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Subject: Background Material for Net Metering Workshop and CEWG Open Meeting

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Sirs,
Attached is a report generated by a subcommittee of the EPS Working Group, entitled "interconnection Barriers to Distributed Generation", submitted on April 9, 2002 and never docketed.

This report addresses topics to be discussed on October 7 at a Net Metering Workshop. The relevant material is found in:
Section 2.1, Unreasonable Buyback Rates,
Section 2.2, Non-compliance with KWH Netting Regulation.

If this report has recently been docketed and distributed to you for background on the October 6 Cost Evaluation Working Group Open Meeting or the October 7 Net Metering Workshop, please forgive the redundancy. It is my understanding that no action has taken place on it since it was submitted in April 2002.

Members of the EPS Working Group and the subcommittee will be in attendance at both meetings.

Arizona Corporation Commission
DOCKETED
OCT 01 2003
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Environmental Portfolio Standard (EPS) Working Group
Docket #

Master Issues List #9
Interconnection Barriers Report

Committee Objective
To identify, describe and prioritize barriers to the growth of distributed generation caused by interconnection issues.

Submitted:
April 9, 2002

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1 Introduction

1.1 Executive Summary

1.1.1 Renewable Energy Motives

A renewable energy market is emerging in Arizona and other states as a result of various forms of Renewable Energy Portfolio Standards and because of the growing demand among consumers for energy that holds the promise of:

- Economies built on a virtually limitless supply of energy.
- Improved prosperity for all citizens of the planet.
- A clean and healthy environment free from the toxic consequences of dependence on fossil fuels.
- A safer world, not torn by disputes over dwindling finite energy supplies, but fueled by unlimited resources.

1.1.2 Premise of the Arizona EPS

The Commissioners of the Arizona Corporation Commission have reiterated both individually and collectively on numerous occasions that the intended purposes of the Environmental Portfolio Standard (EPS) are:

1) To stimulate industries in Arizona and to bring industries to Arizona that build renewable generation equipment or generate renewable energy for use in Arizona.
2) To stimulate the widespread development and use of Arizona's own abundant renewable resources to help stem the flow of funds from Arizona for outside energy supplies.
3) To reduce the impact of non-renewable energy consumption on our environment.

1.1.3 Mechanism of the EPS

The EPS provides the utilities with a source of funds, collected from ratepayers, to use in securing or developing energy generated from renewable sources. The intent is to help offset the higher costs of renewable energy compared to non-renewable energy.

The most effective way to leverage the buying power of the dollars generated by the EPS surcharge is to entice investors to add more money to the mix by building their own renewable generation and competing to sell the energy to the utilities. For this to work, investors must be paid enough for the energy they provide to recoup their investment and make a reasonable return. Therefore, the energy sold back to the utilities must be purchased at a premium over and above that which the utilities would have had to pay for conventionally generated energy. That was the intent of the EPS surcharge, i.e. to provide the utilities with money to offset the premium that they would have to pay to buy renewable energy.

1.1.4 Current Trends

Although regulated utilities are not prohibited from developing their own renewable generation, if they use the EPS dollars for that purpose, little or no industry will be stimulated and widespread development of renewable generation will not be stimulated. In addition, the investment will not be driven by the competitive price for wholesale renewable energy.

The current direction of the major utilities is to use the EPS surcharge to build their own renewable generation. That is, they are using the surcharge funds to build plant, not to competitively buy renewable energy. Thus, they are moving the fulcrum provided by the EPS to the utility side of the lever, effectively multiplying the EPS surcharge funds by a number less than one, rather than the potentially much greater multiplier that could be obtained by encouraging independent parties to invest additional funds in expanded renewable generation.

1.1.5 Business Basics

The amount of money provided by the EPS surcharge is not sufficient by itself to entice manufacturers of renewable generation equipment or producers of renewable energy to locate facilities in Arizona. What will entice them is the assurance that future sales of equipment or energy will be in sufficient quantity in Arizona to make the investment attractive. This requires a high certainty of the EPS initiative continuity and the demonstrated flow of EPS dollars into competitive energy purchases

One of the reasons that so many independent investors have come forward with plans to develop large conventional generating stations in Arizona is that Arizona has a business and political environment friendly to building units in Arizona and selling power into not only Arizona's market but also neighboring states. The same thinking should be applied to renewable generation. The EPS should effectively stimulate a market for renewable energy; not create a windfall for utility distribution companies to own subsidized renewable generation.

1.1.6 Complicating Factors, Barriers

To complicate matters, the utilities control the transmission and distribution network and the ability to connect to it. Potential renewable generation investors must overcome multiple barriers to gain access to the grid. The barriers can all be overcome, but the cost is often high enough to discourage all but the most motivated investors with the deepest pockets.

1.1.7 Magnitude of Barrier Impact

It is impossible to quantify with any certainty how great the impact of these barriers is on the growth of distributed generation or the success of the EPS, especially because both are in infancy and trends are difficult to establish. As a result, this report does not include objective and quantitative analyses. What can be said is that all these barriers will logically impede any particular distributed generation opportunity and that cases are known where plans have been scrapped, projects have been frustrated and budgets have been broken by combinations of the barriers identified here.

1.1.8 Responsibility for Barrier Reduction

The responsibility for and the control of significant change to reduce most of the interconnection barriers belong to the utilities serving the distributed generation investors. This potentially includes all utilities, not just regulated utilities. There may be places where the Arizona Corporate Commission can encourage or hasten change, but in general it will have to be the initiative of the utilities that brings about most of the change. Some good changes (that reduce barriers) have been seen in recent years, but more changes are needed to encourage investment in renewable distributed generation and the success of the EPS.

1.1.9 Impact of Distributed Generation Barriers on EPS

We acknowledge that some EPS Working Group members have questioned whether distributed generation interconnection issues have any direct impact on the success of EPS. To that point, systems eligible for EPS credits, which are interconnected with the local service provider, are a subset of all interconnected distributed generation systems. Therefore, any barrier to the interconnection of distributed generation systems is a potential barrier to the interconnection of EPS-eligible systems. Thus, all the barriers identified by the committee are barriers to both the success of the EPS in particular and the success of distributed generation in general. Since these barriers are not the only barriers faced by distributed generation and the EPS, solving them does not assure success of either agenda. However, not solving them will surely impede the success of both agendas.

1.2 Barriers Committee Formation

As is often the case in a Working Group environment, the committee was formed in an ad-hoc process where the Working Group chairman asked volunteers to step forward, in this case to deal with the matters related to interconnection. Some Working Group members, not on the committee, contributed documentation for research and study. Other Working Group members, not on the committee, were consulted and commented on intermediate results.

1.3 Barriers Committee Statement of Objective

To identify, describe and prioritize barriers to the growth of distributed generation caused by interconnection issues.

There were attempts by parties not on the committee to widen the scope under the committee's consideration to include all barriers to distributed renewable generation. This was not done for several reasons:

1. Master Issues List #9, Interconnection, triggered the committee charter.
2. Since committee participation was originally motivated by the consideration of how interconnection issues impact the success of the EPS, we did not want to burden the members whose participation was motivated only by interconnection issues with many additional issues of lesser interest to them.
3. The scope of interconnection issues was already very large and difficult considering the number of members involved and the personal time available from each to pursue the issues.
4. Considerable effort had already been applied by others to the barriers of distributed generation in general. The results of this effort were available to the committee.

The scope stated above remained the scope throughout the term of the committee.

1.4 Barriers Committee Action Plan

1. Gather documentation related to DG interconnection. This will include laws, codes, standards, practices, guidelines, template/actual agreements, etc.
2. Review the documentation to discover and pinpoint issues.
3. Summarize the issues to a list of named problems with descriptions and references. Prioritize the list.
4. Prepare a written case for each of the named problems. Use the documents and experience as evidence. Review with committee.
5. Submit report to the Working Group and the ACC.

1.5 Barriers Identified by Priority

1. Unreasonable Buyback Rates
2. Non-compliance with KWH Netting Regulation

3. Excessive Safety, Protection and Interconnection Requirements for Large DG Systems
4. Excessive Liability Insurance Requirements for Interconnection Contracts
5. Excessive and/or Inappropriate Engineering Study Fees
6. Repeal of PURPA 210 by Legislation (potential barrier)
7. Excessive or Inappropriate Standby (backup) Charges for Large DG Systems
8. Lack of Uniform Simplified Technical Standards for Large DG Systems
9. Lack of Timely Processing of DG Interconnection Applications from Submittal to Acceptance
10. Interconnection Contracts are too Complicated, Use Tariffs Instead

An important observation is that all the barriers in this list are primarily investor issues, meaning the impacts are against the investor and not the interconnecting utility. To the extent that utilities implement and operate their own generation, these issues become trivial and simplified, because outside investors are not involved. The utilities have a variety of ways to meet the EPS requirements, and do not really have to involve investors if they don't want to. If plans and programs are not executed to promote investor-based distributed generation, these barriers will infrequently be encountered and will not seem significant to EPS success.

1.6 Report Description

The purpose of this report is to describe the most significant barriers to interconnection that prospective developers of renewable generation must overcome in order to compete in the emerging market for renewable energy.

This report is intended as an aid to anyone who is involved with or working on issues related to interconnection barriers. It is the committee's hope that in coming months, those who can make material changes to reduce barriers, will tackle some of the barriers.

This report is the complete findings of the Barriers Committee. Any resources required to support the findings have been quoted within the findings or included in the References section of each barrier topic.

This report is organized by barrier topic in the order of priority assigned to them by the committee.

This report includes recommendations or solution ideas that occurred to the committee during discussion of the barriers identified. However, the committee has made no attempt to solve any of the barriers identified. It provides explanation and clarification of the matters surrounding a barrier and points to the documents that illustrate and implement the barriers. Ideas for next steps are presented where available.

This report represents findings of the committee majority in attendance, and may contain observations not fully supported by every member of the committee.

This report does not represent all the opinions of all the members of the EPS Working Group, and it is not a consensus of full Working Group.

An index of the documentation collected for study and review is included at the end of this section. This documentation was distributed by hard copy or electronic copy to the members of the committee. Only the index is supplied here.

An electronic copy of the final report was provided to Ray Williamson, Utilities Division, ACC on April 9, 2002 by email for attachment to the EPS Docket and for distribution to the Working Group.

1.7 Barriers Committee Members

Rick Gilliam, LAW Fund
Bill Murphy, City of Phoenix
Art Rivera, Renewable Technology Company
David Rowley, SolarFarms, Inc. (chairman)
Chuck Skidmore, City of Scottsdale

1.8 Documentation Index

The Documentation Index follows on the next two pages.

Barriers Committee Report
Documentation Index

Organization	Document Name	Pages	Document Date	Web Location
ACC	Decision 52345	16	7/27/81	none
ACC	Decision 56271	19	12/15/88	none
ACC	R14-2-2XX and 16XX	36	9/18/01	www.sosaz.com/public_services/title_14/14-02.htm
ACC	DGI Final Report	41	6/28/00	http://www.cc.state.az.us/meetings/minutes/dgirpt7.pdf
ACC	Interconnection Issues Report	26	11/15/99	www.cc.state.az.us/meetings/minutes/amd3.pdf
APS	Summary of APS Buyback Tariffs	1	unknown	none
APS	Application for Interconnection of Generating Facilities	2	unknown	www.azpsoasis.com/oasis/unsecure/docs
APS	Sample Residential Interconnect Agreement	17	unknown	none
APS	APS Residential Supply/Purchase Agreement	7	unknown	none
APS	EPR-2 Rates	3	7/1/00	none
APS	EPR-2 Rates	3	7/1/01	none
APS	EPR-4 Rates	2	7/1/00	none
APS	EPR-4 Rates	2	7/1/01	none
APS	Intrconnection Requirements for Distributed Generation Rev 2	32	Sep-99	none
APS	Transmission Tariff Rev.10 Attach. N	64	11/17/00	www.azpsoasis.com/oasis/unsecure/docs
ARS	Arizona Revised Statutes	2	9/17/01	www.azleg.state.az.us/ars/ars.htm
ASES	Policy Statement on Photovoltaic Interconnection Issues	7	10/1/99	www.ases.org/solarguide/photovoltaic.htm
DOE	Distributed Generation Barriers	1	?	www.eren.doe.gov/distributedpower/sublvl.asp?item=barriers
FERC	Code of Federal Regulations	20	4/1/01	www.access.gpo.gov/nara/cfr/waisidx_01/18cfr292_01.html
FERC	QF Application Instructions	7	9/4/00	www.ferc.gov/electric/qfinfo/qfhow.htm
FTC	Report on Regulatory Reform	82	7/1/00	www.ftc.gov/opa/2000/07/electric.htm
FTC	Report on Regulatory Reform - Updated	92	9/1/01	www.ftc.gov/reports/elec/electricityreport.pdf
HR954	Home Generation Act	6	3/8/01	http://thomas.loc.gov
PURPA	16USC12-ii-824a-3 Cogeneration and Small Power Generation	8	1/6/99	www.access.gpo.gov/uscode/title16/chapter12_subchapterii_.html

Organization	Document Name	Pages	Document Date	Web Location
PURPA	PURPA201.txt	115	5/8/97	http://www.ferc.gov/electric/qfinfo/purpa201.txt
PURPA	PURPA210.txt	89	5/8/97	http://www.ferc.gov/electric/qfinfo/purpa210.txt
PURPA	Index of US Code to PURPA	3	8/23/01	www.ferc.gov/informational/acts/purpa.htm
PURPA	Index of US Code to FPA	3	8/23/01	www.ferc.gov/informational/acts/fpa.htm
SEPA (UPVG)	Position Statement on PV Interconnection	10	10/2/00	none
SEPA (UPVG)	Barriers and Solutions to Interconnection, Issues for PV Systems	14	8/1/00	none
SRP	Agreement for Electric and Interconnection Service	21	4/13/01	none
SRP	Interconnection Agreement Template draft	18	5/24/01	none
SRP	Construction Agreement Template draft	13	9/5/01	none
SRP	Solar Choice Rider	1	5/15/00	none
SRP	Renewable Pricing Rider	1	5/15/00	none
SRP	Buyback Service Rider	2	5/15/00	none
SRP	Generator Guidelines web page	1	8/21/01	www.srpnet.com/power/generators
SRP	Interconnection Guidelines for Distributed Generators	33	Dec-00	www.srpnet.com/power/generators
SRP	Rules and Regulations	79	8/28/00	www.srpnet.com/power/generators
TEP	Interconnection Requirements for Distributed Generation	34	3/15/01	none
TEP	Residential Interconnect Agreement	16	unknown	none
TEP	Commercial/Industrial Interconnect Agreement	16	unknown	none
TEP	Residential Non-Parallel Connection	9	6/19/00	none
TEP	Pricing Plan PRS-101 Non-Firm Power QF Under 100KW	1	7/1/00	none
TEP	Pricing Plan PRS-102 Firm Power QF Under 100KW	1	7/1/00	none
TEP	PV Interconnection Application	1	1/30/01	www.greenwatts.com

2 Detailed Barrier Analyses

Following are analyses of the top six interconnection barriers in the above list.

2.1 Unreasonable Buyback Rates

2.1.1 Barrier Cause

Current utility tariffs do not pay a fair market value for electrical energy delivered to the host utility by customer-owned renewable generation. There are several un-captured sources of value that are the reasons why these buyback rates do not provide a fair market value, as listed here:

1) **Cost of Distribution:** The subject renewable energy has already been distributed to nearly the exact point of use by virtue of the generation being distributed. Therefore, part of the value not received is the value of transmission and distribution services and the reduction of their losses.
2) **Cost of Generation:** The subject renewable energy has a higher cost of generation than nonrenewable energy. Therefore, part of the value not received is the value of higher avoided cost for utility generation of equivalent renewable energy.
3) **Intangible Value:** The subject renewable energy has higher intangible value to the public for such reasons as increased energy independence, reduced environmental impact, unlimited supply, reduced water requirements, etc. Therefore, part of the value not received is the greater socioeconomic value of renewable energy consumption.
4) **EPS Credit Value:** The subject renewable energy has EPS credit value, created by the permission granted in the EPS for utilities to accumulate credit for renewable energy generated by others. This value is driven by the independent supply and demand for credits.

In the context of this barrier cause, it must be acknowledged that utilities are now and always have calculated buyback rates for customer generated energy from qualifying facilities using the same authorized and legitimate avoided cost methodology supported by both federal and state regulation. This method was in existence before deregulation, before divestiture by the UDCs of their generating resources and before the EPS. The method has a basis in historical logic and precedent. The method even has some relevance today for centralized non-renewable energy, but still falls short of being tied to the current market price for wholesale energy, the actual cost the utilities avoid when buying power from qualifying renewable generating facilities.

2.1.2 Barrier Impacts

1. Impediment to Investment: Because of unreasonable buyback rates, renewable generation investment dollars from others than utilities, are limited to a very few and fairly small systems, the justification for which is not highly dependent on savings. The only hope for such investments is that the resultant system will displace energy that would have been purchased from the utilities at retail prices. Even this is difficult to accomplish if the buyback rate is not accompanied with KWH netting. The only incentive in such cases is for displacement energy, not for maximum generation. Because of unreasonable buyback rates, large systems, intended to regularly generate more than required for their own use, do not make any financial sense. This impediment to investment means that capital, over and above that provided by the EPS surcharge, will not be forthcoming from non-utility investors. The hoped-for leverage of private investment dollars by the EPS dollars will not happen.

2. Impediment to Renewable Energy Industrial Growth: The possibilities for encouraging a thriving renewable energy industry in Arizona are greatly limited. Surcharge dollars spent by the utilities will stimulate some limited amount of industrial growth. However, because the surcharge dollars are spent mostly on internal programs, the growth will be very modest and mostly within the spending utility. To truly stimulate significant industrial growth, surcharge dollars must be augmented with private dollars that are spent outside the utility. The rules contained in 52345 were written to effect the integration of traditional, large-scale, centralized, utility owned, fossil-fueled generating plants with similar technology in similar locations developed by non-utility generators. The current business model for renewable generators is somewhat different, merging primarily small distributed renewable generation, i.e. customer generators, with traditional, large-scale, centralized, utility owned, fossil-fueled generation. The difference between these two models is largely due to the sources of investment represented by each, the latter model assuming a large quantity of small investors.

3. Impediment to Consumer/Investor Collaboration with Utilities: The magnitude of the unfairness in the buyback value is so great that casual observers are stunned at the seeming indifference of the offering utilities. Customers know that the utilities know the discrepancy in value, so the utilities are assumed to be taking advantage of the customers' ineffectual response. At the very least, customers feel they are being treated with monopolistic disregard and big-business forcefulness. This entire attitude results in an us-vs.-them relationship, not productive for either party. Investors do not expect to get revenues that will automatically pay back any arbitrary investment. However, they do expect to get values that are based on real generation costs and market variables. Rates should take into consideration things such as the new state of electric competition, the differences between non-renewable energy costs and renewable energy costs, the differences between distributed and centralized energy costs, and the differences between kinds of renewable energy (solar electric vs. non-solar electric) as defined by the EPS. Some of these factors are obviously market driven, and may need to be broken out (like a fuel adjustment) for automatic adjustment. Some of the factors are cost driven, and should be tied to the costs of equivalent commodities. Whatever approach is used, it needs to represent a credible attempt to assess a fair value for the commodity being procured. Every investment in renewable generation that adds capacity to the overall electrical grid requires that the customer and the utility do business with each other, or no investment will occur.

2.1.3 Barrier Recommendations
Buyback rates paid for customer distributed renewable energy should be revisited with the objective of paying a fair market value for the commodity. The reassessment should factor in the changes that have taken place in the electric industry as the result of deregulation, the advent of the EPS, and the effect of distributed generation.

2.1.4 Comments on Causes
Cost of Distribution: Renewable generators should be compensated based upon the actual value of the energy where it is actually delivered. In residential and commercial instances, the facility's excess generation is almost certainly consumed in the next nearest load. Such loads are usually on the same distribution transformer or at least on the next nearest transformer. The means that the excess energy moves a very short distance (indeed, the shortest possible distance) from the generator to the load. Although this path is provided by the utility, it does not in any way worsen the loading on any portion of the path. In fact, loading on the transformer primary and upstream distribution is always reduced. Whatever the utility pays for the energy, they get to redirect it at retail rates. The full value of transmission and distribution services is a reasonable approximation of the value provided. If someday a significant percentage of retail customers were to become generators, it would probably mean the utility cost of transmission and distribution would increase on a per KWH basis. Meanwhile, the impact is undetectable.

Cost of Generation: It used to be that every increment of generation and transmission could be justified on the basis of the next lowest cost MWH. That was possible because all MWH were equivalent commodities. Today, via the EPS, quotas have been set for MWH of different kinds. Quotas have been set for total renewable energy as a function of total retail load, and for total solar electric energy as a function of total renewable energy. This means there are now three distinct kinds of energy which cannot be randomly substituted for one another on the basis of cost, and all of which have significantly different costs of generation. For convenience, call conventional energy brown, for it includes all fossil and nuclear generation. Call all renewable energy green, except for solar electric energy. Then call solar electric energy yellow. The costs vary from high for yellow to low for brown. Yellow can substitute for green and brown, green can substitute for brown, and brown cannot substitute for either green or yellow. However, because of costs, green and yellow energy will be produced and delivered only in the minimum amounts required to meet the quotas, until costs become competitive with brown energy, which is not expected any time soon.

The EPS quotas create a demand for green and yellow energy. The cost of generating green and yellow energy is higher than for brown energy. Therefore, the projected cost to build the next MW of green or yellow energy would compare with the old method of assessing avoided cost to establish buyback rates. Since there are large differences between green and yellow energy costs, and since their markets are separate, the calculated avoided costs should also be separate. This method would simply allow for the fact there are three kinds of MWH and that they have three very different costs. This approach is similar to the historical technique, but still fails to factor in certain new conditions.

Since all three kinds of energy can be obtained on the wholesale market, and since utility distribution companies are not supposed to own generation but instead should buy from the wholesale market, it makes sense as soon as practicable to set the value of green and yellow energy to the wholesale market values for the same. This places the green and yellow generation in the right place in the restructured and unregulated generation pool. It increases the size of the competitive renewable energy pool and helps to stabilize renewable energy prices. It is a way of improving and maintaining uniformity among utilities for green and yellow energy.

Intangible Value: Since the current costs for renewable energy are already higher than for functionally equivalent non-renewable energy, it would be hard to justify yet higher premiums for intangible value. This value is most useful in justifying higher buyback rates as compared to current retail rates. The energy available at retail rates gives you the disadvantages opposite to the intangible benefits of renewable energy. It may not be that a price can be put on these intangible benefits, but they should at least give us a sense of doing the right thing in our present circumstances and heading in the right direction for posterity.

EPS Credit Value: The value of EPS credits is based on the small market for these credits in Arizona. The price may be volatile, but the single most important factor in its stability is the assurance that these credits will continue to be needed for a certain number of years in the future. Uncertainty, due mostly to the speculation on regulatory change, will permit only very short-term arrangements and deflate the value of every transaction.

Probably the best way to assess the value of EPS credits is to take a weighted average of as many credit transactions as possible over the recent past. Like the cost of generation, green and yellow credits need to be priced separately, because only a yellow credit can be applied against a yellow quota.

It is likely that green and yellow credit value will always need to be kept separate from KWH value. This will support independence of credit transfer and interconnection agreements and will enable the EPS credit rate to fluctuate with whatever benchmark might be chosen, independent of the green or yellow energy rate.

Utilities may use the transfer of credit ownership as a component in a lease or buy-down arrangement, but even there, in fairness to the customer, the value of the credits should be explicitly declared.

2.2 Non-Compliance with KWH Netting Regulation

2.2.1 Barrier Cause

Some Arizona utilities have failed to provide customers with the choices of operating modes and KWH netting options described in ACC Decision 52345, IV.D. regulation (Reference Item #2) for Qualifying Facilities.

2.2.2 Barrier Impacts

1. **Customer Economics**: The customer KWH bill for net KWH will always be less than for gross KWH.
   Impact: If the customer does not receive KWH netting, it results in less economic justification for an installation and less customer incentive to invest in DG.
2. **Metering Cost**: The alternative methods of KWH netting cost more than what is minimally required to implement the ACC Decision 52345. Meters for interconnections are usually upgraded (changed out) with meters more expensive than were originally required.
   Impact: Whether paid by the customer or the utility, the extra cost is unnecessary.
3. **Metering Complexity**: The alternative methods of KWH netting require more complex instruments than the minimum needed to implement the ACC Decision. Their gross numbers can be used to calculate net KWH per the regulation, but usually are not. Suitable meters are of the least complex design available.
   Impact:
   1) Customers have a harder time understanding the metering technique and results.
   2) Billing information and meter calculations are usually more complicated because of more complex metering.
4. **Legal Exposure**: Utilities are required to meet the ACC regulations unless specifically given exception.
   Impact: Failure to do so may result in at least, disputes with customers who are dissatisfied with the current metering arrangement, and at most, litigation over compliance and tariffs.
5. **Cost of Correction**:
   If utilities have to revise billing calculations, refund or charge monies for previous non-compliant KWH metering, and make mandatory tariff changes, there is considerable administrative cost.

2.2.3 Barrier Conclusions

Based on Decision 52345, regulated Arizona utilities must provide all QF's an option to measure and/or calculate net KWH and a tariff that addresses the net KWH metered (52345, IV.D.). The case studies below indicate that some utilities are not providing some of the options required by Decision 52345. Only APS and TEP are analyzed, because they both were represented on the Barriers Committee.

<u>**APS Conclusions**</u> Based on Cases 1-4 and Reference #5, APS does not provide any option to net KWH, nor do they offer the simultaneous buy/sell mode of operation. They only offer the parallel mode of operation and with it they only offer gross KWH measurements and gross billing.

<u>**TEP Conclusions**</u> Based on Cases 5 and 7, on paper, TEP offers all the metering configurations and billing options intended by Decision 52345. However, in practice, TEP offers only the metering configuration intended by the term Parallel Mode in 52345, and they call it Simultaneous Buy/Sell Mode. TEP could not say what metering configuration they would offer if the customer requested the Parallel Mode option.

It is not possible to determine if TEP meets all the requirements of 52345 without knowing what they would offer under their tariff provision for Parallel Mode, which they say has never been exercised. To meet all the requirements, TEP would have to provide a meter configuration with both a generation meter and a load meter for simultaneous operation as intended in 52345.

Regardless of what TEP calls their methods being practiced, or whether they meet all the requirements of 52345, TEP does practice KWH netting, under their current tariffs for DG <100KW, and as described in Method 3.

2.2.4 Metering Configurations and Calculations for KWH Netting Supported by Decision 52345

This section is here to show the several methods to implement KWH netting supported by Decision 52345. All of the options prescribed by Decision 52345 and available to a QF are presented here, in order of cost, complexity and information available. The terms in and out, sale and purchase are relative to the utility.

The parallel mode is called so because the customer load and generator are connected in parallel with no meters between them. The meter is between the utility and the combined customer load/generation.

The simultaneous buy/sell mode is called so because it permits the simultaneous accumulation of generator output and load consumption. The meters can run simultaneously, but each only in one direction.

The first method is the simplest, cheapest and least informative method. The other methods may be more suitable for commercial and industrial applications, depending on advanced metering requirements and the need for more information.

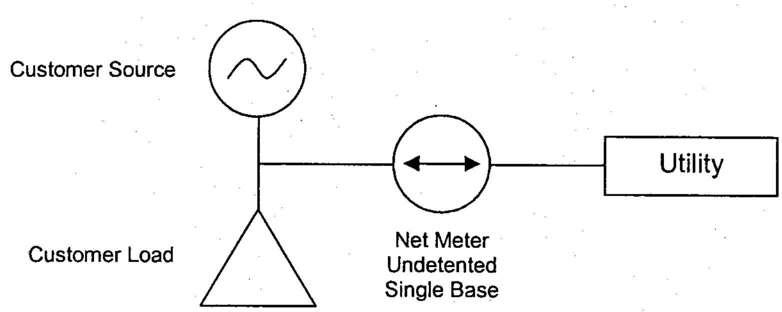
All the parallel mode methods would need a generator (source) meter in addition to what is shown here to meet the EPS criteria for generator metering. Such a meter is not shown because it is not necessary for KWH netting.

Method 1: Least Cost, Least Complex, Least Information
Parallel Mode of interconnection as specified in 52345, IV.D.2
This method measures net KWH mechanically, by permitting a single meter to turn in either direction. There is one reading, which is always the net KWH to date. As is customary, the previous net reading is subtracted from the current net reading for the period net KWH. Gross KWH in and out are not available.

The existing meter base is suitable and the existing meter can be used if it is not detented.

Calculation Example:

Current Net
-Previous Net
Period Net KWH



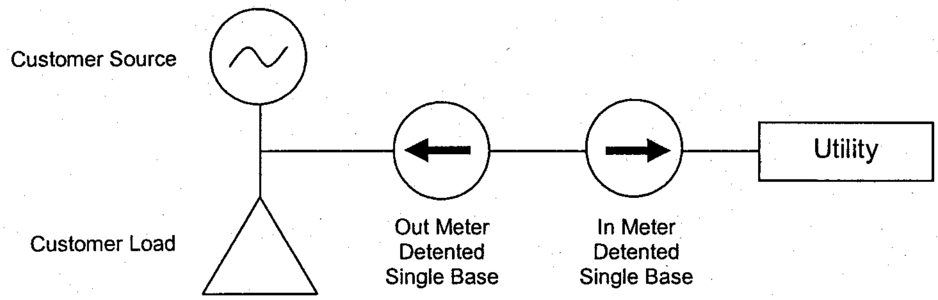
Method 1 is the most practical method for residential interconnections. However, Method 1 does not strictly comply with the 52345, IV.C.4 Metering, which requires two meters on all QF's. Since the second meter is primarily to facilitate load research (as stated in 52345, IV.C.4), it is unnecessary in a residential application. Since Method 1 completely fills the needs of the net metering regulations for residential applications, there should be no charge to the customer for any additional meters or replacement meters if only net metering is required. This method meets all the metering requirements for the simultaneous buy/sell mode using the Net Bill method (52345, IV.D.1.a.), except with one meter instead of two. It also meets the metering requirements for parallel mode (52345, IV.D.2). Gross KWH is not available using this method.

Method 2: More Cost, More Complex, More Information
Parallel Mode of interconnection as specified in 52345, IV.D.2
This method measures gross KWH in and out on two separate meters, detented in opposite directions. The gross KWH in and out for the period are obtained by subtracting the previous gross in and out readings from the current gross in and out readings. Netting for the period is accomplished by taking the difference of the gross in and out KWH for the period.

The existing meter base is suitable for either meter. The existing meter can be used if it is detented.

Calculation Example:

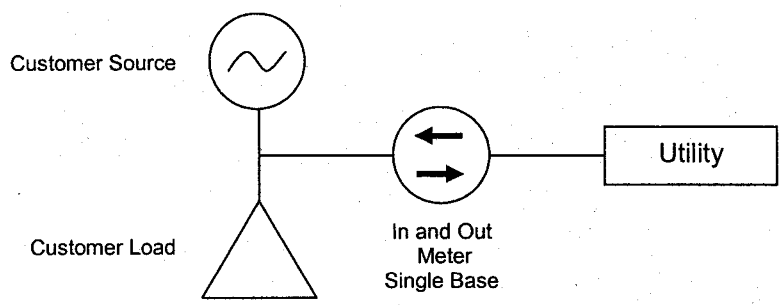
Current Gross Out		Current Gross In	
-Previous Gross Out		-Previous Gross In	
Period Gross Out	minus	Period Gross In	= Period Net KWH (+Out or –In)



This method may be preferred if the customer or the utility wants to keep track of gross KWH in and out. This method is fully compliant with 52345, IV.C.4 Metering, because it provides two meters. This method is more likely to be used for industrial and commercial customers. This method meets all the metering requirements for the simultaneous buy/sell mode, Net Bill method (52345, IV.D.1.a) and for the parallel mode (52345, IV.D.2). Since gross KWH is measured, the gross values can be misapplied by gross billing instead of net billing.

Alternative Method 3: More Cost, More Complex, More Information
Parallel Mode of interconnection as specified in 52345, IV.D.2
This method measures gross KWH in and out on two separate registers in the same meter housing. The calculations are the same as for Method 2.

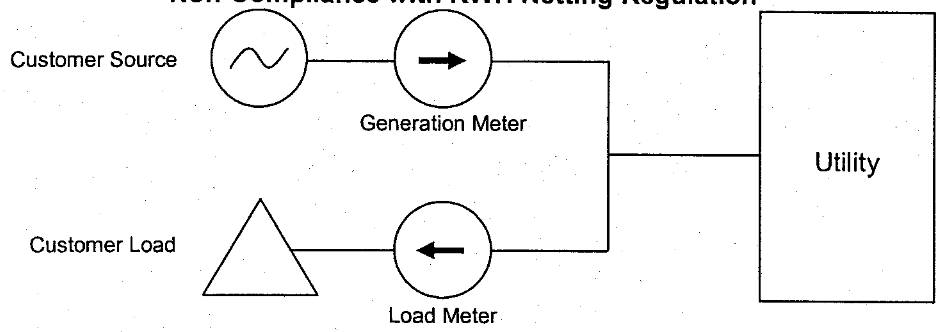
The existing meter base is suitable for this meter. Most customers do not already have this kind of meter; therefore a meter replacement is usually required to obtain it.



This method is very similar to Method 2, except that only one meter housing and base is required. This method is fully compliant with 52345, IV.C.4 Metering, because functionally it is two meters. This method is more likely to be used for industrial and commercial customers. This method meets all the metering requirements for simultaneous buy/sell mode, Net Bill method (52345, IV. D.1.a), and the parallel mode (52345, IV.D.2.). Since gross KWH is measured, the gross values can be misapplied by gross billing instead of net billing.

Alternative Method 4: Most Cost, Most Complex, Most Information
Simultaneous Buy/Sell Mode of interconnection as specified in 52345, IV.D.1.a.-b.
This method measures gross KWH generated and gross KWH consumed on two separate meters. Because power can flow only one way in each meter, the meters can be either detented or not detented. This is the only method that provides measurements of generator and load KWH. It can do this because the generator and load KWH are combined on the utility side of the meter instead of the customer side of the meter.

For simplest installation when adding a generator, the pre-existing load meter can be left as is and the additional generator meter installed to measure the generator output.



Example: Net Bill Method (52345, IV.D.1.a.)

Current Load		Current Generation	
-Previous Load		-Previous Generation	
Period Gross Load	minus	Period Gross Generation	= Period Net KWH (+Out, -In)

A reason for using this method is to understand the generation and load performance regardless of the net KWH. Another reason for using this method is that it meets the additional EPS standard requirement for metering the generator output that will receive EPS credits (Reference #3 and 4). All the other methods would require that a dedicated generator meter be added to meet the EPS standard. This method yields the same numeric results for Net KWH as Methods 1-3. It accomplishes Net Metering or Net Billing as defined in R14-2-201 (See Reference #1 below.).

Example: Separate Bill Method (52345, IV.D.1.b.)

Current Load	Current Generation
-Previous Load	-Previous Generation
Period Load KWH	Period Generation KWH

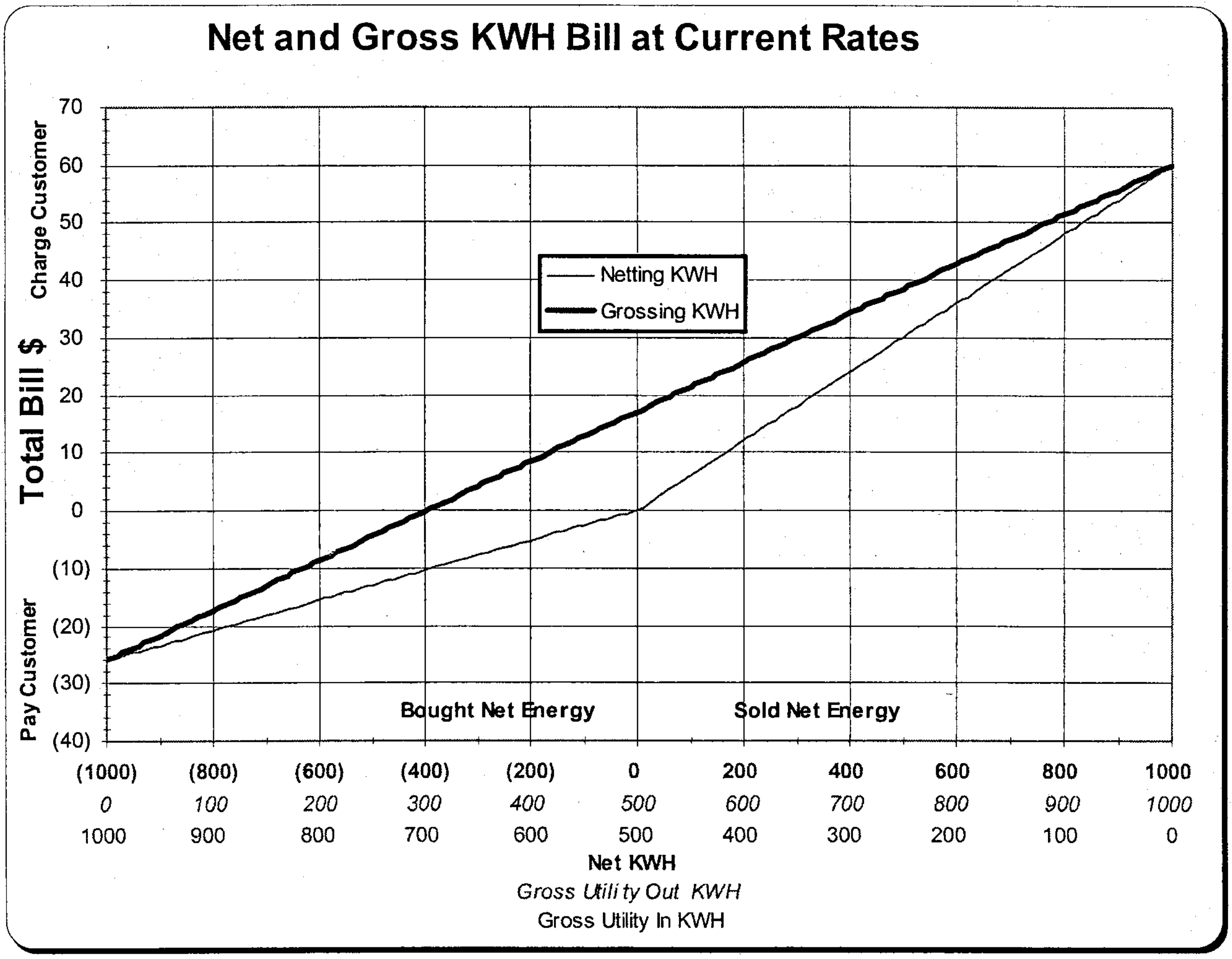
A reason for using this method is to charge different rates for all generation KWH and all load KWH. This method does not provide netting. Although permitted by the Decision 52345, it does not accomplish the Net Metering or Net Billing as defined in R14-2-201 (See Reference #1 below.). The Separate Bill Method is not a KWH netting method.

2.2.5 Comparison of KWH Netting and KWH Grossing for Current Rates

One might well ask, "What difference does it make whether the customer is billed based on gross in/out KWH or net in/out KWH. To help visualize the differences, the methods have been modeled in tables and presented in a graph. The graph presents the relationships among the net energy exchanged, the energy buy/sell rates and the total customer bill for KWH. To use the graph, select the monthly net KWH expected on the horizontal axis. Draw a vertical line through the plots at that net KWH. Read the net KWH bill and the gross KWH bill on the vertical axis.

Assumptions:

1. All the terms and signs are as viewed from the utility.
2. The gross energy exchanged is a constant 1000KWH for every net value. The portions provided by the customer and the utility varies from 0-1000 KWH. So, the net energy exchanged varies from +1000 to zero to –1000 KWH.
3. The buy rates are APS EPR rates. The sell rate is $.06.
4. No provision is made for modeling peak and off-peak differentials. The $.06 rate includes a mixture.



Observations:

1. The maximum difference between the methods is at a net of zero.
2. The gross bill is always more expensive to the customer, unless the in or out amount is zero, in which case they are equal. Some customers cannot generate more than their quiescent load, therefore they never accumulate KWH into the utility.
3. If the in and out rates were equal, the lines would be identical, straight and passing through zero.
4. Most residential users will operate near the right end of the graph. They will normally be unable to generate more than their load, so will infrequently push KWH into the utility.
5. To scale this chart for the actual application, find the difference between the gross and net bills, and then multiply it by the factor that makes 1000KWH become the actual average monthly exchange. Or, multiply the horizontal and vertical axis by any common factor.

Conclusions:

The actual dollar difference between gross KWH billing and net KWH billing for practical situations appears not to be very significant. Some utilities will insist it is so small as to be negligible. If so, they should be as willing to provide netting as the customer is anxious to obtain netting, knowing that the difference will be small.

What really matters is the customer's perception that netting is fairer or a better "deal" than grossing, and is therefore more motivated or encouraged to enter into such an arrangement. However small that difference may be, the customer is right up to the point where the buyback rate equals the sell rate, and then there is no difference.

2.2.6 Barrier Cases

1. APS EPR-4, Purchase Rates for QF's 10KW or less generating renewable energy
   Italicized titles are tariff headings. Underlined headings are author's own headings. Double quotations are taken verbatim from the tariff.
   Application: This tariff only applies to renewable generators under 10KW. If it were compliant with 52345, it would still require a tariff like EPR-2 to include all generators under 100KW.
   Metering Configuration: The configuration described is that of Method 3. There are two registers that accumulate gross in and gross out KWH separately. The meter does not net the in and out KWH. It must be netted by an external calculation, which APS does not do.
   In addition, the APS method of billing for gross in and gross out, is not equivalent to the method described in 52345 as the 'separate bill' method, where the gross generation and the gross load are bought and sold.
   Definitions: The definition for Partial Requirements Service correctly describes this system configuration as a "parallel mode of operation." However, since neither this tariff nor any other tariff offers the simultaneous buy/sell mode of operation described in 52345, APS is not fully compliant with 52345. The mode of operation must be the Customer's choice. Both modes permit KWH netting.
   Other Tariffs and Agreements: Since this tariff only covers APS purchase rates, it must be used in conjunction with another standard retail tariff for sale rates. This tariff references "Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities" of which a copy is not available.
   Monthly Purchase Rate: "Rate for pricing of energy, net of that for the customer's own use, that is delivered to the Company." This rate description is misleading and confusing, but agrees with APS' practices. The referenced rates are applied to all energy into the utility, regardless of the amount out to the customer. So if in and out amounts are equal, in gets a purchase rate and out gets a retail sales rate. This is not compliant with 52345, because the in and out registers are never subtracted for a net KWH result. Their use of the word "net" is misleading. It actually refers to the fact that the source and load energy is combined on the load side of the meter, the difference being measured by the meter. In 52345, "net" means the difference of energy in and out of the utility (or customer), not in and out of the source and load. Although the words in this tariff are not very clear, the APS description in Reference #6 is very clear. APS calls this technique 'net billing'. This is not consistent with the definition of 'net billing' in Reference #1, where 'net billing' and 'net metering' are equated. It is obvious why APS calls this 'net billing', because they net the bill for purchases and the bill for sales, not the KWH exchanged. APS' redefinition of the term 'net billing' leads to confusion regarding their compliance with Decision 52345.
   Payment for Purchases from and Sales to the Customer: "The Company will pay the Customer for any energy purchased as calculated on the standard purchase rate." This means to APS that all the energy accumulated on the in register is purchased, even if the amount on the out register is greater than the amount on the in register. To be compliant with 52345, it would have to say 'pay the Customer for the net energy purchased'. The out and in registers are not netted by APS.
2. APS EPR-2, Purchase Rates for QF's 100KW or less
   Italicized titles are tariff headings. Underlined headings are author's own headings. Double quotations are taken verbatim from the tariff.
   Application: This tariff applies to all generators under 100KW. If it were compliant with 52345, a tariff like EPR-4 for renewable generations under 10KW would not be required, but would be permissible.
   Metering Configuration: Same as EPR-4.
   Definitions: Same as EPR-4.
   Other Tariffs and Agreements: Same as EPR-4.
   Monthly Purchase Rate: *Same as EPR-4.*
   Payment for Purchases from and Sales to the Customer: *Same as EPR-4.*
   Differences between EPR-2 and EPR-4: EPR-2 includes service charge rates for single and three phase services of different capacities, whereas EPR-4 does not. EPR-2 has a provision for sharing the cost of the metering, whereas EPR-4 assesses no metering costs to the Customer. The scope of application is different as described in the titles. None of these differences impact KWH netting.
3. APS Residential Electric Supply/Purchase Agreement
   Parties: The agreement is described as "for the purchase of electric energy from and/or the sale of power to" the customer facility. The words do not explicitly designate 'net power', so the words permit the meaning of 'gross power', which is the meaning APS applies.
   Recitals 2.1: The agreement assumes "parallel mode" only, not permitting the Customer choice of simultaneous buy/sell as required in 52345. No other APS agreement provides the simultaneous buy/sell choice to residential customers.
   Recitals 2.2: The "...Customer shall purchase its electrical power requirements from APS and sell its excess

energy production to APS..." Since APS bills gross Customer power requirements as viewed by the meter, the Customer actually pays for its instantaneous power requirement deficit, not for 'all' its power requirements (the whole load) as implied in the recital. The main point is that the energy deficit and the excess energy is not said to be netted, and never is netted.
Recitals 2.3: The claim that the Customer "intend(s) to interconnect their respective facilities...for displacing electric power purchases from APS," is not true as far as the customer is concerned. The Customer intends to displace power 'receipts' with 'power deliveries' (which is KWH netting), not to displace "power purchases" with 'power sales' (which is bill netting according to APS). However, because APS bills gross KWH delivered and gross KWH received, the Customer's real intentions are defeated, and he is 'net billed' according to APS instead of 'Net Billed' according to 52345. The Customer KWH received is never displaced or offset or netted by the Customer KWH delivered, which would be KWH netting.
Sales to Customer 4.1: "APS shall sell, and Customer shall purchase and pay for, all electric power delivered..." This leaves no doubt that the intention is to bill the gross power delivered/received. To mean otherwise would at least require the use of the words 'the net' in place of "all" electric power.
Purchases from Customer 5.1: "Customer may sell, and APS may purchase and pay for, electric energy that is produced by the Customer's GF, and delivered to..." Same as 4.1, except the purchase is described as optional instead of required.
6. Metering Provisions and Billing Periods: Nothing in this section implies KWH netting. Rather, 6.3 refers to "all energy supplied to the GF and/or purchased by APS", which implies gross in and out metering.

4. APS Agreement for the Interconnection of Customer's Residential Generation Facility to the APS Distribution System.
   This agreement is more extensive in terms and conditions than the one in Case 3. However, it does not refer to netting KWH and it does make the same references to parallel mode as in Case 3. The comments in Case 3 are applicable in this case, however the paragraph numbers vary. This agreement does not have an explicit section or paragraph on metering.
5. TEP Tariff PRS-101, July 1, 2000, Non-firm from Renewables, Cogeneration and SPPS
   This tariff and the one below have the same tariff number and effective date. The titles are different and the contents are different. TEP says this title is the current version, and the other one is obsolete.

   The customer is offered the configuration options in Decision 52345 of Parallel Mode and Simultaneous Buy/Sell Mode.

   TEP says they have no customers listed under the Parallel Mode configuration. They could not describe how it would be metered or billed.

   The Buy/Sell Mode gives the QF three options. The first two are taken almost verbatim from Decision 52345. The third is called Net Metering. This discussion will be one at a time by paragraph number.

   3-b-I, Net Bill Method: TEP says this option is metered with a single meter having two registers. In reality, this meter configuration is what is meant under Parallel Mode in the Decision 52345, but TEP calls it Simultaneous Buy/Sell. It is the method described in Method 3 above. The rate department calls this meter "bi-directional", not because it turns both directions, which it doesn't, but because it has both an "in" and "out" register. This is confusing, because "bi-directional" usually means that the meter can turn backwards and forwards. However, TEP does net the KWH on the bill and apply the relevant rate, whether "in" or "out". As noted in the Method 3 discussion, this is numerically equivalent to the Buy/Sell Mode Net Bill KWH, but by using one meter, it does disagree with the tariff statement 3-b, which says "total" generation and "total" electric requirements are bought and sold. In conclusion, TEP's implementation meets the intentions of the Net Bill Method in 52345, but their application of terms and the ACC Rule is confusing.

   3-b-ii, Separate Bill Method: TEP says they have no customers on this method. They say that doing so would cause some difficulty, because the automated KWH calculation for bills is based on the 3-b-i and 3-b-iii methods. In other words, their billing computer is set to net KWH before applying the rates. They confirmed that if the method were used, the metering would be the same as described in 3-b-i. Once again, the metering method is really Parallel Mode.

   3-b-iii, Net Metering: This option provides a meter that turns both directions. As a result, the KWH billed is the same as with the Net Billing method, just performed by a different meter. The only apparent difference in billing is if the net is into the utility, the customer is credited with the excess KWH against the net KWH for the next billing cycle. The customer cannot forward year-end net KWH credits into January. Once again, the metering method is really Parallel Mode. It should be noted that TEP has said there is a limit to how many customers will be permitted to subscribe to the Net Metering tariff, however the tariff contains no such limit.

It should be noted that TEP does not offer, in practice, a metering configuration that complies with the Simultaneous Buy/Sell Mode. Such a mode requires two meters, one for generation and one for the load. However, they are providing two ways of KWH netting with a single meter. If pressed, they would provide the Separate Bill scheme with a single meter as well, since it is listed in the tariff, but they would be quick to illustrate that for most residential customers, it would not provide an economic advantage.

6. TEP Tariff PRS-101, July 1, 2000, Non-firm QF Cogeneration <100KW
Because this tariff was superseded by the one above, only the differences are listed here:
The title was changed. Paragraph 3-b-iii, Net Metering, was added.
7. TEP Tariff PRS-102, July 1, 2000, Firm QF Cogeneration <100KW
This tariff reads exactly like RPS-101 used to read, except with slightly higher buyback rates. It would be implemented as described about for RPS-101. It does not have paragraph 3-b-iii, Net Metering.
8. TEP PV Interconnection Application, 01-30-01 Rev.1
This interconnection application makes reference to tariff R101-3b-I for Net Billing, R101-3b-ii for Separate Billing and R101-3b-iii for Net Metering. Comments on these are in cases above. Nothing else is said about metering.
9. TEP Commercial/Industrial Interconnect Agreement
In Section 6, Interconnection Facilities and Points of Interconnection, it says: "Where arrangements are made in which the customer delivers energy to TEP's system, a bi-directional KW/KWH revenue meter will be installed in place of the Customer's existing revenue meter." Based on the comments made by the rate department, this would mean a single meter with two registers, one for gross KWH in and one for gross KWH out. Although no reference is made here to what tariff would be applicable, the only ones TEP has that fit this case for buyback rates are PRS-101 and PRS-102 if the generator is <100KW. It is interesting that paragraphs 2.1, 2.4 and 4.5 refer to the system being interconnected in "electrical parallel"" with TEP's system. See Case 5, 3-b-i above to see that their definition are reversed from the 52345 intent, so it is not clear what metering configuration they might offer in this parallel mode.
10. TEP Residential Interconnect Agreement
As regards metering and compliance with Decision 52345, this agreement is much like the one in Case 9. Paragraphs 2.1, 2.4 and 4.5 refer to the interconnection being in "electrical parallel". The same sentence as quoted in Case 9 is found in Section 6. The same uncertainties exist as to what would be provided.
11. TEP Interconnection Requirements for DG, dated 03-15-01
This document states it is to be used by customers and the utility for planning of DG, which will be connected to TEP. It is a far more technical document than the Agreements in Cases 9 and 10 or the tariffs.

In definition 2.4 for Distributed Generator, the word "parallel" seems to be used in the conventional electric circuit meaning, and not in the special purpose meaning of Decision 52345 as regards metering.

In definition 2.14 for Parallel Operation, again the word "parallel" seems to be used in the conventional electric circuit meaning, which is described as "...interconnected to a bus common with...".

In Section 4, Distributed Generation Types, TEP clearly defines the opposite of "parallel" as being "separate". Parallel or not parallel are opposites. This must be kept in mind, because in 52345, the contrast to parallel is "simultaneous", which is a reference to meter configurations, not electrical connections. A Simultaneous Buy/Sell Mode configuration would meet this guideline's definition of Parallel Operation, which is as it should be in strictly electrical terms.

In summary, this document sheds no further light on metering terminology in the tariffs or the agreements in above Cases, and contradicts nothing in Decision 52345.
12. TEP Agreement for Non-Parallel ... with TEP's Distribution System, dated June 19, 2000
This agreement is a shorter form of residential agreement than Case 10 above, and presented in a letterform, but is still 8 pages long. It is applicable only if the customer does not wish to sell excess power to the utility. TEP has customers operating under this agreement, or one very much like it.

This agreement creates the term "non-parallel", which in this document means that the customer does not wish to supply power to the utility. This use of the word is limited to this agreement, and is in conflict with the definition of "parallel" in Case 11 and all the tariffs and Decision 52345. Case 11 would define systems covered by this agreement as being connected in parallel.

No comment is made regarding metering configurations, tariffs or billing options. The interconnection agreement does not provide for any means to prohibit back-feed into the utility, but the customer is asked to guarantee that no back-feed will occur. To ensure the customer meets this requirement, TEP would have to install a meter with two registers, like in Method 3. If the "in" register ever advanced, they would know the customer had not met his requirements. There is no indication as to what meter or configuration might actually be used.

The primary purpose of this agreement is to support the technical issues of an interconnected customer DG, while applying only a tariff for retail sale and no buyback tariff. Some customers prefer this arrangement. Nothing in this agreement either implements or precludes anything required in Decision 52345.

2.2.7 Barrier References

1. **R14-2-201 Definitions, 29.**
   "Net Metering" or "Net Billing" is a method by which customers can use electricity from customer-sited solar electric generators to offset electricity purchased from an Electric Service Provider. The customer only pays for the "Net" electricity purchased.

   Comment: This definition is in complete agreement with Decision 52345 so long as it means to net the KWH exchanged, and not the price of the gross KWH exchanged. The only reason for its inclusion in the regulation is because of the reference to net metering and net billing programs in the EPS rules, R14-2-1618-C.3.c. (See Reference #3).

2. **Decision 52345 (excerpts)**
   IV. Standard Rates for QF's 100KW and Under
   C. Contract Form
   Within 60 days after the effective date of this order, each utility will file with this Commission a standard contract form for use in agreements between QF's and utilities. That form will include, but not be limited to, the following terms:
   1. Metering
   Metering for billing and for load research should be specified.
   Two meters shall be required for all QF's to facilitate load research. Time-differentiated metering should be addressed, if appropriate.
   The contract should specify that the QF is responsible for additional metering costs over and above normal metering and should indicate the methods by which those costs will be recovered.
   Provision should include the access, testing and reading requirements.
   D. System Configurations
   A QF may be operated in either of two possible system configurations.
   1. **Simultaneous Buy/Sell Mode:**
      The QF may elect to operate in a simultaneous buy/sell mode, whereby all the generation output is sold from the generation facilities directly to the utility and all electric requirements are met by sales from the utility. Billing for purchases and sales shall be calculated, at the option of the QF, in either of two methods:
      a. **Net Bill Method:**
         The KWH sold to the utility shall be subtracted from the KWH purchased from the utility. If that calculation is positive, the utility will price the net KWH at the standard retail rate under which the customer purchases its full requirements. If that calculation is negative the utility will price that energy at the standard rate for QF's 100KW and under.
      b. **Separate Bill Method:**
         All purchases and sales shall be treated separately with revenues from sales to the QF calculated on the applicable standard retail rate for full requirements service, and the purchase of power from the QF at the applicable standard purchase rate.
   2. **Parallel Mode:**
      The QF may elect to operate in a system configuration where the QF's self-generation facilities first supply his own electric requirements, with any excess power being sold to the utility.

      All purchases of the QF's excess generation output by the utility shall be calculated under the applicable standard purchase rate.

      The utility shall sell power to the QF as required by the QF at the standard retail rate for full requirements service, unless it can be demonstrated by the utility that the total contribution of the cogeneration or small power production technology of the QF within the utility's jurisdiction is so significant as to necessitate an appropriate rate or rates to reflect the partial requirement characteristics of the group of QFs.

3. **R14-2-1618**
   C.3. Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier:
   Any distributed solar electric generator that meets more than one of the eligibility conditions will be limited to only one .5 extra credit multiplier from this subsection. Appropriate meters will be attached to each solar electric generator and read at least once annually to verify solar performance.
   a. ...
   b. ...

c. Solar electric generators located in Arizona that are included in any Load-Serving Entity's <u>Net Metering</u> or <u>Net Billing</u> program.

d. All Green Pricing, <u>Net Metering</u>, <u>Net Billing</u>, and Solar Leasing programs must have been reviewed and approved by the Director, Utilities Division in order for the Load-Serving Entity to accrue extra credit multipliers from this subsection.

4. **Eligibility Criteria**

The Eligibility Criteria for most technologies has metering criteria that reads as follows:

a. The meter must measure the renewable energy delivered to the load. Where renewable energy is combined with other energy sources, i.e. diesel-electric, the metering must accumulate only the renewable energy.
b. Batteries or other storage devices must be on the source side of the meter.
c. The meter and interconnection must meet all the requirements of the local LSE for billing, even if the LSE claiming the credits is not the local LSE.
d. Net metering is not sufficient unless where it is used there are no loads on the load side of the meter.

5. **APS Handout in EPS Working Group Meeting**

APS' standard offer EPR-2 and EPR-4 rates specify the metering arrangement and the buy-back (or purchase) rates based on the Company's estimated avoided energy costs. EPR-2 is applicable to qualified cogeneration and small power production facilities <100KW, while ERR-4 is applicable only to qualified small power production facilities <10KW using renewable resource technologies. A generating facility meeting the requirements of a "qualifying facility" (QF) as defined by PURPA requirements, will be able, under the provisions of the existing rates to sell excess power to APS. APS presently has no filed tariffs for facilities >100KW. APS buy-back rates will be negotiated on a case-by-case basis for qualified facilities >100KW.

Both the EPR-2 and EPR-4 rates require the installation of a bi-directional meter. A bi-directional meter has two separate metering registers to record sales to the Customer and purchases from the Customer. The Customer is charged the appropriate retail rate under the applicable APS tariff for their energy usage (sales to the Customer). APS purchases excess energy from the Customer at the current buy-back rate in accordance with the provisions of the applicable APS buy-back rate (normally EPR-2 or EPR-4). This is termed "Net Billing". Purchases from the Customer would only occur when the Customer's generation exceeds the customer load at any given instant.

Note that the concept of the "Net Metering" is typically described as "allowing the meter to run backwards". In addition to displacing its own load, net metering would give distributed generation Customers credit for all energy supplied to the distribution grid at the Customer's applicable rate (i.e. full retail value). Net metering would subsidize the distributed generator and shifts additional transmission and distribution costs to other APS Customers. For this reason, APS does not permit net metering.

2.3 Excessive Safety, Protection and Interconnection Requirements for Large DG Systems

2.3.1 Barrier Cause

Personal Safety issues -The key here is to determine which requirements are truly necessary for safety. It is very important to realize that the maintenance of electric facilities is a dangerous business. However, if proper procedure is followed, personal safety is very certain even in the face of unusual and unpredictable circumstances. Many safety precautions are dictated by codes, standards and practices invoked by bodies responsible for public and private safety. Where recommendations are made to implement safety features not directed by these bodies, such a recommendation may be suspected of being excessive. It should be examined carefully for precedence, without which it is probably not reasonable or prudent.

Over/Under Voltage and Frequency Protection - Until the impact of DG increases significantly (say in 20 yrs) the rigidity of the grid is such that the size of generators in the 10 to 100kw size will have little ability to jeopardize the stability of the grid, but will instead increase stability. However, larger generators may well have an impact on stability. The question we should be working on is, at what size does the DG component become a stability concern and how do we manage that for mutual benefit. IEEE worked on this and there is some preliminary information on this.

Modern solid-state converters of sizes up to and beyond 1MW easily meet all requirements without excessive protection, because the protection required and supplied on all converters is built-in, similar, adequate and faster than the grid. To avoid excess protection for large mechanical converters requires a custom review of each situation and the appropriate application of common sets of protective elements for the situation.

Standardized Interconnection Requirements: The ACC recognized the need for standardized interconnection rules and tariffs in 1999 and opened a Distributed Generation and Interconnection investigation, ACC Docket #E-00000A-99-0431. However standardized interconnection requirements were never established and this process was never completed. In lieu of this, utilities have had to unilaterally issue interconnection rules, some of which discourage distributed generation. Other States (CA, TX, and NY) have recently come up with Interconnection rules and Tariffs that treat non-utility generation more fairly.

AEPCO (the Cooperatives) in their Feb. 25th response to ACC Chairman Mundell's Jan.14th, 2002 question on distributed generation (IV.B.8.a) ".....Most utilities understand that distributed generation is a viable option and have established reasonable standards for the protection of all parties. Others, however, have erected barriers to losing a customer and only talk about interconnect requirements, while not acting to establish any interconnection standards. The way to resolve this issue is to establish uniform and reasonable standards for interconnected facilities...by the ACC at the distribution level, so that each party specifically knows in advance what is expected."

This problem is so severe that we have an Arizona utility commenting on other Arizona utilities raising barriers to renewable and distributed generation.

2.3.2 Barrier Impact

This barrier results in uncertainty and indecision by customers of the utilities. This is a series of barriers that taken together create an atmosphere of caution that discourages investment in distributed generation and the renewable technologies promoted by EPS. The complex web of interconnection requirements and tariffs make it difficult for individual utility customers to determine on their own the benefits of large renewable energy projects. The net effect of these diverse requirements is to raise barriers. But most importantly is that in concert they create so much uncertainty that they discourage investment in reliable and renewable resources.

2.3.3 Barrier Conclusion

Uncertainty is the enemy of wise investment. Uncertainty is not necessary.

2.3.4 Barrier Recommendations

The distribution network can be made more intelligent by pairing it with new techniques that provide it with additional options. This requires the cooperation of the owner operator. That is not present today.

There is a concerted effort to quantify the negative aspects of distributed generation without quantifying the positive side. The times that distributed generation can prevent outages or voltage dips should be included in the calculation. Real-time pricing would help resolve this issue.

The ACC should follow through with their 1999 docket, and establish standardized interconnection rules.

2.4 Excessive Liability Insurance Requirements for Interconnection Contracts

2.4.1 Barrier Cause

The LSE for each interconnection believes that their personnel and/or system equipment is under greater risk of injury, damage and loss as a result of the customer applying a power source to lines that otherwise would only have loads connected. This belief causes them to insist the customer pay for insuring against such injury, damage or loss by requiring certain minimum liability insurance levels for these interconnections.

2.4.2 Barrier Impact

The imposition of large insurance requirements has the following impact on the customer:

1. **Cost**: Insurance costs money, so if the liability requirement is in excess of the amount the customer already has or should have, there will be an added cost for the interconnection to provide the required liability insurance.
   Impact: Reduced economic justification for interconnection.
2. **Complexity**: The acquisition of additional insurance for risks unfamiliar to the customer is a complex transaction of administration and procurement that is objectionable and awkward to most customers, demanding personal time and effort, and consuming schedule. Even customer insurance agents will not be able to explain with much clarity who or what is being protected and from what.
   Impact: Increased reluctance to interconnect and increased personal time and effort invested.
3. **Conviction**: Most customers will never be convinced that the additional insurance is really necessary or appropriate. They will object to the "idea" of it, because the insurance is for the benefit of someone who is bigger, richer, smarter and more experienced than they are in these matters.
   Impact: Increased reluctance to interconnect.
4. **Double Coverage**: The customer perceives they are already paying higher costs for equipment that is designed and certified not to cause hazardous conditions for operating and maintenance personnel. Further, the customer perceives they are paying for installation materials and methods compliant with codes and regulations formed to eliminate or reduce the likelihood of hazardous conditions. These higher equipment costs should reduce, not increase the customer's need for liability insurance protection (like an alarm system reduces the premium for home insurance). The customer is being asked to pay for double coverage.
   Impact: Reduced economic justification for interconnection.

2.4.3 Barrier Conclusions

1. The evidence below shows that for several major utilities in Arizona, the current position is to require high liability insurance minimums by the customer for all but certain small PV systems.
2. There is a huge discrepancy (~10X) between the levels of insurance recommended by industry experts and the amounts actually required by utilities.
3. The evidence also shows that there is a trend among some states to limit or eliminate liability insurance requirements for interconnection agreements.

2.4.4 Barrier Recommendations

1. We recommend the utilities should voluntarily move in the direction of lower or no insurance requirement for interconnections, rather than work through the formation of laws or regulations to prohibit or limit insurance requirements for interconnections. Special circumstances may occasionally have risks that need to be mitigated by liability insurance.
2. We recommend that each LSE review their requirements for appropriateness with questions like the following:
   a. Is there any real definable or documented risk associated with the interconnection, presuming utility operating and maintenance protocols are followed?
   b. Is the liability insurance requirement in line with the liability normally required by that kind of customer or facility?
   c. Is the liability insurance requirement consistent with the size and ratings of the interconnection?
   d. Is the liability insurance requirement consistent with the compliance of systems and equipment to codes, standards and certifications?
   e. Is the liability insurance requirement consistent with the use of proven/unproven technology and products?
3. We recommend that every few years an ACC working group should summarize and review the requirements as stipulated by the major utilities, and identify any inconsistencies or striking exceptions among them. The results should be published to all utilities.
4. The Solar Electric Power Association recommends the following in their Position Statement on Photovoltaic Interconnection Issues in the US, October 2000, Contractual Aspects of PV Interconnection, Insurance and Indemnification:
   Any requirements for insurance and indemnification should be reasonable. It may not be necessary to require customer generators to purchase additional liability insurance if the customer already has coverage of at least

$100,000 for residential systems or $250,000 for commercial systems. Moreover, utilities and regulators should be aware that it might be inappropriate to require customer generators to indemnify their utility.

2.4.5 Barrier Cases

The following items are either excerpts or condensations of the material found in the referenced documents. No interconnection agreements were available for utilities not included in this list.

1. TEP Commercial/Industrial Interconnect Agreement
   Agreement for the Interconnection of Customer's Generation Facility to the TEP Distribution System Between Tucson Electric Power Company and Customer
   Section 21, Insurance/Waiver of Subrogation
   Commercial General Liability Insurance or equivalent form of not less than $1,000,000.
2. TEP Residential Interconnect Agreement
   Agreement for the Interconnection of Customer's Generation Facility to the TEP Distribution System Between Tucson Electric Power Company and Customer
   Section 21, Insurance/Waiver of Subrogation
   Commercial General Liability Insurance or equivalent form of not less than $1,000,000.
3. TEP Interconnection Requirements for Distributed Generation 03-15-01
   Section 5.1, Insurance
   Customers interconnecting with TEP shall be required to maintain public liability and property damage insurance. Insurance requirements are spelled out in the Interconnection Agreement between TEP and the Customer. (See 1 & 2 above.)
4. TEP Greenwatts Sunshare Program Hardware Buydown Agreement, Revision 1, 01-30-01
   No requirements.
5. APS Residential Electrical Supply/Purchase Agreement
   No requirements.
6. APS Sample residential Interconnect Agreement
   Agreement for the Interconnection of Customer's Residential Generation Facility to the APS Distribution System
   No requirements.
7. APS Interconnection and Operating Agreement 11-16-2000
   Section 18.1.1
   Worker's Compensation and Employer's Liability Insurance of $1,000,000 per accident.
   Section 18.1.2
   Commercial General Liability including Contactor Liability Coverage for $25,000,000 per occurrence for Bodily Injury and Property Damage.
8. SRP Agreement for Electric and Interconnection Service, draft
   Section 19, Insurance
   General Liability Insurance with a combined single limit for bodily injury and property damage of not less than $2,000,000 for each occurrence.
9. SRP Agreement for Electric and Interconnection Service Between SRP and City of Phoenix (Okemah Park)
   Section 21, Insurance
   Commercial and General Liability of not less and $2,000,000 for each occurrence.
10. SRP Interconnection Guidelines for Distributed Generation
    Section 5.1, Insurance
    Customers interconnecting a DG must comply with insurance requirements specified in the Interconnection Agreement between the Customer and SRP.
11. ASES Policy Statement on Photovoltaic Interconnection issues, February 2000
    Summary of Recommendations
    Bullet 8
    Liability insurance requirements for customer generators should be no more than $100,000 for residential systems and $250,000 for commercial systems.
12. Kelso Starrs and Associates, Thomas J. Starrs
    Barriers and Solutions to Interconnection Issues for Solar Photovoltaic Systems, prepared for the Solar Electric Power Association
    Liability Allocation (parenthetical material not in original)
    One of the most challenging and controversial issues associated with utility interconnection of customer-owned PV (DG) systems is the issue of protecting against the risk of liabilities arising from property damage or personal injury caused by the PV (DG) system. A particular concern is the possibility of a PV (DG) system improperly backfeeding power into an otherwise de-energized portion of the utility grid,

which could inure or even kill a utility worker expecting the line to be out. The question is not so much who is ultimately liable, because established legal principles generally are adequate to determine responsibility and legal culpability. Rather, the issue that generates the most controversy is to what extent a utility may require its customer with PV (DG) systems to carry insurance to protect against worst-case accidents associated with the operation of the PV (DG) system. Many utilities want PV (DG) system owners to carry comprehensive general liability policies with coverage amounts of $1,000,000 or more. Although commercial customer commonly carries this type of insurance, it is essentially unheard of among residential customers, whose homeowner's insurance typically includes personal liability coverage in smaller amounts.

Both utilities and PV (DG) system owners can make compelling arguments in support of their positions. In general, utilities argue that as potential "deep pockets" they are entitled to require substantial liability insurance in order to minimize the risk of being held ultimately liable for damages attributable to generating facilities they neither own nor control. In response, customers generally present several arguments. First, they note that there are no reported instances of property damage or personal injury attributed to an electrical failure in a PV (DG) system. Second, they argue that the addition IEEE and UL standards by inverter manufacturers means that the risk of failures – already very small is even further reduced. Third, they note that as a practical matter, obtaining and maintaining million-dollar liability insurance policies is impracticable for the owners of residential-scale PV (DG) systems because the premiums are likely to exceed the energy benefits of the PV (DG) system.

State policymakers facing the challenge of reconciling these conflicting views have usually either sided with the PV (DG) system owners, or essentially split the difference. According to a recent paper on the topic, five states (CA, MD, NV OR, and WA) have prohibited utilities from imposing insurance requirements on small-scale PV (DG) systems eligible for net metering, and five other states (ID, NM, NY, VT, and VA) have limited the amount of liability insurance that utilities can require for these systems.

13. Interstate Renewable Energy Council, Second Edition 1999, by Chris Larsen
    Section 3.1.3, Liability Insurance
    Liability insurance is required by most utilities that have interconnection standards for PV as a way to protect themselves and their employees should there be any accidents associated with the system. Most homeowners already have at least $100,000 of liability insurance through their standard property insurance policies, so this requirement poses no further costs to the PV owner. In the first test of this issue, the New York Public Service Commission in 1998 rejected the proposal of several NY utilities that PV systems falling under the state's net metering rule have between $500,000 and $1,000,000 in liability insurance. The Commission concluded that $100,000 would be sufficient (Starrs, 1998).
14. State Farm Insurance
    State Farm specializes in homeowner and individual insurance. An attempt was made to acquire a General Liability Insurance policy from State Farm. They have no such policy for homeowners. State Farm can raise the homeowner's liability insurance to $1 million dollars for about $50 per year. Unfortunately, this does not permit the assignment of the host utility as an additional insured as required by most interconnection agreements.

2.5 Excessive and/or Inappropriate Engineering Study Fees

2.5.1 Barrier Cause

As a part of general guidelines and agreements for implementing distributed generation interconnections, utilities have included the right to perform an engineering study of the proposed interconnected system and interconnection.

2.5.2 Barrier Impact

Schedule – Studies take time. Typical responses are four to six weeks. The best timing of this activity is after conceptual design of the proposed facility and before financing the project. Not much can be done in parallel with this activity, and it is usually a linear additive to the overall project schedule. Unfortunately, projects without financing do not get very high priority with available resources for performing studies.
Cost – Presently, both the cost of the study and the cost of any recommended changes to either the utility system or the generation system required to accommodate the distributed generation project are the responsibility of the project investor.
Uncertainty – Because engineering studies are exercised at the discretion of the interconnecting utility, it is often not clear during project estimating and planning whether or not they will be required, how many there will be, and how long they will be, causing a schedule uncertainty. In addition, a design study may result in generation system design changes for reasons not anticipated by the planners based on current guidelines, codes and good practice, resulting in scope uncertainty. Worse yet, the results of an engineering study may impose the cost of utility system changes on a proposed distributed generation project causing cost uncertainty.

2.5.3 Barrier Conclusions

Each utility represented in the Barrier Cases below contributes to the excesses of review, study, analysis and approval. All utilities can take big steps to simplify, shorten and improve the process.

2.5.4 Barrier Recommendations

Engineering studies are inappropriate for most small systems and some large systems. It should be possible to set criteria which, if not met, will require an engineering study. This would reduce some uncertainties. For example, if a small system is not capable of generating output in excess of the designed service capacity, it should not be necessary to study the impact on the utility. In short, do not treat all systems as unique.

Engineering studies done by the interconnection utility should be limited in scope to the utility's own system. The information needed from the customer would be minimal and could be provided before detail design has begun. The cost of such a study should be borne by the utility. This will make certain studies are minimized and that the customer is not paying the utility untarriffed fees to support the utility's ordinary engineering responsibilities. In short, each utility should take care of its own business.

The cost of recommended utility system changes to interconnect with new distributed generation should be supplied by the interconnecting utility. This includes the cost of meters required to implement new tariffs and the cost of distribution systems from the distribution transformer back to the utility generator. The customer should have the same responsibility that he has for any new construction project. The utility's existing tariffs cover metering and distribution costs. This approach would reduce customer cost and make sure the utility would not inflate either the recommended changes or the cost of them. They would certainly optimize both.

A pre-construction design approval for the new distributed generation system should be handled like all new construction plan approvals. Designs would be submitted by the customer for review by qualified utility engineering inspectors, and the criteria for the review would be the current guidelines, codes, practices and standards for distributed generation as applicable to the specific project. The scope of the review should be limited to the customer's scope of supply. The customer would be responsible for obtaining approval before installation and for the cost of customer system design changes needed to obtain approval. Ideally, this would be possible with independent engineering inspectors.

2.5.5 Barrier Cases

1. SRP

Interconnection Guidelines for Distributed Generators, 12-2000
Section 8, Typical Process for Installing a DG, Fourth Step
SRP Engineering and Operations departments conduct a preliminary review of the project to ensure that it meets SRP's guidelines (typically six weeks).
Comments: Considering the level of detail of data provided by the customer, 6 weeks is a very long time for review by the utility.

Interconnection Agreement

7.1.1 Review all information, specifications, designs and test results submitted by Customer pursuant to this Agreement. SRP may require modifications to Customer's specifications and designs based on current industry standards to enable SRP to operate its system as safely and reliably as possible. SRP shall notify Customer in writing of the results of its review of the specifications, designs and test results in a timely manner and shall include in its notifications to Customer any discovered flaws or design errors.
Comments: This seems to require more information than in the first reference. It also seems to include review and corrections on the generator design.

7.2 SRP's review of Customer's specifications, designs and test results shall not be construed as confirming or endorsing the design or as any warranty of safety, durability or reliability of Customer's Generating Facility, or of Customer's equipment or protective devices or the technical or economic feasibility of the Generating Facility. The sole purpose of SRP's review is to evaluate whether the Generating Facility will adversely impact SRP's system.
Comments: Though the customer is required to submit to the review, and is required to pay for it, he is assured that he will get nothing for it, and that it is done solely for the benefit of the utility.

2. TEP
Interconnection Requirements for Distributed Generation
1. Scope, Facilities that will be connected directly to the transmission system will be reviewed by the utility on an individual basis.
Comment: If by transmission system they mean at voltages above distribution voltage, the rule is probably justified. At lower voltages, review should be on an exception basis.

3. Overview if Distributed Generation Issues, The utility shall disallow the interconnection of a Customer's generating facility if, upon review of the Customer's design or facility, it determines that the proposed design or facility is not in compliance with applicable safety codes, or is such that it could constitute a potentially unsafe or hazardous condition.
Comment: This requirement would be fair if the last phrase were dropped, which leave the utility room to say that just about anything they decide constitutes an unsafe or hazardous condition.

7.1.6 General Technical Requirements, It is strongly recommended that the Customer submit specifications and detailed plans as specified in the Application and Equipment Information Form (refer to Appendix A) for the installation to the utility for review and written approval prior to ordering any equipment.
Comment: This is apparently because the utility may refuse to connect to certain generation equipment or may decide the arrangement is not suitable. This should be possible contingent only upon the customer failing to meet codes or guidelines available before design.

7.7.1.6. With the addition of generation at a Customer site, the ground fault current magnitude might increase to the level where the grounding grid is insufficient to protect personnel from step or touch potentials. Therefore, a study may be required to ensure the adequacy of the Customer's grounding grid to keep the step and touch potentials at a safe level in the vicinity of equipment accessible by utility personnel or the general public.
Comments: A grounding study is unusual, but sometimes required by TEP.

8.2 The "Application and Equipment Information Form" (see Appendix A) must be completed by the Customer and all supplementary information requested therein must be provided to TEP for review
Comment: Review of the customer design by the utility is mentioned many times in this document. It probably is being assumed that at least two reviews are held, one at application and one after final design.

Application Process
Step 4 – Upon completion of the design, the Customer submits the final design package (as specified in the Application Form of the Interconnect Requirements manual) to TEP for final review and approval. Customer notifies TEP interconnection contact person that information has been submitted, and TEP reviews information and informs Customer within fifteen (15) working days of receipt as to sufficiency of information and whether any information is missing.
Comments: This delay period of 3 weeks only yields an indication that the data submitted is sufficient.

Step 5 - Upon receipt of completed and sufficient application information, TEP reviews the application for conformance to the interconnect requirements within thirty (30) working days, unless other timeframes are mutually agreed upon. TEP will respond to Customer within this time as to whether the submitted design

information complies with the interconnect requirements or if there are any issues in non-compliance.
Comments: The final review period is 4 weeks. The total review time including Step 4 may be up to 7 weeks.

4. APS
Interconnection Requirements for Distributed Generation
3. APS Policy on Customer-Owned Generation
APS can disallow the interconnection of a Customer's generating facility if, upon review of the Customer's design, it determines that the proposed design is not in compliance with applicable safety codes, or is such that it could constitute a potentially unsafe or hazardous condition.
Comments: Same as TEP. Leave off last phrase.

4.2 Parallel System
APS does not extend "blanket approval" to any specific type of generator or generator scheme since each project is site specific and needs to be reviewed on a case-by-case basis.
Comments: Here it is made clear that approval is never based on type and reviews are not based on exception. This statement is typical in all utility agreements.

2.6 Repeal of PURPA 210 by Legislation

2.6.1 Barrier Cause

This year in the 107th Congress, two bills have been submitted that will negatively impact Distributed Generation in general, and most attempts to connect renewable energy sources of any kind to the grid. The House Bill is HR381, submitted on January 31, 2001 and the Senate Bill is S552, submitted on March 15, 2001 (See evidence #1&2). They both promulgate repeal of PURPA 210 (See evidence #3). Source information about these bills can be found at http://thomas.loc.gov.

2.6.2 Barrier Impact

If either bill is enacted, no utility will have any legal or regulatory requirement to buy or sell energy to a Qualifying Facility. Without legal pressure, utilities are not expected to enter into new contracts, whether for renewable energy or not. Current regulations would have to be aligned with the new law. All forms of distributed renewable energy, especially solar-electric will be road-blocked because utilities will have no reason to buy excess energy or to sell energy deficits to independent distributed generators.

2.6.3 Barrier Probability

These bills were submitted in 2001 but were not acted upon the same year because of the great distraction in the legislature of legislation initiated by terrorism and war. However, it is most probable that the bills will be introduced in 2002.

2.6.4 Barrier Conclusions

These bills are worded very much alike. One was obviously derived from the other. They are functionally identical, except for a difference in the effective dates. It is interesting at how one-sided and deceptive the short titles are. Florida has a great involvement in this, with 5 representatives and a senator contributing. Republicans outnumber Democrats as cosponsors, but the bills are sponsored by one of each.

2.6.5 Barrier Recommendations

The typical response to proposed legislation is appropriate; letters, calls and email. Arizona's Jon Kyl is on the senate committee handling this bill.

2.6.6 Barrier References

1. HR 381 (A summary of this bill and its status as of 11-05-01.)
Title: To prospectively repeal section 210 of the PURPA of 1978
Purpose: To prospectively repeal section 210 of the PURPA of 1978.
Sponsor: Rep Cliff Stearns REP FL Energy and Commerce
Introduced: 01/31/2001
Latest Major Action: 2/14/2001 Referred to House subcommittee
Committee Name: On 01-31-01, Committee on Energy and Commerce
Committee Name: On 02-14-01, Subcommittee on Energy and Air Quality
Short Title: This Act may be cited as the "Ratepayer Protection Act".
Co-sponsors:

Rep Bilirakis, Michael - 03/13/2001	REP	FL	Energy and Commerce
Rep Boehlert, Sherwood L. - 06/7/2001	REP	NY	
Rep Boyd, Allen - 03/13/2001	DEM	FL	Appropriations
Rep Brown, Corrine - 03/27/2001	DEM	FL	
Rep Frelinghuysen, Rodney P. - 03/27/2001	REP	NJ	Appropriations
Rep Hastings, Doc - 03/13/2001	REP	WA	
Rep Istook, Ernest J., Jr. - 03/29/2001	REP	OK	Appropriations
Rep Lewis, Jerry - 03/13/2001	REP	CA	Appropriations
Rep Mica, John L. - 03/29/2001	REP	FL	
Rep Murtha, John P. - 03/27/2001	DEM	PA	Appropriations
Rep Towns, Edolphus - 03/13/2001	DEM	NY	Energy and Commerce

Bill Summary:

Declares that no electric utility shall be required to enter into a new contract or obligation to purchase or sell electric energy or capacity pursuant to the PURPA of 1978 governing cogeneration and small power production.

Directs the FERC to promulgate and enforce regulations to assure that no utility shall be required to absorb the costs associated with electric energy or capacity purchases from a qualifying facility executed before this Act's enactment date, and governed by such provisions (thus assuring such utilities recovery of all costs associated with such purchases). Provides that such regulations shall be treated as a rule enforceable under the Federal Power Act.

2. S 552 (A summary of this bill and its status as of 11-05-01.)
Title: A bill to provide that no electric utility shall be required to enter into a new contract or obligation to purchase or to sell electricity or capacity under section 210 of the PURPA of 1978.
Purpose: A bill to provide that no electric utility shall be required to enter into a new contract or obligation to purchase or to sell electricity or capacity under section 210 of the PURPA of 1978.
Sponsor: Sen. Bob Graham DEM FL Energy and Natural Resources
Introduced: 03/15/2001
Latest Major Action: 03/15/2001 Referred to Senate Committee
Committee Name: On 03-15-01, Committee on Energy and Natural Resources
Short Title: This Act may be cited as the "Transition to Competition in the Electric Industry".
Cosponsors: None
Bill Summary:

The bills states that no electric utility shall be required, under the PURPA of 1978, to enter into a new contract or obligation to purchase or sell electricity or capacity from or to qualifying cogeneration and small power production facilities.

These bills require the Federal Energy Regulatory Commission to promulgate and enforce regulations designed to ensure that no electric utility will be required to absorb the costs associated with purchases of electric power or capacity from a qualifying facility pursuant to PURPA obligations before enactment of this Act.

3. PURPA 210 (obtained from http://energycommerce.house.gov/107/pubs/energyelec.pdf.)

SEC. 210. COGENERATION AND SMALL, POWER PRODUCTION.

(a) COGENERATION AND SMALL POWER PRODUCTION RULES

Not later than 1 year after the date of enactment of this Act, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to—

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale or purposes other than resale.

(b) RATES FOR PURCHASES BY ELECTRIC UTILITIES

The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying co-generators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative
electric energy.

(c) RATES FOR SALES BY UTILITIES

The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—

(1) shall be just and reasonable and in the public interest,
and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) DEFINITION

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) EXEMPTIONS

(1) Not later than 1 year after the date of enactment of this Act and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act, from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(A) any State law or regulation in effect in a State pursuant to subsection (f),
(B) the provisions of section 210, 211, or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act, or
(C) any license or permit requirement under part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.
(f) IMPLEMENTATION OF RULES FOR QUALIFYING COGENERATION AND QUALIFYING SMALL POWER PRODUCTION FACILITIES
(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.
(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).
(g) JUDICIAL REVIEW AND ENFORCEMENT
(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be obtained under section 123 in the case of a proceeding to which section 123 applies.
(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 123 with respect to an action to which section 123 applies.
(h) COMMISSION ENFORCEMENT
(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act, such rule shall be treated as a rule under the Federal Power Act. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.
(2)(A) The Commission may enforce the requirements of subsection
(f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—
(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) [1] or
(ii) an action under paragraph (1).
(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.
(i) FEDERAL CONTRACTS
No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.
(j) NEW DAMS AND DIVERSIONS
Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of a new dam or diversion unless the project meets each of the following requirements:
(1) NO SUBSTANTIAL ADVERSE EFFECTS
At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment, including recreation and water quality. Such finding shall be

made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act (whichever is appropriate as required by that Act or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.

(2) PROTECTED RIVERS

At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

(A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.

(B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) FISH AND WILDLIFE TERMS AND CONDITIONS

The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.

(k) DEFINITION OF NEW DAM OR DIVERSION

For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar devices) 1

(l) DEFINITIONS.—

For purposes of this section, the terms "small power production facility", "qualifying small power production facility," "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act.