDC with validated meter data to satisfy tariff billing and operational requirements. The method of compensation was not resolved.

10. ISSUE: **Performance Metering Specifications and Standards.** The identification and agreement on standards should be determined at a later date to insure that this critical area of agreement is adequately explored and resolved. The Subcommittee reached consensus that, as a minimum, the following standards should be adopted, where applicable:

- Metering standards

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing and Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.11	Instrument Transformers for Revenue Metering, 10 kV- 350 kV (0.6-69kV NSV)
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.19	Utility Industry End Device Data Table

ANSI C12.20	0.2% and 0.5% Accuracy Class Meters (approved but not yet released)
ANSI C12.21	Protocol Specification for Telephone Modem (not yet approved)
ANSI C12.22	Meter Interface to Network Protocol Gateway (not yet approved)
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (70 kV - 230 kV NSV)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

EEI Electricity Metering Handbook

Electric Utilities Service Equipment Requirements Committee (EUSERC) Book NEC and Local Requirements

Although each utility presently has individualized standards for utility service, installation, maintenance and testing requirements, there was consensus that the metering agents will strive to develop common standards, where appropriate.

- Meter Accuracy

All Metering Agents must meet the existing Commission requirements for metering accuracy (+ or – 3 percent); however, a more restrictive ANSI standard may be appropriate in the future.

- Installation

All meters and installations shall meet the LDC's and ESP's safety requirements. Service and metering equipment shall meet the LDC's published electrical service requirements based on Electric Utility Service Equipment Requirements Committee (EUSERC). Meter installations may be subject to permitting and inspections by the local authority having jurisdiction for compliance with local codes and ordinances. The local authority having jurisdiction shall release all inspection clearances to the LDC. MA's must coordinate the installation of new meters and meter change-outs with the LDC and the ESP. MAs are responsible for notifying the customer, the ESP and LDC of required repairs.

- Open Architecture

A critical requirement of direct access is the communication of interval metered data to a variety of key players. It is imperative that this specification include references to the entire process of data communication including data format, storage, access rights, validation, editing, responsibilities, etc. Historically, each meter manufacturer developed their own communications protocols for interrogating and programming their own meters. This process led to the emergence of such software products as MV-90, which can communicate to multiple platforms and convert information to a common format. Considerable inefficiencies could be circumvented by migrating to standard formats such as the ANSI C12.19 *Utility Industry End Device Data Tables.* This specification should, at a minimum, call for adherence to this standard for metered data storage, where applicable.

Open architecture makes it possible for customers to switch energy suppliers without changing meters. The principle is to ensure that multiple ESPs can use, or read a particular meter, subject to having proper authority with proper security protection. Thus, open architecture standards are desirable. Without some level of standards, ESPs could create barriers to customer switching via proprietary metering systems. Enron and CellNet advocate the model that was adopted in the telecommunications industry and was proposed in the July 25, 1997, Meter and Data Communications Workshop Report to the California Public Utilities Commission. This model allows various telephones (cellular, PCS, traditional lines, etc) to communicate with any other type of telephone. This has created a fiercely competitive industry, which benefits customers. The proposed California model would require the MA to license their communications protocol, but not security passwords, at the meter to any market participant. APS feels that this requirement would breach the security of metered data and, at worst, incur significant transition costs to customers for reprogramming or rendering existing meters useless, thus increasingly stranded costs. The other area of open architecture should occur at the meter data management server. APS suggested that the marketplace would establish any open architecture desired or needed without regulatory intervention. The data format and communication standards for the server have been discussed at a high-level in other portions of the Areas of Agreement of this report.

11. ISSUE: **Validating, Editing, Estimating, and Storage.** Currently all utilities have their own set of validating, editing, and estimating (VEE) standards. Many of these standards were developed for the most part to manage simple kWh monthly meter reads and not hourly data. The Subcommittee agrees with APS' recommendation that developing common standards through a consensus process will require more time and a different group of technical experts than currently exists in the Subcommittee. Therefore, the Subcommittee recommends that agreement be reached on the need for a common set of VEE standards at this time. Enron provided the following initial list to the Subcommittee for future consideration:

- Interval Data Transformation

  Standard and approved quality checks on raw meter read data will be performed. These checks include validating, estimating and/or editing consumption data to render it validated where required by market participants as defined in this section.

- Consumption data will be validated and corrected using the following approved and documented validations and algorithms.

a. Spike Check
b. High Low Average Daily Usage Check
c. Sum Check
d. Hardware Checks
e. kVarh (If collected, additional estimation rules.)

- Validation results will be stored with and at the same interval frequency as the source data.

- Estimated usage data will be identified and what percentage of estimated usage data will be allowed. The estimation technique will accompany this identification.

- Usage data will be translated to and maintained in the agreed upon MA data exchange format.

- Monthly Validating, Estimating and Editing.

a. Hi/Low Usage
b. Hi/Low Demand
c. TOU Usage
d. Zero Consumption for Active Meters
e. Usage for Inactive Meters

- Meter Configuration Recommendations

a. Meter Read Dial Quantity Difference
b. Meter Read Dial Decimal Quantity Difference
c. External Meter Identification

- Missing/Incomplete Data Recommendations

a. Missing Usage Meter Read
b. Missing Demand Meter Read

12. ISSUE: **FERC Requirements.** In the Federal Energy Regulatory Commission's (FERC) Open Access rulemaking (FERC Order 888/888A), FERC held that it had exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission in interstate commerce by public utilities, up to the point of local distribution. FERC further agreed that when transmission is sold at retail as part and parcel of a bundled delivered product called electric energy, the transaction is a sale of electric energy at retail and, therefore, the bundled transmission service is outside the authority of the FERC.

The FERC will exercise jurisdiction over all other aspects of this transaction, most notably those involving transmission and ancillary services. It is in this area of influence that the FERC has established some requirements relative to metering. The FERC has determined that any entity seeking and acquiring access to third party energy suppliers, should have the capability of determining hourly consumption for purposes of billing required services (i.e., transmission and ancillary services). If it is found that an Affected Utility's current FERC open access tariff requires modification to facilitate data access and to fully accommodate retail access, then the Arizona Corporation Commission may have to cooperate or concur with the incumbent utilities for an unbundled retail transmission tariff to the FERC.

13. ISSUE: **Data Access Frequency and Timeliness.** The consensus was that access to meter data should be at a minimum on a monthly basis for validated meter reads necessary for billing purposes. Such information should be made available to the electronic mailbox within 24 hours of the actual meter read date for customers who have untimed meters and within 48 hours for customers who have hourly interval meters.

14. ISSUE: **Metering Certification Process.** The consensus was that all metering personnel should be subject to a certification process. All metering agents and their individual service personnel must be certified to insure the safe and reliable operation of the metering system. Since the ESPs and the MAs must obtain a CC&N for doing metering and meter-reading in Arizona, the consensus was that all parties are certified as part of their compliance with their CC&N. As part of their CC&N filings, Staff will require the ESP's and the MA's to present the procedure used to verify the certification of their metering personnel.

15. ISSUE: **Should Load Profiling Be Allowed?** Load profiling is the process of estimating a customer's hourly load shape based on an appropriate sample of historical usage patterns for similarly situated customers. There was consensus that load profiling should be allowed as an economic alternative to hourly meter reading. A proposal was made that customers under 20 kW, at least initially, be permitted to use load profiling to satisfy the requirements for hourly consumption data. Such a load profiling provision should include the requirement for a statistically significant metered load sampling basis to meet scheduling and settlement requirements. The method for allocating cost responsibility to ESP's for any irreconcilable energy imbalance charges resulting from the inaccuracies introduced by load profiling remains to be determined. Ultimate implementation of hourly metering for customers under 20 kW will be determined by the experience gained with the application of load profiling as well as the economics of system-wide hourly metering implementation. The Mines and the Coalition note that the appropriate minimum level for requiring hourly metering may be in the 20-50 kW range, as has been determined in California. APS suggests that consideration should be given to equating kW to kWh to facilitate the identification of customers eligible for load profiling.

Load profiling methodologies need to be periodically reviewed by the Commission to determine whether it is appropriate to continue their use. The inaccuracies inherent in load profiling may disadvantage some customers by requiring that they pay based on a load profile that is different than their own. ACAA suggests that customers should be held harmless from any negative consequences as a result of the design and implementation of load profiling. It is essential that the load profiling methodology be reviewed and updated regularly by the LDC and the ESP's to ensure that the profile adequately reflects the usage patterns of the customer it is modeling. Ultimately, dynamic load profiling should be the goal, if load profiling continues. This would permit the ESP's to modify the load profiles of its customers based on the most current usage information and will help reduce variations between the load profile and actual usage and will reduce any misallocation of costs.

F. UNRESOLVED ISSUES REGARDING LOAD PROFILING. The consensus of the Working Group was that the development of a load profiling methodology would require considerably more time to resolve than was available. There are four principal interrelated issues surrounding load profiling: (1) Economic efficiency; (2) System reliability; (3) Proper allocation of energy cost responsibility to customers; and (4) Proper allocation of energy cost responsibility to third party suppliers.

1. ISSUE: **Economic Efficiency**. One of the fundamental overriding objectives of competition in any industry (including the electric industry) is the attainment of greater economic efficiency. The prevailing wisdom on the subject dictates that in order to achieve this goal it is imperative that consumers receive appropriate pricing signals that accurately reflect the cost of the product they are consuming or the service they are receiving. Electric energy is a commodity which all suppliers recognize has a cost that varies depending on a number of possible factors including the nature of the fuel source for the generation, the time of year and the time of day in which it is supplied. Accordingly, the unresolved issue involves how to best ensure that consumers receive price signals consistent with their individual usage.

2. ISSUE: **System Reliability**. As part of the procedures associated with energy supply, third party suppliers will have to furnish energy schedules for their customers, including any that may be load-profiled. In day-ahead planning, the anticipated hourly energy usage of customers along with the resources necessary to meet that demand (plus reserves) is scheduled with the transmission system's control area operator. In a competitive market, the schedules of retail customer loads will be furnished by authorized scheduling entities, such as aggregators. These scheduling entities will be required to submit schedules in which expected hourly loads and resources are in balance and reserves are provided. It is well understood that actual loads and schedules will not match perfectly. For this reason, the control area operator is required by FERC to provide regulation and frequency response service, the cost of which is charged to customers as an ancillary service. In performing this service, the control area operator uses Automatic Generation Control (AGC) to make sure that resources exactly match load in real time, ensuring system reliability.

Some parties are concerned that load profiling will decrease the accuracy of scheduling process, thereby making day-ahead planning more difficult. Others point out that those who submit inaccurate schedules will be subject to monthly energy imbalance charges. These charges will be assessed after monthly energy usage is apportioned in accordance with the customers' respective load profiles. All parties agree that the load profiling protocol should be designed in a way that minimizes the opportunities for taking unfair advantage of the scheduling process

3. ISSUE: **Proper Allocation of Costs to Customers**. An additional unresolved issue with load profiling is how to best ensure that consumers are paying an appropriate amount for their individual contribution to the system peak or to the peak hours. This issue occurs because every customer in a particular class is lumped in with all others of that class and a usage pattern is deduced for the class as a whole. Energy will then be scheduled to cover the generalized estimates for the customer class's needs without any specific consideration of individual customers taking place. (Without hourly meters this is all you can do.) This method has the distinct disadvantages of (a) failing to monitor the hourly use of individual customers, many of whom may be larger users of electricity than those included in their class during the more expensive peak periods, and (b) requiring the control area operator (or the ISO) to supply,

or arrange for the supply of, any additional energy that may be needed above the estimated scheduled amounts for those customers who are consuming more than anticipated by their generation suppliers without the control area operator (or the ISO) being able to specifically identify those individual customers who are the cause of the energy deficiencies. The inability of the control area operator (or ISO) to identify those individual customers who are these energy "absorbers" leads to the economically distorting effect of costs being incurred without proper assignment to the customers causing them. In the absence of hourly metering, all that can be done is to assign the additional costs over the entire class and build them into the customer charges, probably on an average basis. But this solution cuts against the grain of competition's objectives by failing to link cost responsibility to cost causation.

One way to capture as much allocable efficiency as possible is to require that all time-of-day information captured by an individual customer's meter be used in fitting his or her energy usage into the load profile. Thus, for example, a customer with a time-of-day meter would have his or her known on-peak hours placed within the on-peak portion of the load profile.

4. ISSUE: **Proper Allocation of Costs to Third Party Suppliers**. Another issue is that energy suppliers are not being assessed appropriate cost responsibility for any energy deficiencies that have to be made up by the control area operator (or ISO) to ensure energy deliveries to load-profiled customers. Unless all load-profiled customers are supplied by one energy company, the inability of the control area operator (or ISO) to identify specific customers responsible for unscheduled energy additions during given hours will consequently render that entity unable to specifically identify the energy supplier that should be responsible for the additional cost. Again, some form of averaging or generalized cost will have to be spread over all suppliers of that particular customer class; this will, of course, mean that some suppliers will pay more than their customers are actually responsible for and some will pay less. The issue then becomes one of finding the best possible way to ensure that suppliers pay their fair share of the cost.

VIII. BILLING AND COLLECTIONS

A. INTRODUCTION

On April 9, 1997, the first meeting was held of the Unbundled Services and Standard Offer Working Group. The objectives of the Working Group and the key issues were developed at this first meeting. At the next meeting of the Working Group on May 9, 1997, the participants began discussing the key issues. During these discussions, it became apparent that the implementation of the billing and collection issues would involve much more discussion. Thus, the participants agreed to establish a Billing and Collection (B and C) Subcommittee. Representatives from APS, ACAA, Enron, ESI, Tucson Electric Power, Trico Electric Cooperative, Citizens Utilities, Sulphur Springs Valley Electric Cooperative (SSVEC), the City of Mesa and the City of Tucson volunteered to be on the subcommittee. The Residential Utility Consumer Office was also invited to participate in the subcommittee. David Jankofsky, chairman of the Working Group, appointed John Wallace of the Commission Staff to head the Subcommittee.

B. ACTIVITIES OF THE BILLING AND COLLECTION SUBCOMMITTEE

The first meeting of the Billing and Collection (B and C) Subcommittee was held on May 28, 1997. The Subcommittee developed a scope of issues relative to billing and collection, which are required to be resolved in order to implement the Commission's Retail Electric Competition Rules. The Subcommittee's objectives were to identify, discuss, and resolve billing and collection issues for the purpose of making recommendations to the Commission for incorporation in appropriate rule making. The Subcommittee began with 41 key issues regarding billing and collection. At the August 21 meeting, these were consolidated into nine major issue categories:

- What bill options are available?
- Who is the responsible paying party?
- Who should have the authority to order a disconnect, connect or reconnect?
- What are the communications standards?
- What minimum information needs to be included on the bill?
- How does the customer switch his/her supplier?
- What consumer protection standards need to be in place, including confidentiality of billing data, etc.?
- What type of billing data needs to be stored? For how long? Who should store it?
- Whose phone numbers should be on the bill?

After this first meeting, subsequent follow-up meetings were held on July 1, July 30, August 21, September 10, and September 25, 1997. The remainder of this report will discuss the B and C participants' consensus and non-consensus on the nine key B and C issues listed above.

C. AREAS OF AGREEMENT

1. ISSUE: **Who Is the Responsible Paying Party?** Most participants agreed that the responsible paying party was the end user or customer of record. Most participants also agreed that if the ESP is issuing a consolidated bill and the customer defaults, the ESP would still be responsible for paying the LDC for services rendered to the customer, pending transfer of the customer to a different energy service provider or the default provider.[4]

Most participants agreed that the end user was also the responsible paying party in cases where the LDC issues a consolidated bill. Under this scenario, the LDC would be responsible for paying the ESP upon the LDC receiving payment from the end user. However, there was not a consensus about the responsibility of the LDC paying the ESP for electricity provided to the customer who is in default. Generally, the Affected Utility participants did not believe that the LDC should be responsible for paying

[4] Affected Utilities are currently authorized to recover in rates an amount which reflects the amount of uncollectible expense that they experience. Enron proposed that it may be appropriate to revisit the level of uncollectibles recovered in the distribution rates of the Affected Utilities as ESPs bear the risk for non-payment for, at a minimum, the energy portion of the bill and, at a maximum, the total bill amount depending on the bill option available to the customer. APS stated that the risk may be actually larger now, since non-payment by an ESP to the LDC (even for those customers that did not pay the ESP for the wires charges, etc. and were not remitted to the LDC) could pose a higher risk in terms of both credit worthiness and quantity of money than individual non-paying customers today.

the ESP when a customer has not paid the LDC. If the LDC were to be held responsible for non-payment of competitive generation, it would shift those costs to the regulated price of distribution costs and to those customers not participating in the competitive market. Enron argued that if the ESP was going to assume the risk of nonpayment in cases where the ESP issues a consolidated bill, then the LDC should assume the risk of nonpayment in cases where the LDC issues a consolidated bill.

2. ISSUE: **Who Should Have the Authority to Order a Disconnect, Connect or Reconnect?** The participants reached the following consensus on this item.

Functionally, disconnects and connects should be handled by the LDC. Only the LDC should order connects, disconnects and reconnects. In a competitive marketplace, the ESP cannot order a disconnect for non-payment, but can only send a notice of contract cancellation to the customer and the LDC. A standard time frame for notification will be established. The customer would then have to find another ESP. The consumer protection requirements for ESP's will be examined further to clarify their role and the ESP's responsibilities in a competitive market. Disconnects for non-payment should occur only when the regulated LDC does not receive payment for its services. Disputes over payments to the ESP are not subject to disconnect. Upon written authorization by the consumer for service from an ESP, the LDC will provide connection in a non-discriminatory fashion and under the same terms and conditions granted to an affiliated ESP's customers.

Some of the subcommittee participants have indicated that the detailed requirements set forth in the Electric Utilities Rules, R14-2-201, et. seq., which were originally intended for a monopoly setting, may not be appropriate in a competitive marketplace, where flexibility is a key issue. Other participants have voiced concern that consumer protections must be maintained.

Because of time constraints in completing the final report, the B and C Subcommittee recommends that it be directed to continue to review the billing and collection standards and consumer protection issues including slamming that have been incorporated into the Retail Electric Competition Rules and provide specific provisions to apply to the Energy Service Provider. Additionally, the specific provisions for the distribution company may be inappropriate and/or in conflict with the specific provisions that apply to the ESP and need to be reviewed.

3. ISSUE: **What are the Data Communications Standards?** The consensus among participants was that the transmittal of billing data among suppliers will be via EDI data file format.

4. ISSUE: **What Minimum Information Needs to be Included on the Bill?** The consensus that was reached by the participants regarding the minimum information that needs to be included on residential customers' bills for customers who take other than Standard Offer Service is as follows:

- Customer name and address
- Date and meter reading at the start of the billing period or number of days in the billing period
- Date and meter reading at the end of the billing period
- Billed usage and demand
- Rate Schedule number
- LDC and Billing Agent (if the ESP) telephone number(s)

- Service account number
- Amount due and due date
- Past due amount
- Adjustment factor, where applicable
- Applicable taxes
- The ACC telephone number and address
- Basic Service Charge
- Distribution Charge
- Transmission and ancillary services charges
- Generation (i.e., ESP energy charge)
- System Benefits Charge
- CTC charge
- Metering and billing charges
- Other products and service charges (if applicable)

The majority of participants believed that, in a competitive market, more information was better than less to allow residential customers the opportunity to compare prices and other characteristics of competitive services. The majority of participants also believed that the billing agent may customize a residential bill and include less information upon receiving a written request by a residential customer stating what information should appear on his/her bill. ACAA expressed a position that consumers should not have to face any barriers to get information. In ACAA's opinion, it is better to err on the side of more consumer protection and education by giving consumers more information than some of them need. ACAA believes that more information would be preferable to setting up a billing process to give expanded bills only upon request, which favors billing agents and ESP's.

Enron and TEP commented that residential customers may not want this much information and that only approximately five key items need to be included. The five key items are:

- Customer Name and Address and other identifiers,

- Billing Period for which the bill is rendered,

- Billed Usage and Demand, if applicable, and other information necessary to determine computation of the bill,

- Amount Due, Due Date, and Past Due amount,

- Telephone numbers of the ACC, LDC and ESP.

Enron and TEP also believe that the amount of information included on residential bills should be determined by the competitive market. Enron and TEP believe if customers want more billing information, then they can call their billing agent and receive it. Some participants believe that competition will provide innovation in billing. They believe that making the requirements to include 20 items on a bill as a minimum standard is over-prescriptive and counter to the goal.

Participants also debated whether unit pricing and type of generation by percentage should be included on residential customers' bills. During Subcommittee meetings, there was consensus that such information should not be placed on the customers' bills. During the last meeting of the Unbundled Services Working Group, this recommendation was discussed in full detail and by a vote of 7 to 4 (which represented the number of organizations in attendance at the meeting) the Subcommittee's recommendation was accepted by the full Working Group.

5. ISSUE: **How Does a Customer Switch His/Her Supplier**? The participants reached the following consensus on this issue. Assuming the data communications interface between the LDC and ESP have been established and the metering requirements are met, a customer or its authorized agent must provide 15 days advance notification to the LDC and existing ESP of his/her intent to switch suppliers.[5] Other customer responsibilities in switching to an alternate ESP need to be established, but are generally not involved with billing. The existing billing agent must forward 12 months of billing history to the new ESP within the same 15-day period.

As mentioned previously, because of time constraints in completing the final report, the B and C Subcommittee recommends that it be directed to continue to review the billing and collection standards and consumer protection issues including slamming that have been incorporated into the Retail Electric Competition Rules and provide specific provisions to apply to the Energy Service Provider.

6. ISSUE: **What Consumer Protection Standards Need to Be in Place, Including Confidentiality of Billing Data, Etc.?** The participants reached the following consensus on the definition of customer specific billing data:

- kW, kWh, kVar, total billed amount and unique customer identifier which may include customer name, address, telephone no. and account no.[6]
- Payment history (due dates, date of payment, etc.)
- Credit profile (employer, deposit information, etc.)

Customer specific billing data will only be released to parties with whom the customer has given authorization for the disclosed purpose. The customer authorization must be specific in relation to the three items listed above and must be written, electronic or through voice verification and must be able to be audited. Access to customer specific billing data will coincide with the contractual relationship with the customer. Unless otherwise specified by the customer, the previous twelve (12) months of customer specific billing data will be sent to the party that has a customer authorization.

For billing purposes, only item no. 1 (kW, kWh, etc.) above will be released to the customer's LDC and ESP without specific customer authorization.

[5] The participants acknowledge that the 15-day advance notification may be longer in rural service territories or in cases where weather prohibits the LDC from reading the meter within that time period. In these cases, participants agreed that the time period will be no longer than the next scheduled meter read date.

[6] The Participants recognize that the items included in no. 1 are not an exact list.

Customers have a great deal of protection available to them in the new restructured environment. They have civil protection afforded them with regard to the contracts they sign which protect them against fraud, paying for services they do not receive, etc. They have the law to protect them against illegal discriminatory practices such as red-lining. The Commission's existing rules provide consumer protection. The licensing procedure or the application for a Certificate of Convenience and Necessity (CC&N) requires proof of financial viability, to reduce the potential of unscrupulous, "fly-by-night" ESPs. It also provides for disclosure of a maximum lawful rate to be charged for service under the adoption of a tariff. In addition, the customer protection and customer switching sections of this report provide further customer protection with regards to ordering disconnects, connects, and reconnects as well as switching energy suppliers.

7. ISSUE: **What Type of Billing Data Needs to be Stored? For How Long? Who Should Store It?** The participants reached the following consensus on these issues. Data used in determining the bill should be stored for a minimum of three (3) years. Thirteen (13) months of on-line billing data will be maintained in the agreed upon standard format. The designated billing agent shall maintain its billing data for a minimum of three years. These requirements are in addition to any federal, state or local requirements.

8. ISSUE: **Whose Telephone Numbers Should Appear on the Bill?** The consensus of the participants in the B and C Subcommittee was that the telephone number of the LDC, ESP and the ACC should appear on a customer's bill.

D. UNRESOLVED ISSUE

ISSUE: **What Billing Options Are Available?** The participants in the B and C Subcommittee identified three billing options.

Option 1: Two Separate Bills, one bill from the Electric Service Provider (ESP) and one bill from the Local Distribution Company (LDC). For the purpose of this report, the LDC provides Distribution Service as defined by Commission's Retail Electric Competition Rules.

Option 2: A combined bill from the LDC that includes charges from the ESP.

Option 3: A combined bill from the ESP that includes charges from the LDC.

There was not an agreement among participants about whether the consumer or the LDC and ESP should choose the billing options available to consumers. ENRON, PG&E Energy Services, RUCO and the Mines and the Coalition believed that it should be the customer who chooses among the three options.

APS, TRICO, Navopache and Citizens believed that the LDC and ESP should mutually agree to which of the three options are available to customers. After a determination on billing options is made by the LDC and ESP, the consumer would be able to choose among the mutually agreed upon billing options. If the LDC and ESP cannot come to agreement regarding the billing options available to customers, then the option of separate billing will be the only option available to customers. In addition, if a LDC or ESP is unwilling to provide consolidated billing and collection services, then this would limit customers' choices for billing options.

TEP and ACAA believed that during the transition period to competition, the consumer should receive a consolidated bill from the LDC in order to keep the transition to competition as simple as possible for the consumers. After the transition period, the consumer should be able to choose among the billing options.

There was also a discussion about whether a LDC could directly provide consolidated billing services or whether the LDC must form an independent affiliate to provide consolidated billing services. PG&E Energy Services and Enron's position was that the LDC must form an independent affiliate to provide consolidated billing services.

IX. CUSTOMER REQUIREMENTS

The Unbundled Services and Standard Offer Working Group also identified a series of questions/issues designed to determine roles of the various stakeholders in the process of educating customers about the emerging competitive world of electricity. It was noted that thirteen years after the divestiture of the telecommunications industry, many consumers were still unaware that the company that carried their local calls may not be the same company carrying long distance ones. And, while some education would take place as a result of the marketing efforts of the participants in the market, the Working Group members recognized the need for additional "non-advocacy" education so that consumers could better evaluate the marketing claims of the vested interests and generally make better decisions.

A. AREAS OF AGREEMENT

1. ISSUE: **Telephone Number on the Bill.** The first issue discussed was the Billing and Collection Subcommittee's recommendation of which telephone numbers should be included on customers' bills. This issue applies to those customers who choose to receive non-Standard Offer Service. In such instances, a new provider may be providing metering, as well as billing and collection service to a particular customer. The new provider, then, is essentially the point of contact that the customer has with the electric "world", although transmission and distribution is, in all probability, coming from a second company, and generation may be originating from a third source.

New providers would generally prefer to be the only point of contact for the customer, and, therefore, the only telephone number on the bill. In the case of a billing problem, it is clear that the new provider would be required to answer the customers' questions and resolve their problems. However, if the problem that the customer has is an outage caused, for example, by an electrical storm, the distribution company is the entity with the most current information on the cause and when power might be restored.

New providers argue that, in this scenario, it is up to them to establish systems and lines of communication with the distribution company to get enough information so that the new provider can answer customer inquiries. Indeed, the new provider is also a customer of the distribution company. The new provider should get the same good customer service as would an end-use customer. The conclusion of this reasoning is that the only telephone number that should be on the end-user's bill is that of the new provider. To the extent that the new provider does not answer questions to the customers' satisfaction, a loss of customers may occur.

Incumbent utilities argue that most customer-service calls involve outages and that they, as the "wires companies" should also be listed on the bill to ensure that end-users get the most current information available on their particular problem. Incumbent utilities also stated that they have sophisticated systems in place that provide immediate identification of customer outage areas and that capability would allow the LDC to give a more immediate and accurate response to the customer inquiry.

After much discussion, it was the consensus of the Working Group that both telephone numbers should be on the bill: that of the new provider or their representative, and the number of the distribution company. Indeed, the existing rule R14-2-210.B.2.e., which is incorporated by reference into the rules governing the transition to competition (R14-2-1613.A.) requires the telephone number of the new provider. It would be logical for a message to appear next to the telephone numbers to the effect that questions about outages should be directed to the distribution company, while all other questions should be directed to the new provider. (The Billing and Collection Subcommittee also has indicated that, pursuant to R14-2-1613.H., the number of the Corporation Commission should also be on the bill, as is reported in that chapter of this report.)

2. ISSUE: **Customer Complaints.** The second issue discussed derived from the first. Working Group participants desired information on the measures that would be used by the Commission's Consumer Services Section to ensure that customers received timely information in response to their complaints or inquiries. After being given such a briefing by Commission Staff (that taking and responding to complaints was the singular function of Consumer Services Section), Working Group participants felt that the existing mechanism was adequate to handle consumer complaints/inquiries, so long as Utilities Division management monitored the complaint level to ensure that the level of inquiries during the transition did not overwhelm the ability of the Staff to handle them. In addition to the Commission complaint resolution process, the Commission may require that the ESP's demonstrate a complaint resolution procedure.

3. ISSUE: **Consumer Education.** Deriving from this discussion, in turn, was a question regarding customer education in general. While there will be great amounts of information coming from the providers—incumbent as well as new—in the competitive market, that information will undoubtedly be heavily laced with marketing the services of a particular provider. There was a general consensus among the members of the group that the Commission had a role to play in providing a certain amount of "baseline", unbiased information that consumers could use as aids in making choices. The exact mechanism was left undeveloped, due to the time constraints on the Working Group. However, Staff is considering a mechanism similar to the Small Water Assistance Team concept in which some information is developed by Staff and made available to the public at the Commission offices in Phoenix and Tucson. Additionally, a series of "town hall"-type meetings would be held using this model to explain the

principles of electric competition to attendees and to educate them on the types of issues they should analyze in making any choices offered to them. The Working Group recommended that the Commission require Staff to form a new Customer Education Working Group to develop specific recommendations on Customer Education programs.

In the context of customer education, the idea of a Commission Staff-approved bill insert was also discussed. The first question that naturally arose was the number of such bill inserts that would be required. Some participants felt that one was insufficient and that three might be a better number in order to increase the chances that customers would take the time to read the information at least once. Depending upon the precise educational mechanism, the costs could be quite high. In California, approximately $89 million is being spent on education. While there is precedent in the telephone industry for mechanisms such as this (for example, see R14-2-1401, et seq.), with mechanisms for cost recovery by the telephone companies involved (e.g. R14-2-1408), the situations are not necessarily analogous, leaving incumbents in the position of trying to recover the costs of such a program, they argue, from their remaining "captive" ratepayers, or having shareholders bear this burden.

X. ADMINISTRATIVE REQUIREMENTS

Various administrative questions were also discussed by the Working Group. Most of these dealt with the mechanisms for filing tariffs and changing existing tariffs and are generally covered by the existing statutes and regulations governing such filings.

A. BACKGROUND

The first administrative issue discussed by the participants in the Working Group was the tariff filing date: December 31, 1997, for both Standard Offer and Unbundled Service offerings. While some members of the group disagree with the date as matter of policy, that issue was beyond the scope of this Group. Incumbent utilities, while required to file unbundled service tariff offerings by December 31, 1997, are not technically required to file Standard Offer tariffs unless they so choose. If an incumbent does not file a Standard Offer tariff, the approved tariff currently on the file with the Commission for bundled service (essentially Standard Offer Service) would remain in effect. New providers are not required to file any tariffs by December 31. However, to offer any services (except Billing and Collection), new providers would be required to file an application for a Certificate of Convenience and Necessity, and file tariffs for the services proposed to be offered. As noted earlier in this report, any tariffs filed must, by the Rules, include supporting information. They must also be non-discriminatory. Hence, to the extent that new providers wish to enter the competitive portion of the market quickly, they would have to move through this process quickly.

Incumbent utilities expressed some concern that since they would have to file unbundled tariffs by December 31 (in all probability before new providers have entered the market), that they would be "tipping their hand" on their services offered and pricing. While that in a sense in true, it is no different than the procedure that the competitive long distance carriers have historically operated under. These tariffs may be changed at the discretion of the companies, both incumbents and new entrants alike, subject to Commission approval.

B. AREA OF AGREEMENT

ISSUE: **Pricing Flexibility.** Another administrative issue that arose concerned pricing flexibility once the tariffs were in effect. The Rules do presently provide for downward pricing flexibility, if so approved by the Commission (R14-2-1606.G.3.). However, the Rules do not presently provide a mechanism for raising the rates of these services outside of a rate case.

Using the telephone rules (R14-2-1401, et seq.) as a model, one possible solution would be to allow upward pricing flexibility (of a maximum rate) outside of a rate case for a service offered in a portion of the market that has been determined by the Commission to be competitive pursuant to R14-2-1606.A. The comparable telecommunications rule, R14-2-1110, provides that Commission approval is required to raise a maximum rate for a service to be considered to be competitive, after staff analysis, but a rate case is not necessary. The Working Group did feel that the tariffs and tariff changes especially required enough flexibility to be responsive to the customers' needs. To effectuate this change, a modification to the Rules would be necessary.

XI. RECOMMENDATIONS

This section contains the recommendations that came from either the Working Group itself, or from Staff as the result of the Working Group's efforts. Recommendations are considered those items that require a change or modification to the existing Rules or that require Commission action. This Section does not include a listing of the items on which the Working Group reached consensus, since many of those items of consensus/agreement do not necessitate a rule change. Those consensus items can be found in each individual chapter of this Report, and can be found in summary form in the Executive Summary at the beginning of this Report.

A. WORKING GROUP RECOMMENDATIONS

In addition to the consensus items mentioned in this report, the following are the recommendations to the Commission from the Unbundled Services and Standard Offer Working Group:

System Benefits Charge

- The Working Group recommends that the Commission change the wording in R14-2-1608.A. as follows:

  > ~~In addition, the Affected Utility may file for a change in the System Benefits Charge at any time.~~ Affected Utilities shall file for a review of the System Benefits Charge every three years. The amount collected annually through the System Benefits Charge shall be sufficient to fund the Affected Utilities' ~~present~~ Commission-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning programs in effect from time to time.

Solar Portfolio Standard

- The Working Group recommends that the revised objectives of the Solar Portfolio Standard, as agreed upon by the Working Group and included in this report, be incorporated into the rules to clarify the purpose and future implementation of the Standard.

- The Working Group recommends that the penalty be changed to a mechanism whereby the penalty funds are utilized to install solar electricity systems in Arizona.

- The Working Group recommends that the Solar Portfolio Standard include incentives of some type to encourage the electric service providers to take actions which will better meet the objectives of the Solar Portfolio Standard.

- The Working Group recommends that Electric Service Providers be allowed to "bank" or save up any extra (that is, above the annual portfolio requirement) solar kWh produced in a year for use in later years.

- The Working Group recommends that excess solar kWh should be tradable commodities that may be sold to other interested parties.

- The Working Group recommends that the cost of the Solar Portfolio Standard should be limited to an acceptable cost/benefit point, and a cost-reduction incentive should be provided to protect Arizona consumers from increasing solar purchases if lower-price objectives are not met. The Working Group recommends that the Commission establish a mechanism to develop the cost-impact cap and decide on a date when the costs of solar electricity is to be compared to the cost-impact cap. This "decision point" would be used by the Commission to determine if the Solar Portfolio Standard percentage should change.

Metering/Meter Reading Issues

- The Working Group recommends that the definition of metering and meter reading services be added to the Electric Competition Rules.

- The Working Group recommends that the Rules state that the internet is the preferred method for handling metered data exchange.

Customer Requirements

- The Working Group recommends that the rules say that "Any tariffs submitted for competitive unbundled services shall include information about any elements necessary for the consumer to receive full electric service. It is presumed that any contingency charges (e.g. transmission congestion charges, or energy imbalance charges) are the responsibility of the provider unless specifically stated otherwise in the tariff."

- The Working Group recommends that, for customers in the competitive environment, the telephone numbers of both the Electric Service Provider and the Local Distribution Company be included on the bill.

A. STAFF RECOMMENDATIONS

To the extend that the Unbundled Services and Standard Offer Working Group was unable to come to consensus on particular issues, the Staff has developed recommendations for Commission consideration:

Standard Offer Services

- Staff recommends that the issue of provider of last resort be addressed by the Commission at the same time as the Commission makes a determination whether competition has been substantially implemented, pursuant to R14-2-1606.

System Benefits Charge

- Staff recommends that, if the Commission decides to allow an independent SBC administrator, that the Commission relieve the affected utilities from the existing, related Commission requirements to perform such programs and provide such services. Further, Staff recommends that if the Commission decides to move to an independent SBC administration, that it be done over a reasonable transition period, to allow the affected utilities to efficiently transfer existing programs to the new, independent administrator.

- Staff recommends that, if the Commission were to opt for an independent SBC Administrator, the party making the triennial filing should change from the affected utility to the administrator, for certain of the programs mentioned.

B. RECOMMENDATIONS CONCERNING FURTHER WORK

Metering/Meter Reading Issues

- The Working Group states that the Metering Subcommittee has not had enough time to accomplish its objectives and recommends that the Metering Subcommittee be allowed to continue meeting until all objectives are accomplished.

- The Working Group recommends that a workshop be held on Metering Data Exchange so that a statewide data format can be developed for exchanging data.

- The Working Group recommends that the Metering Subcommittee should develop the details on the Load Profiling methodology.

- The Working Group recommends that the Metering Subcommittee should develop the minimum metering requirements.

- The Working Group recommends that the Metering Subcommittee should determine which universal metering identifier should be used.

- The Working Group recommends that the Metering Subcommittee finalize the Performance Metering Specifications and Standards.

- The Working Group recommends that the Metering Subcommittee develop a set of Validating, Editing, and Estimating (VEE) standards.

- The Working Group recommends that the Metering Subcommittee investigate the definition and use of open architecture for metering.

Billing and Collection Issues

- The Working Group recommends that the Commission direct the Working Group to continue the efforts of the Billing and Collection Subcommittee to review the billing and collection standards and consumer protection issues.

Customer Requirements

- The Working Group recommends that the Commission require Staff to form a Customer Education Working Group to develop specific recommendations on customer education programs.

APPENDIX A

UNBUNDLED SERVICES
AND
STANDARD OFFER WORKING GROUP

ADVOCACY COMMENTS

- Arizona Community Action Association
- Arizona Electric Power Cooperative
- Arizona Public Service Company
- Arizona Solar Energy Industries Association
- Arizona Utility Investors Association
- City of Tucson
- Electric Competition Coalition
- Energy Strategies (ASARCO, BHP Copper, et al.)
- Enron Capital and Trade Resources
- Land & Water Fund of the Rockies
- PG&E Energy Services
- Residential Utility Consumers Office
- Salt River Project
- Solar Energy Industries Association
- Tucson Electric Power Company

Arizona Community Action Association
Advocacy Comments for the Unbundling Working Group Report
October 28, 1997

Introduction

With the advent of restructuring, the electric industry is undergoing a monumental change from a regulated monopoly to partial deregulation. As a result, low-income and residential rate payers and small businesses are facing challenges which will bring both risks and opportunities to them as consumers. The process of electric restructuring, while promising more consumer choice and lower rates in the name of free market competition, brings the threat of increased costs, reduced consumer protections, and the possibility that utilities, in order to reduce costs, could eliminate their programs which make electric service more affordable for low-income customers. The bottom line is that small consumers may not benefit to the same degree as large consumers, if at all. Actually, small consumers face more risks in this changing environment and it is vital that they are protected and educated both during and after the transition to competition. Unless small consumers are protected and provided for, competition will likely allow limited or expensive service to rural and low income customers, lack of available consumer education, and lack of consumer protections (lack of access to service due to poor credit or payment history, slamming, lack of universal service, etc.).

Arizona Community Action Association supports the position that all consumers should benefit equitably under competition and that low-income and residential consumers should be held harmless from cost increases resulting from restructuring. Continuation of low-income, energy efficiency, and environmental programs should be assured and funded. Residential and low-income consumers should have accessible, reliable power at affordable prices with adequate consumer protections. Costs should not be unfairly assigned/shifted to small consumers but rather be paid for by those who caused them and created the need for more generation.

1. System Benefit Charge

All major electric utilities in Arizona have some type of energy affordability programs for their low-income customers. Low-income programs include rate discounts, medical life support discounts, bill assistance, energy education, weatherization and repair/replacement of evaporative coolers, air conditioners, heat pumps, and hot water heaters. These programs are designed to be a comprehensive approach to helping low-income consumers afford their electric bills. Typically, a low-income consumer pays 3 to 5 times what an average residential consumer pays, by percentage of income. Low income customers must have access to low income programs, especially since there is a risk of increased costs or at least limited opportunities for lower rates.

At a minimum, the survival of low income programs at current funding levels must be assured and expanded (if at all possible) to more closely match the need. Currently, utility and federal assistance programs serve approximately 10% of the eligible population.

ACAA supports the Working Group Report recommendation that Affected Utilities shall file for a review of the System Benefits Charge (SBC) every three years. This would allow for programs to be adjusted and their funding to be adjusted.

ACAA also supports the concept of an Independent Administrator for DSM and renewables programs. <u>However, we do not believe it should apply to low-income programs.</u> The administration of low-income programs should remain with the Affected Utility or local distribution company (LDC) because these programs are decidedly different in purpose, scope, and impact on consumer's lives. Further, the Affected Utility has a vested interest in making their product and services affordable for low-income consumers. A number of diverse programs have been lumped together in the SBC. It may very well be that environmental and nuclear decommissioning should also remain with the utility/LDC.

Because the Working Group was unable to address, in any depth, low-income programs as a part of the SBC, ACAA supports the recommendation that this be addressed in the coming months, along with other issues the Working Group was unable to resolve.

2. Obligation to Serve/Provider of Last Resort

The obligation to serve concept is based on a fundamental common law which requires a utility to provide adequate, affordable, and reasonably efficient service to all who desire it without unjust discrimination. Regulated utilities have been subject to the obligation to serve requirement in exchange for their monopoly service territory, and although competition will split the electric industry into regulated and unregulated entities, both should retain an obligation to serve.

The reason behind continuing the obligations to serve requirement for regulated entities and imposing it upon the unregulated ones lies in the fact that electric service is essential to all people in today's world. For regulated (distribution) utilities, continuing the obligation to serve requirement means continuing the obligation to connect, which simply maintains historical obligations on the part of electric utilities. For unregulated utilities (electric service providers), an obligation to serve includes an obligation to participate in providing service to residual consumers, an obligation to make services available on a non-discriminatory basis, and finally, an obligation on part of all electric service providers to help fund the cost of serving residual consumers through a non-bypassable end use charge.

Requiring these obligations to serve of both regulated and unregulated utilities is necessary, reasonable and appropriate. These obligations are the foundation for providing affordable service in a partially deregulated environment, and it is in the public interest that affordable service be available to all segments of the population.

3. Consumer Protections

Lack of consumer protections in a restructured marketplace will shake consumer confidence in and acceptance of retail competition. In order to encourage consumer acceptance and participation, the transition to competition will require an organized approach to monitoring and preventing consumer abuses.

a. At a minimum, existing consumer protections must be maintained.

b. Privacy of customer specific data must be maintained. Customer specific data should not be released without written the consumer's verifiable consent.

c. Low-income, residential, and small commercial consumers should not be subjected to unfair or discriminatory application practices, credit denial, or credit barriers.

d. Access must be ensured without discrimination.

e. Consumers must be guaranteed regulatory and private right of action recourse to disputes.

f. Specific anti-slamming requirements should be adopted.

g. A Code of Conduct for ESPs should be adopted.

h. New rules for partial payments should be adopted.

i. No disconnection of access for nonpayment of competitive supply.

j. CC&N required for ESPs and aggregators. A less stringent filing requirement could be made available for non-profits, neighborhood associations, home owner associations and other similar entities.

4. Consumer Education

Of major concern to low-income and residential consumer advocates is the lack of public information regarding the monumental change facing consumers. Most people are unaware of the impending change and are not involved in the process. ACAA supports the recommendation that a Working Group be formed to develop consumer education programs and standards.

5. Billing (Easy to Understand, more infor ranther than less, green labeling)

Competition will fundamentally change the way customers buy electricity. They will truly be consumers, saddled with the responsibility of shopping wisely for their electrons and service. Since the electric world, as they know it, will be changing so dramatically, consumers must have every chance to not only learn about the intricacies of the electron product but also the market. One way to help residential consumers navigate those treacherous waters is to give them adequate information. A critical link in the education/information process is the monthly bill. Bills must be easy to understand, but also contain sufficient information for consumers to understand and learn about the competitive world.

Some utilities and new market entrants are pushing for minimal information on bills, saying that customers may request additional information if they choose. While this may reduce costs for the billing agent, there is a higher public need. ACAA recommends providing more rather than less information, in order to take maximum advantage of the educational/informational opportunity presented by monthly bills. If customers do not want unbundled bills, then they can request one from their provider.

Studies show that consumers want more rather than less information on their bills, including the generation mix. This information will help environmentally conscious consumers choose a generator who is "cleaner and greener". In other states, consumers have been willing to pay higher rates to support cleaner, more environmentally sound generation. APS' "green" project in Flagstaff has produced higher than expected participation. All Arizona consumers should be afforded the opportunity to choose "green".

Several parties in the working group said how difficult, if not impossible, it would be to provide the generation mix on bills or on marketing materials. It is being done in other states, so there must be a way to do it with some level of compromise. Perhaps the mix could be calculated for the past quarter or six months. For instance, a simple disclosure would suffice, like: XYZ Energy Service Provider generation mix for the last six month period included 45% coal, 35% natural gas, 10% hydro, 10% solar. Just like many products, consumers want to know what is in their electricity. Consumer friendly labeling is a small price to pay for a market option desired by many and which provides important consumer education.

6. Load Profiling

It is imperative that customers retain the price/energy consumption connection. Further, customers must not be disadvantaged or put at risk of higher bills as a result of load profiling, especially those who use less than the class average. It is important that these customers are able to reasonably predict and anticipate what their bill will be, without any surprises due to unexpected charges over which they have no control and for which they have no responsibility. If the Commission orders the rules to be modified to allow load profiling, consumers, especially low-income consumers who are financially at risk with bill/price fluctuations, must be held harmless.

The Working Group Report suggests that all customers must predict their hourly load for a 24 hour period so that ESPs and LDCs may ensure reliable energy service. This requirement is onerous for the residential class and could be difficult to execute. ACAA recommends that small consumers be exempted from this requirement.

7. Geographic Deaveraging

Distribution costs are higher for rural customers, who may number only a few to a mile, compared to urban customers at many times that. A utility with both high and low density in its territory will typically average the distribution costs. This means that urban customers are subsidizing the distribution rates for rural and non-metropolitan customers. Without this subsidy, rural customers would see significant cost increases, something the rural areas of Arizona can little afford. Some utilities have admitted that they are discussing cost based scenarios which would result in higher costs to non-metro areas.

The non-metro areas of Arizona are characterized by higher poverty rates, less economic development, lower median income, older housing stock, and higher unemployment rates. As a result, rural customers will be harder hit by cost increases. Small businesses in rural Arizona are an important part of the local economy. Increases in electric costs could harm marginally viable businesses and even reduce the potential for economic development so desperately needed in these areas. Low-income consumers would be further disadvantaged by increased costs. While cost based rates appear to go hand in hand with a free market, from a public policy perspective it is important to balance the needs of urban and rural customers. Vulnerable rural areas and customers (residential and commercial) must be protected from the vices and abuses of the free market, otherwise they may be priced out of the market. The promised benefits of competition should accrue to rural areas and not result in higher prices.

The Telecommunications Act of 1996 sets a precedent for prohibiting competitive deaveraging saying that rates for rural and high cost areas shall be no higher than rates in urban areas for interexchange carrier rates. While large consumers have been the driving force behind competition, we must look closely at the impact on towns, rural areas, low-income and residential consumers, agricultural users, and commercial customers and not leave them worse off as a result of competition. Rural Arizona, already ranked first in the country for rural poverty, cannot withstand the negative economic impacts. Therefore, ACAA recommends that the Commission ensure that distribution rates are not deavearaged.

Affected Utilities is a necessary condition for electric competition to commence on January 1, 1999. ECC urges the Commission to continue its support of competition for as many of these services as may be practicable, including the standard offer and any system benefits program. By allowing new entrants to provide metering, billing and information services, Arizona customers will have the opportunity to chose, to receive the quality of service they demand, and to encourage all providers to lower their costs and prices by being more efficient.

files\ECC\unbundld.com

utilities. Any electric service provider may offer services described under R14-2-1606 which includes the standard offer service. A.A.C. R14-2-1606(H).[1] Competitive pricing through a bid process for the standard offer will assure the Commission that the most efficient service will be made available to Arizona customers. Furthermore, Affected Utilities will have the incentive to be more careful in allocating their cost of services among bundled and unbundled rates if the standard offer services are competitive.

Affected Utilities Should Adopt Standards of Conduct Between Their Regulated Functions and Marketing Activities.

Arizona utilities are aggressively marketing outside of their service territories. Substantial costs are being incurred in these marketing efforts. The Affected Utilities will be entitled to recover their costs of providing the local distribution system from suppliers of competitive generation. Other costs might be recovered through the bundled standard offer. Utilities have a financial incentive to attempt to shift the assignment of costs from unregulated activities to the regulated (both bundled and unbundled) activities. Consequently, the Commission should carefully review the actual cost of unbundled and bundled services and marketing activities of the Affected Utilities.

One goal of the working group was to develop a method to avoid "uneconomic bypass or cross subsidization of competitive ventures by regulated utilities." Competitive marketing activities by the Affected Utilities should be separated from their monopoly functions and their captive ratepayers should not incur those costs. For example, energy management services are already available in the competitive marketplace. The Affected Utilities should not use revenues from their monopoly functions, such as system benefits charges, to fund their competitive marketing efforts. APS, for instance, has said: "Load management and energy management services will not be part of any unbundled offering. All such services will be market-driven. The company has transitioned its DSM [demand side management] activities into market transformation initiatives. It is anticipated that these market transformation initiatives will be funded through the systems benefits charge." These "market transformation activities" of APS include trade ally programs and consumers education programs.[2] APS' market transformation activities should not be funded by APS' captive ratepayers or by those who select other providers and as a result pay the system benefits charge.

---

1 In the rules, "electric service provider" is defined as "a company supplying, marketing, or brokering at retail any of the services described in R14-2-1605 or R14-2-1606." A.A.C. R14-2-1601(5).

2 Arizona Public Service Company Comments to ACC Unbundling Working Group (April 30, 1997), at pp. 11 & 12.

Cross subsidization between the Affected Utilities' monopoly activities and marketing functions must be prevented. ECC strongly supports the adoption of affiliate rules requiring the Affected Utilities to implement standards of conduct. A clear line should be drawn as to the personnel, facilities and costs which are attributable to the regulated bundled and unbundled services and the competitive marketing activities of the Affected Utility or its affiliates. Logically, the Affected Utilities will be separating these costs and functions when they prepare their unbundled rates and standard offer tariffs. The Commission should carefully review the adequacy of the separation so as to avoid any cross-subsidization and any anticompetitive sharing of personnel or information between the regulated functions and marketing activities of the Affected Utility or its affiliates.

System Benefit Programs Should be Opened to a Competitive Bid Process With an Independent Administration of System Benefit Revenues.

The rules provide that the pro-rata costs of system benefits will be collected from customers who participate in the competitive market in an amount "sufficient to fund the Affected Utility's present commission-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning programs." A.A.C. R14-2-1608(A). When filing this non-bypassable rate by December 31, 1997, the Affected Utilities are to provide adequate supporting documentation for their proposed system benefits rates. A.A.C. R14-2-1608(B). The system benefits charge should be calculated to approximate a customer's current contribution to the identified programs as now incorporated into bundled rates. As retail competition matures, the magnitude of these charges should decline.

ECC believes, in a competitive environment, public benefit programs should be handled by a statewide funding mechanism and not by a regulatory commission. To the extent low income programs are needed, they should be funded from a broad tax base, and not as a surcharge on a particular power source or class of customer. Furthermore, these public benefit charges could place Arizona consumers at a competitive disadvantage.

System benefit programs take on a life of their own. Demand side management and other energy efficiency programs are being subsidized even though they are already available in the open marketplace. In keeping with this transition to open markets, these system benefit programs should be subject to a competitive bid process. The system benefit revenues should be collected and distributed by an independent body. ECC does not believe that environmental requirements should be charged to competitive customers. All industries must comply with environmental laws and obligations as the cost of doing business. The utilities' capital costs of complying with environmental regulations are already included in the book value of electric facilities. Therefore, a separate charge for environmental regulation is not warranted.

CONCLUSION

The competitive marketplace offers lower-priced services tailored to the demands of individual customers. Prompt filing of the unbundled services and standard offer tariffs by the

ELECTRIC COMPETITION COALITION
For the Pursuit of Open Markets and Consumer Choice 7000
North 16th Street ■ Suite 120-307 ■ Phoenix, Arizona ■ (602) 395-1612 ■ Fax: (602) 395-1943

UNBUNDLING AND STANDARD OFFER SERVICES

COMMENTS OF ELECTRIC COMPETITION COALITION

October 28, 1997

INTRODUCTION

The Electric Competition Coalition ("ECC") appreciates this opportunity to comment on the report of the Unbundled Services and Standard Offer Working Group. ECC strongly endorses the objectives adopted by the group at its first meeting, which included developing a fair, equitable, non-discriminatory method of offering both standard offer and unbundled services that:

- Provides opportunity for customer choice.
- Provides opportunity to minimize consumer and utility transaction costs.
- Does not promote uneconomic bypass or cross subsidization of competitive ventures by regulated utilities.

In the context of the groups' objectives, ECC believes the key areas include (a) the prompt filing of unbundled services tariffs, (b) the prompt filing of standard offer services tariffs, (c) the prompt implementation of standards of conduct, and (d) the use of competition in providing as many services as may be practicable, including the standard offer services and any system benefits program.

The Prompt Filing of Unbundled Services Tariffs Is Needed in Order to Start Retail Wheeling of Generation in Arizona.

ECC urges that the Affected Utilities file their unbundled services tariffs as required under the Electric Competition Rules. By December 31, 1997, each Affected Utility is required to file tariffs for "unbundled service," so as to provide the following services to "all eligible purchasers on a non-discriminatory basis":

1. Distribution service;

2. Metering and meter reading services;

3. Billing and collection services;

4. Open access transmission service (as approved by the Federal Energy Regulatory Commission, if applicable);

5. Ancillary services in accordance with Federal Energy Regulatory Commission Order 888 (III FERC Stats. & Regs. para 31,036, 1996) incorporated herein by reference;

6. Information services such as provision of customer information to other Electric Service Providers;

7. Other ancillary services necessary for safe and reliable system operation.

A.A.C. R14-2-1606(C).

Electric generation is available today for competitive sale. Arizona customers and new entrants are eagerly awaiting the unbundled rates so that they may evaluate the cost-effectiveness of competitive generation. The Affected Utilities have had 10 months in which to prepare these unbundled tariffs. The costs of these unbundled services are known by the Affected Utilities. Nevertheless, they wish to harbor this information so as to delay competition. A prompt filing of these tariffs is necessary in order for competition to begin.

Metering, billing and information services are recognized as competitive services under the rules. A.A.C. R14-2-1605 & R14-2-1606. By making these services competitive, innovative products and services will be offered to customers. Customers will be given the freedom to control their energy usage through more efficient pricing programs, the use of smart appliances, and new technology in meter-reading and data collection. Similarly, competitive billing and information services will give consumers the opportunity to receive the type of information that they value.

ECC urges that the Commission continue its support of open market services for all metering, billing and information functions. The incumbent utilities, on the other hand, are resisting competition by attempting to retain a monopoly advantage over services. Customers should have a choice in selecting their provider. Customers will also benefit because the incumbent utilities will be encouraged to be more efficient in managing and pricing all of these unbundled services.

Standard Offer Service Should be Opened to Competition.

Standard offer service should be opened to the new competitive environment. New entrants should be able to provide "standard offer" service at market based rates, which are approved by the Commission. The rules define a "standard offer" as "Bundled Service offered to all consumers in a designated area at regulated rates." A.A.C. R14-2-1601(7). ECC does not agree with the conclusion in the report that these services may only be provided by incumbent

MEMORANDUM

DATE: October 30, 1997

TO: David Jankofsky

FROM: Vinnie Hunt

SUBJECT: Systems Benefits Charge Administrator

cc:R. Ballard, R. Meyerson, J.Perry

The City has been advocating for the establishment of an independent administrator for the system benefits charges. It is important for the Commission to realize that the funds collected through the SBC are collected from ratepayers and are to be used for programs which benefit the public at large. The funds must be fairly collected and distributed with proper accountability and oversight. The City of Tucson feels that in a competitive environment the distribution of the SBC funds should be through a competitive process with an administrator independent from the affected utilities. The administrator can be subject to ACC oversight.

There are several reasons behind our position as I will discuss briefly below. We will also rebut the arguments that the affected utilities have put forth stating that they should be the SBC administrator.

Argument For An Independent SBC Administrator

- Effective administration of the moneys collected through the systems benefit charge (SBC) will be critical if the public benefits programs are to be continued in a competitive environment. The SBC moneys are currently collected and administered by utilities with ACC oversight. These moneys belong to the ratepayers and are collected in the public interest. As such they need to be carefully managed with full accountability. An independent non-profit entity could most cost effectively administer the system benefits funds.

- An independent SBC administrator would allow for competition in the disbursement of the SBC funds. The ACC has recognized the benefits of competition in the generation of electricity and the City feels that there are similar benefits to be achieved by allowing SBC funds to be distributed through a competitive process. The SBC administrator would distribute the funds received by identifying the programs which are determined to be most important to fund. Stakeholders would have input into the determination of the programs selected for funding. Once specific programs have been identified the administrator would procure those services through an open competitive process, such as an RFP or RFB. Utilities as well as others who are qualified would be allowed to compete for implementation of the individual SBC programs.

- Affected utilities are currently not effectively implementing SBC programs, especially in the areas of energy conservation. The utilities themselves admit that they cannot meet their currently regulated requirements for solar electric generation. APS also is indicating that in a competitive environment that it will be more cost effective for them to take the $0.30/KWH penalty rather than try and meet the Solar Portfolio requirements. To have the effected utilities in charge of implementing energy conservation programs is like having the fox watch the hen house. The affected utilities, even if their regulated DISCO administers the funds have revenue derived from sales of KWHs and therefore their interest is in selling KWHs not in implementing low income, energy conservation and renewables programs. .

- Affected utilities will have a competitive advantage by promoting the benefits of the SBC to their customers. For example APS recently announced that they are helping to subsidize the cost of solar electric power to customers in Tempe. It is the ratepayers who ultimately subsidize the solar, however APS is promoting themselves by saying they are subsidizing the program. In a competitive environment even if the DISCO implements the programs, with ratepayer funds, the GENCO could get the spin-off public relations benefits.

Rebuttal to the Affected Utilities Arguments Against an Independent Administrator

- Affected utilities are indicating that they have programs established for distribution of the SBC, therefore the new administrator would have to start over, which would increase costs. It is agreed that the affected utilities currently have programs ongoing and that it would not be in the public's best interest to unilaterally cut them. However, SBC programs are intended to be changed therefore the new administrator would transition the affected utilities out of their programs over time. For example, existing long term programs with utilities, such as TEP's and APS's requirement for solar generation would continue (if considered cost effective), to be funded so that those type of commitments can be meet.

-Affected utilities state that if they cannot recover SBC to cover existing regulated programs they would have to raise rates on their captive customers. The affected utilities would have to be relieved of their responsibilities for programs as such funding for their commission approved programs is taken away from them.

- Affected utilities indicate that by dividing up the funding for public programs that each program will be less efficient. For instance, there is a minimum or "critical mass" of funding needed to establish a low-income, DSM or renewables program. The City could not agree more. An independent administrator would operate over a state-wide basis and therefore be able to achieve significant economies of scale over the affected utilities. The administrator would also have a one time learning curve whereas the affected utilities each must learn new programs. Affected utilities also have differing programs which makes it difficult to oversee and coordinate the SBC programs.

Other SBC Issues

Collection of SBC funds should be by the distribution company through a KWH wires charge. Once collected the funds would be transferred to the SBC administrator. The SBC administrator along with stakeholders, would identify programs to be funded, and allocate funds accordingly. Services necessary to meet the program needs would be obtained through a competitive RFP or RFB process or grant funding. Procuring services in this manner is consistent with the intent of restructuring the electric industry by allowing competition for these services. Affected utilities, energy service companies, municipalities, etc., could be allowed to compete for funding of those programs which they are qualified to implement.

Certain programs within SBC, such as nuclear decommissioning are better left with the affected utility to administer, since it is in their best interest to do so.

The ACC should be the agent to set up and oversee the SBC administrator. The administrator could be set up as a board which meets several times per year. The SBC administrator would require a knowledgeable staff to implement the programs selected by the board and approved by the ACC. Implementation would be through a competitive proposal and contracting process. The City of Tucson would be happy to help the ACC with the details for the establishment of the independent SBC administrator.

file:sbcad3

CITY OF TUCSON
INVESTING IN OUR COMMUNITY

MEMORANDUM

DATE: October 29, 1997

TO: Dave Jankofsky

FROM: Vinnie Hunt

SUBJECT: Unbundled and Standard Offer Working Group Report Comments

City of Tucson staff recognize the challenges facing the Commission as it moves toward retail electric competition. All participants in the various working groups have their own interests. City staff is in favor of competition and believes the Commission should continue to proceed with the schedule set in the rules. There are many issues which must be resolved, however, without a clear schedule there will be no sense of urgency.

The City of Tucson has been a willing participant in the most recent working groups, and has expended considerable resources (as have other participants, as well as the ACC). The City will continue to participate and advocate as a large utility customer, as a consumer representative, and as a tax collector.

The original guiding principles used to develop the rules for retail electric competition should not be forgotten when the commission contemplates recommended changes or modifications to the rules.

The most contentious area in the restructuring process is stranded costs. City staff feels that the issue of stranded costs (if any) needs to be carefully considered. We are very disappointed that the ACC working group on stranded costs was unable to consider many of the factors related to stranded cost due to lack of information and was unable to reach consensus on most key issues. Stranded costs should be evaluated on a bottom-up, asset-by-asset approach, with the burden of proof being placed on the utility. Utilities are the beneficiaries of stranded cost recovery and, as such, need to prove to ratepayers the validity of their claims. The ratepayers should not be required to disprove utilities claims, which would be necessary if the revenue requirement approach, recommended by ACC staff, is used.

Comments Specific to the Unbundled and Standard Offer Services Working Group

Overall, staff did a good job of reporting the major issues discussed during various meetings of the main group and subgroups. It should be noted that consumer and environmental groups were underrepresented and, therefore, majority positions are meaningless because utilities were often in the majority at the meetings.

- The City recommends there be a rate cap imposed, whereby the sum of the unbundled services cannot exceed the equivalent regulated bundled rates for electricity.

- The Commission should consider eliminating the affected utilities from administering system benefits programs. This is discussed further in an attached memorandum.

- The City concurs with the working group recommendation that the Commission begin a public education campaign on electric restructuring. Without such a campaign consumers will not be able to make informed choices. The average consumer needs to understand the benefits of competition otherwise they will view restructuring as a way for large customers to get a price break for electricity at their expense.

- The City feels that energy service providers must be required to indicate their source(s) of generation. Utilities argue that this would be burdensome since they often don't have their power balances for a month or more after the fact. In a restructured environment, customers will be billed for power and the cost associated with that power. It is inconceivable that ESPs will not know their power generation sources. How will generators be compensated if this is the case? The intent is not to unduly burden ESPs, but to provide consumers with information regarding their power suppler(s).

- The City of Tucson supports the Solar Portfolio standard. Most notably, the objectives of encouraging the economic development of the solar industry in the State of Arizona and the environmental benefits to the state. As recommended by the subcommittee, the rules should be modified to enhance the benefits for consumers through incentives that encourage both in-state power plant installation and manufacturing. Also recommended by the subcommittee and supported by the City, is the allocation of penalties collected from ESPs who do not meet the Solar Portfolio standard percentage requirements, to the system benefits charge. Collected funds would be used to purchase solar electric generation sources.

contribute to net income. They have no place in a rate case.

Beginning in 2003, all of the funding will come from the SBC because all utility customers will be in the competitive market. Therefore, there will be no justification for pursuing these programs through the rate case process. Funding levels should be adjudicated in a separate, consolidated proceeding much like the Integrated Resource Planning docket. By 2003, if not sooner, the Commission should reassign the responsibility for these programs from the Affected Utilities to some other party such as an independent administrator. It would be preferable if the Commission would make its intentions clear by amending the competition rule.

4. Solar Portfolio Standard

The solar portfolio standard is illegal.

AUIA purposely didn't participate in the subcommittee working on the solar portfolio standard because we had nothing positive to contribute. The reason is simple: we believe that this provision of the rule is illegal and a blatant abuse of regulatory power.

If the Commission or the Legislature wished to create incentives to promote the development of solar resources, there might be several acceptable mechanisms. But here the State is wielding its regulatory authority to force utility shareholders to spend their capital on an uneconomic technology with no assurance that they will be able to recover the investment. In addition, they are being forced to subsidize one energy source to the exclusion of all others which is clearly anti-competitive.

CAOs will balance the system because they have to in order to keep the lights on and the wires from melting.

This is a reasonable assumption, provided that CAOs have sufficient real time control over the system, including must-run generating capacity, and that they aren't repeatedly stuck with unrecovered costs resulting from fixing system imbalances.

When it is completed, the Safety & Reliability Working Group report will identify a long list of protocols and working agreements that must be completed to keep the system patched together until an independent system operator (ISO) comes along in 2002 or 2003. Among the unresolved issues is a method of compensating CAOs for curing system imbalances.

The transmission operators usually will have no way of knowing who caused an imbalance. They will only have access to the ESPs who schedule loads on their systems; they will have no access to the individual customers or aggregators who actually cause the imbalance. Therefore, the CAOs' only choice will be to apportion the cost among all of the ESPs which is like rewarding the incompetent and the dishonest for messing up the system.

The report of the Unbundling Working Group assumes that Local Distribution Companies (LDCs) will be responsible for tracking down the source of system imbalances because they will have access to metering data for billing purposes. But wait a minute. How could they do it?

It's one thing to download a stream of metering data into a computer that spits out monthly bills. But there is no way (and no incentive) for an LDC to figure could out which ESP's customers are responsible for a daily imbalance or a series of them. The LDC won't see daily or hourly schedules. It won't see the load profiles behind the schedules. If it has no access to the meter it will probably get no more than monthly billing data from the ESPs.

In our view, there is no question that the financial integrity and/or reliability of the electric delivery system will be compromised to some degree by retail competition. The problem is complicated by the fact that the ACC doesn't regulate high voltage transmission. The issue for the Commission is how to mitigate the damage. The introduction of load profiling and the separation of the metering function from the LDC will contribute to the difficulty of operating the system fairly and efficiently.

We strongly suggest that the Commission should become familiar with the impact of retail competition on every element of the electric delivery system. It may decide that the alleged benefits of competitive metering and billing aren't worth the increased risk to the integrity of the system, at least until the transition to full competition has been achieved.

3. System Benefits Charges

The provisions in the rule for calculating and implementing the system benefits charge (SBC) are illogical and will be a source of continuing conflict unless they are amended.

The Working Group report reflects considerable disagreement over the application of these charges. The simple facts are that the groups who are supposed to benefit from these charges are unhappy with the structure. They are distrustful of a mechanism that depends on a group of utilities that are going through a regulatory metamorphosis and may be increasingly reluctant (and perhaps unequipped) to lead the charge for these programs. Two basic issues dominated the discussion: funding levels and administration.

a) Funding Levels
The language in the rule can be interpreted to mean that the scope and funding for programs supported by the SBC are frozen at their current levels. Obviously, this is unacceptable to the program beneficiaries and prompted the suggested rule change that would require the utilities to review their financial needs for these programs every three years.

An alternate reading is that the funding levels could be increased, but that the increases could be funded only by charges to customers in the competitive market rather than customers who are served under regulated rates. The staff concedes that this strange construction was purposeful in that it was designed to avoid the necessity of litigating a utility rate case in order to adjust the SBC.

b) Administration
Peering into a murky future, the beneficiaries of the SBC programs would also like to transfer the locus of responsibility for implementing these programs over a period of time to an independent administrator. Under this proposal, the administrator, with direction from the Commission, would manage the use of the funds through multiple vendors who might or might not include utilities. The Affected Utilities have argued that if they are not going to administer the programs, they should be relieved of responsibility for them.

c) Conclusion
It is an absurd circumstance in which the funding for these programs can be increased only by mounting a string of utility rate cases or by targeting customers in the competitive market for special assessments. These programs have no real bearing on a utility's rate base, especially with the deregulation of generation. The charges simply cover mandated expenses and do not

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
CHAIRMAN
JAMES M. IRVIN
COMMISSIONER
RENZ D. JENNINGS
COMMISSIONER

IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA

DOCKET NO. U-00094165

COMMENTS OF THE ARIZONA UTILITY INVESTORS ASSOCIATION ON THE WORKING GROUP REPORT ON STANDARD OFFER AND UNBUNDLED SERVICES

1. Introduction

At the conclusion of the Working Group sessions in October, the staff invited participants to submit "dissenting" opinions which would be appended to the Working Group report.

However, it is difficult to agree or disagree with a report that contains so few conclusions. Where the critical issues are concerned, it is largely a collection of opposing viewpoints. Even the so-called consensus items are little more than opinions about how things might be or ought to be with very little direction about how to get there from here.

Nevertheless, some of the issues assigned to this working group are critical to the successful introduction of competition to the Arizona market and are also tied to the safety and reliability of the delivery system.

Therefore, AUIA submits these comments, not so much in dissent but to focus a spotlight on a few key issues. These issues are:

Ñ Metering and meter reading
Ñ System benefits charges
Ñ Solar portfolio standard

2. Metering, Meter Reading and Billing

Making these services competitive during the phase-in will cause confusion among consumers, create billing conflicts and increase the risk of system failure.

APS and other utilities have effectively argued the case for retaining metering and meter reading as regulated services in an addendum to the Working Group report. They cited economies of scale, cost savings, accuracy and other issues. AUIA agrees with most of their points and will not repeat them here. While there are dozens of potential customer problems involved in competitive metering and almost none were resolved by the Working Group, we will focus on two issues.

a) Provider of Last Resort

On the one hand, the new market entrants (principally Enron and PG&E) have argued incessantly that incumbent utilities should not be allowed to bundle or mix any competitive services, such as metering, with their regulated activities, claiming it would create an unfair advantage. But on the other hand, in order to take the risk out of competitive metering, the Working Group report includes the requirement that the utilities must act as the metering agents (MAs) of last resort.

Therefore, an electric service provider (ESP) would be free to detach a customer from the utility's meter (with or without compensation is unclear), but if the new MA failed to deliver or the customer became dissatisfied, the utility would be required to hook him up and reinstate metering service until he changed his mind again. At a minimum, the Commission must provide for a schedule of connection and disconnection charges, including equipment costs, to be assessed against the competitive MAs and their customers. Otherwise, the cost of indulging these competitive metering whims will be paid by the regulated utility customers.

In fact, if metering services are going to be declared competitive, there should be no provider of last resort. Let the market work. Otherwise, ESPs and their customers will be free to experiment with various metering schemes with no market risk. It should be noted here that the State of Nevada, which is scheduled to start competition a year later than Arizona, has chosen not to make metering a competitive service. Also, Enron's subsidiary electric utility, Portland General Electric, has chosen to retain metering services in its plan for retail competition. The irony of this should be obvious.

b) System Integrity

APS et al touched briefly on safety and reliability in their addendum on metering services. But AUIA is concerned that the big picture of system integrity has been largely overlooked in these working groups precisely because they have each put their hands a different part of the elephant. The electric delivery system is a continuum, from the demand created by the customer to its fulfillment at the generating station. So far, neither the rules nor the working groups have approached it this way.

For example, it is assumed that every load scheduler will submit a balanced schedule, including reserves. But no one has demonstrated how schedulers will provide reserves that will actually be accessible to control area operators (CAOs) on a real time basis. In fact, schedules will often be out of balance because of bad estimates, unpredictable weather, equipment failures or because some people will game the system if they can get away with it. Again, it is assumed that the

Economic Development

Solar thermal offers additional economic benefits to Arizona. Just as with PV, the solar thermal industry has the potential to bring jobs to Arizona. There were once many companies manufacturing solar water heating products in the state. These companies shipped solar products throughout Western United States and made use of another of Arizona's natural resources, copper. The jobs that a solar thermal industry creates extend to all sectors of the economy. Skilled and unskilled jobs are created in manufacturing, as well as in service and installation. With the existing infrastructure in place, this technology is ready for immediate expansion.

Air Quality

The use of solar thermal water heating systems assist in Arizona's efforts to improve air quality. According the Arizona Public *Service's Consumers Guide to Solar water Heating,* a solar water heating system that provides 55% of a 70 gallon per day load at 120 degrees will eliminate 2800 pounds of pollution when replacing an electric water heater in the Phoenix area. When replacing a gas water heater, 1200 pounds of pollution are displaced at the source, producing results directly over our neighborhoods. Most DHW systems that are on the market today will provide a family with significantly more that a 55% solar fraction resulting is greater air quality benefits that the above statistics.

The numbers for other Arizona cities are even more attractive. Prescott tops the list with a 3500 /1500 pounds (electric/natural gas) per system savings in pollution, followed by Flagstaff at 3300/1400 pounds and Tucson with 2600/1100 pounds.

Commercial solar heating systems for heating larger volumes of water can be economically competitive and provide additional business opportunities for utilities. These large scale systems would produce additional air quality benefits.

Less Demand on the Systems Benefit Charge

Inclusion of solar thermal water heating will reduce the need for some programs under the systems benefit charge. Some who are involved in the restructuring process will be seeking higher levels of funding for solar technologies, environmental and low income programs to be included in the systems benefit charge. The inclusion of solar DHW, in the Portfolio, will eliminate the need for developing more traditional utility programs for DHW. This will allow the market to develop without funding under the SBC.

Conclusion

Inclusion of solar water heating in the Solar Portfolio Standard, by simply adding the phrase, **"or electricity displaced by solar thermal energy technologies"** will provide utilities a low-cost option to fulfill a portion of the requirement of the standard If the goal of the standard is to bring solar technologies costs down to more marketable levels and to provide the environmental and economic benefits that solar has to offer, all solar technologies should have equal footing in the standard. Inclusion will provide a site based method of bringing restructuring to residential and the small commercial customers. The solar industry will benefit by the resulting economies of scale and the competition for improved and cost effective products. This will serve the state of Arizona well in the coming century.

Solar Thermal Technologies in Electric Utility Restructuring
Solar Water Heating in
Arizona's Solar Portfolio Standard

The Arizona Solar Energy Industries Associations (ARISEIA) supports the solar portfolio in the restructuring rules approved by the Arizona Corporation Commission. We feel that any changes made to the portfolio should be meant to simply fine tune the document and that it's goals should not be reduced or delayed. Minor changes, those that would facilitate the orderly development of the industry, yet not dilute the Portfolio, should be considered.

We feel that the benefits to the state of Arizona far will far outweigh the small cost to the consumer. The state will receive a rapid return on their investment through cleaner air and economic development. The solar industry will be advanced through the greater use of technologies, important to our future, that could be left undeveloped in the drive for competition. It will allow movement towards a 21st century technology in financial partnership with the electric utility industry.

This Solar Portfolio Standard will bridge the gap between the bottom line realities of a competitive business during a period of history where there is an excess energy supply and a long-term need to develop alternative resources. Solar technologies are the obvious choice for alternative energy in this state where solar insolation is our greatest natural resource. However, an important solar technology has been excluded from this document: solar thermal water heating . While solar thermal does not produce electricity, it does capture energy as a renewable resource, something that differentiates it from energy efficient technologies. This energy is quantifiable in the form of BTU's, which can easily measured and converted to an kilowatt hours. The advantages of solar as a clean technology are achieved with solar thermal water heating and can be done directly at residential customers homes.

Please consider the following information regarding the inclusion of solar thermal water heating in the Solar Portfolio Standard:

Cost to the Providers and Public

Not only would the addition of solar thermal water heating provide a less expensive means of reaching a portion of the solar portfolio standard, but it will be a technology that can provide business opportunities to providers. A Business Opportunity Prospectus for Utilities in Solar Water Heating, prepared by the Energy Alliance Group for the Utility Solar Water Heating Initiative (US H20) demonstrates how utilities can turn what was once thought of as a loss of electric sales into increased revenues.

Depending on the type of systems used, solar water heating systems can produce energy at the equivalent rate of under four cents per kWh. Technology advances and industry standards that have been developed and implemented in Arizona will insure the quality of systems installed.

Simple rules and guidelines for the inclusion of solar water heating can be easily developed. The output of thermal systems can be easily measured through the installation of a BTU meter.

(b) **Who Is the Responsible Paying Party?**

The Working Group agreed that if ESP's provide consolidated billing they should be responsible for 100% of the charges they are collecting for the LDC, which includes not only the wires charge, it also may include system benefits, meters, meter reading and any ancillary charges incurred by the customer. The ESP's are suggesting that if the LDC provides consolidated billing it should also be responsible for payment to the ESP for non-payment by the customer. APS does not agree with this statement, as under competition, a regulated monopoly distribution service should not be impacted by any costs associated with the competitive market. Requiring the LDC to be responsible for non-payment of competitive services would adversely affect regulated customers.

(c) **Who Should Have the Authority to Order a Disconnect, Connect or Reconnect?**

Another area of agreement is that only the LDC can authorize connects, re-connects and disconnects. APS, however, does feel there should be a standard time in the Rules to avoid multiple switching of service providers for a minimum period of time. Since the Working Group report has not fully addressed how either end-use customers or the ESP will be held accountable for delivery of energy during the "lags" that will occur from the time of notification of either a connect or disconnect to the new connect or termination of service. The responsible payer of the bill must be held responsible for payment of all delivered energy; this would require both a disconnect meter read and a new connect meter read when a customer changes competitive energy suppliers. Currently APS' connects and disconnects number about 1/3 of our total customer count on an annual basis. With customer choice of energy suppliers, this "churn" in customers will inevitably increase significantly, so that this gap in the process is a very important issue that must be resolved prior to wide-scale direct access. Along with this, the issue of meter ownership is still unresolved and it remains unclear as to who will be responsible for the physical disconnects if the meter does not belong to the LDC. This again emphasizes that the Rules for the LDC may be inappropriate and/or in conflict with the specific provisions that apply to the ESP and need to be reviewed.

(d) **What Minimum Information Needs to be Included on the Bill?**

Additional evaluation of R14-2-210 is also required to address the consensus of the group for the minimum information to appear on direct access residential customers' bills. While APS agrees this information should be included, the format should be versatile enough to allow for re-bundled pricing if so desired by individual entities.

(e) **How Does a Customer Switch His/Her Supplier?**

As the electric industry evolves from being a fully regulated monopoly service into providers of transmission, generation and distribution services, customer switching, as shown again by the telecommunications industry, is a subject of significant consequences if appropriate safeguards are not established initially. APS is in agreement that the working group has not adequately covered customer protection against switching and slamming and therefore concur with the recommendation for the group to continue to address this issue prior to any rulemaking.

company's cash register. As such it is integral to the company's operations. As we have learned from the experience in the United Kingdom and seen through participation in both the California deregulation process as well as in work shops conducted in Arizona, unbundling of the metering function is fraught with complexities; complexities arising from the need to insure safety, reliability and consumer protection; complexities which will only insure that customers will be greatly inconvenienced and delayed in choosing and switching energy service providers (ESP); complexities without any offsetting cost savings

Proponents of deregulation of metering services often cite the provision of regulated metering services as a barrier to competition. In reality the exact opposite is true. Imagine if you will the ease with which one is able to switch telephone long distance providers. The reason is that in the telephone industry, metering is not unbundled, nor does metering take place at the customers' facility. Metering is accomplished at the switching station where each phone company can either provide its own software to monitor its calls or subscribe to the local phone company to provide it with such service. The result is seamless customer switching from provider to provider with a simple phone call. By contrast, unbundling electric metering will require close coordination between the local distribution company, the outgoing ESP, the new ESP and the customer. Arrangements must be made to among other things (1) arrange for, at best, the legal transfer of meter ownership and/or operational control and O&M responsibilities, or, more likely, the physical switch out of the meter, (2) make arrangements for a final meter read, (3) verify the certification status of the new metering provider, and/or (4) arrange for on site meter testing. Far from representing a barrier, retention of regulated metering will make such a switching process unnecessary, insuring the seamless switching process that characterizes the telephone industry. Because the introduction of competition into the energy marketplace poses significant challenges as it is, it is suggested that at the very least the metering services continue to be provided by the LDC during any period of transition.

In addition to making the switching process more cumbersome, it is highly unlikely that any significant cost savings will be realized from the deregulation of metering services. Two reasons are readily apparent: (1) the provision of metering services exhibits many of the characteristics of natural monopolies and (2) significant competition and innovation already exists even in a marketplace where utilities exercise the purchase power of scope and volume. Much like the provision of other distribution services, metering is a service where duplication is costly and undesirable. Even proponents of deregulated metering vociferously have expressed this same conclusion, citing the duplication of metering services as a barrier to market entry. What regulated metering has brought to the consumer and which it will continue to bring to the consumer is the cost reductions possible from the efficiency of not only volume purchases, but also from the economies of mass installations, operations and maintenance. As has been noted by a number of ESP's including Enron Capital and Trade Resources, Inc. a leading proponent of deregulated metering, competition already exists in the metering marketplace. It is this competition which has seen innovation after innovation introduced into the marketplace, a marketplace vying for the regulated utilities' business. Automated Metering Reading is but one such innovation that came about, not because of individual customer choice, but rather because the economies of system-wide applications have resulted in continually declining costs and a growing market.

Lastly it should be noted that many of the value added benefits so often cited by proponents of deregulated metering are not really dependent upon the metering function at all! Deregulated metering proponents talk about bringing additional value to the customer by providing such value-added services as information services, means to help customers manage their electric consumption, phone messaging, security services, etc. The fact is that none of these services require any interaction with the meter whatsoever. What is required is a communication link to the customer's facility. While it is true that remote meter reading also requires communication services, it is not nor will it be the exclusive communication link to the customer's premise. Other communication links already exist. The cable companies have established communication systems, as have the telephone companies. In fact many meter vendors are aligning themselves with these traditional communication providers to perform automated meter reading. Other options include cellular, paging systems, PCS, etc. The provision of value added services could and will tap these other communication media's to enter homes and businesses. Metering services do not necessarily represent the only entry for such services. The ACC should reject any arguments that suggest that without deregulated metering the consumer will be denied the benefits of these new and innovative products and services.

b) **Meter Ownership**

There has been discussion if metering is competitive, who should own the meter. APS agrees with the Working Group <u>if metering is competitive</u>, <u>that only</u> the ESP or LDC as service providers, and who are dependent on the accuracy of the meter, should control and/or own it.

c) **New Meter Providers Should Not Be Allowed To Pick and Choose Which Parts of the Meter Should Be Competitive**

APS has concerns that ESP's will be allowed to redefine metering in such a manner as to minimize their costs at the expense of creating more complex operational and legal processes. There are those that have suggested that the instrument transformers (i.e. PT's(potential transformers) and CT's(current transformers)) required in higher energy rated meters be excluded from the function of deregulated metering. It needs to be understood that the "meter" in large commercial and industrial applications consists of the instrument transformers, test switches in addition to the exposed meter itself. The accuracy of the meter is dependent upon these PT's and CT's, which are part and parcel to the metering function. If metering is competitive, the ownership and maintenance of these instrument transformers should become the responsibility of the metering agent.

d) **Load Profiling Should Be Allowed On An Interim Basis**

Because the energy scheduling and settlement process requires hourly load data, APS believes the best means of meeting such requirements is with the provision of hourly meters. However, recognizing that the provision of hourly meters for residential and small commercial customers currently represents a barrier to direct access, load profiling on a statistically significant sampling basis for customers under 20 kW should at least initially be permitted. The ultimate implementation of hourly metering for customers under 20 kW will be determined by the experience gained in the interim period and by the economics of system wide hourly metering implementation.

However, in accepting load profiling it is important to recognize its shortcomings and potential risks. Among the risks is the potential for gaming and cost shifting. Without the ability to accurately measure customer loads, system operators are left without the ability to properly allocate energy cost responsibility to customers, in particular energy imbalance costs. As a result such costs end up being allocated on an average basis, allowing those who are responsible for these costs to escape cost responsibility and shifting the cost burden to others.

Load profiling also fails in permitting the benefits of economic efficiency. The efficient allocation of resources is dependent upon the provision of appropriate price signals so that customers can respond accordingly, ensuring. In a market where costs vary hourly, load profiling severs the relationship between price and response. The customer receives no feedback on his pattern of energy consumption. Energy efficiency programs become ineffective.

And finally, load profiling has negative implications for system reliability. Although not expected to be a problem, load profiling, nevertheless, provides the potential for degrading system reliability. System operators schedule the provision of reserve capacity to cover the uncertainty of hour by hour load changes. In the event unanticipated load increases materialize which exceed the availability of generation resources, system reliability can be placed in jeopardy. In the event marketers, free of any after-the-fact accountability, game the system and schedule less load than they really expect, system operators could be caught in a capacity short situation.

e) **Open Architecture Standards Should Be Established by the Market**

APS does not believe it is necessary for the Commission to order the implementation of an open architecture standard. The impact of such a standard being adopted and retroactively applied to existing meters means that the security codes which safeguard the confidentiality of the individual customer's metered data must be released to other vendors. Although it is possible to provide for maintenance of customer data security such procedures will require significant expense and are not warranted. Insofar as new installations are concerned the marketplace is already at work in garnering support for adoption of an open architecture standard. Nation-wide adoption of such a standard will come about without regulatory intervention.

f) Issues Resolved To Date Have Been At A Policy Level. Many Issues Remain To Be Resolved at an Operational Level Before Direct Access Can Be Implemented

Whereas the metering subcommittee has made significant progress, all parties to these proceedings need to recognize that any agreements reached to date have been at a relatively high policy level. A great deal of work remains to be done before direct access should be allowed to be implemented. Agreements need to be reached on the details of implementation. For example, detailed procedures still need to be determined for meter switching, common terms and conditions for required ESP/LDC agreements, protocols and procedures for meter data management, data validation and estimating procedures, meter certification and testing processes, treatment of meter stranded costs, data storage responsibilities and standards, cost recovery mechanisms for transition costs, the development of load profiling methodologies and appropriate cost allocation procedures.

I. Billing and Collection Issues

The area of Billing and Collections has been a long and arduous topic with considerable discussion from all the group representatives. While there was a consensus among the group on certain items, there are still significant areas to be resolved. In fact, as indicated in the Working Group report, the entire Arizona Administration Code R14-2-201 through R14-2-213 requires extensive modifications base on resolutions to these areas, as indicated by the issues still outstanding and open for continued discussion.

(a) **What Billing Options are Available**:

This area remains a topic of discussion, as the Working Group has not reached any agreement on billing options. APS believes that the LDC or any entity should have the right to bill for services provided or, at their choice, contract with another entity for this service. In the telecommunications industry, US West, as a regulated industry, bill their own customers, and also offers long distance carriers consolidated billing at the same time at competitive pricing. Even with open access, the Affected Utilities will always have a relationship with the customer for providing distribution service, whereas there could be multiple ESP's throughout the year. It is uncertain as to what the transaction costs would be to have a number of various entities collect from one particular customer throughout the year for service provided by the LDC. This further emphasizes the argument that the LDC's should have the right to bill in the most cost-effective manner possible and to reduce risk of non-collectible revenues.

Arizona Public Service Company
Comments on the Unbundled Services and Standard Offer Working Group Report
10/29/97

As indicated in the Working Group Report, the subcommittee groups primarily worked on the larger policy issues and then on the operational detail only to the extent time permitted. The Working Group and Staff have made a number of recommendations that will assist in the transition to a competitive market and state that additional details will require resolution prior to the competitive market beginning in 1999. The Working Group also recommended that the Metering and the Billing Subcommittees be directed by the Commission to continue meeting to allow for the accomplishment of their objectives. This includes recommendations as to how the existing Rules would need to change. Arizona Public Service Company (APS) believes that there are significant issues that remain to be addressed by the Subcommittees that will impact the Rule and which are necessary for direct access to be successfully implemented. The original Rule was considered to be a framework from which the working groups were to flesh out the necessary details and recommend modifications and additions to the Rules; this has yet to be fully accomplished. Therefore these issues should be worked out and resolved prior to redoing the Rules – to ensure that the modified Rules provide a rigid framework to support the implementation of competition in a timely and effective manner. The operational and transaction sides of the business are critical parts of the successful implementation of the competitive generation market and will require significant dedicated resources to accomplish.

I. Standard Offer Service

APS believes that its obligation to provide any service designated "competitive" by the Rules should terminate at the end of the transition period to a competitive market as contemplated by the Rule. However, even in the competitive market there will be those providers that choose not to serve and customers that simply do not want to make a choice. Therefore, the obligation to serve at that time should become the obligation to serve as "purchasing agent" for any customer within APS's distribution service area that either requests such service from APS or does not make a selection of a competitive provider of a necessary service. As such an "agent", APS would purchase competitive services on the customer's behalf, and then bill the customer at cost plus a small administrative mark-up to be determined by the Commission.

II. Systems Benefits Charge

APS's agrees with Staff that the intent of the Systems Benefits Charge (SBC) was to ensure that departing customers would pay the same amount for the programs included in the charge as the customers who remain with the incumbent utility. This would allow for the continuation of the programs approved by the Commission for each Affected Utility. Additionally, we agree with Staff's recommendation that if the Commission decides to allow an independent SBC administrator, as has been recommended by a few parties, that the Commission relieves the Affected Utilities from the existing, related requirements to perform such programs and provide such services.

However, APS believes that the Affected Utilities are in the best position to effectively administer the programs that the Commission approves rather than an independent administrator. An independent administrator would only add another level of bureaucracy to the process, would not be regulated by the Commission and it is unclear as to how the Commission would mandate what specific programs the ratepayer funded dollars would be utilized for and how they would audit that entity or require it to refund dollars to ratepayers not appropriately spent or managed. Moreover, APS has concerns that unless the SBC is designed to recover the costs of <u>utility</u> programs, it could be characterized as an unauthorized tax.

III. Solar Portfolio Standard

APS believes the SPS would be improved by the addition of strong incentive-credits for Arizona economic development as proposed in the report. However, in order to improve the cost and sustainability of the SPS, the solar kWh requirement should remain at 0.5% until 2003 when a review should be conducted of the SPS costs and the progress the solar industry has made in cost reductions.

Only if that review is favorable should an increase in the SPS be considered. If an increase is warranted, it should then be done on an incremental basis, such as by 0.1% per year until a new target is reached, rather than the doubling to 1% in 2001 as proposed today. This gradual increase would be beneficial to protect the electric consumers against higher costs, and would avoid unrealistic expectations by the solar suppliers of an increase in demand independent of cost reductions. In addition, this would help the suppliers see a sustainable increase in demand, and gradually increase their production, instead of requiring a sudden increase all in one year.

IV. Metering and Meter Reading Issues

a) The Introduction of Competition Can Best Be Facilitated By Continuing the Bundled, Regulated Provision of Metering Services

With the formation of the Metering Sub Committee one of the main topics of discussion has been whether the meter should remain part of the LDC's regulated services or become an unregulated competitive service. Due to the amount of controversy over this issue, Staff has requested that "white papers" to discuss this issue. This alone, indicates the merits of metering remaining regulated under the LDC. If the Arizona Corporation Commission wishes to facilitate the introduction of competition into the Arizona energy marketplace, it should leave the provision of metering services as part of the regulated distribution function. The meter is the end point of the distribution system. It is the point of connection to the customer and the

AEPCO's General Comments Regarding the Solar Portfolio Standard (continued)

Short of exempting of the Cooperatives, it is important that when considering AEPCO's members' 1995 retail sales (sales by our Class A members) to determine the amount of solar capacity needed, special contract sales, because of their nonfirm interruptible contingent, or buy through nature, should be excluded from the total.

AEPCO's other suggestions offer solutions to current problems with the Rules or respond to concepts raised in the Subcommittee:

a. The current rules favor new market entrants:

While the percentage figures appear facially neutral, in application they favor new market entrants, particularly power marketers. Because of the need to plan and provide for the obligation to serve all who request service, Arizona's utilities *have already committed to energy resources* at least through 2003 (to include projected growth levels). *The Standard will be excess capacity for them* and increase their overall costs, making them less price competitive with newcomers who can fashion their portfolio of resources from scratch, as sales are made, and to meet whatever rules come along. As multi-state sellers, such new entrants can also tote the same "solar or renewables portfolio" to whatever state requires it. Arizona's rural electric cooperatives cannot. They are Arizona cooperatives, not giant holding companies, not subsidiaries of another state's IOU's. They are already committed to the renewables goals of the IRP. An excess capacity solar standard should not be further stacked against them.

Recommendation:

Phase in the portfolio standard as new generation resources are needed to serve the retail competitive load. The ACC already has IRP plans which indicate those dates for Arizona's utilities. New market entrants with existing resources could file similar documents. Otherwise, the ACC would presume all resources to be new. This will provide a fair and economically efficient means for Arizona's consumers to meet the Standards.

b. The rules should encourage remote small-size "distributed" solar generators:

Solar generation is ideal for rural Arizona where loads are remote and uneconomic to build distribution lines. ESP's should be rewarded with a double count as a incentive to install such systems at consumers' homes, ranches and businesses.

c. Complying with the Standard is unworkable in an unknown market:

Competitive electric generation is an unknown product. No realistic forecasts of sales by affected utilities or new market entrants can reasonably be made. Therefore, it is impossible to accurately predict and acquire the "right amount" of solar resources to meet the Standard. Yet, ESP's will be required to meet the Standard on a continuous basis with each kW sold. If they do not "consistently" do so, they face a penalty. If they "under buy", they are penalized. If they "over buy", they pay more than necessary for energy and will be uncompetitive in pricing. While the "banking " and "trading" recommendations of the Subcommittee are a step in the right direction, some sort of flexibility or forgiveness mechanism in the Standard itself is needed in the first few years until reasonable estimates can be made.

Arizona Electric Power Cooperative, Inc.

P.O. Box 670 • Benson, Arizona 85602-0670 • Phone 520-586-3631

General Comments Regarding the Solar Portfolio Standard

Arizona Electric Power Cooperative, Inc. (AEPCO) is a generation and transmission cooperative; it is a non profit entity and has no shareholders. AEPCO has no retail customers. AEPCO makes wholesale sales to its member distribution cooperatives. AEPCO's members are AEPCO's owners. Without shareholders, and as a nonprofit organization, AEPCO's member-customers have no venture capital to invest in a solar enterprise.

AEPCO does not need any new generation until after the turn of the century. Thus, any new resources required by the Rules to be added to our system in the interim (I) violate least-cost principles; (ii) are unnecessary; (iii) serve only to drive up system costs; and, (iv) constitute 100% potential stranded investment. In effect, adding such a new resource simply drives up the cost of our competitive price.

1. The Effect of the Solar Portfolio Standard on AEPCO's Member-Customers

We must point out that the ("Standard") impermissibly interferes with AEPCO's internal affairs and contractual relations with its Class A members who are required to buy all their power requirements from AEPCO. It micro manages both our and their business operations. The ACC's Standard forces AEPCO and its members to ignore and breach those contracts and allows the members to purchase their solar resources elsewhere or forces AEPCO to add unnecessary generation resources and recoup those additional imposed costs through higher prices, thereby making AEPCO power more expensive for our members' customer-owners and less competitive. Neither of these is good business and neither is good policy-making.

Additionally, AEPCO's solar requirements may not be sufficient demand for a solar supplier to locate in our members' service areas. Consequently, the chances that a solar supplier, if stimulated by the Standard to locate manufacturing in Arizona, would build in such an area, is remote. More likely only solar collectors would be so located, providing perhaps a job to a minimum wage glass cleaner. Thus, no new jobs or economic benefit would reach the rural customers of AEPCO's members because of the Standard. Instead, they simply would pay more for the electricity they buy. And, since a significant portion of the rural customers AEPCO's members serve are low income, it would appear their only "reward" from the Standard will be higher power costs, the result of unnecessary generation.

2. Solutions and suggestions for change:

AEPCO believes that the market should regulate the amount of solar energy included in an Energy Service Provider's (ESP's) portfolio; that an ESP should purchase and sell "green power" based on its customers wants and needs. Therefore, the Rules should require each ESP to make "green power" available, thus assuring customer choice. The creation, stimulation and stabilization of an Arizona solar energy industry could then be left to a systems benefit charge equally levied on all by the ACC through bills, to a tax or tax credit levied by the Legislature, or to other subsidy/incentive mechanisms which would be used towards reducing the cost of solar energy so that once competitively priced, it would become the resource of choice for all.

AEPCO would also suggest, as in the State of Nevada's solar standard rules, that Arizona's Rule should exempt electric cooperatives from compliance. The 10-13 MW of solar capacity which AEPCO or its members might need to install to comply with the standard are insignificant when compared to the state total and therefore bear little effect on the economic impacts potentially generated by their implementation.

Measurement Cost Issues

AEPCO does not agree with the position offered by some of the new market entrants that affected utilities should cease competitive marketing activities at the end of 1997, nor does AEPCO believe that Affected Utilities should be burdened with additional restrictions to their marketing activities and costs. AEPCO agrees with Staff that there is a considerable disincentive implicit in the competitive environment to "loading" marketing costs into competitive tariffs and that this will not happen.

Solar Portfolio Standard

AEPCO's position on the Solar Portfolio has been previously submitted.

Customer Requirements

AEPCO concurs that it will be necessary to ensure that meters will continue to be installed in a safe way such to preserve property and life. The individual installer's certification program recommended in the report may become burdensome and costly. As an alternative, a corporate certification program may prove to be just as effective and probably less costly.

In the area of billing concerns, the report does not address how some of these issues (responsible paying party, authority to connect/disconnect, *etc.*) were handled in the telephone rules. AEPCO requests that Staff address these issues by reporting on the telephone rules and how they are now working.

Administrative Requirements

One point that AEPCO wishes to comment on is that when affected (distribution) utilities are required to file an unbundled tariff including rates for competitive services such as metering and billing, the filed tariff will not be an accurate price signal for competitive service. Practically, it can only be reflect the average imbedded cost of service in a non-competitive environment. It will not identify the incremental cost of adding new customers or services, nor can it reflect the true cost of the same systems recovered over potentially fewer consumers. This disconnection between cost and service provided, coupled with the fact that affected utilities are required to provide this competitive information long before the new market entrants, is a point in the rules where fairness is not being well served.

Generalities

"Consumers" as used in the report are often not specifically defined and should be construed to mean all consumers (residential, rural, low income, industrial, commercial). In early drafts of this report, this was not the case, but referred to mainly large consumers. AEPCO believes that Staff tried to fairly represent opinions, but cautions readers to judge carefully which consumers may be considered in blanket characterizations.

Because so many issues have not been resolved, the new rule-making process will be difficult, and a third attempt at the process may be required to incorporate further details as they are worked out.

Advocacy Comments for the Unbundled and Standard Offer Working Group Report

The Arizona Electric Power Cooperative, Inc. ("AEPCO") submits the following advocacy comments on the Unbundled and Standard Offer Working Group Report (the "Report"). AEPCO congratulates the members of the Working Group and the Staff of the Arizona Corporation Commission for the comprehensive analysis that went into the preparation of this report. Although AEPCO disagrees with several of the Report's statements, conclusions and recommendations, the process and the resulting Report are valuable.

By re-opening the Rules docket, the Arizona Corporation Commission (the "Commission") has indicated it will hold hearings and consider amendments to the Rules on a variety of issues. For this reason, AEPCO will abbreviate its advocacy comments to this Report and will not critique the Report line by line or issue by issue. Instead, these comments will focus on major subject areas of most concern to AEPCO, its member owners and their member customers.

Standard Offer Service

AEPCO is not a retail provider and therefore does not directly offer electric service to retail customers. However, AEPCO, as the full requirements power and transmission provider to its members, is directly affected by how standard offer service must be provided. We believe that the rules are clear on how standard offer service is defined and why it is required. During the transition period to retail competition, each Affected Utility will continue to provide, and are in fact obligated to provide electric service to the non-competitive sector. New entrants are not obligated to serve, are not expected, and should not be allowed to offer standard offer service to the non-competitive sector under a phase-in plan.

AEPCO also believes that in a competitive environment, a choice not to switch suppliers is indeed a choice. Non-switchers should not be pooled and allocated to others. Depending on how the Customer Selection Work Group defines the competitive sector during the transition to competition, this may or may not be a critical issue during the phase-in period.

Any provider can develop and file a bundled rate that looks like standard offer service, which can be offered to the competitive sector.

After competition is fully implemented, the issue of "provider of last resort" becomes a separate issue, and in fact, we believe that this issue has not been adequately addressed either in the rules or in the Work Group report. AEPCO believes that the provider of last resort should be obligated to serve those high risk customers that no one wishes to serve. In a manner similar to the insurance industry, these customers can be pooled and allocated, by bid process, to an energy provider. As during the transition period, non-switchers have made a choice and should not be included in this pool of customers.

Unbundled Services

Unbundled services are those, for the most part, offered by our distribution member-owners. AEPCO would like to point out that the competitive rules have generally ignored the substantial differences between the nature of the already disaggregated cooperative structure and the fully integrated nature of the investor owned utilities in this state.

AEPCO advocates careful segregation and pass-through of Affected Utilities' distribution costs to prevent another larger entity from using a portfolio of high and low costs distribution areas to competitive advantage. At the same time AEPCO warns that geographically averaging these costs, may over time burden its member-owners and more specifically, their consumer-owners, with higher rates.

System Benefits Charge

Although there have been other interpretations offered during the Working Group meetings, AEPCO agrees with the position offered by Staff that referenced their original intent to recover from departing customers the costs for currently approved programs and being recovered in currently approved rates. All customers in an affected utility's service territory would continue to pay the same for these programs and the affected utility would have the approved funds to carry out the approved and mandated programs.

Any increase in these programs undertaken for the public good, especially if administered by a third party, is probably a "taxation," *i.e.* an enforced contribution levied by the authority of the state for public needs, and as such, it is a power reserved for the Legislature.

Comments of Asarco, BHP Copper, Cyprus Climax Metals, Phelps-Dodge and the Public Interest Coalition on Energy

Asarco, BHP Copper, Cyprus Climax Metals, Phelps-Dodge and the Public Interest Coalition on Energy[1] have been participants in the Unbundled Services and Standard Offer Working Group and its subcommittees. This involvement has included participation by individual companies, as well as representation by Energy Strategies, Inc. on behalf of the entire group. We wish to commend the efforts of the Arizona Corporation Commission staff and the various parties in addressing a number of important unbundling issues. As in other aspects of implementation, additional detailed work must be performed. It is critical that Staff and stakeholders continue to put forward the time and work commitment necessary to achieve implementation of retail access on January 1, 1999.

Regarding the issues raised as part of this working group process, we wish to emphasize the following points:

1. **Filing of unbundled tariffs**. It is important that Affected Utilities adhere to the December 31, 1997 date for the filing of unbundled tariffs, as required in the Rule. Timely filing will allow Staff and other parties the necessary opportunity to review the proposed terms and conditions for unbundled services and to verify that the rates for "non-competitive" services such as distribution and transmission do not include costs associated with provision of competitive services, such as generation.

2. **Non-discriminatory rates for "non-competitive" services.** As indicated in the Report, it is critical that rates for "non-competitive" services be non-discriminatory. That is, the price of services such as distribution and transmission should be comparable for similarly-situated customers, irrespective of whether the customer purchases competitive services from the utility, a utility affiliate, or a third-party provider. Failure to require non-discriminatory treatment could result in the creation of market power for utility-provided or affiliate-provided generation.

3. **System Benefits Charge.** The intent of the Rule regarding the System Benefits Charge (SBC) is clear: it is to recover retail access customers' *pro-rata share* of costs associated with specific, Commission-approved programs. Some parties have suggested

---

[1] The Public Interest Coalition on Energy is a consortium of energy consumer interests which includes Arizona Association of Industries, Arizona Retailers Association, Arizona Small Business Association, Arizona Hotel/Motel Association, Arizona Multihousing Association, Arizona Mobile Home Parks Association, Arizona Food Marketing Association, National Federation of Independent Businesses, Arizona Mining Industry Gets Our Support, and Lake Havasu Manufacturing Group.

that the per-kwh amounts collected from retail access customers through the SBC can be greater than the contributions made by those who pay regulated rates. Such a outcome is in conflict with the Rule and with basic standards of fairness. Retail access customers should not be required to bear a larger share of Commission program costs than customers who purchase regulated service.

4. Solar Portfolio Standard. The increased complexity suggested for the Solar Portfolio Standard speaks to the difficulty of incorporating such a mandate into a competitive market environment. We suggest that consideration be given to scaling back the requirement by 50 percent so that the cost to consumers and availability to suppliers does not unduly hinder retail access implementation. We support the cost-impact cap recommended in the Report.

5. Load profiling. The use of load profiling will allow customers with small loads to participate in retail access without having to have an hourly meter installed. We believe this approach makes sense. While implementation of load profiling protocols is no trivial matter, we believe that some of the utility criticisms of using load profiling are overstated. An example is the concern that an absence of hourly meters undermines competition because all customers are not receiving hourly price signals. This argument assumes that the mere presence of hourly meters would cause customers to choose to purchase their electric power from the hourly spot market. Yet such an outcome is highly unlikely. Many customers will prefer to contract for services at prices which are fixed or otherwise insulated from spot market volatility. Such a preference is not at all incompatible with competitive markets. In such cases, a risk premium is built into the fixed price and the wholesaler accepts (or otherwise mitigates) the risk of the day-to-day volatility.

Regarding the proper allocation of costs to customers, it is important to bear in mind that load profiling will not make this allocation any less accurate than it is today. The absence of hourly metering inherent in load profiling does mean that it is not possible to identify individuals whose *relative* usage is heavier during expensive hours of the day when compared to the average profile. (Note that customers whose *total* usage is higher than average *will* be identified under load profiling.) This situation is identical to the situation today for any customers without hourly or time-of-day meters. Such customers are not assigned their proportionate share of costs incurred by their supplier during expensive hours of the day. Load profiling will allow this practice to continue, but it is justified on the grounds that these customers have loads which are too small to warrant the expense of an hourly meter.

6. Metering as a competitive service. The Rule indicates that metering is to be a competitive service. Access to this business activity appears to be an important consideration for new market entrants contemplating doing business in Arizona.

Allowing access to this activity may also serve as a stimulus to product and service innovation.

Utilities have raised a number of objections to competitive metering. It may be possible for the implementation difficulties which are alleged to be addressed if competitive metering were phased in for larger users first. Perhaps such an approach would allow competition in this area to evolve within the framework of accumulated experience in data access, communications, and security. From a customer's perspective, it is important that any competitive metering serve to *increase* a customer's choices, not limit them. For this reason, competitive metering in Arizona should be accompanied by restrictions on the development of tying arrangements, in which a supplier prohibits the purchase of one service (e.g., metering) unless the customer also purchases another (e.g., generation). Such arrangements can create inefficient barriers to changing service providers.

Finally, if metering service is to be made competitive, customers should be allowed to purchase their own meters if they wish. This option will place an upper boundary on the cost that suppliers will attempt to charge. Note that customer ownership would still require assigning control of the meter to the authorized metering agent.

Kevin Higgins,
Energy Strategies, Inc.
October 29, 1997

Comments of Enron Capital & Trade Resources

INTRODUCTION:

Enron Capital & Trade Resources (Enron) hereby submits its comments with regard to the unbundling report submitted by staff on November 1.

Enron commends the Arizona Corporation Commission's leadership in adopting the rules that will enable competition for the provision of electric service to consumers in Arizona to include generation, metering, billing and customer services. Arizona is taking a leading role in the west, following closely behind California, in its proposed implementation, beginning January 1, 1999. We fully support the move to competition as quickly as possible and encourage the Commission to keep the momentum heading in this direction and resist the rhetoric from the incumbent utilities in going more slowly. Moving slowly on this issue can only benefit the utilities, not the citizens on the state. The pace of competition should be set based on what is the best policy for consumers. There are no technical obstacles to bringing choice to consumers today if one does not waiver in our commitment.

With the adoption of the rules, many debates have been launched in many different arenas. The cooperatives and the invester-owned public utilities have filed court cases against the Commission alleging that the Commission does not have authority to implement the rules. The litigation is pending. The Legislature has commissioned working groups to decide whether or not legislative action is necessary to implement competition on a "date certain", to examine what the role of the legislature should be with regard to providing competition and whether or not any changes to the tax code are necessary. The conclusion of the legislative working groups were: that the legislature does not need to act to implement competition by a date certain, the only role of the legislature should be to clarify the public policy of the state being one of competition in the generation of electricity, and changes to the tax code may be required, but it is premature to determine that need at this point.

Since the adoption of the rules, market entrants have been anticipating the implementation date of direct access by participating in the rulemaking process through the Commission and/or legislative working groups, participating in the court cases, preparing for direct access by opening local offices, investing in metering, billing, customer service infrastructure, hiring employees, increasing awareness of the issue through outreach programs, etc. Already, a significant investment to serve Arizona residents and industries has occurred. It would be unfortunate to falter at this point.

COMMENTS ON THE WORKING GROUP PROCESS

Enron has participated in the Unbundled/Standard Offer Working Group and in the sub-committee working groups including the metering sub-committee, the billing subcommittee and the solar portfolio standard sub-committee. Several things have become apparent through the participation in these working groups:

1. Consensus is not necessarily a balanced perspective of the marketplace

The overall question is: Are we trying to make decisions that create the best opportunity for a successful marketplace or are we trying to reach consensus?

In most of the meetings, there was a high concentration of utility personnel and the cooperative representatives, a representative from the mines and the coalition and one or two new market entrants. In some instances the small consumers were represented, in others they were not. The meeting process of the committees and the sub-committees was an extremely time intensive process. Many market participants were not represented in the process simply because of an inability to staff their offices and have a representative at the meeting. Understandably, this was a concern to all involved in the process, however, utilities, through cost of service regulation, can provide more bodies and representation than those in the competitive arena.

In many instances, the majority of the voting was represented through the voting of the utilities, including public power, and the cooperatives. These parties, in general, were in agreement on many issues. Opposing view points could very easily be voted out by this majority. However, that "majority" represented one constituency in the market and does not demonstrate a balanced viewpoint of all of the stakeholders.

2. Effective use of committee time

A lot of the committee time was not spent on how to move forward with implementing the Commission's rules but were engaged in debating whether or not the utilities agreed with the Commission's rule that metering, billing and customer services are competitive. Because the investor-owned utilities and cooperatives have court cases pending and have taken public positions in opposition to these services being competitively provided, a lot of valuable meeting time was spent debating those issues which would not be resolved through a committee process. The Commission must not allow the obstruction of the meeting time of the committees to be translated into a reason for delay of implementation of competition.

3. Involvement of the Commissioners

The Commission Staff has completed the first round of committee meetings. Several of the recommendations are for continued meetings of the committees. It is important that the continuation of the committee meetings have specific objectives to be accomplished within a specified amount of time. Such clarity would allow the committees to perform the tasks required of them in an efficient manner.

Secondly, Enron believes it is important to allow the stakeholders an opportunity on an equal basis to present their positions directly to the Commission for their consideration on whether or to what extent changes need to be made to the rulemaking. The Staff has acted as a arbiter of sorts between the opposing viewpoints driving towards consensus. But again, the question must be: Does consensus allow the market to operate to its fullest extent to provide choice to all customers or are we negotiating that opportunity away? Within some areas, negotiation may make sense; but in other areas, such as the provision of competitive metering and billing services, these issues are part and parcel with the offering of power and the opportunity of the market to develop. These "tough calls" can only be made by the Commissioners once they have heard the arguments.

UNBUNDLING REPORT

There are several issues which were discussed on a peripheral basis in the Unbundling Report which are of significant consequence to the success of direct access.

1. Unbundling of the Utility Costs by 12/31/97
2. Metering and Billing/Collection offered competitively
3. Separation of competitive services from regulated services
4. Exit of the utility from the merchant function
5. Affiliate standards of conduct
6. Phase-in schedule
7. Long-term agreements
8. System Benefits Charge (SBC)

Unbundling of the Utility Costs by 12/31/97

In the rulemaking, the utilities are ordered to file their unbundled tariffs by 12/31/97 in order to begin implementation of competition by January 1, 1999. The report indicates that the utilites believe they are being disadvantaged competitively by filing their unbundled tariffs prior to new market entrants filing their tariffs to provide services. This is an incredible attempt to delay and confuse issues without merit and deserves no consideration by the Commission.

It is absolutely imperative that the utilities identify and unbundle the costs that are currently being recovered in Commission-approved rates to perform the services they are performing today. These costs can be determined through FERC account numbers which is the standard method by which utilities identify costs for reporting purposes and in determining financial statements. These account numbers are used to determine revenue requirements for rate cases and should be available to determine the costs contained in existing rates. This exercise merely asks the utilities to identify the costs by their appropriate cost categories . The costs should identify the utility's cost of generation, transmission, and distribution excluding metering, billing, collections and customer service. There should also be an identification of the costs recovered for systems benefits

(DSM, low-income assistance, renewable technologies, etc.). Additionally, there should be an itemization of the utilities metering costs, billing costs, collection costs and customer service costs.

The process needs to begin with an identification of the cost to the utiity to perform the services for which it has received authority to recover through regulated rates. Once competition begins, the Commission should require utilities to file an updated cost of service study to determine what the utilities costs are today as opposed to the last time that rates were reviewed by the Commission. If the utility's current rates reflect an outdated cost of service that is in excess of the utility's actual costs, unbundling inflated rates allows the utility an opportunity to recover excessive costs through its distribution rates.

Absent the itemization of the utility's cost to provide each of these services, the utility would be able to "play games" with what costs are truly avoided by a customer choosing a competitive provider. For example, if a utility does not identify its generation costs or metering costs, recovery for some of these services may continue through the distribution charges. That type of cross subsidization will limit the ability of competition to flourish because participants in the competitive process are still subsidizing the utility's services through the distribution rates. In essence, paying for the same service twice-once from the supplier of choice and once to the utility through the distribution rates.

Metering and Billing

Enron has prepared a white paper about why Metering needs to be competitive. That report is attached to Staff's Unbundling/Standard Offer report. Because the comments submitted were limited to only addressing metering, it is important to understand that Enron believes that a viable market rests on the ability of energy service providers to provide metering, billing, collections and customer information services. We, in conjunction with R. W. Beck, have prepared a report which addresses the interplay of all of these areas and the affect on the competitive market. Enron will be happy to submit this report to the Commission for its review. Enron believes the report should be considered along with Staff's reports in reaching conclusions about proposed changes to the rulemaking.

In short, the utilities oppose metering and billing being competitive because they want to retain control of the customer. Unbundling those services means true choices for consumers. This may mean the utility is not the provider of choice. If metering and billing were not competitively offered, the utility would continue to be the only communication link to the customer. That link is important to competition for that reason.

Competitive metering can provide the customers with choice without compromising the integrity of the distribution system. To indicate that competitive metering would compromise the distribution integrity is a red herring. Enron's position in the metering sub-committee were to discuss the protocols through which metering services could be provided safely and accurately.

It was agreed that the equipment used by metering agents would meet minimum specifications and standards for, among other things, accuracy. (See metering sub-committee report Section E, Areas of Agreement, Issue 10, Performance Metering Specifications and Standards.) The group also agreed that metering agents needed to be certified "to insure the safe and reliable operation of the metering system." In addition, metering agents would have to present their procedures for certifying their metering personnel. (See metering sub-committee report Section E, Issue 14, Metering Certification Process).

In addition to certain minimum metering specifications, the group agreed that it is important for the appropriate parties to be able to access the metering data. This would happen through a compatible communication system, which is referred to as an open architecture (See metering sub-committee report, Section E. 10. D.). However, the utilities objected to mandating that an open architecture for communications be part of the report. They felt that would happen naturally in the market. However, in their white paper at 12, they indicate that they absence of compatible communications would create barriers through substantial switching costs. Enron's position in the discussion was to encourage open architecture. It is curious that the utilities opposed open architecture and cite the lack thereof as a competitive barrier in the white paper.

Separation of competitive from regulated services

In many of the discussions of the working group, there were discussions about the utilities simultaneously offering regulated services while competing with market entrants for customers to offer power, generation, metering or billing. There are inherent flaws in having one entity offering both services. Enron submits that there needs to be a clear separation between the entity offering regulated services and the entity offering competitive services. The utilities should form affiliates to perform competitive services. The affiliates should be separate corporate entities from the utility. The utility must conform to a strict code of conduct with regard to its relationship to the affiliate.

The reason for the separation is clear. The utility has been performing a full-service role to consumers for a long time. Allowing the utility to continue to offer regulated services while simultaneously offering competitive services will perpetuate the image in the consumers minds that nothing has changed. One of the largest obstacles to new market entrants is overcoming the name and recognition barriers that the utility has built up through its regulated position as a monopoly provider. In addition, if the competitive services are offered through the utility, it will be very difficult for the Commission, or any body, to determine that ratepayers are not subsidizing the efforts of the competitive services, for which the shareholders will benefit.

Ratepayer subsidization is an unfair competitive advantage in the market place and will stunt the participation and development of the competitive market. For example, if utility ratepayers pay for the cost of the billing system through their regulated rates and charge an affiliate for only the incremental cost of competitive billing services, all other market entrants will be disadvantage by having to provice their billing services at the market rate, which will be in excess of the utility's incremental cost. In reality, if the utility or its affiliate had to solicit billing services from an independent entity, they would likely pay more for the service. Charging less than a fully allocated cost for the service provides the affiliate with an advantage relative to the rest of the field. The cost of that advantage is borne by the regulated ratepayers. It is unfair to provide the use of regulated assets to one market participant to the exclusion of all others.

Nevada's legislation has taken the step in separating competitive services from the regulated utility. For these illustrative reasons, many other types of subsidization are possible, it is important to have the regulated and competitive entities function as separate corporation with enforceable standards of conduct. Enron anticipates supporting a request to the Arizona Corporation Commission to adopt these standards of conduct in the near future.

Exit of the utility from the merchant function

Within the rulemaking, there is discussion about "reaching a determination that full competition has developed." At that point, the Commission may make a determination that the standard offer service is no longer necessary. It appears as though the intent of standard offer service is to provide consumers with a "bundled" offering in the transition period to competition. One of the items that is being discussed in all forums is whether or not it is appropriate to maintain the phase-in schedule proposed in the rulemaking. If a more aggressive schedule were adopted, beginning no later than January 1, 1999, the subject of provider-of-last resort will become more critical. For example, Salt River Project has proposed that 20% of the market be available on January 1, 1999 with 100% of the market eligible within 6 months. It is important to discuss the role of provider-of-last resort in the context of a competitive environment.

Discussion of the standard offer service by the incumbent utilities and the role of provider of last resort are issues intimately woven into the issues surrounding a phase-in or a flash-cut. Part of the concern is who will supply the "customers that nobody wants". Enron has submitted throughout the sub-committee meetings that the old model of letting the utility fulfill that role doesn't fit a competitive environment. There is no need to perpetuate the role of the utility in the merchant function when a competitive alternative could perform the same role and potentially provide cost reductions to the consumer.

Enron advocates a clean separation of competitive services from regulated functions. The reason to restructure the electric industry is a belief that competition is a more efficient means to provide disciplining in the market than regulation. With that as a premise, if services are considered to be competitive, they should be removed from the list of

The role of an administrator is to determine the allocation of the funds collected through the SBC to the appropriate parties who are providing the services. The administrator can be determined by a competitive bid process so that the lowest cost for administration is obtained. In addition, the administrator can determine the allocation of the funds through a competitive bid process for the services for which the SBC was collected in the first place. This process will introduce efficiencies by awarding the administration and the funds to the lowest-cost provider of the service.

Independent administration of the SBC funds will assure that the SBC funds do not fall to a party which has a stake in the process. Under today's rubric, the utility can act as the collector of the SBC, the administrator of the program and it, or its affiliate, could be the recipient of the funds. With that much self-interest, it is appropriate to separate the collection of the SBC through a utility's rates from the administration and receipt of the funds to remove any concerns of self-dealing. The utility is not precluded from submitting a bid to perform the service. along with any other service provider, they are just not the default provider nor are they the administrator.

Phase-In Schedule

A great deal of debate has centered around whether or not to change the phase-in schedule proposed by the rulemaking. In the rulemaking, 20% of the peak (1995) capacity will be made available on January 1, 1999. No more than 50% of the available capacity can be allocated to customers of 3 MW or greater and a minimum of 15% of the available capacity must be reserved for residential customers. In January 2001, 50% of the peak capacity will be made available with no more than 50% available for customers of 3MW or greater and a minimum of 30% of available capacity reserved for residential. In January 2003, 100% of the peak capacity will be made available. The lengthy implementation process defined in the rulemaking raises issues of discrimination and the difficulties of the selection process, as described in the customer selection report.

Many participants believe that an acceleration of the phase-in schedule can be accomplished without delaying the start of competition on January 1, 1999. Salt River Project (SRP) has stated that they believe that competition can begin on January 1, 1999 with 20% of the capacity available and within six-months open the entire market. Enron would support a phase-in of a limited duration, as proposed by SRP, so long as the start date does not slip. Alternatively, Enron supports opening the system to all participants on January 1, 1999 and allowing the market to self-moderate the connection of customers. In other words, there will be a natural phase-in of competition as meters and other equipment are installed in response to customer choice. This would provide an effective phase-in of competition without the artificial limitations imposed by the rulemaking.

COMMENTS OF THE LAND AND WATER FUND OF THE ROCKIES ON
THE UNBUNDLING AND STANDARD OFFER SERVICE WORKING GROUP REPORT
October 29, 1997

The Land and Water Fund of the Rockies (LAW Fund) provides the following advocacy comments with respect to the Unbundling & Standard Offer Working Group Report. While the majority of these comments are focused on the programs covered by, and administration of the System Benefits Charge, we also address consumer education, and bill disclosure issues

System Benefits Charge (SBC)

The SBC is a key issue for public interest advocates, representing the means by which important public interest programs, developed in a highly regulated environment, can continue in a lesser regulated one. These programs provide tangible benefits to the customers of the Affected Utilities. The areas of agreement identified in the Report include:

1. Low-income Programs,
2. DSM portion of the System Benefits Charge,
3. Nuclear Decommissioning Portion of the System Benefits Charge, and
4. Amounts Collected Annually through the System Benefits Charge (addresses ambiguity of the current language in the Rule, and suggests an alternative wording).

In this section we will address the DSM programs covered by the SBC, the ambiguity noted in number four above, including our rationale for changes in the funding levels of certain elements of the SBC. The last area discussed will be the alternative administration possibilities available to the Commission. The Working Group Report notes only one area of disagreement in the SBC section, i..e. administration. We present our view of this topic below.

DSM portion of the System Benefits Charge

The report notes as an "area of agreement" in the System Benefits Charge section that DSM measures that are already *market-driven* should not be included in programs that are funded by the SBC. Market-driven measures are those energy efficiency measures that are currently being purchased and installed in a fully-functioning private market in a self-sustaining manner, without the presence of market barriers to cost-effective energy efficiency, and without the need for system benefits programs to support the broad adoption of measures. By definition, if market barriers to measure adoption are present, and if systems benefits programs can reduce or eliminate the market barriers and acquire cost-effective benefits for ratepayers and society, then the measures are not yet market-driven. They may be partly market-driven, but the market isn't fully transformed. The degree of transformation will be reflected in cost/benefit analyses.

The report continues with agreement that DSM programs that are designed to reduce or overcome market barriers to cost-effective energy efficiency that are not otherwise addressed adequately in competitive or regulated markets are subject to funding through the SBC. As a further point of clarification, we want to note that this definition does not limit the DSM portion to information and education programs. A good deal of the literature available today includes reduced-cost financing and rebate programs as integral parts of transforming the energy efficiency market. See for example, *A Scoping Study on Energy Efficiency Market Transformation by California Utility DSM Programs*, (Eto, et al., July 1996). Moreover, cost-effective programs not specifically designed to transform the market should also be considered for funding through the SBC. The LAW Fund supports SBC funding for market transformation programs, but not to the exclusion of other cost-effective DSM programs.

As a result of the threat of competition, utilities across the country have been on a binge of cost-cutting. Indicators include large scale employee cuts (once unheard of in the industry), closing of customer service centers, reductions in O&M budgets and research and development expenditures, and scaling back and eliminating programs which don't directly enhance earnings. DSM and renewables programs fit into the latter category. In addition, promoting a resource that reduces sales runs counter to the traditional incentives of a competitive profit making business. Prior to the global tobacco settlement, one didn't see tobacco companies promoting smoking cessation programs.

Demand-side management is a very cost-effective resource. While DSM programs may not add to the short-term profitability of the utility, its many benefits include risk diversification, localized transmission and distribution savings, targeted peak reductions, and reduced bills for customers. The benefits of DSM tend to favor residential and small commercial customers. As competition is introduced into the Arizona energy market, many people expect that large customers, with their strong buying power, will capture the best energy supply deals on the market. DSM may turn out to be the major benefit of competition provided to small customers, but funding levels as of December 1996 were very low. We believe the proper amount of DSM and associated funding can be estimated by examining the DSM amounts the utilities found to be cost-effective in "pre-competition" Arizona.

In pre-competition Arizona, utilities were interested in developing programs that provided long-term benefit to consumers, with lesser emphasis on short-term earnings. For example, APS testified in the 1993 IRP that over the next ten years, its resources were planned to increase by 888 MW. Of this amount, approximately 518 MW would be met through DSM programs. The cost of DSM has been coming down, but even at a cost of $250 - $300/kW (approximate 1993 average DSM costs), 52 MW of DSM per year would have cost about $15 million. The rate settlement in 1994 established a budget of $14-18 million for DSM and renewables. With about $3 million earmarked for renewables, the range for DSM is $11 - $15 million per year. As the threat of competition became more real, these amounts were slashed to a minimum of $7 million, with authorization up to $10 million for energy efficiency and renewables in the 1996 APS rate case settlement. The market transformation programs currently being promoted by APS are focused on information and education, and are very inexpensive.

As indicated above, present DSM costs have come down, but we believe the pre-competition amounts still provide a useful starting point. A more current example of DSM costs and benefits is the result of a recent $5 million DSM bid let by Public Service Company of Colorado (now New Century Energies). The utility recently signed contracts for 30 MW of DSM at an average cost of $162/kW. This compares to a capital cost of $800 to $1,500 per kW for traditional supply-side resources (excluding nuclear). All customers of New Century Energies will now enjoy a reduction in their utility bills through the utilities ability to meet a portion of its growing needs at an extremely low cost.

Another point of reference is the SBC levels developed in other states. In recognition of the benefits of these programs developed under a regulatory regime, regulatory bodies around the country have developed mechanisms like the SBC to assure that they continue to be funded.

[illegible]	[illegible]
California	**3.0 mills**
Connecticut	5.5 mills
Illinois	**0.7 mills**
Maine	1.0 mills
Massachusetts	**4.0 mills**
Montana	1.1 mills
New Hampshire	**1.5 mills**
New York	0.9 mills
Rhode Island	**2.3 mills**
Vermont	4.5 mills
Wisconsin	**3.6 mills**
Average	**2.55 mills**

Source: *A Status Report of Public Benefit Programs in an Evolving Electric Utility Industry*, New York State Energy Research Development Authority, September, 1997.

Recommendation:

- Retain and fully fund existing utility DSM programs
- Increase the funding for DSM to pre-competition levels
- Use a bidding process to capture the most cost-effective DSM measures

System Benefits Charge Language Ambiguity

The key language for the SBC is as follows:

> The amount collected through the System Benefits Charge shall be sufficient to fund the Affected Utilities present Commission-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning programs.

According to the report, the SBC was developed "to ensure that customers who select a new electric service provider will continue to contribute to these public interest programs, thereby allowing their distribution utility to meet mandated requirements and to fairly compete for customers as Arizona transitions into a competitive environment." We agree fully with this premise. When applied to the real world in Arizona however, existing circumstances confound achievement of this goal. Certain existing programs are not fully funded currently, while others, in place when the Rule was approved, are already being phased-out. Still other programs in effect today were not approved by the Commission until sometime in 1997.

For example, it was observed that it will be difficult, if not impossible, for the State's two largest utilities to achieve the renewable resource goals identified in the 1993 IRP at present funding levels. In other words, present funding levels are insufficient to fund present Commission-approved renewables programs. At the very least, sufficient funding, as provided in the rule, must be required. The Commission addressed funding for renewables in the 1993 IRP. During the hearings in Docket No. 93-052, Arizona Public Service Company (APS) indicated that it is willing to strive toward a "goal" of 12 MW for renewables by 2000. The Commission in its order in this matter responded as follows:

"We [the Commission] regard these statements as serious commitments and will accept them as planning goals. However, if APS and TEP appear to fall significantly short of meeting these goals, we shall reconsider short-term set asides."

Further perspective may be gained through comparison with another element of the SBC. In a nutshell, the renewables problem is that utilities have been collecting insufficient amounts through rates to properly fund their programs. APS has been collecting about $11 million/year through rates to fund decommissioning of Palo Verde. Experience at other utilities has indicated that these costs tend to go up rather than down. If it's determined that decommissioning is being greatly underfunded, should APS be denied the opportunity to increase the charge? If funding is inadequate to achieve program goals, clearly the funding level must be increased. Similarly, renewables programs should be fully funded to meet program goals

Adequate funding may require an increase to the renewables element in present rates. While a price increase is not our goal, there are ways of eliminating any price increase. The growth in Arizona has resulted in rate decreases for several years. Increasing renewables funding should only reduce the amount of the price cut.

Other ambiguities exist with respect to DSM programs and the language requiring programs to be *present Commission-approved.* Thee are a number of programs in place at the end of 1996 that are being phased-out, while several DSM programs under way had not been approved by the Commission until after the Restructuring Rule was adopted. We believe it makes sense to review DSM programs periodically. Indeed, this is a very healthy and worthwhile exercise. It is our view that the Rule as written however, does not accomodate such changes. As a result we agree with the concept noted in the report of reviewing the SBC every three years. This allows all parties to formally review existing programs and their administration, re-evaluate the market, change emphases, add new programs, change or eliminate programs that aren't meeting goals, changed energy supply and demand circumstances, experience elsewhere around the country, and new and emerging technologies. As discussed below in the administration section, we don't believe that the Affected Utilities are necessarily the appropriate party to make these filings.

The timing of the first review will be very important. It should be far enough out that effectiveness of current programs can be determined, particularly in light of the transitioning electric industry, but soon enough that ineffective programs are replaced quickly and efficiently. On balance, we recommend that the first review take place after three years of a competitive market into Arizona, in late 2001 or early 2002. This timing will also eliminate transitional biases for the fully competitive market effective in 2003. [The other option is to have the first review immediately on the chance that we can increase the funding for DSM]

Recommendations:

- Increase the funding for elements of the SBC which are not at present sufficiently funded.
- In conjunction with the rate filings required by December 31, 1997, the SBC should be applied consistently to both competitive and standard offer rates.
- The first of the three year reviews of the SBC should occur in late 2001 or early 2002.

Other Areas of Agreement

While not noted in the report specifically, we don't believe there was any disagreement voiced regarding the other elements of the SBC, namely the renewables and environmental programs. We suggest that report reflect agreement in these areas.

Administration of System Benefits Charge

The Rule is silent on this issue and as a result, it was discussed at some length and with some confusion. At the outset, we want to make clear that we are in no way suggesting that funding for programs be taken away from the Affected Utilities, while responsibility to perform those programs remains. Indeed, the Affected Utilities are in the best position to fully administer many of the programs. We also want to be clear that funds collected for public interest purposes should be used for such purposes. Presently, underspending on public interest programs such as low-income, DSM, and renewables results in rate reductions to consumers. While this is not a bad thing in and of itself, the anticipated societal benefits intended by incorporating these programs into electric utility rates, are lost.

In our view, the programs within the SBC each have individual goals, and the SBC is designed to assure adequate funding for each program to accomplish its goals. An unambiguous example is the nuclear decommissioning program, discussed above. Clearly, the utility with this liability has the proper incentives to assure that its goal is accomplished. With respect to environmental programs, which the group defined as costs incurred related to meeting new environmental regulations, the Affected Utility also has the proper incentives. Both of these SBC elements relate to liabilities associated with supply side resources, and the incentives are very much aligned with the company's goals. Low-income programs are less straightforward, however the utility certainly will benefit from proper implementation and management of these programs. Conversely, as described above, the incentives of a utility in the business of selling energy are not aligned with those necessary to produce effective and efficient DSM and renewables programs.

Our goal is to help design the restructured electric industry in Arizona in the best way possible to achieve the individual goals of the SBC programs. There are several aspects of administering the SBC funds to accomplish program goals. These include (1) the collection agent, (2) the contracting agent, and (3) the Commission review and approval process.

The collection agent may be the least controversial element of administering the SBC funds. In our view, the collection agent for a wires charge is best performed by the wires company. The extent of the responsibility of the collection agent is to assure that the proper level of funds are collected and held in an account for disbursement to the contracting agent. In some cases, i.e. nuclear decommissioning and environmental programs, and probably low-income programs, the wires company is best suited to also serve as contracting agent. For DSM and renewables programs however, the contracting agent should be independent of the wires companies.

The Affected Utilities not only have incentives diametrically opposed, but have also demonstrated little enthusiasm for capturing the efficiency benefits available in the marketplace. Moreover, the Affected Utilities' renewables programs have fallen far short of goals and, at least on the surface, without significant cost reductions. Utilities in other parts of the country have made considerably better progress. We believe that an independent advicory counsel or board, comprised of a small group of representatives, with the help of a knowledgable Staff, can meet for short periods several times per year to perform the necessary functions to achieve the DSM and renewables program goals. This board would act as bidding and contracting agent to capture the most cost-effective DSM and renewables from the market. The Commission will establish and approve these programs in the review proceedings discussed above.

A distant second option is to allow the wires companies to act as contracting agent, but only under strict control and supervision of the Commission. For example, the Commission should establish segmented bidding procedures for DSM (beyond current utility programs). For example, in Colorado the PUC limited the amount of DSM for which the utility could bid to 50%.

Recommendation:

- Establish an independent contracting agent for the DSM and renewables elements of the SBC.

Solar Portfolio Standard (SPS)

The LAW Fund previously provided comments on the Solar Portfolio Standard Subcommittee Report. We understand that these will be incorporated in the larger Unbundling and Standard Offer Working Group Report.

Customer Education

Customer education is very important and we urge the Commission to establish a task force to develop an effective media campaign. Without such a program, it's unlikely that electric utility customers will have even the rudimentary knowledge with which to understand the choices available to them, let alone make good decisions. Unless all customers understand the potential benefits of competition available to everyone, the restructuring efforts over the past several years may be viewed as simply another way of giving the large and powerful customers a price break.

Bill Disclosure

As discussed in the Working Group meetings, the purpose of disclosure is to allow customers to make informed choices about the energy supply options available to them. Shopping for electricity is a new experience for consumers. Experience with pilot programs showed a high level of consumer confusion as complex price structures made it difficult to compare competing offers and the intangible nature of the commodity made it nearly impossible for customers to determine the sources of their power or to verify whether sellers' claims were true. Without a common language that provides an accurate, objective basis for comparing claims of competitive suppliers, customers will find it difficult, or in many cases impossible, to compare the price, fuel and emissions characteristics of potential electricity purchases. In fact, in some of the retail choice pilots, misleading claims were common.[1] Customer focus groups conducted with pilot

---

1 Some argued that a number of the environmental claims made in the pilots violated existing laws regarding environmental claims used in marketing and that, had the law been adequately enforced, some, or perhaps all, of these abuses would not have occurred. They may be correct in arguing that some of the abuses in the pilots were, in fact, in violation of the current Federal Trade Commission (FTC) guidelines.

program participants in New Hampshire and Massachusetts confirm that consumers strongly dislike making the "apples to oranges" comparisons with which they have been presented.

Standardized, consumer-friendly labeling and disclosure is required in many sectors of the retail economy such as food, automobiles and consumer credit to correct informational imbalances between seller and buyers and to provide a uniform basis for comparison of material terms. A uniform disclosure mechanism for retail electricity sales will give customers an accurate, objective basis for comparing price and environmental claims of competitive suppliers.

A disclosure policy covering price, fuel mix and emissions will also protect suppliers from unfair trade practice claims by setting clear rules of the road. It protects against customers having difficulty comparing prices and a backlash aimed at environmentally-benign resources by helping to insure that customers get what they want and pay for. Depending on the level of customer demand, it can result in cleaner resources and less pollution.

A comprehensive report is available on this subject that resulted from seven months of effort among regulators, utilities, the coal industry, environmental groups, independent energy suppliers, and other stakeholders on the internet at www.rapmaine.org.

Recommendation:

- We urge that disclosure of price, fuel mix, and emissions be required for all ESPs at least quarterly and monthly, if possible.

However, even if we could assume adequate funding of the FTC's enforcement activities, relying solely on existing law would fall far short of the proposed disclosure in a number of respects. There would be no uniform price information; absent some type of environmental claim, there would be no fuel or environmental information at all; and if an environmental claim were made, it would only provide the same information as the disclosure label if the marketer wished to make broad environmental claims regarding both fuel and emissions.

LAND AND WATER FUND OF THE ROCKIES
ENERGY PROJECT

COMMENTS ON SOLAR PORTFOLIO STANDARD SUBCOMMITTEE REPORT

In the interest of brevity, the Land and Water Fund of the Rockies (LAW Fund) focuses its comments on five conceptual areas: penalties, incentives, future rule changes, and resource review.

Penalties

The LAW Fund supports a penalty provision in this section of the Rule that is high enough to encourage ESPs to purchase appropriate levels of energy derived from solar electric renewable technologies. We are not opposed to increasing the penalty to 50¢, although 30¢ is probably sufficient if a workable credit system is incorporated. The funds collected through this provision, if any, should be used to advance the development of solar electric resources, i.e. to meet the objectives for the Arizona Solar Portfolio Standard outlined in the report. In our view, the best way to accomplish this goal is to transfer the funds to the administrator of the System Benefits Charge monies, and charge this entity with achieving the greatest amounts of solar electric renewable technologies possible through a competitive bidding process.

APS has proposed a concept of a 30¢/required solar kWh wires charge, reduced by 30¢/actual solar kWh provided by the ESP, ostensibly to avoid the "problems with penalties." The difference, if any, would be paid to the regulated "wires" companies to use in acquiring as much solar as possible. This complicated administrative approach has several fundamental flaws. First, it guarantees unnecessarily that every customer pay an explicit price for the Solar Portfolio Standard. In reality, the relatively small cost of the Standard, to which all ESPs are subject, may be absorbed by the ESP. Second, the nature of the regulated wires companies is unclear at this point. Companies whose sole business is to build and operate wires may be poorly suited to administer these funds. Finally, the majority of Arizona retail electric customers will be served by regulated wires companies that are affiliated with generation companies. These corporate affiliations may provide mixed incentives to the wires company administering the "penalty" funds. We oppose APS' approach and suggest that a wording change in the Rule may solve the concern that the penalty monies may not be used to purchase solar resources.

Incentives

We are longtime supporters of incorporating effective incentive provisions in regulatory regimes to encourage desired behavior. The LAW Fund supports adoption of incentive provisions which encourage not only early implementation, but also in-state manufacture and installation. Section 1609C of the Rule provides a 2-times credit to ESPs for early installation. This section can be modified to include a similar credit for in-state manufacture and installation, but a maximum credit of 2 should be imposed. In addition, the credit should have an expiration date (e.g. 2004) to avoid the possibility of effectively cutting the Standard in half. We believe that implementation of the Standard percentages as written, in conjunction with appropriate credit provisions will inherently provide cost reduction incentives to ESPs, and no further direct incentive is necessary. Moreover, these incentives, along with the banking (i.e. carry-forward) proposal in the Subcommittee Report, provide a mechanism for ESPs to avoid the large lumpy solar resource additions implicitly required by the Rule.

Future Rule Changes

There is justifiable concern that ESPs which, in good faith, implement the provisions of the Solar Portfolio Standard and work hard to acquire least cost solar resources, may be left with potentially strandable assets should a future Commission reduce or eliminate the Standard. We agree that at the time of any future Commission review which results in adverse changes to the Standard, the Commission should take steps to protect solar investments made to date. For example, ESPs that choose to pay the penalty, gambling that the Commission will eliminate the Standard, should not entirely escape cost responsibility. Continuation of penalties for a specified period and other creative cost-sharing options should be considered as options. In this regard, wording changes to the Rule must be carefully constructed to assure that all ESPs are treated fairly and equitably.

Resource Review

It's apparent from this report, other working groups, and other proceedings at the Commission, that a periodic review of electric resource needs, costs, characteristics, availability, and so on will continue to be a necessary function of the Commission. The LAW Fund recommends that the Commission continue a workable resource review process, allowing for participation in a public forum, that is an effective descendent of the IRP process to fulfill these needs.

PG&E Energy Services

October 28, 1997

David Jankofsky
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Unbundled Services and Standard Offer Working Group Report

PG&E Energy Services submits the following brief comments:

1. It is imperative the Affected utilities file their open access distribution tariffs as required by the Commission's rules no later than 12-31-97 in order to meet Arizona's January 1, 1999 start date for competition. There is a strong likelihood these filings will need revisions because the Work Group's report is nearly silent on the appropriate content of the tariffs.
2. Since the rules have been re-opened, we request the Commission declare standard offer service competitive and establish parameters related thereto. There is simply no reason to deny standard offer customers the benefits of competition. We believe there is a need to continue default service in perpetuity and that it can be provided via competitive bidding for standard offer.
3. The entire restructuring process would be much simpler if the Commission would revise its phase-in plan to empower **all** retail customers to begin shopping for new suppliers, to allow all customers to sign new contracts and to allow all customers to request start dates for new service that commence on or after January 1, 1999. Customers that **actually** complete this process can then be placed in a queue according to the date they submit their switching request. Then, each affected utility prepares schedules for new service requests. If an affected utility has valid technical reasons for not meeting a requested start date, they must fully state their reasons to the customer (and new supplier) and indicate a revised start date. Clearly, no delay in meeting requested start dates should be tolerated for a minimum amount of switching (say, 20%). This suggestion simplifies considerably the current phase-in program and addresses a number of stated problems. In particular, this proposal eliminates the need to determine eligibility as the current rules contemplate. The Commission should likewise establish a date (say, December 2000) beyond which it will not tolerate any delays in meeting requested start dates.
4. There is no need for the Commission to require tariffs for rebundling of services by electric service providers (or by affiliates of affected utilities). Rebundling is simply a re-packaging of regulated services (for which tariffs will already exist) and competitive services (for which certificates are required to offer service). There are

simply too many rebundling permutations to require an exact tariff in each case. It would needlessly limit the rebundled offerings to customers.

5. Line extension policies need to be revised to reflect the realities of competition. They must exclude the revenues and cost of competitively provided services because the utility providing the extension cannot be assured of being the provider of competitive services for the life cycle of the infrastructure involved in the extension. This would also solve any alleged rural subsidy issues on a going forward basis.
6. We support the use of an independent systems benefit charge administrator for all demand side management, low income, and existing solar programs. The transition to an independent administrator should occur quickly and ideally would occur no later than the creation of marketing affiliates.
7. Please realize that demand side management, low income and solar programs each create marketing advantages. If a systems benefit charge is collected from **all** customers and provided to the affected utilities to then undertake these programs, then a marketing advantage will accrue to the affected utility's marketing affiliates. Hence, in this case, the programs must be offered under the banner of all certificated providers. There are other solutions, however, to this problem.
8. The solar portfolio percentage and timing probably needs downward revision in order to relieve pressure for rate increases during the period of stranded cost recovery. The percentage could then increase upon expiration of stranded cost recovery. Customers must not be welcomed to competition with a price increase.
9. A threshold of 20 kilowatts for requiring a real time meter is too low and may be a barrier to competition. For example, there are many thousands of small commercial customers in excess of 20 kilowatts that lend themselves to load profiling.
10. The Commission must keep mandatory information requirements for billing to a minimum. We endorse Enron's suggestion in this regard.
11. We endorse Enron's metering white paper.
12. We hope this Commission will, as California has, keep billing and metering as competitive services. Just recently, it has been reported than an Arizona utility has been selected to provide billing services to California's Bay Area Association of Governments.

Again, it is absolutely critical for the affected utilities to file their open access distribution tariffs as required by 12-31-97.

Thank you for the opportunity to provide these final comments.

Sincerely,

Tom Brodrick

Tom Broderick
Regulatory Consultant
PG&E Energy Services Corporation

RESIDENTIAL UTILITY CONSUMER OFFICE'S ADVOCACY COMMENTS IN RESPONSE TO THE UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP REPORT

October 29, 1997

I. PROCEDURAL COMMENTS

RUCO wishes to commend Staff on its efficient and unbiased management of the Unbundled Services and Standard Offer working group proceedings. Staff's Report on these proceedings presents a balanced and fair representation of the views espoused by the stakeholders in attendance at the many working group meetings.

II. STANDARD OFFER SERVICE

The method of computing proper Standard Offer rates should be consistent with the Retail Electric Competition Rules' ("Rules") requirement that Standard Offer Tariffs "should reflect the costs of providing the service." A.A.C. R14-2-1606(B)(3); A.A.C. R14-2-1606(G)(2). Standard Offer rate determination should also reflect the Rules' promise that "Consumers receiving Standard Offer service are eligible for potential future rate reductions . . . " A.A.C. R14-2-1606(B)(4). In order to enable the Commission to carry out these basic tenets of the Rules, RUCO suggests the following revisions to the Rules' Standard Offer provisions.

A. Standard Offer Service Should Be A "Re-bundled Service."

The Rules' definition of Standard Offer service is adequate in that the Standard Offer will consist of bundled service offered to all consumers in a designated area at regulated rates. *See* A.A.C. R14-2-1601(7); A.A.C. R14-2-1606(A). However, while the Rules describe Standard Offer as a "bundled" service, it would be more accurate to refer to Standard Offer as a "re-bundled" service.

To arrive at the correct Standard Offer rate for each tariff class, the existing utility rates must first be unbundled. This unbundling should be done on a revenue neutral basis to insure that changes in rate design do not get intermingled with the unbundling process itself. Once unbundling has taken place, that is, when customer service, distribution, transmission, generation, system benefits charges, and stranded cost recovery charges have been properly developed, these unbundled charges can <u>then</u> be rebundled into a total Standard Offer rate for each customer tariff. Requiring unbundling before arriving at Standard Offer rates assures that charges that should be competitive will not inadvertently make their way into distribution rates, which will remain regulated after the ultimate goal of deregulated generation rates is achieved.

1. The Commission should set a market-based retail generation price for determining Standard Offer rates.

The generation component of the Standard Offer price should be a market-based price for *retail* generation services for serving that particular customer class, and not the market-based *wholesale* price of generation services. The Report reflects this when in Section II(A) it states that the incumbent utilities "will be required to offer this service at cost-based rates . . ." The market-based cost for providing generation services is by definition *retail, not wholesale.*

Once the market-based retail generation services rate is established, if annual stranded costs are properly levelized or allocated during the period in which a stranded cost recovery charge persists, the overall Standard Offer rate will likely be lower than current rates. In order to encourage competition, the regulated generation price should not be set so low as to deter competitors' entry into the market. Conversely, it should not be set so high that consumers awaiting entry into the competitive market suffer undue price discrimination.

2. **A.A.C. R14-2-1606(B)(1) should be changed to reflect the unbundling requirement.**

As described above, proper computation of Standard Offer rates requires unbundling of charges for included services. A.A.C. R14-2-1606(B)(1) should be changed to reflect this requirement. Allowing the Affected Utilities to continue to charge existing rates for the Standard Offer would result in discriminatory pricing to consumers awaiting entry into the competitive market during the phase-in. The Affected Utilities should not have the choice of replacing their current rates or not.

B. **Determination of Retail Generation Services Costs for the Standard Offer.**

1. **A Least-Cost Planning docket should be implemented to set appropriate generation rates for Standard Offer service.**

In order to establish an appropriate and accurate Standard Offer generation tariff, the Commission should establish some sort of least-cost planning docket, which might be held on an annual or bi-annual basis. During such a docket, the Commission would be presented with information about the costs of the various types of power (short-, medium-, and long-term costs for peaking, cycling, and baseload power, and the spot market price). This data would comprise a hypothetical least-cost resource portfolio. The Commission would not review the prudence or appropriateness of actual power contracts the distribution utility enters into for the purpose of serving Standard Offer customers. The hypothetical least-cost portfolio would be determined during the docket for the purpose of selecting a mid-range price for each type of power supply option based on available information. The Commission would then consider the load shape and load factor over the course of the coming year (or two years), and using the selected mid-range price, would calculate a reasonable least-cost mix of supply options. Using this information, the Commission could determine an appropriate Standard Offer generation rate.

The implementation of a least-cost docket in order to determine a fair and appropriate Standard Offer generation component would assure compliance with the intent of the Retail Electric Competition Rules' mandate that Standard Offer rates "shall reflect the costs of providing the service." *See* A.A.C. R14-2-1606(B)(3).

C. **Duration of Standard Offer Service.**

1. **A working definition of "substantial implementation of competition" is needed.**

A.A.C. R14-2-1606(A) provides that Standard Offer service must be offered by the Affected Utilities until the Commission determines that competition has been substantially implemented for a particular customer class. The Commission's determination of "substantial implementation of competition" should be based upon a factual finding that no significant amount of market power impacts the market prices for retail generation services for that class of customers. Language to that effect should be added to the Rules.

The issue of load pockets will be an important one to deal with in determining whether competition has been substantially implemented. A load pocket is a region within which no competition for power production from outside the region is possible due to physical transmission system constraints. In the Phoenix metropolitan area, for example, during peak periods in the summer, even though customers may have chosen an out-of-state competitive generation provider, the local distribution company may be capable of providing only locally generated power to customers, due to congestion problems. This poses an important market power issue which the Rules must address. Unless substantial amounts of excess generating capacity can be constructed inside load pockets, with ownership of such generation sufficiently diversified, all existing generation within the load pockets may need to be regulated during peak load times, such as during summer months. In fact, continuing regulation of generating units in load pockets may be the only realistic policy option that will prevent the exercise of market power by the owners of those units.

2. **The duration of Standard Offer service should not be tied to recovery of stranded costs.**

There is no need for the duration of Standard Offer Service to be tied to the Affected Utilities' recovery of all stranded costs. If the Stranded Cost charge is collected as a distribution/transmission wires charge in a competitively neutral manner, its recovery should have no impact on whether retail generation markets are competitive or not. For this reason, the language "and until all Stranded Costs pertaining to that class of customers have been recovered," should be deleted from A.A.C. R14-2-1606(A).

D. **Provision for Default Service ("Provider of Last Resort")**

Once retail generation services have become sufficiently competitive to warrant discontinuation of Standard Offer service pursuant to A.A.C. R14-2-1606(A), the Commission should implement a method for determining a default provider of last resort. Default service will differ from Standard Offer service in that the Commission will no longer regulate the price of the generation component of the rate.

RUCO believes that in the interest of fairness to generation providers and in order to obtain market-based rates for Default Service consumers, the provider of last resort should be selected by a bidding process. The Commission should adopt specific rules to govern the process of bidding out Default service.

III. CONSUMER PROTECTION ISSUES

A. Slamming Protections

In the telecommunications industry, "slamming" is the colloquial term for unauthorized switching of a consumer's long-distance service. The Commission has foreseen the need for consumer protections against slamming in the Retail Electric Competition Rules. *See* A.A.C. R14-2-1613(C). RUCO believes that Arizona's electricity consumers should have the advantage of strong, effective protection against the predatory practice of slamming. RUCO also believes that preserving a pro-competitive environment in the restructured electric industry should be a priority. To this end, customers' ability to knowingly change carriers should not be unduly restricted; however, safeguards are necessary to ensure that a consumer's chosen supplier will not be switched without that consumer's informed consent. To protect customer choice and ensure a strong, competitive market, abusive marketing practices must be prevented. If such abuses do occur, they must be detected and corrected quickly.

RUCO believes that a properly implemented anti-slamming policy could avoid consumer abuse problems of the type which have occurred, and are still occurring, in the telecommunications industry. Such a policy should be adopted as part of the Rules. Among the issues that the Rules should specifically address are customer solicitation; customer authorization for transfer; the process for electric service provider changes; unauthorized transfers; and penalties. RUCO would welcome the opportunity to participate in the drafting of anti-slamming provisions.

B. Customer Education Requirements

The best consumer protection measure is consumer education. Adequate customer education requires frequent messages from a variety of sources. In the long run, dollars spent on customer education should more than offset dollars which would be spent handling customer inquiries and complaints due to inadequate education. The Rules currently do not address this essential component of electric restructuring. RUCO contends that the development of customer education requirements is crucial and would welcome the opportunity to participate in the drafting of such requirements.

Core Communication Messages

The following elements should be included in customer education programs.

1. **Basic Concepts.** An understandable, non-technical explanation of the basic concepts of restructuring;
2. **How To Participate.** An explanation of where and how customers will purchase power in a restructured industry. This would include information about default power service, bilateral contracts, and the roles of aggregators and the ISO;
3. **Reassurance.** An assurance that the safety and reliability of power delivery will be maintained regardless of where and how the customer purchases power;
4. **Cost Comparison Method.** An explanation of how to compare supplier offers and what customers might want to consider as they evaluate the merits of various offers;
5. **New Bill Appearance.** An explanation of how unbundling services and rates will change bills and how to read and understand the new bills, including an explanation of the components of generation and transmission costs;
6. **Stranded Cost Explanation.** An explanation of stranded costs, again in understandable, non-technical terms. The explanation should address what stranded costs are, how they are measured, possible mitigation efforts, authorized recovery amounts, and the expected duration of recovery;
7. **New Consumer Rights and Responsibilities.** Information about consumer rights and responsibilities in a restructured industry. This would include changes to consumer protections, additional responsibilities customers now have, the Commission's role in a restructured industry, and importantly, where customers can go to find out more detailed information or to get assistance if they have further questions;
8. **Low Income Assistance Availability.** Information about the availability of low-income assistance programs;
9. **Energy Efficiency Information.** Information on energy efficiency and competitive energy service companies;
10. **Slamming Protections.** Information on what customers must do to switch providers, and how to report potential marketing abuses (slamming).

Possible Means of Disseminating Core Messages

There are a number of ways the requisite customer education messages could be disseminated, including:

1. **Community advisory groups.** These could be locally formed in order to test the efficacy of proposed educational materials before they are implemented.
2. **Bill Inserts.** For maximum efficacy, these should be repeated every other month.
3. **Media visits.** Discuss the impact of restructuring with local print and

broadcast media. Ensure that media representatives have the information needed to help educate consumers.

4. **Paid advertisements.**

5. **Direct mail.** Brochures describing the basics of retail competition, who to call for additional information, and when public forum activities are scheduled.

6. **Public forums.** Held on community level before choice is available, to be repeated as level of interest demands.

7. **Public speaking opportunities.** Utility employees could take advantage of opportunities to speak on electric restructuring before local civic and community groups.

8. **Website information.** Utilities with websites in place could easily utilize them to disseminate information regarding restructuring.

Funding of Customer Education Programs

Although funding of customer education is an important element of restructuring of the industry, the Rules do not currently address this issue. RUCO contends that this issue must be resolved. The Commission could mirror the approach taken in the IntraLATA Equal Access rules and find that all reasonable costs incurred by the Affected Utilities will be recoverable in rates. *See* A.A.C. R14-2-1408(A)(Emergency Expired). This would spread the cost among all users of electric distribution services. To insure that the customer education costs are reasonable, the Commission should review and approve the customer education programs.

IV. CONCLUSIONS

Although the unbundled services and Standard Offer working group has made good progress in setting a direction for implementation of competition in Arizona's electric industry, numerous critical issues remain undecided. In some instances, crucial issues have yet to be addressed at all in a meaningful way. Within the parameters of these advocacy comments, RUCO has not attempted to address all those issues, but has instead confined its comments to the most fundamental ones.

Because of the number of pivotal issues regarding unbundled services and Standard Offer service which have not been adequately resolved, RUCO strongly urges that the Commission hold evidentiary hearings on electric industry restructuring. These hearings should not be adversarial hearings, but should take the form of legislative-type, factfinding hearings. An evidentiary factfinding process is essential to ensure that the Commission has a reasoned basis for the modifications it must make to the existing Electric Competition Rules. RUCO strongly urges that such evidentiary hearings be scheduled immediately, so that electric industry competition in Arizona can become reality in a timely, orderly manner.

SRP

October 27, 1997

Mr. Ron Franquero
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Dear Mr. Franquero:

As SRP's representative on the Unbundled Services and Standard Offer Working Group, I respectfully request that this statement of SRP's position be appended to the working group's report.

Deregulation of the generation market is complex. We are concerned that efforts to deregulate metering, meter reading, billing and collections as an adjunct to the deregulation of generation are counterproductive. Deregulation of the revenue cycle functions will add to the complexity, increase consumers' costs and delay the onset of competition. We encourage the Commission and its staff to carefully consider the concerns expressed in the Metering Subcommittee report, "Policy Considerations for Retaining Regulated Services" which was prepared principally by Arizona Public Service. We support the conclusions reached in this white paper. At best, deregulation of the revenue cycle functions could be revisited once competition of the generation market is under control.

No Need to Delay Competition

SRP embraces competition and seeks to bring the benefits of competition expeditiously to all customers. If the decision were made to use the existing regulated metering infrastructure, many of the problems and areas of controversy outlined in the "Metering" section of the draft Working Group report could be eliminated. Issues ranging from how to divide the costs and responsibilities to the very definition of what constitutes a meter could be deferred for resolution until competition in the generation market is established. Additionally, SRP believes that any business, including energy service providers and utility distribution companies, should retain the fundamental commercial right to bill customers for services rendered. Thus, our position on billing is similar to our position on metering; billing should remain regulated at this stage.

We endorse the use of load profiles for residential customers and other customers with loads under 20 kW until such time as hourly metering becomes economic for small loads. With the use of load profiles, deregulation can commence without delay otherwise necessitated by the costly and unnecessary change out of existing meters. We are confident that, when developed and applied judiciously to individual customer segments, load profiling will produce efficient market results with a minimum of distortion caused by the approximation of real-time use.

We do not see widespread use of Automated Meter Reading (AMR) as a requirement for introduction of choice. Nor is AMR either necessary or sufficient to allow distribution entities or energy service providers to offer enhanced services such as home automation, home security, and paging services as some potential energy service providers have otherwise suggested.

No Need to Increase Consumers' Costs

We do not believe that AMR is a generally cost-effective solution in support of deregulation. Recent responses to our requests for proposal for fixed-network AMR solutions generated 25 to 50 percent greater costs per read. Moreover, the technology provided by the leading vendors was not sufficient to support demand metering, time-of-use metering, or real time pricing on a reliable basis. (Casual claims of capabilities that were made by vendors in initial conversations were not repeated in the final bids we received.)

More importantly, the reliability of the distribution system relies on the fact that its components are integrated. Metered usage provides critical data for use in energy accounting, energy loss analysis, and distribution system load forecasting. Thus, metered usage enhances the reliability of the distribution system as well as minimizes its design and operating costs. It is most practical and economic to capture and store this data at the level of the utility distribution company.

Competitive metering also increases the potential level of stranded costs and thus the consumers' costs. We estimate the potential stranded metering costs statewide in excess of $200 million.

SRP recommends that metering and billing (at least distribution charges) remain the responsibility of the distribution utility to maintain the high levels of accuracy and the efficiency that our customers enjoy today. We know of no industry where the firm that provides the product or service is not permitted to measure, bill and collect for that product or service.

Today, SRP performs the revenue cycle function efficiently, economically, and creatively. Our meter reading costs are benchmarked with those of other gas and electric utilities regionally and nationally, and our costs compare favorably.

SRP's meter reads are validated essentially three times for reasonableness against usage history:

- Once at a high level by the ITRON handheld device as the read is input. Suspicious reads are flagged, giving the reader an opportunity to recheck the read.
- Once more at a more stringent level by our mainframe billing system prior to bill calculation, with "out of range" usage levels flagged for further review by billing technicians. If the usage level cannot be reasonably explained, a re-read of the meter is scheduled.
- Finally, after bill calculation, where out of range dollar amounts are flagged for review by billing technicians.

These several checks flag not only read errors, but metering faults and power theft, as well.

SRP also is an industry leader in its billing capabilities. Bills are generated the same night that meters are read, and with the use of state-of-the-art mailing software and mail insertion equipment, bills are placed into the U.S. mail the following workday.

SRP was among the first utilities nationwide to offer time-of-use metering to residential customers. We now serve over 75,000 residential customers on time-of-use rates, which encourage the efficient use of resources.

SRP offers a variety of value-added billing options at no cost to the customer:

- Customer choice of bill due dates
- Spanish bills
- Large-print bills for the vision-impaired
- Summary and aggregated bills for multiple accounts

We also have a "no bill" option with our pre-paid metering program - the second largest prepaid metering program in the country. Customers report extremely high levels of satisfaction with this program and have recorded reductions in energy usage in excess of 10%.

The transition to customer choice of generation supplier should occur as quickly as possible and therefore revenue cycle functions should remain part of the distribution company. SRP believes resolution of the overabundance of issues concerning deregulation of the revenue cycle functions will delay competition. Additionally, one of the major goals of moving to a competitive electric industry is to decrease consumers' costs. Implementing competition in the metering and billing markets today will increase their costs.

Thank you for the opportunity to comment.

Sincerely,

Michael W. Lowe

SRP

P. O. Box 52025
Phoenix, AZ 85072-2025
(602) 236-5900

ARIZONA CORPORATION COMMISSION

September 30, 1997

Mr. Ray Williamson
Economist, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Comments on the Solar Portfolio Standard

Dear Ray:

Salt River Project Agricultural Improvement and Power District (SRP) offers the following comments on the Solar Portfolio Standard (SPS), as defined in R14-2-1609.

While SRP agrees with the intent of the SPS, the company believes that the Standard as currently written will place undue financial burdens on Arizona's consumers and on the energy service providers supplying these customers. SRP takes exception to the SPS on a number of counts, including the lack of funding for the SPS, the infancy of the solar industry from a manufacturing capability perspective (and thus the sustainability issues), and the level of investment required to satisfy the SPS.

SRP recognizes the potential customer, environmental and economic development benefits of renewable energy resources such as solar electric technologies to Arizona industry and consumers. SRP also realizes that in an urban environment such as our service area most grid-connected solar applications are not cost effective today, and may not be cost effective for five-to-10 years. Thus, the phase-in and percentage of solar resources required by the SPS, as now written, will not only add to the system costs of all affected energy services providers, including SRP, but will also increase the cost of energy to the Arizona consumer. This consequence is in contradiction to the premise of the Retail Electric Competition Rule which is to bring down the cost of energy to the ultimate consumer.

SRP agrees with the SPS subcommittee recommendation that the cost of any SPS should be limited to an acceptable cost/benefit point, and a cost-reduction incentive should be provided to protect Arizona consumers from increasing solar purchases if the lower-price objectives for solar technologies are not met.

Further, SRP supports the expansion of SPS to include other renewable technologies including wind, biomass and solar hot water systems.

ARIZONA CORPORATION COMMISSION
RECEIVED
1997
Director of Utilities

Sincerely,

Janene Miller

Janene Miller,
Manager, R&D

SOLAR ENERGY INDUSTRIES ASSOCIATION

SOLAR THERMAL TECHNOLOGIES FOR RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL WATER AND SPACE HEATING APPLICATIONS

A PRIMER FOR PORTFOLIO STANDARD ISSUES IN REGARD TO ELECTRIC UTILITY RESTRUCTURING

Introduction

Current draft utility restructuring legislation does not include solar thermal water or space heating technologies within the definition of renewable energy technologies in regard to renewable energy portfolio standards (RPS). As a result, the legislation favors large-scale grid-tied projects over small-scale residential renewable energy producers. The Solar Energy Industries Association (SEIA) has drafted this primer in an effort to change this definition as it currently stands by demonstrating the value and necessity of including solar thermal technologies in a proposed RPS. First, here are some facts regarding today's solar thermal water and space heating industry:

- Today, over 1 million buildings utilize solar thermal generated energy to offset conventional water heating technology, which is primarily electricity.

- The industry consists of experienced small manufacturers that currently produce the highest quality solar thermal technologies in the world today.

- The non-profit Solar Rating and Certification Corporation and the Florida Solar Energy Center offer the most comprehensive rating and certification options available to solar manufacturers in the world. Ratings are based on actual field performance, thus resulting in one of the only few 'real world' appliance certifications available today.

- In a recent study performed by the Florida Solar Energy Center (FSEC), if the potential market for solar water heaters in the US was fully realized, 41 million kWh equivalent would be generated per year - equivalent to the output of eight 100 MW fossil-fueled generating plants.

Proposed Change

Each of the proposed bills define renewables in the following manner:

> "The term 'renewable energy' means electricity generated from solar, wind, waste, except for municipal solid waste, biomass, hydroelectric, or geothermal resources."

The national solar energy industry requests that this definition be expanded by adding the following phrase, **"or electricity displaced by solar thermal energy technologies."**

(over)

[illegible] Washington, D.C. [illegible] Tel: (202) 383-2600 Fax: [illegible] E-mail: info@seia.org http://www.seia.org

Rationale

The rationale for the proposed change includes the following:

- Many utilities studying the potential of using solar thermal water heating technologies as a tool for distributed generation and renewable energy deployment understand that allowing solar thermal technologies to be included in the definition of renewables may add significant value to future investments in solar water heating technologies.

- Solar thermal water heating systems can be measured in the **exact same manner** by which other end-use renewable energy technologies are measured. The addition of a low-cost Btu meter to the system with a readily available device that converts the Btus directly to kilowatt-hours is an easy way to measure energy output for the purposes of the RPS.

- Utility programs utilizing cost-effective solar thermal technologies may, in may cases, be the lowest cost means of complying with an RPS.

- As currently crafted, photovoltaic systems configured as rooftop distributed generation would be eligible to participate in RPS's, providing at least some electricity for electric water heaters. Heating water with solar thermal technologies can be accomplished at one-tenth the cost.

Conclusion

This change in the definition of renewable energy will most certainly give utilities an option that is low-cost and extremely valuable to fulfill renewable energy portfolio standard requirements and is essential to assuring that the US fully recognize its renewable energy generation potential.

TUCSON ELECTRIC POWER COMPANY COMMENTS TO THE REPORT BY THE UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP TO THE ARIZONA CORPORATION COMMISSION IN THE MATTER OF ELECTRIC SERVICE COMPETITON

October 29, 1997

OVERVIEW

Tucson Electric Power Company ("TEP") supports the policy decision of the Commission to introduce competition in the electric services industry in the State of Arizona. We also support the efforts and report of the Unbundled Services and Standard Offer Working Group (the "Working Group"). However, TEP does not believe that the report of the Working Group provides enough guidance to the Arizona Corporation Commission (the "Commission") regarding many of the complicated and detailed issues that it discusses. This opinion is supported by the Commission Staff's comments in the Working Group report. As a result, TEP believes that formal hearings should be held before the Commission regarding several of the issues. In addition, it may be useful to have the Working Group continue to meet to further develop understanding and consensus prior to any decisions by the Commission regarding the issues considered in the Working Group's report. These comments clarify our positions and concerns regarding the Working Group's report and the important issues discussed therein.

KEY WORKING GROUP ISSUES

The Working Group was charged with considering the following issues (i) standard offer service, (ii) unbundled services, (iii) systems benefit charges, (iv) measurement/cost issues, (v) the solar portfolio standard, (vi) customer requirements and (vii) administrative requirements. Subgroups were formed to discuss the solar portfolio standard and the unbundled service issues surrounding metering, and billing and collections. The entire Working Group discussed all of the other issues. Each of these topics also included a variety of subtopics, which were discussed by the Working Group in various levels of detail.

STANDARD OFFER SERVICE

Pursuant to the Commission's competition rules, standard offer service must be provided by the incumbent monopoly service provider until retail electric competition has been substantially implemented. Further, the competition rules allow that incumbent utilities can file to modify their existing tariffs prior to December 31, 1997, or the tariffs in place at that time will by default become their standard offer tariffs. The Working Group's report states that there was general consensus on the definition of standard offer service. Further, the report discusses three other related issues relating to whether or not new competitive suppliers can offer standard offer service to customers that do not yet have a choice under the phase-in to competition, to those which have access to the competitive market and to parties that have access to the competitive market but which do not choose to exercise that right.

We support the findings in the Working Group's report stating standard offer service should in all cases be provided by the incumbent utility during the transition to competition. We also support unbundled bills to all customers (those with and without competitive access) which include all required unbundled services, including market-based generation charges and stranded investment charges. Without detailed bills, it will be very difficult for customers to fully understand the component costs of their electric service and to analyze competitive opportunities.

UNBUNDLED SERVICES

In the area of unbundled services many different topics are outlined in limited detail in the Working Group report. Many of the issues are described to have achieved a consensus but limited details suggesting in-depth discussion appear in the report. Additionally, there is no discussion of important issues such as the complications that may result in computing rates and recovery levels when services are unbundled. The level of service demand, and as a result the appropriate cost-based price level, will be unpredictable when certain services become optional and customers have the ability to move back and forth between suppliers. This complication is an issue with services that may be partially monopoly and competitive (for instance metering) and requires clear definitions between regulated and competitive services.

The unbundled discussion does not discuss the issue of reliability. The unbundling of services at the distribution level requires more than a reliance on the efforts of the Federal Energy Regulatory Commission (the "FERC") to establish transmission related ancillary services. The reliability or ISO subgroups may have spent some time on these issues but it would seem that some level of discussion is also necessary as to the potential rate impacts of any required reliability-related services that may or may not be adequately contained in the FERC's ancillary service list such as load following or other ancillary services not currently in the FERC open access tariff.

We believe that the market will be more consumer friendly if there is clear and consistent pricing signals. In our opinion, clear and consistent pricing signals cannot exist without consistency in the unbundled tariffs filed by the incumbent monopolies. Further, as stated above, we believe that all customers should receive the same type of unbundled pricing information regardless of whether they have chosen to access the competitive marketplace.

SYSTEMS BENEFITS CHARGE

TEP is in agreement with the Working Group report on most of the system benefit charge issues. In regard to the administration of systems benefit proceeds, we believe that the monopoly distribution suppliers should administer any funds that directly support any of the mandated programs and we do not support the creation of any new beauracracies to administer the proceeds.

MEASUREMENT/COST ISSUES

Measurement/Cost issues would seem to be an area where significant issues arise. However, there is little discussion of significant issues including cost shifting and competitive/non-competitive business separation.

Another issue that arises in several different places and is relevant in this area is the Commission Staff's continued (and somewhat vague) reference to oversight of the unbundled service offerings of the offerings of all competitive suppliers. Taken literally, the references Staff makes on the level of oversight would suggest that they would not only approve all individual, unbundled products, but would also approve the pricing of various bundled products and services. We are concerned that a high level of competitive service oversight will impede competition and require a significant quantity of Commission and Commission Staff time. Again, we suggest that a forum be developed which insures that such details are discussed and ultimately set.

METERING AND METER READING ISSUES

Meter and meter reading issues generated significant and relevant discussion as well as some consensus. Many detail issues are outlined in the Metering and Meter Reading section of the Working Groups report to the Commission. TEP's position on these issues is included in the attached Appendix A. Ultimately we support competitive metering and meter reading as long as important data and security issues are accounted for. We believe that the information flows from meters and access to and ownership of meters must be accounted for prior to opening these services to competitive supply. In regard to meter ownership for instance, we believe the meter owner should be required to transmit accurate and timely information to the parties supplying the various services. This seemingly small issue is not an easy one though. Ownership by a home or business owner, which seems like a reasonable option on the surface, may be problematic if issues surrounding private ownership of meters and the control of and access to data by appropriate parties cannot be insured.

TEP commends the efforts of the metering and meter reading group to date and suggests that additional discussion in an appropriate forum is necessary to complete the discussions held and consensus reached to date.

BILLING AND COLLECTIONS

See Metering and Meter Reading Issues above. See also Appendix A for further discussion of TEP's positions on billing and collection issues.

CUSTOMER REQUIREMENTS

The customer requirement discussions are interesting but limited in the level of consensus reached. The topics discussed, primarily what phone numbers should appear on bills, complaint response, consumer education and consumer information, are all important issues. However, TEP believes that successful customer education is vital to the successful implementation of competitive energy services.

CONCLUSION

TEP commends the Working Group for their efforts to date on a long and complicated list of issues but respectfully submits that there are few areas in which reasoned conclusions can be drawn from either the consensus of the Working Group or the evidence presented in the report. Therefore, TEP supports further evolution of the key issues through some combination of additional Working Group discussion and hearings before the Commission.

APPENDIX A

TEP METERING, BILLING AND OTHER POSITIONS

October 29, 1997

METERING

Working Group member's discussions regarding the unbundling of metering take two primary positions. One position, taken by most of the regulated utilities, is that metering should stay bundled with the distribution system in order to take advantage of economies of scale and consumer protections. The position of several other parties is that metering is an important asset to all suppliers in a competitive environment and that competition will bring forth significant technological innovations. TEP supports a position slightly different than either of these proposals.

TEP believes a phase-in approach to competitive MBIS would best meet the needs of customers and suppliers if the Commission continues to support a phase-in approach to competitive electric supply. If the Commission were to change to a "flash-cut" approach to competitive electric supply, than TEP believes that MBIS should also flash-cut to competition. However, a flash-cut would require a later competitive start date, such as 2001. The later date would allow time for the operational details to be established and many of the standards issues analyzed as discussed below.

TEP believes that the transition period will be necessary to avoid a disruptive impact on both the distribution system and customers. To the average customer, metering and billing traditionally have been the interface with the electric system and, by and large, will continue to be. Although consumers will have the choice of providers of various services, the electric system will continue to be transparent to most customers. Customers do not know, or understand, where their electricity comes from or how it is transmitted. On the other hand, every customer wants assurance from the industry that:

- their meter accurately measures power usage,
- their meter is properly read,
- they receive understandable bills that are produced in a timely fashion,
- that a billing agent will provide quick resolution of billing disputes or other complaints, and
- that they will receive full information and assistance concerning every aspect of electric supply.

Therefore, it is vital that the Commission start a customer education program, develop technical standards and establish clear definitions of who provides each metering and billing function before the transition to competitive MBIS is final.

Experience in Other States

Several other states are currently creating the transition to competitive metering. Arizona can learn from their efforts. Both California and New Hampshire are in the process of establishing competitive MBIS. TEP and other parties in the workshops believe that the California and New Hampshire models are worthy of study for use in Arizona. TEP supports aspects of these models as a reasonable compromise between keeping metering bundled with the Local Distribution Company ("LDC") and complete unbundling starting in 1999.

In general, the New Hampshire model offers partial unbundling to resolve the conflict between economies of scale and customer choice issues. The LDC retains some of the metering role of a regulated entity, yet Energy Service Providers ("ESPs") are allowed to offer competitive choices to customers who can take advantage of the market. The New Hampshire PUC has divided metering into two components: basic and advanced. Basic metering, which is the metering currently provided to customers by utilities, remains regulated and is provided by the LDC. Advanced metering is metering provided by competitive power suppliers at market prices. LDCs could offer advanced services only through competitive affiliates. In the New Hampshire model, the LDC does not have an advantage over ESPs in the market place for advanced metering, yet the provision of basic metering services exclusively from the LDCs ensures that metering is not a barrier to generation choice.

Although the New Hampshire model has many benefits, it does not solve several operational issues that must be resolved before MBIS can become competitive. Due to the increased number of participants at this interface, it is essential that metering installation and operational details be finalized before customers choose different MBIS suppliers. The California metering model does establish clear standards for meter installation and qualifications for suppliers.

TEP recommends that the Commission review the California and New Hampshire metering models and also establish an Electric Services Protocol Committee ("Protocol Committee") to facilitate the transition from the current regulated structure to unbundled metering, billing and customer information services. The Protocol Committee would be composed of representatives of all interested parties, including consumer groups, local distribution companies, service providers and system vendors. The Protocol Committee would function as a technical clearinghouse to consider, develop and recommend standards, protocols and systems for competitive MBIS.

Education

As indicated above, TEP believes that competitive MBIS should be implemented after customers are educated as to the available choices concerning MBIS. The average residential customer does not understand the complexities of the system and could easily make incorrect choices given these misunderstandings. The telecommunication industry is riddled with "slamming" practices that literally prey on uneducated customers who do not understand their choices. It is essential that slamming practices in a competitive electric service industry are avoided , and an extensive education process for the entire state of Arizona can be instrumental in this process. The State of California estimates that its education expenditures will be $90 million. TEP believes that the Commission should play an important role in the education process.

Clear Definitions

There are two decisions the Commission must make before competitive MBIS can be established. First, a clear definition of the elements of metering and meter reading that are to remain under regulation must be established, or as provided in the New Hampshire model, which services remain as "basic" metering. As previously stated, TEP believes that certain metering and meter reading functions should be competitive. Meter reading is clearly an area in which all customers could benefit from competition. As more and more customers install advanced meters, manual meter reading will only be required where advanced metering has not been installed. On the other hand, some ESPs have indicated that there are several functions they do not want to be involved with, and, therefore, these functions should remain regulated. The Commission must be careful to analyze the cost of splitting the metering function into competitive and regulated segments. In the final analysis, the customer must realize savings in order to justify MBIS going competitive.

Second, the Commission must decide which competitive services, if any, a regulated LDC can offer. Establishing a fair industry structure is essential for customers, LDCs and competitive service suppliers. There are proposals in other state deregulation processes that require functional separation between a company's regulated and competitive services. TEP is not opposed to this type of structure as long as the regulated LDC is fairly compensated for all the services it provides. At this point in the Commission's proceedings, it is not clear if regulated distribution companies will be allowed to compete in MBIS or if only affiliates or subsidiaries can offer such services.

New Meter Technology

The development, installation and use of new meter technology with multi-function, real-time, communications capabilities ("Smart Meters") will benefit consumers, service providers and the local distribution system. Public policy should accommodate such development, installation and use, but in full recognition of the consumer interests and system considerations discussed below.

Smart Meters will increase the capability of LDCs to monitor and control loads, identify certain system problems and record valuable customer usage information. This will improve efficiency, reduce costs and provide better customer service. Regulatory rules and system protocols must ensure that data and information, generated by Smart Meters which are not owned or controlled by the LDC, are made available to the LDC on a real-time basis for appropriate system usage. Although the Metering Subcommittee started to investigate these issues, TEP believes that the Protocol Committee should finalize any standards and system protocols.

Meter Ownership, Installation and Maintenance

At the time full consumer choice is implemented, the Commission should permit meters to be owned (as used herein, "own" should be read to include "lease") by the customer, the local distribution company or any service provider subject to meter access and compatibility standards determined by the Working Group. All meters must comply with applicable standards and must be compatible with the distribution system to which the customer is attached. In order to ensure proper installation and protect the integrity of the distribution system, a licensing system must be established to ensure the technical and financial capability of all meter service providers. Although the "wires" system will continue to be owned and operated by the LDC, which will remain a regulated entity under Commission jurisdiction, parts of the metering system will be competitive. Before ESPs start providing specific metering services, the Commission must define which functions remain with the "wires" system and which functions are competitive metering functions. The LDC should continue to offer services at tariffed rates for the components of the metering system that remain with the "wires" functions. The LDC must remain whole for the functions that it performs.

Market Absorption of Smart Meters

TEP believes that a substantial period of time will pass before large numbers of Smart Meters are installed on residential customer facilities. There are several reasons for this, including: (a) in a period of industry restructuring, the LDC should not be expected to incur the capital cost of installing Smart Meters on a system-wide basis (TEP estimates, for example, that it would cost between thirty and fifty million dollars to install Smart Meters on its distribution system); (b) many small users will find it inefficient to install Smart Meters; and (c) new service providers will direct their principal marketing efforts to a select class of customers, particularly industrial and large commercial customers, who will find it more beneficial and cost-effective to install Smart Meters in a shorter time-frame. The result is that a transition will be required, during which the time the local distribution system will have both traditional meters with limited capability and Smart Meters connected to sophisticated communications systems. TEP believes that the LDC will be best equipped to manage this transition as part of a tariffed service until such time as systems, standards and protocols are developed and in place.

Meter Replacement/Transfer

Subject to protections of the LDC as discussed in the next paragraph, each customer should determine when and if its meter is to be replaced and who will own the meter. The customer should choose whether to leave the installed meter in place, purchase a meter or enter into a contract with a meter service provider. When an installed meter is replaced or the customer changes service providers, the rights of all parties should be protected by contract. For example, the initial contract between a customer and meter provider should cover the parties' rights and obligations if the customer decides to change meters upon termination of the contract or prior to its expiration. Standard commercial practices will develop for numerous circumstances occasioned by customers moving or changing services. Because the customer is the one who will choose to change meters, the cost of meter replacement should be borne by the customer unless the service provider absorbs such cost as part of its service offering.

These protocols must be subject to the following: (a) if a customer chooses not to replace its existing meter, the LDC meter will continue to be owned and controlled by the LDC at least until it is replaced at the end of its useful life; (b) removal of the LDC meter should be performed by the LDC at a tariffed rate and (c) the LDC should be held harmless for removal of meters which were installed as a tariffed service and which have not been fully depreciated. While such meters could be included as stranded costs, it would be practical and equitable to pay the LDC the book value for such meters at the time of replacement.

Meter Reading

Regardless of who performs the meter reading service, the information and data must be provided to all contracted ESPs and the LDC for operational purposes. As noted above, the Smart Meter information and its real-time reporting will be of significant value in the operation of the distribution system. The Protocol Committee must establish standards for meter reading and data exchange requirements before these services are unbundled from the LDC.

Metering Communications Systems

Sophisticated communications systems will be required in order to exploit the full capability of Smart Meters. Open system architecture will permit interconnection among the LDC and other service providers. The Protocol Committee will facilitate the development of standards and protocols, rather than leaving this critical process to a totally unstructured environment.

Metering Services Provider of Last Resort

Customers must have the right to procure or not procure a new metering service provider(s). It would be an encroachment on that choice for the Commission to adopt any industry structure that might result in the imposition on a customer of any inconvenience, increased cost, or unwanted metering services. Because essentially all metering services will involve some form of customer-provider interaction or equipment modification, such as billing and payment of charges or changing out a meter, practically any change not selected by the customer will result in inconvenience, increased cost or unwanted services being imposed on the customer. Unlike an allocation plan such as has been proposed for the sale of electric power to customers who do not choose a new provider, which would be transparent to the customer, a change in metering services will have a direct and personal impact on the customer. TEP, therefore, believes that the customer's choice to change meters is paramount, and, in the absence of the customer exercising its choice, the LDC should be the de facto metering service provider.

<u>BILLING</u>

After all electric services are unbundled; it is conceivable that two, three or more providers will be involved in any particular customer's service. This will necessitate sophisticated, complex billing systems in order to provide customer information, collect service charges from the customer, ensure accurate remittance to providers, and establish re-billing, dispute resolution and collection procedures, etc. The

Protocol Committee can be instrumental in the transition from current single-provider billing to a multi-provider system.

Customer Choice

As is true with all elements of metering services, the guiding principle should be that the customer has the right to choose how it is billed and pays for electric service. If the customer selects multiple service providers, the customer should decide if it is to receive a single bill or multiple bills. If the customer chooses to receive separate bills from each provider, it would remit payment individually. If the customer chooses to receive one bill with multiple provider charges, each provider's charge would be itemized and the customer would remit a single payment to the billing agent for disbursement. In such cases, TEP submits that either the LDC or the ESP should be the billing agent. Both of these entities have a vested interest in billing accuracy and customer service.

Re-bills, Collection, Dispute Resolution

Procedures for managing these issues will fall into two categories: one in which the customer chooses to receive individual bills from each service provider and another in which the customer chooses to receive one bill for all services with each provider's charges itemized. Issues will be simplified in the first category, but not eliminated.

When the customer chooses to be billed by each service provider, matters between them will be handled directly by the two parties. For example, each provider will be responsible for its own collection problems. What happens, however, if a third party provider is in the middle, such as a meter provider? If a customer believes its generation charge is too high, does it deal with the generation company or the meter services customer? Or, must the distribution company shut off service upon notice from the generation company that the customer has not paid its bill?

These problems may be magnified in cases where the customer chooses to receive one bill for all services with each provider's charges itemized. Is the billing agent then responsible for all customer issues? The Protocol Committee could be instrumental in resolving many of these issues.

<u>CUSTOMER INFORMATION</u>

Customer information is at the very heart of unbundling metering services. The free flow of information will be essential to the opening of competitive markets to new service providers. Because more information will be potentially available to numerous entities that traditionally have not had access to sensitive customer information, the proper use and protection of that information must be ensured. So both customers and providers have vital interests in the form and substance of information flow.

It should be emphasized that the customer information system ("CIS") of distribution companies often integrates customer services, such as billing, collection, and dispute resolution, with system operations. For example, TEP's map room utilizes the CIS to locate and identify customer facilities and to dispatch technicians for service calls. The operational features of the CIS must remain available to and in the control of the LDC, which should be properly compensated if its CIS must be modified in an unbundled environment.

TEP believes that customer usage information should be available to all providers of electric services beginning at the time competition is introduced, subject only to customer consent and confidentiality protection. Standards and protocols must be developed to validate data, ensure that communications systems are available to provide access to information by all legitimate users, and guarantee confidentiality of information such as customer credit history. This is another area where the Protocol Committee can be very helpful in working with all interested parties to assure the availability of accurate information on a fair and equitable basis.

SUMMARY

In summary, TEP believes that the Unbundling Workgroup provided a valuable study into the magnitude of issues surrounding distribution unbundling. Clearly, there are still many issues that need more analysis and discussion between the various interested parties. Therefore, a transition to competitive services is the only fair and reasonable response the Commission can provide. TEP supports a transition to competitive MBIS that retains economic efficiencies and offers customer choice. The New Hampshire model is a prime example of a compromise between the two extremes of continued regulation of MBIS and immediate unbundling of MBIS.

TUCSON ELECTRIC POWER COMPANY
ADDITIONAL COMMENTS
ON
SOLAR PORTFOLIO SUBCOMMITTEE REPORT

Section IV.D of the Report notes that Tucson Electric Power Company ("TEP") suggests that, in addition to the incentive credits recommended by the Subcommittee for early installation and Arizona content, Competitive Suppliers who invest in solar manufacturing or similar facilities in Arizona should get credit against the Solar Portfolio Standard requirements. TEP also suggests that clarifying language be adopted to remove any uncertainty as to whether credit will be given for customer-sited and customer-owned facilitie. TEP offers the following language for the Commission's consideration as possible amendments to the Rules designed to address these issues:

"A. A Competitive Supplier will be entitled to receive a credit against the Solar Energy Requirement if the Competitive Supplier owns or otherwise makes an investment in any solar energy-related manufacturing, systems integration, or other similar business enterprise for which physical facilities are located in the state of Arizona. Any such credit against the Solar Energy Requirement will be equal to the amount of nameplate capacity produced in a calendar year times 2,190 hours (based on an assumption of 25% capacity factor for solar energy generation). Any assumptions and standards related to the determination of the Solar Energy Requirement may be adjusted by the Commission from time to time to reflect changes in the cost and operation of solar technology and related market conditions.

B. A Competitive Supplier will be entitled to receive an appropriate credit against the Solar Energy Requirement if and to the extent the Competitive Supplier incurs costs, including any financial incentive programs or measures, associated with the installation and ownership by a customer of New Solar Resources at that customer's residence, commercial or industrial location. Prior to implementation, the Competitive Supplier will file an application with the Commission for approval of the program or measure and approval of the credit proposed to applied against the Solar Energy Requirement."

APPENDIX B

MEMBERS OF THE UNBUNDLED SERVICES AND STANDARD OFFER WORKING GROUP

Organization	Representative
AEPCO	Josie Stukes
AriSEIA	Michael Neary
Arizona Community Action Association	Betty Pruitt, Deanna Weed
Arizona Consumers Council	Barbara Sherman
Arizona Corporation Commission	Ron Franquero, David Jankofsky, Steve Olea, James Rolle, John Wallace, Ray Williamson
Arizona Food Marketing Alliance	Dwayne Richard
Arizona Multihousing Association	Suzanne Gilstrap
Arizona Municipal Power Users Association	Michael Curtis, Thomas Hine
Arizona Public Service	Barbara Klemstine, Bill Maese
Arizona Utility Investors Association	Bill Meek
Arizona Department of Commerce	Steven Ahearn
BHP Copper	Sandra Dunphy
Brown & Bain	Michael Patten
Irrigation & Electrical District's of Arizona	Robert Lynch
Cell Net Data Systems	Chris King
Citizens Electric	Paul Townsley
Citizens Utilities	Brenda Asplin, Thomas Ferry, Sean Breen

Organization	Representative
City of Mesa Electric Utility	Darrel J. Pichoff
City of Tucson, Dept. of Operations	Vincent Hunt
City of Tucson, Water Department	Sandy Elder
Connext	Kevin Coons
CSW Communications	Erich Landis
Cyprus Climax Metals Company	Mike McElrath
Duncan Valley E.C.	Jack Shilling
Economic Energy Alternatives	David Caplow
Electric Competition Coalition	Douglas C. Nelson, P.C.
Energy Strategies, Inc.	Kevin Higgins
Enron Corp.	Janel Guerrero, Mona Petrochko
Goldwater Institute	Michael Block
Honeywell	Jeff Sutherland
IEEE	Richard G. Farmer
Intel Corp.	Marty Sedler
Land and Water Fund	Rick Gilliam
Margrave Clemins & Verburg	Michael W. Margrave, Esq.
MLB Consulting	Maureen Bureson
Munger & Munger	Michael Raci
Navopache Electric Cooperative	Dennis Hughes
Office of the Governor	Stu Goodman

Organization	Representative
P G & E Energy Services	Tom Broderick, Jorj Nofal
PacifiCorp	P. J. Anderson
Rate Management	John E. O'Hare
Residential Utility Consumer Office	Greg Patterson, Deborah Scott
Resource Management International	Alan Propper
RW Beck/Enron	Jeff Brown
Salt River Project	Jana Brandt, Mike Lowe
Schlegel & Associates	Jeff Schlegel
Southwest Gas Corporration	Brooks Congdon
Sulphur Springs Valley Electric Cooperative (SSVEC)	Scott Sindel, Anselmo Torres, Jr.
Streich Lang	Louis Stahl, Esq.
The American Hydrogen Association	Mike Loomis
Trico Electric Cooperative	Charles Emerson
Tucson Electric Power Company	Caroline Gardiner
WAPA	Kim Clark
Western Interstate Energy Board	Doug Larson

APPENDIX C

POLICY CONSIDERATIONS FOR RETAINING REGULATED SERVICES

October 30, 1997

Prepared for:
ACC Unbundling Working Group
Metering Sub committee

Prepared by:
APS with input from various Sub-Committee participants that support this position

Executive Summary

Although many stakeholders in the electric services industry agree about the extent to which retail competition can be efficiently introduced, the provision of electric metering services is an area where any benefits of competition are speculative at best and more likely are non-existent. This paper explores the economic, operational, reliability, safety and regulatory issues that must be considered before deciding how to structure the metering segment of the retail electric market in Arizona. Upon consideration of these issues, the most beneficial alternative for all stakeholders is to retain metering services as a regulated monopoly of the local electric distribution company ("LDC"). The following points support that conclusion:

1. The provision of metering services exhibits the classic economies of scale characteristic of natural monopolies. This is why no one (including energy service providers) has suggested that duplicative meters are a viable option in a competitive marketplace. A single provider of metering services will be best able to exploit the economies of scale and scope associated with the installation, operation, maintenance and regulation of the metering system. As a consequence, consumers will benefit from least-cost provision of these services by such a provider. In addition, a single source provider will minimize the cost of regulatory oversight by the Arizona Corporation Commission ("ACC" or "Commission").

2. The meter and its related complex system of wires, transformers and other devices are operationally part and parcel of the electric distribution system. The meter is merely the end point on that distribution system and must be controlled by the LDC if it is to be held accountable for the safe and reliable operation of the distribution system.

   In addition, accurate metering is necessary for a well-functioning settlement process for transmission, distribution, and generation services and, at least early in the provision of direct access, the development of load profiles. The LDC already provides such accurate metering service. In the absence of its continued service, a host of issues arise relative to the establishment and maintenance of technical standards for meter functionality, safety, installation, reliability and performance.

3. Preserving electric metering as a regulated monopoly service will prevent the formation of new market barriers to competition by facilitating switching from one electric generation provider to the next.

4. Allowing competition in metering would substantially complicate and increase total stranded costs. Therefore, having the LDC remain the sole provider of metering services will improve the efficiency of any stranded cost recovery program.

5. Customer choice of competing metering providers is not essential to and may not even facilitate a competitive market for metering technologies. The intense competition among meter suppliers is the result of there being hundreds of large meter buyers around the world. This competition in the existing meter market is best evidenced by the evolution of an increasing array of metering innovations such as demand recorders, kvar, and time of use meters, automated meter reading, etc.

Introduction

The restructuring of the electricity industry has three crucial public policy objectives: (1) to supplant cost of service regulation of electric generation with a market-based pricing mechanism; (2) to achieve this transition without incurring needless additional costs; and (3) to distribute any welfare gains from this transition to as many customers as possible.

This paper takes a critical look at whether competition in the provision of electric metering furthers any of these policy objectives. It also examines the experience to date with competitive electric metering.

The paper concludes that electric metering remains a natural monopoly service indistinguishable from other distribution functions. Promoting competition in electric metering introduces new inefficiencies into the system and higher transaction costs, and it could threaten reliability and safety. Such competition could likewise interfere with the broader competition in electric generation, which is clearly the most likely source for any significant gains in overall efficiency. Finally, competitive electric metering presents a number of administrative and regulatory issues that will also translate into higher costs for electric consumers.

Economic Efficiencies

It has long been recognized that there are significant economies of both scale and scope in the provision of many of the electric industry's services. These economies continue throughout the entire range of output for the applicable services. It is precisely for this reason that many of these services were best provided by regulated monopolies. Most participants in industry restructuring have acknowledged these natural monopoly benefits by moving towards competition in electric energy generation, but not for distribution services, which continue to exhibit the continuous economies of scale/scope characteristic of all natural monopolies. These economies apply equally well to metering services, which merely represent the end point of the distribution system.

Many assert that competition must invariably produce lower prices regardless of an industry's underlying cost structure. However, this is simply untrue. Competition will lead to the lowest possible prices for consumers only under certain conditions. One of those conditions is that total and average costs for the industry or for a particular service are lowest when several companies supply the service (meaning that each individual service provider faces increasing average and marginal costs). This is admittedly true for most industries and services, but if there are continuing economies of scale in the provision of the service, then average costs continue to fall, and costs can be lowest only when one entity provides the service.

Electric metering clearly exhibits continuous economies of scale. While there is a high initial cost of establishing a network or system, it is comparatively inexpensive to add one more customer into that system. Consequently, total and average costs for metering are likely to be lowest if the ACC entrusts one company with providing these services. Nowhere in the public record (to the best of our knowledge) is there any indication that anyone, including energy service providers, supports the availability of duplicate meters at the end-use customer's premise. Quite the contrary and because of the expense involved, ESP's have been very vocal in opposing any requirement that they provide duplicate meters as a barrier to entry. ESP's do not seriously contest the existence of continuous economies of scale in electric metering. What they see is an opportunity to profit from the current system of average pricing by the LDC, which means that some customers are charged for metering costs that exceed those costs directly attributable to them. Such arbitrage does not benefit electric customers as a whole and, in fact, only increases the total costs of metering within any given distribution system.

Specific Economies of Scale: Acquisition, Installation and Maintenance

Consider, first, the acquisition of metering equipment. In retailing, the U.S. has observed a dramatic concentration in the number of firms. Where once Americans bought most groceries, clothing, and durable goods from locally owned retailers, today they make the majority of their purchases from regional or national retail chains. This underscores a fundamental source of cost savings – economies of scale in the acquisition of retail merchandise. That is, the larger a firm's network of retail outlets, the greater its expected sales, and the more the retailer will be able to realize volume discounts in the acquisition of merchandise.

This example is entirely appropriate to the case of metering services in electricity, where the LDC purchases metering equipment on behalf of its customers. The larger the customer base, the greater the volume discounts realized in such purchasing. While it may be possible for firms other than the LDC to also realize such savings, it is highly unlikely that multiple buyers could achieve the same level of discounts as a single buyer. This is true even in the case of an energy marketer with a nationwide presence, because the marketer would specifically have to have a significant presence in several other states that had allowed metering services to be provided competitively. Of all the states moving towards competition in the retail electric market, only California, Maine, and New Hampshire (to a limited extent) have decided to allow competition in metering services. California is the farthest along in the implementation of competition in metering and billing, and yet the process of determining the market structure for this segment of the retail sector is ongoing, and the final outcome of the process remains uncertain. Therefore, a marketer would not be able to obtain volume discounts similar to the LDC even if it were purchasing metering equipment for all its customers.

Perhaps more important than volume purchasing discounts, there are substantial economies of scale in the installation of meters within a given geographic area. More precisely, it is much less expensive to install meters in all houses in a neighborhood than it is to install the same number of meters in widely scattered areas. Information received from various meter vendors comparing the installed cost of meters in limited quantities revealed costs four to five times the costs for system wide implementation.

Another example of the economies of density that can be exploited by the LDC is meter reading. A meter reader who reads every meter in a consecutive path will read 10 times as many meters as one who reads every 20^{th} meter.[1] Allowing a single firm to install meters in every home in a neighborhood will use labor and capital much more efficiently, and since the cost of installation is high relative to the cost of the meters, this will help substantially in making more technically advanced metering systems more cost effective for small customers.

The very same economies of scale apply to meter maintenance. Utilities such as APS and the distribution cooperatives (whose territories encompass sparsely populated rural areas) are fully cognizant of the efficiencies of maintaining meters in a concentrated geographic area versus more spread out meter locations. It is not uncommon to experience cost differentials of 2 to 1 in the relative costs of providing such services in areas of sparse meter density as compared to areas of high meter density. It simply takes more time (i.e., labor costs) for a meterman to service a number of meters scattered throughout an area than to service the same number of meters in a concentrated area.

Economies of Scale in Meter Data Collection: Exploiting Network Effects

To collect information at the metering site and transmit it to a central data processing installation requires a data communications network. One fundamental characteristic of a meter reading network, or any network (whether it be manual or automated), is the economies of scale or network effects, which are determined by the number of other people using the <u>same</u> network. More precisely, the benefits any one consumer receives from network goods and services increase with an increase in the total number of people using the same network. In the case of a communications network, there are both direct and indirect effects. The direct effect is that the network is more valuable to any subscriber the more subscribers that are connected to the network. The indirect effect is that the average cost of serving additional subscribers is falling over all potential subscribers.

---

[1] King, Chris S., "Competition at the Meter: Lessons from the U.K.", Public Utilities

Electricity consumers are better off using the same network for metering data collection, because regardless of the data collection method used, there are substantial fixed costs involved in implementing the network. The traditional method of data collection, on-site meter reading, requires large investments in personnel and fleet services. Advanced methods being tested today require connecting meters on the customer's premise to the central data processing unit by a data communications network. While the choice of network – e.g., wireless or wireline – will influence the cost of service, the fixed costs remain large. Some of the most economical systems are Power Line Carries Systems that use the distribution lines as the communication network.

The most important cost consideration in the implementation of such a network is that once the network has been brought to a neighborhood, the cost of serving additional customers in the area is very small. In other words, the marginal cost of service is less than the average cost, and adding additional customers to the network will lower the average cost of service to all customers.

As an example, consider that a remote data collection network for one million meters can provide hourly metering for close to $1 per meter per month for small users and $20 per meter per month for the largest users. In contrast, the current system in the United Kingdom (which has introduced competition in the metering services market for large customers) only serves 20,000 meters, at a cost of $120 per meter per month.[2]

While the UK experience was limited to only the largest consumers, the California proceedings provide even more compelling evidence of the dramatic economies of scale from widespread implementation of advanced metering. Estimates of the cost of providing metering service to small California customers in a multi-firm market vary widely—from a high of $27 per meter per month, to a low of $5—based on assumptions of between 5 and 10 percent penetration. In either case, the cost exceeds that which would have been incurred by the LDC as a regulated monopoly.

Fortnightly, 134:20 (November 1, 1996), pp. 22-25.

[2] See Chris S. King, note 1.

Economies of Scope in Metering and Distribution

There are important economies of scope between distribution and metering services as much of the infrastructure needed to install, maintain, and repair metering systems may also be used to install, maintain, and repair distribution networks. Thus a LDC repair technician on a service call may be relied upon to determine and fix a problem whether it is in the customer's metering equipment or in the distribution network leading to the premises.

Furthermore, much of the information necessary to ensure system reliability may be monitored and collected by next-generation metering systems. Many distribution operators are testifying that 50 percent of the benefit of their AMR systems is the knowledge gained and used to improve system reliability; e.g. John Choate of Mid-South Electric, Texas and Mike Riley of Roosevelt County Electric, Portales, New Mexico. Thus, as meters get "smarter", there will be increasing economies of scope in the relationship between metering and the provision of system reliability.

"Regulatory" Economies of Scale

If the ACC chooses to allow competitive provisioning of metering services, it will find the cost of oversight much greater than in a market where only the LDC provided such services. For example, the Commission will have to sure that all independent suppliers of metering services properly record customer information and make it available in a usable form and on a timely basis to other parties who need it.

Energy diversion has a major financial impact on the LDC and on the efficiency of metering services. Diversion also creates a potential safety hazard, as is discussed later. With an ESP's venture into the metering market place, additional supervision will be required to ascertain the ESP is actively monitoring this type of fraud and has a structure in place to guarantee that the LDC is fully compensated for this loss. The Commission will also need to implement enforceable consumer protection measures, including anti-slamming rules, anti-fraud protection, and effective consumer education. The cost of monitoring compliance on these issues will be substantially lower in a single-provider market than in a multi-firm market.

Operational Safety and Reliability

Safety issues are also a large concern. Responsibility for safe access to any part of the system is paramount. LDC's provide extensive hours of training on safety issues related to all aspects of the distribution system. This expertise must be maintained to prevent unnecessary endangerment to the personnel responsible for these services and to the public.

The meter and everything on that system of wires, transformers and other devices are part and parcel of the distribution system. The meter is merely the end point on that system and should be owned and controlled by the LDC just as the LDC owns and controls all other essential functions of the distribution system. Simply stated, the meter must be properly installed, calibrated, maintained and controlled by the LDC if the LDC is to be held responsible for safe and reliable distribution service.

There are many coordination issues associated with competitive metering. If independent metering firms are not properly integrated with generation services, there may be serious coordination problems in the implementation of new metering systems. Accurate and efficient billing can occur only if metering information is provided on time, free of errors, and in usable form. If many different metering companies must send information to many different billing companies, the possibility of delays and errors increases. Furthermore, coordination problems in the competitive provision of metering could lead to significant problems with settlement, load imbalances, and other serious issues that might affect both the settlement process and system reliability.

Consider the following example. The United Kingdom implemented retail access in 1994 with competition in the provision of metering services. However, the sector has experienced significant coordination problems in the wake of this transition. Customers who had contracted for advanced metering systems did not always receive them in a timely fashion, and many of the new meters that were installed were not properly connected to the data collection network. In the first six months, usage for over 50 percent of the customers that had signed up for new metering systems was not properly recorded. As a result these customers' bills had to be estimated. There were problems with load imbalances, and the distribution companies cash flows suffered considerably.[3]

Control of the meter and all its related functions and services will become even more important as more meters with multi-function, real-time, communications capability ("Smart Meters") are installed on the distribution system. Smart Meters will increase the capability of the LDC to monitor and control loads, identify certain system problems and record valuable customer usage information. This will improve efficiency, reduce costs and provide better customer service.

Appendix A is a list of the metering and meter reading services currently provided by LDC's. It is an extensive list consisting of both assets and services. Appendix B shows how the non-utility ESPs have proposed to define metering and meter reading services. Although the ESPs want metering and meter reading to be competitive, the ESPs have never indicated they are not willing to take over ALL the services that are involved with metering and meter reading. If ESPs are permitted to selectively cherry-pick those meter and meter reading services that they identify as preferable, presumably the LDC will maintain all the services that the ESP does not want. Therefore, and even aside from the foregone economies of scale previously discussed, there will be no cost savings to the customer since the LDC will have to maintain metering and meter reading equipment and a workforce to provide the services the ESPs do not want to offer

[3] Henney, Alex, "Competition, Confusion, and Chaos: The Metering Muddle," Public Utilities Fortnightly, 134:20 (November 1, 1996), pp. 26-29.

Higher Transition Costs and Market Barriers

Retaining electric metering as a regulated monopoly service would facilitate customer switching of generation providers and the recovery of stranded costs. Rather than a simple meter reading, competitive metering means that every time a customer changes an ESP there is a possibility that the meter will also need to be changed. ESPs in the Metering Subcommittee Working Group have indicated a preference for them to provide the metering service for the customers that they serve. This only can be accomplished if they replace the existing meter or buy the meter from the LDC or the prior ESP. In addition, the PTs, CTs, socket and wiring, all of which are integral parts to the meter, would also have to be transferred. The process of switching energy providers would then involve coordination and agreement of a date for one entity to read and pull its meter and have the new entity install its meter, or an arrangement for the transfer of the current meter installed on the location and the reprogramming of the meter for access (which would require a visit to the location by both entities), as well as an arrangement for transfer of the ownership of the PTs and CTs, socket and wiring. The majority of the LDC's meters that are removed in this scenario could become additional stranded investment.

Preserving metering as a regulated monopoly service will eliminate opportunities for anti-competitive behavior. If competitive metering firms use different technologies that are incompatible or if they do not interconnect, then the distribution system is comprised of several small, distinct networks. In the case of metering, service providers in a competitive market would have strong incentives to implement incompatible metering technologies.

By using incompatible technologies, firms would be able to impose substantial switching (transactional) costs on consumers. This is because consumers will, in one way or another, bear the initial costs of connecting to the metering network. Any time a consumer wishes to change service providers using incompatible technologies, he must bear the fixed costs of acquiring new equipment that is compatible with the new service provider's network. In addition, consumers may have to continue to pay for their old equipment.

By imposing switching costs on consumers, firms can afford to relax price competition. That is, if a customer must pay some fixed cost to change networks, then the service provider can raise the price of the service up to the point of marginal cost plus switching cost.

Furthermore, if a firm is offering both metering and generation services, it may use incompatible data standards to lock a customer in to both the generation and metering services. Thus by choosing a data network that is incompatible with those of other service providers, a firm might be able to force its customers (by refusing to supply metering and generation services separately) into a tying arrangement where they pay above market prices for generation services.

If the ACC allowed energy service providers to offer metering, it would have to ensure that each company did not engage in anticompetitive tying arrangements. Regulated monolopy metering requires regulatory oversight of only the LDC. Moreover, no LDC would be able to enter into tying arrangements because it would be obligated to provide metering on a non-discriminatory basis at cost-based rates regardless of the supplier of generation services.

Technology Enhancements

The claim is frequently made that competition for metering services will foster technological innovation and stimulate customized solutions to customer-specific requirements. However, competitive metering in each utility's current service area is not essential to and may even inhibit a competitive market for metering technologies.

The already intense competition among meter suppliers will continue as long as there are hundreds of large buyers around the world. This has be demonstrated by all the various types of metering now in place to register load data based on demand intervals, kvar's, time-of-use, and multi-function meters. As new types of load information requirements prevail, meter technology will grow with the market requirements. LDC's will continue to provide this to customers in the most cost-effective manner. Competition among metering service providers in Arizona would contribute little if anything to effective competition or advancement of meter technology or costs.

Finally, proponents of multi-firm provision of metering argue that a competitive marketplace is necessary to ensure that consumers will benefit from new, value-added services such as load management or home security services. This argument is specious for two reasons.

First, any firm wishing to provide such services simply requires a communications link to the customer. At present there is a multitude of such possible links, including cable television, local telephone, and wireless. Thus metering is only one of many vectors for gaining access to the customer, and no firm in a retail access environment would be prevented from offering these services if metering remains a regulated service.

Second, experience in the telecommunications sector suggests that one should examine self-serving promises to provide new services with a critical eye. Recall that in the period leading up to passage of the 1996 Telecommunications Act, which deregulated important parts of the communications industry, cable television companies, and local and long distance service providers, announced extensive plans to offer telephony and video delivery, respectively, and provide many new services. Subsequently, however, it has become clear that the cost to upgrade infrastructure to provide these services will be much greater than previously imagined. Furthermore, the extent to which consumers will actually demand and be willing to pay for these new services remains unclear. The result has been a dramatic scaling back of investment plans and expectations of new service offerings. Firms in the retail electricity market could learn from the cable experience—investment plans and claimed new service offerings should be evaluated with a great deal of caution. Additionally, policy makers should be wary of allowing such unsupported claims, many of which may go unrealized, from swaying sound public policy.

Other Supportive Arguments

Stranded Cost

Allowing competitive firms to provide metering services would substantially complicate the Commission's plans for stranded cost recovery. First, the Commission would have to incorporate stranded metering infrastructure into the stranded cost base, having made the distinction between those customers who will continue to receive metering services from the utility and those who do not. The costs of existing metering infrastructure no longer being used to bill for services will still need to be recovered. Moreover, to the extent that customers opt for other metering providers, the LDC's average cost of providing metering service would increase relative to today due to lost economies of scale and scope. This problem is greatly exacerbated if all related facilities such as potential transformers, current transformers, and wiring are also owned by the customer's chosen metering agent. This would further complicate the determination of appropriate stranded costs.

Load Profiling

Load profiling may be a necessary interim step if there is to be widespread direct access available to all consumers. Because the incumbent LDC's are presently in possession of detailed customer and load data, they are in the best position to develop these load profiles during the transition period. Furthermore, it may be desirable to perform on an on-going basis, more detailed sampling of consumption patterns through the installation of real-time meters on a sampling basis. Leaving the LDC as sole provider of metering services allows such sophisticated sampling to be conducted at least-cost to the ultimate end-user.

Customer Service

Many, if not most customers will be inconvenienced at best if metering is unbundled from Distribution Service. They will be the object of aggressive marketing efforts by new providers, deal with multiple bills for what they view as the same services, find it harder to resolve billing questions and other disputes and be concerned with protecting the confidentiality of credit and other personal information.

To illustrate some of these issues, consider the process by which a customer is billed for electric services. First and foremost, every customer wants the assurance that it is paying only for the electricity used. That involves a technically reliable meter that is properly installed, calibrated and maintained. There must be an accurate reading and recording of this usage, and the timely availability of meter data to facilitate accurate and prompt billing for that usage. Under regulation, customers have confidence that one company is responsible for those functions and will carry them out with oversight of a public agency.

The California Experience

In the Arizona proceedings, some parties will likely invoke California as a precedent for competitive metering. However, the effort to implement competition in metering services in California is only in the most preliminary phase. It would be hasty and injudicious to conclude that the California experiment in the competitive provisioning of metering will succeed even on the technical level, let alone be beneficial for consumers.

The CPUC emulates the British regulator's unfortunate habit of unbridled "enthusiasm for competition regardless of practicalities." And whereas the 1994 deregulation in the UK applied only to 100 kW customers, the CPUC has immediately extended competition to 20 kW customers. California's plan will result in increased regulatory, settlement, and transaction costs, thereby increasing the burden on the market.

The reasons for such increased regulatory and transactional burdens are obvious. The utility distribution companies must have accurate meter information even if another company provides metering. In California, this problem was addressed by the CPUC, which "will direct those energy suppliers that wish to offer their own metering services to enter into a service agreement with the distribution company specifying the nature of the information to be collected, the means for sharing data, and a reasonable approach for ensuring that the metering equipment is installed, calibrated and maintained properly."[4] Besides the increased transaction costs of negotiating such a contract with every competitor, it was not clear in California what explicit charges the new ESPs may demand from the utility for access to such vital information. In Arizona, there would be virtually no limit on these charges. In addition, the CPUC is required to review and approve each agreement, prevent discriminatory or anticompetitive behavior, and resolve all disputes. This regulatory supervision would be burdensome even if all parties were cooperative. However, several marketers in California have challenged the Commission's authority to order and approve these service agreements.[5] In Arizona, the Commission's own Legal Issues Working Group has raised the possibility that the Commission may lack authority to regulate non-LDC providers of metering services. Such a lack of accountability is ominous given that some ESPs may have no incentive to ensure meter accuracy or may even have an incentive to underreport consumption.[6]

Second, the Commission must ensure that the ESPs do not use meter technology to lock in customers and hinder price-based competition for electric power. The CPUC's attempt

---

[4] CPUC Decision 97-05-039 (Opinion on the Unbundling of Revenue Cycle Services), p. 15.

[5] Opening Comments of Southern California Edison Company (U 338-E) on Proposed Decision of ALJ Weissman, p. 5.

[6] For example, a marketer reselling power from the Power Exchange for a fixed fee will be unaffected by the actual meter reading. An ESP reselling electricity from the pool at

to create feasible and tested open architecture metering systems through willpower has already been mentioned. Not only would similar standards need to be developed and implemented before 1999, the Commission would need to check regularly to determine that each ESP is in compliance.

Third, the Commission must protect the distribution utility's revenue stream if another ESP takes over billing services. Accordingly, the CPUC has ordered the California utilities to establish and file credit requirements for ESPs. Once again, even if the credit requirements do maintain the utilities' financial security, they create another regulatory hurdle subject to dispute, arbitration, and verification.

The UK Experience

The California plan is controversial, and no one knows what will happen, especially the CPUC. California's attempts to avoid the problems with metering competition are either difficult to enforce or will result in increased regulatory, settlement, and transactions costs, which will themselves further burden the competitive generation market. Perhaps instead of drawing conclusions from other states in this country that have only proposed to open up metering to competition, we should examine the experiences of the United Kingdom, which opened metering services for large customers to competition in 1994.

Most drastically and importantly, the UK approach caused losses in both technical reliability and financial security. As summarized in *Public Utilities Fortnightly*,

> Opening access in 1994 was quite another experience: a shambles.... [P]art of the mess was due to the electricity regulator's enthusiasm for competition regardless of practicalities. He introduced competitive metering late in the process, without defining the responsibilities of the "meter operator" to ensure that meters were not only on site but connected to a modem that was, in turn, connected to a data aggregation system and the whole setup both commissioned and registered. Competition requires a system for identifying each meter, its characteristics, its operator, its

---

a fixed unit price could increase profit by underreporting consumption when the pool price is higher than its contract price.

supplier, its line-loss factors, and so on. Introducing such a system becomes far from trivial when tens, if not hundreds, of thousands of meters are involved. Worse, the regulator decided to allow customers lacking a half-hour meter to take competitive supply on load profiles.

> In the ensuing chaos, some companies were not billed for six months. The cash flow of the distribution companies suffered severely (the larger ones were $100 million down for a while) and the problem took two years of intense clerical effort to straighten out.[7]
>
> [C]ustomers had no clear incentive to get meters installed properly and on time. For UK Data Collection Services, Inc. (UKDCS)—current manager of the metering data repository—that failure took the form of missing half-hourly data. As a result, over 50 percent of customers' bills had to be estimated. In short, according to UKDCS, the "U.K. competitive market [was] close to chaos."[8]

Insufficient attention to meter reliability thus threatened the success of the entire open access experiment by undermining the financial stability of the market.

The technical snafus in the UK reveal two unanticipated problems. First, competitive meter operators did not install and connect meters by the time the electricity pool required them. Second, the operators did not succeed in linking their meters to an integrated data system. As a consequence, the financial settlements which depended upon this data were jeopardized, delayed, and required complicated and controversial estimations.

The Experience of Other Industries

In proceedings throughout the country, some have drawn improper analogies with metering experiences in other industries, particularly the natural gas and telecommunications industries.

For example, it has been claimed that deregulating natural gas commodity prices in California without implementing competition in metering services somehow reduced the benefits of competition to consumers. One party even suggested that natural gas competition in California was not robust for this very reason. Only three gas marketers

[7] See Alex Henney, note 5.
[8] See Chris S. King, note 1.

remain in the market, and it is claimed that competition would have been more effective if metering had been deregulated.

First of all, there is no evidence to support such an assertion, and the belief that there is any logical connection between successful gas commodity competition and gas metering competition appears a strained assumption at best. Moreover, by focusing on the plight of third-party marketers, the obvious and large benefits to consumers from competition for supply–lower delivered prices for all customers–are ignored. Customer savings on commodity prices easily exceed the entire portion of their bills allocable to metering. Furthermore, given the complex nature of a competitive market, it is absurd to suggest that a market with three gas marketers is necessarily inefficient or that more marketers would or should appear if natural gas metering were deregulated. In sum, what the experience of the natural gas industry has really shown is that large benefits can be achieved for consumers without deregulating metering services.

Some parties have also attempted to draw parallels with the telecommunications industry in an effort to demonstrate a reason for metering competition. In fact, any attempt to draw analogies between metering of electricity and telecommunications is entirely inappropriate. Many telecommunications services are not "metered" in any conventional sense. Second, the physics and technology of the metering in telecommunications is wholly different from that of electricity. Third, it is less obvious that telecommunications "metering" exhibits continuous economies of scale.

Conclusions

In summary, there is major economic efficiency, operational, reliability, safety, customer service, and regulatory reasons to retain metering services as integral parts of distribution service. By unbundling metering services, the citizens of Arizona are being asked to accept higher metering costs and increasing operational complexities associated with the establishment and enforcement of: performance; safety and reliability standards for a heterogeneous meter population; data exchange, customer turnover procedures, consumer protection safeguards, etc., in return for non-existent savings. Not only will the unbundling of metering services fail to produce benefits, it almost certainly will be accompanied by a degradation in some electric services. Marketers on the other hand are aggressively promoting the unbundling of metering services for the simple objective of acquiring an additional profit taking opportunity to supplement what has turned out to be very thin margins from the sale of energy in a competitive market.

Continued LDC provision of metering services as a regulated function will ensure that all authorized parties will have fair and equal access to customer information and data. Moreover, end-use customer choice of metering providers is not essential to having a competitive market for metering technologies, and may, in fact, impede such a market by denying new technologies the economies of scale provided by the LDCs metering activities.

Appendix A – Definition of Metering and Meter Reading Services (LDC's)

Installation of all single and three phase meters
Installation of instruments, current and potential transformers, test switches and wiring.
Maintenance and troubleshooting of all of the above
Test and maintain all other equipment (RTU's, recorders, communications) necessary to meet the requirements of specific customers' applications, when used primarily as a billing/energy accounting tool.
Clean, repair and calibrate customer owned meters (typically for trailer parks and contractor/electricians.
Replacement and return of existing LDC metering equipment.
Timely communication of any and all metered data, used primarily for billing or energy accounting to all authorized parties.
Delivery of customer data to customer.
Programming of solid-state meter registers.
The validation, editing, and estimation process to convert data to billing and settlement processes.
The provision of data storage and other data management services.
Maintaining security of metered data access.
Provision of diagnostic services.
Field work such as; connects and disconnects, new service inspections, wire current transformers and potential transformers at customer's installation, set single and three phase meters, tap load conductors at transformers, work installation checks for meter and current transformer accuracy, test capacitor bank control units for correct operation, maintain meters at distribution substations, investigate customer premise for correct rates.

Appendix B – Definition of Metering and Meter Reading Services (ESP's)

End-use revenue electricity meters shall consist of the following:
Meter socket
Meter
Recorders
Test Blocks
Pulse equipment
Miscellaneous wiring

New metering installations shall be in accordance with the standards adopted by the Unbundling Working Group for retail customers.

APPENDIX D

BEFORE THE ARIZONA CORPORATION COMMISSION

COMPETITION IN METERING AND METER READING SERVICES IN A RESTRUCTURED ELECTRIC INDUSTRY

ENRON CAPITAL AND TRADE RESOURCES, INC.

OCTOBER 1997

R·W·BECK

COMPETITION IN METERING AND METER READING SERVICES IN A RESTRUCTURED ELECTRIC INDUSTRY

Table of Contents

R·W·BECK

SECTION I
EXECUTIVE SUMMARY

Enron Capital & Trade Resources supports competition in the Metering, and Meter Reading markets as part of the restructuring of the Arizona electric services industry. In telecommunications, "the unbundling of the value chain" into many separately provided services has led to significant cost savings for consumers, better customer service, and the evolution of a host of previously unavailable services. Other industries' experience also shows that:

- Systems will be created to capture and manage customer information.
- Customer information will provide value to customers in many new ways not originally envisioned.
- Products and services will be more widely available.

Competition in electric utility Metering Services (MS) will foster the growth of a technology and information-based industry, bringing substantial benefits to consumers and to the Arizona economy. The success of the Direct Access market will hinge on the success of Energy Service Providers (ESP's) in providing lower costs, increased innovation, and superior service.

The Commission's decision to deregulate MS will enable value-added service offerings to off-set some of the installation cost of Direct Access Meters (DAM), bringing them to more and more customers without any utility expenditure at all. In the electric industry, new sources of value through unbundled MS functions could:

- Induce companies to provide direct access meters to customers.
- Make AMR technology universally available through retrofit of existing meters, without constructing new electrical facilities.
- Inspire new products and services.
- Encourage outsourcing to specialized customer service companies to lower costs without sacrificing customer quality.

There is already active competition in the metering , and meter reading functions. They are not natural monopolies. To allow more customers to access competitive services, Enron advocates:

- A full unbundling of distribution rates.
- Meter ownership to be open, subject to accepted standards for meter accuracy, access, maintenance, and testing.
- Permitting the replacement or retrofit of individual meters.

- Multiple provider access to a single meter, as the only long-term solution.
- A metering communication system capable of communicating with the utility and the customer's own ESP.
- The data from a customer's meter accessible to anyone, with the customer's consent.

Therefore, the Commission should:

- Allow customer choice and open market competition for metering, and meter reading services.
- Order the utilities to make the necessary studies to provide unbundled Metering and Meter Reading costs.
- Sanction utility-industry workshops to discuss what standards/protocols can be tentatively identified to get the unbundling of Metering and Meter Reading functions off the ground, and to work out procedures for the sharing of meter data.
- Make the policy decisions necessary to allow Metering and Meter Reading competition to evolve with the remainder of the restructuring process.
- Allow the marketplace to search the available alternatives and come to a consensus on standards.

SECTION II
CUSTOMER CHOICE IN METERINGAND METER READING SERVICES IS AN IMPORTANT COMPONENT OF DIRECT ACCESS IN A RESTRUCTURED ELECTRIC INDUSTRY

Direct Access will be significantly enhanced by the unbundling of Metering and Meter Reading functions, and the benefits of generation competition will be brought to more customers, especially residential and small commercial customers, sooner than otherwise would be the case. The Commission should stay the course and adopt a goal of promoting competition in the metering arena because such competition will lower the costs of these services to consumers and stimulate innovative responses to customer specific requirements. There already is fierce competition in these areas, particularly at the wholesale level, and this market, along with Billing and Information Systems are not natural monopolies. The potential efficiency gains from a competitive marketplace far outweigh any arguments for a perpetuated monopoly. Moreover, competition will provide a dramatic opportunity to foster the growth of a technology and information-based industry and bring substantial benefits to consumers and to the Arizona economy.

SECTION 1 A. COMPETITION IN METERING SERVICES WILL PROVIDE ECONOMIC BENEFITS FOR ARIZONA

Competition in Metering services will bring Arizona customers substantial benefits. These benefits will not be obtained if competition is limited to the generation of energy. Permitting competition in all of the non-monopoly functions, including Metering and Meter Reading, will stimulate competitors to innovate and market lower cost and more efficient services. In turn, this will increase the market share of new competitors, encourage even more new entrants, and intensify the competition, which will ultimately benefit all Arizona electric consumers.

The Commission has espoused the fundamental policy that it should continue to regulate <u>only</u> natural monopoly services, such as the provision and maintenance of electric distribution lines. The Commission should encourage competition in areas where there is not a strong, overriding rationale for maintaining a regulated monopoly. Examples are everywhere: natural gas procurement, long distance and local telephone service, airlines, and electric generation. We submit the metering and billing of electric services also fits this category. The history of other new technology-based industries gives the Commission strong evidence that competition in Metering Services will lower costs, increase innovation, improve service, and benefit consumers.

To date, the regulatory process has been singularly ineffective in promoting cost-effective and efficient metering by the utilities. Most still send meter readers out to walk around and manually read meters. Utilities have had every opportunity, but very little incentive, to innovate these services through the application of technology. Rather, there is considerable internal inertia to rely on existing "proven" methodologies and an obvious aversion to perceived risk taking. Clearly, until competitive pressure is brought to bear, the utility Metering and Meter Reading functions will continue to be far less than "state of the art." Customers will suffer by paying more for less.

The restructuring of the electric industry heralds the start (or the acceleration) of a new technology-based, information-based industry. This industry holds great promise for Arizona by encouraging competition and innovation of market participants which will ultimately drive down costs to consumers.

The development of the Metering Services market would be halted in its early stages if, instead of a competitive market, the Commission adopted a system-wide implementation of a single provider of metering or communications systems, particularly one with low technology capabilities. To lock into a proprietary system of one provider would in effect lock out the benefits of Metering Services competition. These are some of the benefits Enron believes Arizona consumers will receive if Metering Services are unbundled and provided competitively:

- The ability to control their energy bill through:
    - Adjusting consumption to electricity pricing
    - Smart appliances operate during off-peak periods
    - Reduction in meter-reading costs as industry changes from manual reads to cellular or radio technology

- More detailed information on usage to allow for energy management savings
- Incorporation of other customer-valued services (phone messaging, security, smoke or CO_2 detection)
- Customized bill information through advanced metering

In addition, the natural gas experience provides clear evidence that trying to create only partially unbundled energy markets results in a stifling of competition, thwarts entrants, and significantly delays and diminishes the benefits of competition for customers. The metering, billing, and information service functions are not natural monopolies, and there is already active competition in this area, particularly among wholesale providers. To resist the development of competition in Metering Services is ultimately futile--particularly when there are significant benefits to this competition. The experience in other industries provides persuasive evidence that more customers will have access to these enhanced services, as well as direct access services themselves, if the market is allowed to make use of the added value that competition will wrest from the provision of metering services. The power of customer choice can transform the entire MBIS market, and the Commission should encourage and support this positive and beneficial transformation.

B. ABSENCE OF COMPETITION IN METERING SERVICES IN OTHER STATES

It is not an easy task for a government to "create" a market, when in fact, most markets spring forth spontaneously as the result of concerted and repeated human endeavor to accomplish a certain end. This is amply illustrated by the half-successful or failed attempts of government to manage the creation of new markets. In California's Natural Gas Policy Act of 1978[1], the California Public Utilities Commission unbundled natural gas transportation and procurement for non-core customers, but halted its unbundling efforts for core customers at the point where core customers only benefited from competition for the commodity itself. The net result has been fewer competitors and less value for core customers. In response to gas price competition from marketers, the utilities reduced their cost of gas to meet the competitive market price.

This left those same marketers with extremely thin margins, and with no ability to create additional value for customers by providing better or less expensive service in other areas, such as transportation, or metering and billing. As a result, nearly fifty marketers entered the market and only three survive fitfully today. By shielding competitive markets within the protected utility monopoly, the California Public Utilities Commission drastically diminished the chance for new entrants to successfully compete with established utilities. The Commission must recognize that it needs to allow competitors the flexibility to offer innovative packages of unbundled services in order to provide customers with new reasons to purchase their services. This is one of, if not the primary, means by which the new entrants carve out a place in an evolving market.

1 Natural Gas Policy Act, Pub.L. No. 95-621, 92 Stat. 3350.

SECTION III
METER OWNERSHIP

Meter ownership should be open to whatever arrangements the market finds to be efficient, subject only to the requirement that all meters attached to the utility distribution system must meet accepted standards for meter performance to ensure accuracy and reliability. The American National Standards Institute already maintains such standards for electricity meters. See ANSI Standard C-12. Other metering standards are:

IEEE 1377-Draft Standard for Utility End Use Devise Applications Layer Communications Protocol, prepared by the AMRA/IEE SCC 31 End Devise/TRU Subcommittee and Industry Canada Task Force for Data Communications, 1996.

IEEE 1390 and 1390.1, the IEE Standard for Utility Telemetry Service Architecture for Switched Telephone Network, September 1995.

In addition, as discussed below, customers who select third party meters must ensure that they also adopt a communication system which does not preclude communication with the utility and the customer's own ESP.

SECTION IV
ACCESS TO METER DATA

The data from a customer's meter should be accessible to all ESP's whose services are metered. This would include the distribution and transmission utilities. In addition, the customer's electric consumption data should be made available to anyone else, with the customer's consent. The additional access should in no way interfere with the ability of the authorized ESP or the utility to read the meter for purposes of billing their services. Likewise, the ESP or utility should in no way interfere with or increase the cost of obtaining access to the meter data.

SECTION V
SYSTEM WIDE VS. INDIVIDUAL INSTALLATION OF DIRECT ACCESS METERING

Although system wide installation is not required to commence Direct Access, the installation of direct access meters (DAM, defined as remotely interrogable meters capable, at a minimum, of storing hourly interval consumption reads) should proceed as customers and the market desire. Small commercial and residential customers can be adequately served using "load profiling methodologies" and after the fact settlement of energy charges; large commercial and industrial customers, on the other hand, will most likely require highly individualized arrangements, which also argues against system wide installation of any single type of DAM. In addition, system wide installation by the utility carries with it the burden of huge costs for ratepayers. As explained above, the unbundling of Metering Services will allow value-added services to off-set some of the installation cost of DAM units, bringing them to more and more customers <u>without any utility expenditure at all</u>. Under no circumstances should the Commission burden all ratepayers with the costs of a system wide installation of DAM through the old fashioned, and unnecessary mechanism of adding massive amounts of distribution plant to the rate base.

SECTION VI
THE CONDITIONS FOR OPEN ENTRY INTO METERING SERVICE MARKETS

As explained above, there are substantial existing barriers to entry into the Metering Services markets. First, the utilities do not offer unbundled metering services at this time, so the development of such service elements and the identification of costs are required. Second, unless other vendors' meters can be used to replace utility meters, new entrants face substantial competitive disadvantages in the installation of duplicate meters. This is both wasteful of money and effort and may face serious practical difficulties in making changes to the electric system of customers' homes or businesses. These barriers are essentially insurmountable, thus necessitating a Commission order allowing competition in MS functions.

Enron advocates the following conditions for open entry:

A. The Commission should order the utilities and all other ESP's and vendors who install meter facilities to use standard architecture wherever possible. This means that such devices can be interconnected with the utility system and meet ANSI and other necessary standards. The Commission should allow specific communications standards to develop through the marketplace, rather than by regulatory fiat. This is possible because in the early stages of competition in the market, the Commission can rely on integrators to find ways to communicate with the utilities--essentially testing out the best communications protocols. This trial and evolution will result in de facto industry standards. In addition, there will not likely be immediate roll out of real time meters to all customers. As explained above, industrial and commercial markets require the flexibility to use different systems. Load profiling removes the immediate need for meter standards for small commercial and residential consumers. Thus, there will be a natural phase-in of new metering technology and communications protocols. During this time, standards will develop.

B. The Commission should allow open market competition for all metering functions. This will require that the Commission adopt a reasonable methodology for cost allocation to each MS function. It will also require that the utilities set unbundled prices for separate services. Customer choice, not the utilities' decisions, should govern who performs metering, and metering related services. The only requirements should be those absolutely necessary to ensure safe, accurate, and reliable Direct Access electricity metering.

C. According to Article R14-2-1610, Spot Markets and Independent System Operation, the Commission is considering the development of an independent system operator for the transmission system. One precaution is that the ISO must adopt settlement procedures that do not require billing to customers on daily basis. There is no reason for the ISO to require customer billing on any basis more frequent than monthly. However, the decision by the Commission to have competition for the provision of Metering Services can proceed simultaneously with the development of the ISO.

SECTION VII
METER COSTS

Will system wide meter retrofit provide the lowest incremental cost? This could result in low-tech solutions without the ability to generate added value. Value-added metering solutions can allow more customers to take advantage of metering technology at low or no cost. A system wide "one size fits all" solution will not meet the varied needs of the customers or the marketplace. It could result in enormous unnecessary expenditures.

All competitors do not face the same costs for performing metering services. However, many non-utility parties do not have the information to allow them to calculate unbundled rates at this time. Only the utilities have the necessary information to allow them to calculate and allocate the costs of these services. Enron advocates a full unbundling of distribution rates into the Metering, Billing, and Information Services (MBIS) components. Such an unbundling would thus require no credits in the distribution rates, and customers would then only be charged for the specific unbundled services they purchase from the utility or other ESP.

SECTION VIII
DATA CONFIDENTIALITY AND SECURITY

Under an open access system, the information obtained from the meters must be validated. Because the meters will be accessed remotely, manufacturers have established communications protocols to these meters. Actual access to the meter information requires some level of password knowledge. As the information moves along the meter information highway, there are various points where that information can be encrypted to a higher degree. Using public key encryption technology, access to this data can be restricted.

As an additional level of protection, the information contained in the metered data as well as the actual names and addresses, credit history, etc. would be protected. In much the same way, National Security Information is protected and freely exchanged among those authorized to have access. Systems for providing such protection currently exist and are in common usage throughout the country. Physical access to the records, (existing mainly on computer databases) can be controlled using similar methods. Although these techniques are extreme, they could be implemented rather quickly. As an additional mechanism for protection, those power marketers, power brokers, energy service providers, etc. that require access to this information would be required to sign strict non-disclosure documents to protect the information. Software and hardware monitoring of those accessing the metering and billing information can be instituted with current technology, and periodic audits by outside experts could verify that the integrity of the data has been maintained. The technology exists to monitor those individuals accessing these data and proper protection could be implemented to restrict physical access to it. The Commission should certify all suppliers or individuals accessing the data. All of these techniques can be incorporated into procedures for metering services programs to ensure that there is no additional risk to customer privacy or utility revenues by virtue of third party metering and billing providers.

SECTION IX
COMMUNICATIONS STANDARDS

As discussed above, Enron urges the Commission to require that parties install metering equipment and communications systems and networks which are capable of interconnection and communication with the utility and all other ESP's serving a customer. This Commission need do nothing more. Communications standards and protocols will develop, and will develop faster once there is substantial competition. History teaches that the choice of standards by regulatory decision-making is rarely the right answer. The experience of the Electric Power Research Institute (EPRI) is instructive here.

The original EPRI communications standard UCA was developed by a committee of EPRI utility members, but neglected to include the capability of communicating via protocols which function on the Internet. This was obviously an unacceptable result and the protocol had to be revised. The Commission should avoid finding itself in the same situation and should allow the marketplace to search the available alternatives and come to a consensus on standards after obtaining real-world experience in moving meter data and preparing customer bills. There need not be Commission-approved standards for external devices or networks. As explained above, a defined standard is not required to either commence Direct Access or to commence the unbundling of Metering Services functions.

SECTION X
ADDITIONAL COMMENTS

Enron is strongly in favor of a strategy permitting the replacement or retrofit of individual meters. No other strategy is fully consistent with the level of unbundling needed to achieve the customer benefits described herein. Clearly, the installation of duplicate hourly meters is hugely wasteful and inefficient. It is important for the Commission to permit replacement of the utility meter because it avoids duplication and allows customer choice; the utility and the ESP <u>can meter independently</u>, if this is the option the customer prefers, because both parties will have communication access with the meter. Secure and confidential communications are possible and should be required through mutually acceptable standards, as described above.

A strategy of system wide utility replacement or retrofit is wasteful of ratepayer funds, prevents the development of added value services, and stifles innovation in the market. In fact, such a system places the risk of advances in technology on captive ratepayers rather than on the market participants. Enron believes that multiple provider access to a single meter is the only long-term solution.. It can be implemented as soon as the Commission agrees to allow unbundled Metering Services functions.

Section XI
ENRON'S RECOMMENDATIONS

The Commission should continue the 12/31/97 order to the utilities to make the necessary studies to allow an unbundling of Metering Services costs. In addition, the Commission should announce a policy in favor of open architecture for metering functions and allow customer choice and open market competition for metering services. Furthermore, the Commission should order that all meter providers and network system providers make meter data available to the utility and all other parties, such as ESP's, who actually provide consumption-based electric services to the customer. This is all the Commission has to do to set the forces of competition and innovation in motion. Competitors will make the necessary investments and start to develop options for customers so that unbundled services will be a reality in time to commence with Direct Access on January 1, 1999.

The Commission should encourage utility-industry workshops to discuss what standards/protocols can be identified to get the unbundling of Metering and Meter Reading functions off the ground, and to work out procedures for the sharing of meter data. Under no circumstances should the Commission delay Direct Access implementation. Rather the Commission should make the policy decisions necessary to allow Metering Services competition to evolve with the remainder of the restructuring process. There will be a gradual introduction of competition, as customer choice will govern transition. Enron is firmly convinced that unbundling these functions will not delay Direct Access, and will provide tremendous benefits to customers in the short and long term.

SECTION XII

ANALYSIS OF THE IMPACT OF UNBUNDLING MS FUNCTIONS IN THE ELECTRIC INDUSTRY

The unbundling of Metering, Billing, and Information Systems (MBIS) functions will create competition among ESP's and utilities to provide better, less expensive services to customers. Metering and meter reading services are key components of MBIS, providing the absolutely necessary raw material for Direct Access information flow. If we assume that market competition induced each utility in the country to adopt the "best practices" or the most efficient procedures and technology for MBIS functions, a significant and growing component of total distribution costs, consumers nationwide would save several billion dollars annually.

In telecommunications, "the unbundling of the value chain," or the division of standard telephone services into many separately provided services, has led to significant cost savings for consumers, better customer service, and the evolution of a host of previously unavailable services, i.e., call waiting, forwarding, *69, etc.

The deregulation of the electric utility industry provides an opportunity to improve efficiency and reduce costs to an extent at least equal to the gains made in telecommunications, approximately 40%. If a competitive market develops in the electric services industry, it should experience the same results observed in other industries. The price of services (or the cost per transaction) will decrease, the quality of service will rise, the menu of customer-driven services will increase, and more focused service providers will enter the market to compete.

However, the deregulation process must avoid the primary mistake made in the deregulation of gas--the failure to offer fully unbundled potentially competitive merchant services. To allow effective competition, there must be Direct Access on a level playing field, and metering, billing and information services must be unbundled. In addition, unbundling places financial and competitive risks on the service providers, not on the ratepayers, as is the case in the current regulated bundled monopoly model where these costs are included in the rate base.

In this way metering services can be managed and provided by one or more full service ESP's or by companies which specialize in these services.

An Economic Model for Unbundling Meter Services

Energy Service Providers can compete along a continuum of services, from basic energy services to information marketing, "Continuum of Customer Services," for examples of "Quality of Life" services as well as "Energy Services" that can be provided.

Analogies from other industries include credit cards and the travel industry, such as airline, hotel and automobile rental reservations. The experience in other industries shows us that systems will be created to capture and manage customer information (such as the evolution of airline reservation systems into sophisticated yield management systems), and that customer information will provide value to customers in many new ways not originally envisioned.

Transforming the electric utility industry from a regulated monopoly to a competitive segmented market will require dramatically higher information levels than those available today, as well as direct access to, and management of, the customer base. But as to the central question of whether the consumer benefits from these new "bells and whistles"--the answer is undeniably yes.

The existence of new sources of value have changed system economics so as to strongly encourage providers in other industries to absorb customer acquisition costs with the result that products and services are more widely available. Consider the experience in credit cards that no longer charge annual fees, cellular carriers who bundle free or low cost phones with cellular service, and countless other examples throughout industry.

The result is that the services are less expensive to obtain and are more widely used. In exactly the same way, in the electric industry the creation of new sources of value through unbundled MBIS functions could induce metering companies to provide free real time meters to customers. This would increase customer access to Direct Access <u>without burdening ratepayers with the cost of new meters installed by the utility</u>.

More importantly, AMR via competitive technology provides the platform or the means to offer other energy services to the customer, and are already available from many companies. There are various competing technologies and firms already competing in the electric markets and still others preparing to enter such markets.

The Commission should recall that MBIS competition already exists in terms of electric meter technology--where it has been allowed to thrive: the wholesale market. Meters installed by Pacific Gas & Electric Company (PG&E) to serve the University of California have been routinely <u>replaced</u> by those of the Western Area Power Authority (WAPA) under its contract with Pacific Gas & Electric Company. This permits WAPA to install and read its own meters and pay PG&E the transmission charges indicated by those same meters, and is a living example of the model that all customers could follow in an unbundled MBIS market.

More importantly, the competition fostered by unbundling of MBIS services will generate substantial customer benefits, even for smaller use customers, through economies of scale and scope. At current installed costs (for replacing the residential utility electric meter with a retrofit unit) the cost savings associated with better energy management and more efficient meter reading have a payback period for residential consumers of approximately 18 months.

However, as more meter units are sold and competing MBIS providers expand their market share, the experience of other industries tells us we can expect that the price of metering equipment will decrease within 5 years and may shorten the payback period to 7 months or less.

At this point, competition will have clearly brought substantial benefit to consumers. New services and higher technology will be more affordable for many more customers. The combination of additional revenue sources and falling component costs could make AMR technology universally available. Furthermore, this can be achieved without charging ratepayers for the retrofit of utility systems.

Consumer benefits provide the most compelling argument against bundling meter services with utility distribution services. Consumers differ in their needs, and a regulatory solution of "one size fits all" tends to result in fitting none well. Residential consumers do not need or require the same type of metering services as do, for example, large commercial customers. Further, to benefit consumers with lowered costs, competition is the proven method for driving down cost of service. In the absence of competition, utilities have no incentive to reduce their costs, or the charges to consumers.

This is especially true if utility installed meters are in the rate base. On the other hand, consumers can directly benefit from the economies of scale available at production levels of only 100,000 units[2]. This eliminates any economic efficiency rationale for system wide monopoly metering by utilities. Ultimately, from the consumer's point of view, it is eminently reasonable to anticipate that some meter company competitors will be able to provide metering information to some utilities at a lower cost than that of the utility itself. However, from an emerging competitive market perspective, if the Commission permits meter services to be bundled with utility distribution service, the Commission would actually limit access to the metering market for new entrants because the utilities would gain an unfair competitive advantage.

2 Cost effectiveness estimates provided by Robert Russ, Chief Operating Officer, Diablo Research Corporation.

Utilities can retrofit existing meters with their chosen version of new technology without having to construct new electrical facilities. If a competitor is forced to construct a new AMR gateway downstream of the utility meter, this could require entry to the customer's house, the modification, or removal, of portions of a wall, or the movement of the circuit breaker box. All this construction results in increasing costs as well as delays, permitting difficulties, or simply aesthetic concerns for consumers. The increased costs are estimated to average as much as $191.00 per installation. The imposition of such costs on new entrants does <u>not</u> represent a level playing field.

services provided by a regulated entity and provided by the market. The default provider or supplier-of-last-resort role performed by the utility perpetuates the utility in a merchant role that is no longer appropriate in a competitive role. It also allows for blurring of the lines between competitive and regulated services. The provider of last resort role also provides the utility with a guaranteed market segment. Enron submits that role can be performed by the market. Enron believes that competitors can bid for the provider of last resort role. The lowest bidder, and anyone willing to match the bid, will be the provider of last resort or the standard offer supplier. This means that Enron would be the provider of last resort for non-choosing customers in a phase-in approach, for the customers who are not chosen in a flash-cut situation, or for customers who are dropped because they default in paying their chosen ESP. Any reason that can be imagined for customers not to participate in the competitive market can be handled through a competitive bid process for a supplier of last resort role.

Recently, Enron submitted a proposal before the Pennsylvania Public Service Commission in response to a filing made by the Philadelphia Electric Company (PECO) to implement competition. Enron's proposal provided for stranded cost recovery through the securitization of generation assets, the unbundling of generation costs and Enron assumed the role of provider of last resort. In addition, the telephone industry had an alternative method of allocating non-choosing customers among all competitive providers to prevent customers from defaulting to the utility for service. It is important for the Commission to consider competitive alternatives on this issue.

Affiliate Code of Conduct

It is absolutely imperative to have appropriate codes of conduct governing the relationship of a regulated utility with its affiliate prior to the implementation of direct access. These rules will set the stage for determining what is and what is not appropriate transactions between utilities and their affiliates. Without setting the rules, an unlevel playing field exists. Allowing utilities to determine what the rules should be as we go will disadvantage, if not prevent the development of a healthy competitive environment within the state.

Rules will also provide the vehicle for identifying infractions, a forum to disclose and resolve the infractions and implement penalties where appropriate. Penalties must be commensurate with the severity of the action and the effect on the marketplace; otherwise, they will not deter anti-competitive behavior. Resolution of a complaint of a violation of a code of conduct must be in addition to any state or federal remedies. However, these avenues alone are not effective deterrents. Markets respond quickly and require a quick response from regulators when problems arise. Allowing infractions in the market to continue until state or federal courts reach a judicial decisions could undo any of the progress this rulemaking was intended to provide.

The types of issues that need to be addressed through a rulemaking on codes of conduct which address with non-discrimination, separation, disclosure and information standards with a complaint resolution process and penalties. These standards should be adopted on a state-wide basis so that all suppliers, utilities, affiliates operate upon the same set of rules regardless of service territories.

Long-Term Contracts

Many of the utilities have engaged in negotiations with large consumers whereby, those consumers are effectively taken off the market prior to the implementation of direct access. The utilities have agreed to provide discounts today in exchange for long-term contracts of at least 5-years in length. This action effectively removes those consumers from competition by energy service providers when open access is implemented. It provides the utility with a jump-start over all other competitors, since all other competitors must wait for the implementation of the rules. It also provides certain customers with reductions in their distribution costs, which only the utilities can provide. This is anti-competitive and is the "cream-skimming" or "cherry-picking" of which new market entrants are often accused. The Commission should not condone or approve these exceptional contracts which circumvent open and fair competition with the implementation of the rules.

System Benefits Charge

Enron believes that there are roles that the utility has traditionally performed that were necessary due to a lack of alternative providers. These roles provided social and environmental benefits such as low-income assistance and renewable energy and/or demand-side management services. Those roles were required by the Commission. With the advent of competition for electricity supply and services, it is important to re-evaluate the previous paradigm for its application in a competitive environment.

Enron agrees that funding for some of these social programs that cannot be provided, at this time, through a competitive process should continue. It is appropriate that all segments of the market support these social programs through the collection of a system benefits charge (SBC), an amount that is collected through the utility's distribution tariffs.

First, it is important to perform an evaluation of the existing programs and determine which programs should be continued for social reasons and which can be performed competitively. For example, there are programs that fall under the heading of demand-side management for which a great deal of competition exists in the marketplace today. These programs should be competitively provided and not funded through a SBC.

Once the determination is made that there are programs for which a competitive market has not developed, the SBC will fund the continuation of those programs. In some instances, the utility may still be the only provider of these services. Therefore, the utilities should not be relieved from their responsibility of providing these services until a viable market is demonstrated.

Metering Continuum of Customer Services

Independent metering companies can provide a continuum of value-added customer services to improve quality of life

Energy Services

- Standard and consolidated monthly billing of utility provision
- Load management
- Outage monitoring
- Energy management tools via the internet

"Quality of Life" Services

- Home management/automation
- Home security/latch key
- Internet access
- Toxic gas monitoring
- Community bulletin board in home

Metering System Economics

In other industries, value-added services have tilted system economics in favor of absorbing upfront customer acquisition costs with the result that products and services are made more widely available

Industry	**Investment/Incentive**
• Credit Card	• No annual fee credit card • Reduced-rate cards
• Cellular phones	• Equipment
• Direct Digital Satellite	• Free trial period • Equipment

Metering companies interested in selling AMR related services may be willing to fund a portion of the customer's cost to install it

Enron Capital & Trade Resources

CHART 3

A number of companies are prepared with technologies that can provide energy services to end users as soon as metering is unbundled...

Metering
Competing AMR Technology (Energy Services)

✓ = current ✓ = planned ✓ = potential

Technology	Company (Utility)	Contiguous Scale Required	Time of Use	Monthly Meter Reading	On Demand Meter Reading	Theft Detection	Outage Detection	Load Profiling
RF Fixed	Kansas City PL (Cellnet)	Yes	current	current	planned	current	current	planned
RF Mobile	Itron[1]	Yes	current	current		current	current	planned
Fiber Coax	PSE&G (Lucent)	Yes	current	current	planned	potential	current	planned
Telephone	Wisconsin Energy (Energy Oasys)	Yes	current	current	current	current	current	planned
Telephone inbound	Schlumberger	No	current	current	current	current	current	current
Outbound	Schlumberger	Yes	current	current	planned		planned	planned
Radio	Diablo	Yes	current	current	planned	current	planned	potential
2 Way Paging	Various	No	current	current	current	current	current	planned

[1]Migrating to RF fixed system

Source: Literature Search; Chartwell Inc., Interviews with Enron, Portland General, RG&E, and Baltimore Gas and Light

Enron Capital & Trade Resources

CHART 4

... these technologies will also provide quality of life improvements

Metering
Competing AMR Technology
(Quality of Life Services)

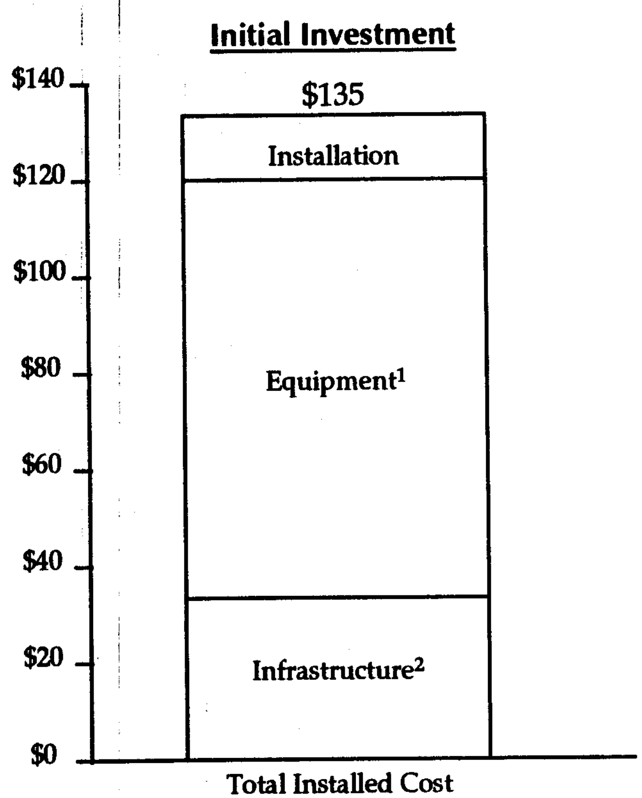
✔ = current ✓ = planned (✓) = potential

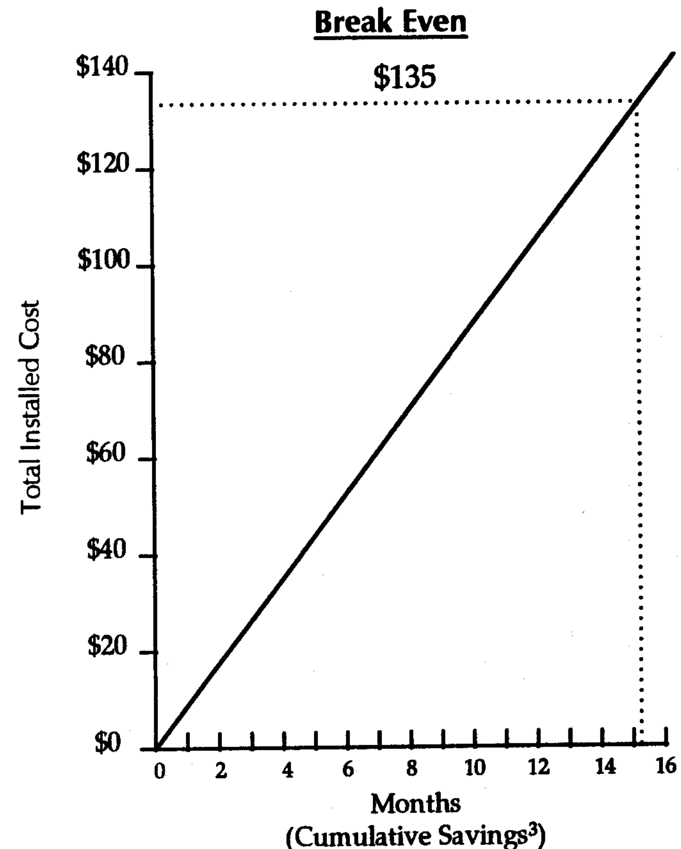
Technology	Company (Utility)	Home Energy Mgt.	Home Security	Internet Access	Other Non Energy Services[1]
Radio	Diablo	✓	✓		✓
RF Fixed	Kansas City PL (Cellnet)	(✓)	(✓)		
RF Mobile	Itron[1]	(✓)[2]	(✓)[2]		
Fiber Coax	PSE&G (Lucent)	✔	✔	✔	✔
Telephone	Wisconsin Energy (Energy Oasys)	(✓)	(✓)	(✓)	(✓)
Telephone inbound	Schlumberger	(✓)	(✓)	(✓)	(✓)
Outbound	Schlumberger				
2 Way Paging	Various	(✓)	(✓)	(✓)	(✓)

[1]Includes examples such as cable television service, load telephone service, medical alert
[2]Migrating to RF fixed system
Source: Literature Search; Chartwell Inc.

At currently estimated installed cost (replacement/retrofit of existing meter), savings associated with better energy management and more efficient meter reading have a payback period of approximately one and a half years.

Metering
Break Even Analysis
(Typical Residential User)





[1]Average equipment cost for "second generation" real time meter with two way capability; [2]Infrastructure includes all equipment necessary to support the meter at minimum efficient scale; [3]Savings at $8.80/mo. including meter reading savings ($0.35/mo.) and energy savings ($8.45/mo.)

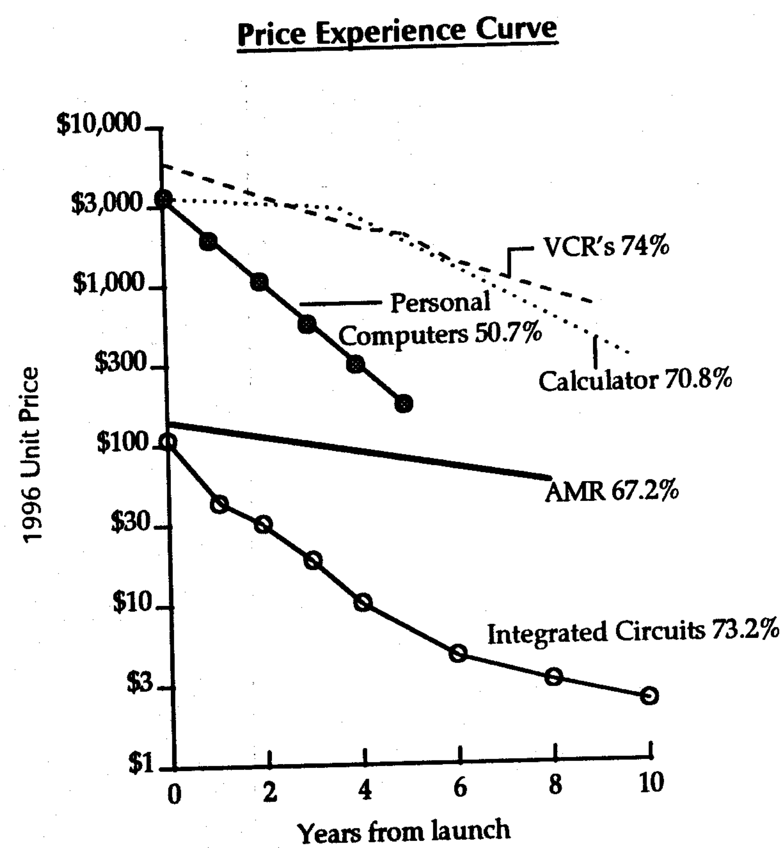
Note: Installation costs averaged from estimates by Diablo Research, Portland General, Landis and Gyr, and Schlumberger; Equipment costs averaged from estimates by Diablo Research, Enron, and Schlumberger; Infrastructure costs averaged from estimates by Diablo Research,and Schlumberger; Energy savings averaged from estimates by Diablo Research, Enron, and Landis and Gyr; Meter reading savings averaged from estimates by Diablo Research, Landis and Gyr, and Schlumberger.

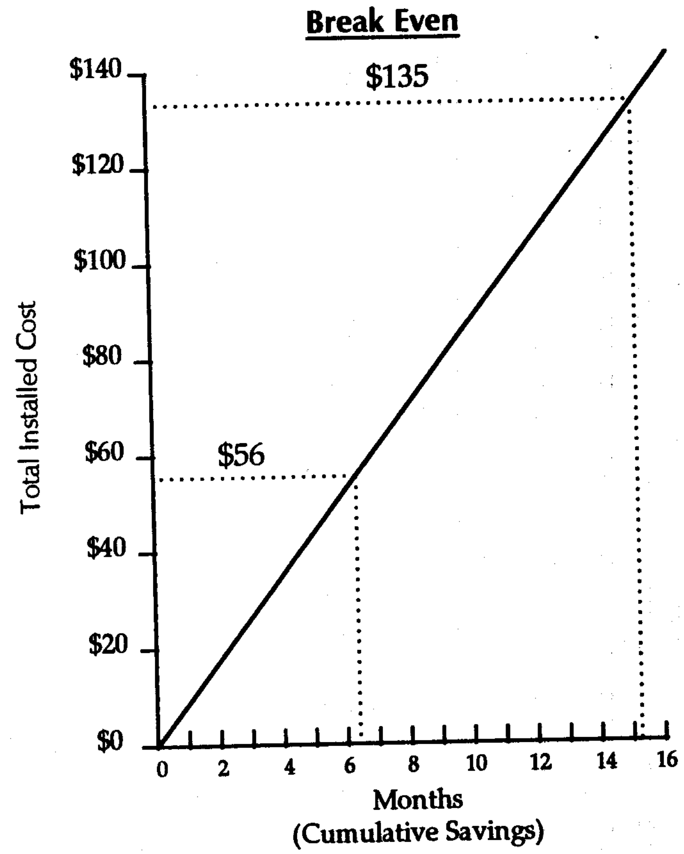
Enron Capital & Trade Resources

CHART 6

Metering
Experience Curve Effect
(Typical Residential User)

... but like calculators and VCR's, the fully installed cost of an AMR meter is expected to fall. In five years, this cost could fall enough to make the payback period less than seven months





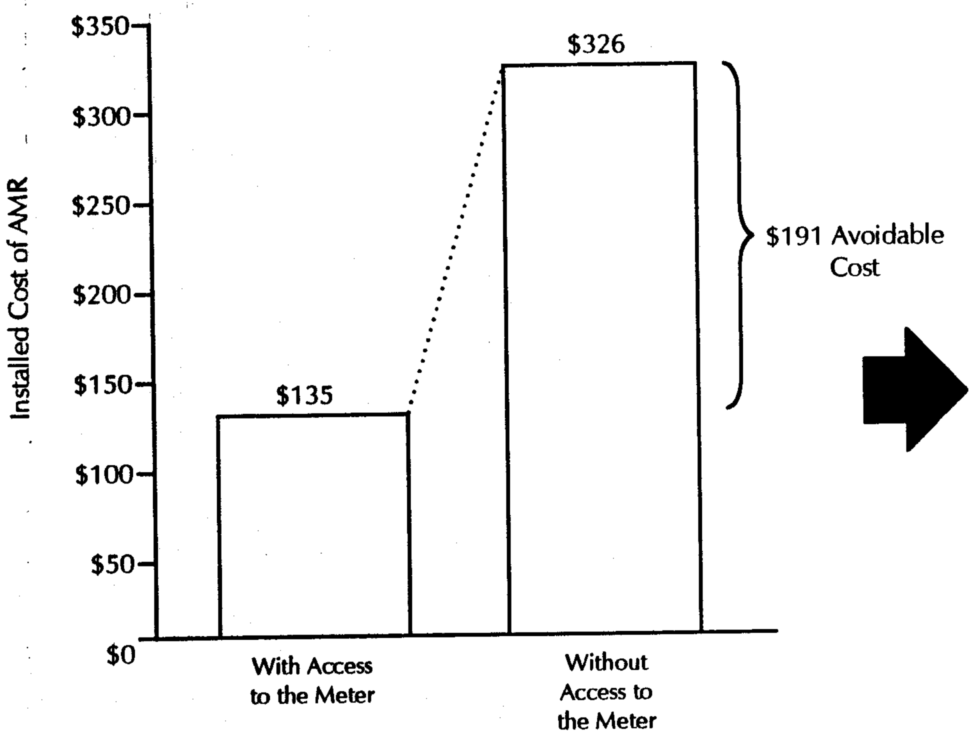
Source: Diablo Research, Portland General, Landis and Gyr, Schlumberger, The Cobra Group, Bain Experience, Bain Estimates

Enron Capital & Trade Resources

CHART 7

Without access to the meter, the installed cost of AMR capability could be an additional $191 or higher. This would significantly inhibit the end user's access to the technology

Metering
Level Playing Field



Installing an AMR gateway downstream of the existing meter would require entering the customer's home and possibly the partial removal of a wall and/or movement of the breaker box

Note: Average equipment cost for "second generation" real time meter with two way capability; Infrastructure includes all equipment necessary to support the meter at minimum efficient scale; Savings with basic service are $8.80/mo. Including meter reading savings ($0.35/mo.) and energy savings ($8.45/mo.); Installation costs averaged from estimates by Diablo Research, Portland General, Landis and Gyr, and Schlumberger; Equipment costs averaged from estimates by Diablo Research, Enron, and Schlumberger; Infrastructure costs averaged from estimates by Diablo Research and Schlumberger; Energy savings averaged from estimates Diablo Research, Enron, and Landis and Gyr; Meter reading savings averaged from estimates by Diablo Research, Landis and Gyr, and Schlumberger