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Arizona Corporation Commission
1200 West Washington Street
Phoenix AZ 85007

Attention: Carmen Madrid

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-10345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 et seq.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNBLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 et seq.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECCTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-165

Dear Mrs. Madrid:

Enclosed for filing in the above-referenced proceedings are an original and ten 910) copies of the prepared testimony of Dr. Jonathan Jacobs and the comments of Tom Broderick. This testimony and these comments are submitted on behalf of PG&E Energy Services Corporation.

Please let me know if you have any questions.

Sincerely,

Lawrence V. Robertson, Jr.

Lawrence V. Robertson, Jr.

cc: Service list

BEFORE THE ARIZONA CORPORATION COMMISSION

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Commissioner - Chairman
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TESTIMONY AND COMMENTS OF DR. JONATHAN JACOBS AND MR. BRODERICK ON BEHALF OF PG&E ENERGY SERVICES CORPORATION

NOVEMBER 30, 1998

COMMENTS OF MR. TOM BRODERICK

ON BEHALF OF PG&E ENERGY SERVICES CORPORATION

NOVEMBER 30, 1998

Although the APS Settlement Agreement has a number of positive features, PG&E Energy Services Corporation ("Energy Services") **opposes** approval of the APS and TEP Settlement Agreements in their current form for a simple reason: they eliminate economic viability for an ESP during the years of stranded cost recovery.

We have analyzed the APS Settlement in great detail. We have not specifically analyzed the TEP Settlement Agreement but are confident that our conclusions and recommendations apply to that company as well. We expect to compromise in a Settlement, but to continue to provide support for a settlement that we now know is fatally flawed, is something we are not prepared to do. The market will not compromise in areas the Settlement requires ESP's to compromise. If Energy Services' support of a settlement is important to the Commission, then the Settlement Agreements must be restructured by: 1) Interpreting language in the Settlements in the way in which we believe Staff intended and not in the manner that APS and TEP have interpreted in their testimony, related exhibits and tariff filings, as more fully explained below; and 2) Incorporating revisions presented by Dr. Jonathan Jacobs on behalf of Energy Services into the Settlements.

The major recommendations by Dr. Jacobs, Energy Services' Director -- Market & Financial Modelling, call for: 1) Increases to and favorable formulaic interpretations of the Market Generation Credit; and 2) Tariff language which reduces the exposure of ESP's to increased transmission charges from APS and TEP. Dr. Jacobs' recommendations are the **minimum** revisions necessary to obtain Energy Services' support of the Settlement Agreement. We have thoroughly quantitatively analyzed the APS Settlement and delayed drafting our comments and testimony until we were certain that our analysis was accurate. Dr. Jacobs' testimony presents the results of that analysis.

Settlements, by definition, reflect the relative negotiating strengths of the parties. We observe that the APS settlement is at least on par (and probably superior) to the TEP settlement for their respective shareholders in spite of the former company's unwillingness to divest any generation assets. It is difficult for us to fathom how APS can now be deemed eligible for 100% stranded cost recovery by agreeing to divest only $162 million of transmission assets when compliance with the Commission's Order required divestiture of billions of dollars in generation assets to achieve that same opportunity. One can conclude, therefore, that APS enjoyed a very strong negotiating position. The Settlements also favor residential customers, the solar industry and standard offer customers but these benefits pale in comparison to those benefits APS' shareholders will reap relative to the minimal financial integrity criterion established by this Commission for companies that fail to divest generation. Unfortunately, the APS Settlement has produced **no** improvement in APS' Market Generation Credits as compared to their own proposal of August 21, 1998. In fact, the Market Generation Credits may actually be less in the APS Settlement than in their August 21, 1998 proposal. This is because the 3 mill adder was fully offset by other changes in the credit's formula. ESPs live or die by the market generation credit. We commend the

Commission Staff's Herculean efforts to produce a settlement. We have no doubt they did their best. Unfortunately, the Settlement just didn't get there for ESP's. In light of the massive concessions to APS relative to the minimal financial integrity standard, we do find several of the characterizations and criticisms of ESP's by Staff's witnesses (Lee Smith and Richard La Capra) disturbing, puzzling and unsupported.

We would very much like to embrace an improved settlement in Arizona. In fact, that is our only option at this point. However, we cannot embrace a settlement that provides **no** opportunity for Energy Services commercial efforts. We have learned from settlements in other states that, once approved, settlements only worsen with the passage of time because language interpretations do not improve. We must push for precise and exacting language in any settlement to avoid erosion of even minor victories.

We simply cannot afford to participate indefinitely in Arizona regulatory and legal proceedings. Our level of involvement in Arizona restructuring has been second only to our efforts in California. Our recently concluded CC&N hearing was our most expensive and time consuming licensing effort to date. Ironically, our CC&N application contributed to pressures that helped produce the APS Settlement that we now oppose. Despite this expense, had the Affected Utilities August 21, 1998 compliance filings actually complied with the Commission's stranded cost order, we would have been willing to participate in a final and subsequent hearing to unbundle tariffs and to incorporate the approved CTC charges therein. However, Energy Services will **not** participate in yet another protracted hearing involving stranded cost issues previously decided by this Commission. For these reasons, we must seek an improved settlement and a market opening of January 1, 1999 as planned.

TESTIMONY OF DR. JONATHAN JACOBS

ON BEHALF OF PG&E ENERGY SERVICES CORPORATION

NOVEMBER 30, 1998

Q. **1. Please state your name, address, professional background and experience, and whom you are representing?**

A. My name is Jonathan Jacobs, 345 California Street, 32nd Floor, San Francisco, California. I am employed by PG&E Energy Services ("Energy Services") in the capacity of Director – Market & Financial Modeling, and am representing it in this proceeding. If Energy Services sells commodity electricity products in Arizona, I and my staff will be responsible for developing the methods and tools we use to price Arizona commodity electricity products, including estimates of the costs of managing the associated risks. My background and experience are set forth in Attachment JJ-1.

Q. **2. What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to explain, in detail, the inadequacy of the Market Generation Credit ("MGC") in the APS Settlement Agreement and to present a specific proposal to make the MGC acceptable to Energy Services. As Mr. Broderick indicated in his comments, absent re-interpretations and revisions to

APS' MGC, Energy Services has no option but to **oppose** the Settlement. The Settlement can be made acceptable to us only by revising the MGC in the following manner: 1) include a substantially larger "adder" —I suggest at least 8 mills/kWh, and preferably 10 mills/kWh, with no adjustment for load factor; 2) include language specifically describing the way in which an energy supplier will physically meet its supply option, the better to control that supplier's cost exposure; and 3) clarify the Settlement's interpretation that the monthly CTC can be negative with customers owed refunds without limit in such instances. The unbundled tariff can be made acceptable by inserting clarifying language presented herein.

Similar concerns would apply to TEP's credit. We have not performed as detailed an analysis of the TEP proposal because the proposal is less clear, and because of our own resource constraints.

Q. **3. Please summarize your analysis and conclusions concerning the Market Generation Credit.**

A. APS' Settlement MGC (as displayed in Exhibit A) is one monthly uniform cents per kilowatt hour credit for all peak hours and a different credit for off peak hours. The peak credit is NYMEX Palo Verde futures prices as of the previous November plus an adder of 3 mills/kWh, inflated by a distribution loss factor and adjusted by the ratio of the customer (or class) load factor to the system load factor. The off peak credit is similar except it is based on the NYMEX times a "light load ratio."

Our analysis indicates:

- The APS MGC did not increase in the Settlement as compared to their filing of August 21, 1998. In fact, the MGC is probably less and the Settlement increased the risk of serving retail customers by dropping the hourly "shaping" with California Power Exchange prices.
- The Settlement MGC fails to cover even the basic costs of raw energy to a retail customer.
- The Settlement MGC fails to properly credit for the other costs of serving retail customers including ancillary services, settlements of energy imbalances, risk management, and transmission charges to ESP's beyond those charged to retail customers in APS' OATT retail network tariff.

Since the MGC is the reduction to customers' bills as a result of switching, an inadequate MGC means that ESP's will be unable to offer retail customers any savings as a result of switching. It is well understood that ESP's must offer customers savings to entice them to switch, to overcome issues such as customer fear of UDC retaliation, the incumbents' avoidance of customer acquisition costs, inertia and other real and perceived incumbent advantages.

Q. **4. What is the role performed by a supplier credit such as the Market Generation Credit (MGC)?**

A. In order to implement retail competition it is necessary to distinguish those functions a utility performs, such as electricity distribution, from those which can be performed by competitive suppliers. One can either go through a detailed rate-making process in order to identify specifically only those cost components relevant to distribution service and then create "wires-only" rates; or one can begin with an existing bundled tariff and identify a credit for the services avoided by customers who choose competitive supply. This is the path that has been chosen in most jurisdictions, and it is reflected in the Settlements with APS and TEP proposed by Staff.

Utility accounting can be complex and it may be difficult to identify the appropriate costs to incorporate into a generation credit. A reasonable approach would be to determine the compensation that would be required by an efficient competitive supplier, and set the credit at that level. If the market is truly competitive, a supplier's pricing should be only slightly above its costs, once one has incorporated all appropriate cost components.

Of course, not all these costs are visible or represented by transparent prices. Therefore one has to make some assumptions. It behooves us to err on the side of overestimating the credit, both because it will provide additional stimulus to market entry and because any overestimation should be captured by customers as competition drives prices down closer to costs and drives suppliers to reduce their costs even further.

It is tempting to rely wholly on visible signals, such as pricing in the California Power Exchange (CAPX) or on the New York Mercantile Exchange (NYMEX). If the other cost components are ignored, the generation credit is set too low and retailers such as PG&E Energy Services will decline to serve load in Arizona.

Q. **5. What are the components that should go into a generation credit?**

A. At a minimum, a generation credit should recognize the following costs:

- Market price of wholesale energy
- Additional value of shaping or load-following
- Premia associated with the risks of serving retail load
- Transmission and distribution costs incurred by competitive suppliers
- Commercial costs
- Reasonable profits

Q. **6. Does the APS Settlement adequately address these cost components?**

A. No. It explicitly incorporates the market price of wholesale energy, as represented by a Palo Verde forward price, but does not specifically address any of the other components. The adder of 3 mills/kWh, adjusted for load factor, is far from sufficient.

Q. **7. What do you mean by the value of shaping or load-following?**

A. The Settlement MGC is based on the price for a product, NYMEX futures, delivered at a **constant** rate each hour for 16 "peak" hours every day but Sunday. It is a wholesale product. A retail customer's demand, though, is **variable**. In the summer demand peaks in the afternoon -- very steeply so in Arizona. For example, APS 1996 system hourly loads indicate that the load in the hour ending 5PM on an August weekday was more than 50% greater than the load in the hour ending 7AM; yet both these hours fall within the peak period.

The hourly prices are highest in the afternoon too -- the price for the hour ending 5 PM is almost three times the price for the hour ending 7AM. An ESP must procure power in quantities that meet retail customers' loads in peak periods when prices are highest.

If one seeks to meet retail load, one can begin by purchasing a block of energy at wholesale, e.g., based on a NYMEX contract. The delivery pattern of that wholesale product will not match customer loads – in some hours too much energy will be delivered, and it will have to be sold off, while in other hours the supplier will need to procure additional hourly energy. The hourly variations, both up and down, are referred to as shaping energy. The Settlement MGC fails to capture the cost of shaping energy.

Q. **8. Does the Settlement MGC contain any offsets, perhaps in the off-peak hours to compensate for under recovery during on-peak hours?**

A. No. The Settlement MGC under-compensates for shaping in **both** peak and off-peak periods. I conducted an analysis using California Power Exchange prices to date and a dynamic load profile for Southern California Edison's GS-2 rate. (I had requested load profiles from APS in a data request, but they refused to provide the requested information stating, "This information is competitively sensitive and confidential and will not be provided.")

Using the SCE data, I found that profile-weighted average prices are higher (and therefore, the MGC is less) than straight averages (what APS' method would use), *both* in peak and off peak periods. Here are the magnitudes of the differences:

Month	Period	Difference between Load-weighted and Flat Average Prices (mills/kWh)
April	Off peak	0.31
April	Peak	0.50
May	Off peak	0.31
May	Peak	0.87
June	Off peak	0.62
June	Peak	0.94
July	Off peak	1.10
July	Peak	2.05
August	Off peak	0.84
August	Peak	2.75
Sept.	Off peak	0.50
Sept.	Peak	2.88
October	Off peak	0.61
October	Peak	0.40
Nov.	Off peak	0.96
Nov.	Peak	0.04

The overall average difference is 1.2 mills/kWh. We should expect that the SCE load profile is less peaky than APS' due to the extreme summer Arizona climate, meaning that if anything this understates the cost of shaping.

While the shaped costs exceed the flat costs in every period, the differences are largest during on-peak summer months. This is to be expected, since those are the months in which peak prices are highest, and the difference is driven by customers' tendency to demand the most energy in the highest-priced hours. It is important to note that there were significant differences in July and November **off** peak periods.

To repeat, I would expect these cost differences to be even greater in Arizona's desert climate -- they could easily double. And lastly, these differences do not include the risk premia associated with shaping energy to a retail customer.

Q. **9. Your last sentence indicated that the cost of shaping is not simply the difference between a flat load product (e.g., NYMEX) and a load-weighted market (California PX). What is the additional cost?**

A. At this point we come to the additional costs associated with risk management. The largest component of risk is price risk, and Staff is commended for having attempted to address it by basing the energy credit on a forward market price rather than a spot price or an arbitrary figure. Otherwise it would be very difficult to give customers a price for an annual contract in advance. For example, according to our records (Bridge Telerate historical database), during November 1997 the price of the August 1998 Palo Verde contract varied between 34.25 and 34.90 mills per kilowatt hour. According to APS, the actual price in August 1998 was 54.05. The 20 mill difference represents price risk that a marketer would have to build into the price of every kilowatt hour.

Shaping energy has to come from a spot market (e.g, California Power Exchange). It does not come from NYMEX. If one knew that the cost of shaping energy would bear a fixed relationship to the cost of "flat" energy, one could hedge one's exposure to the spot market by buying NYMEX contracts according to that relationship. Unfortunately, such a fixed relationship does not exist. There are actually a number of risks involved here:

- The shaping premium is based on an assumption about the customer's load profile. The actual customer load profile may differ from that forecast.
- The customer's total consumption may be greater or less than expected, even if the pattern of usage is as predicted. This variation much be settled at an average of the spot market price, which can be far from the NYMEX price (recall the $20 increase in August 1998 NYMEX prices from Nov. 1997 to contract expiration noted above, let alone any price fluctuations from the end of July through the month of August).
- Prices vary, and the variation is not uniform. In other words, if the average spot market price turns out to be 10% higher than the

NYMEX futures price, the bulk of that increase will be in the highest-price hour. That means that peak-hour prices will be much more than 10% higher than was expected in a computation of the shaping premium that excluded consideration of price risk.

This non-uniformity is exacerbated by APS' failure to divest its generation. APS' large share of the Arizona generation market will be increased by its asset swap with TEP, and can grow even larger if APS is permitted to bid on other assets TEP is divesting. It can profit from this market power by exacerbating the spreads in hourly prices even if the average price stays the same.

There are hours in which transmission between California and Arizona is congested. In those hours the power of the dominant suppliers in Arizona is even greater. There may fundamental differences between the markets represented by NYMEX and the spot market. NYMEX contracts are fulfilled at Palo Verde while if a spot market is based on the California Power Exchange, one needs to allow for the additional costs associated with that market – PX administrative charges, ISO grid management charges, access fees, ISO neutrality charges, etc. There may be a liquidity premium associate with the spot market.

Because the Settlement MGC is based on the NYMEX futures price, the supplier effectively has to buy a series of options to eliminate the uncertainty or risk posed by an MGC based on NYMEX. As a guideline to the values of these options, consider what one might have expected to pay for a series of at-the-money options on monthly energy at Palo Verde, based on futures prices for 1999 observed on Nov. 20, 1998, and assuming a 5% risk-free rate, and 75% volatility:

	Futures price (=strike price)	Option duration (months)	At-the-money option price in $/MWh
Jan	28.37	2	3.56
Feb	27.25	3	4.20
Mar	25.75	4	4.59
Apr	23.00	5	4.59
May	22.50	6	4.93
Jun	31.25	7	7.40
Jul	48.00	8	12.16
Aug	63.50	9	17.07
Sept	53.25	10	15.09
Oct	30.25	11	8.99
Nov	28.75	12	8.92
Dec	31.25	13	10.09

To evaluate more precisely the costs of the options that would be needed requires some assumptions about a logical procurement strategy. Suppose for example on sought to buy options on the amount of energy that would be transacted in the spot market. This is the difference between the total energy needed to serve customers and the amount bought in the forward market. The amount bought in the forward market would be a flat amount ranging approximately between our anticipated customer maximum load or customer minimum load depending on our hedging strategy.

If the supplier were to buy forward energy based on maximum load, then the supplier would be selling the power to the spot market during the off-peak when it is surplus to customers. If the supplier were to buy based on minimum load, then the supplier would be purchasing from the spot market during customers' peak hours. One could purchase in the middle and both sell in off-peak hours and purchase in on-peak hours. Either way, one would need an option for approximately 50% of the energy requirement.[1]

The average of the option prices in the table given earlier is about 8.5 mills/kWh. One way to estimate the cost of these risks would be to apply the option cost to 50% of the energy requirement and spreading it over all the load. That would result in an adder of 4.25 mills per kilowatt hour.

Q. 10. Why do you need an option when the risks also run in the opposite direction?

A. This is a risk / reward trade-off that a supplier cannot absorb. Retail direct access contracts contain profit margins equaling but a tiny fraction of the risk described above. One cannot risk losing several mills on these contracts even if there is the possibility of making several more mills with good luck. This is the way markets allocate risk: a supplier will surrender the "upside" to a third party and even pay a premium in order to avoid potential losses. An Electricity Service Provider such as PG&E ES is in the business not of taking risk but rather of helping customers use electricity intelligently. Furthermore, the risk doesn't tend to average out with more customers, as all customers' load shapes tend to move together seasonally.

[1] In the first case, one needs an option to address the risk that the spot price will be less than the forward price upon which one over-purchased. In the latter case, one need an option to address the risk that the spot price will be greater than the forward price upon which one purchased minimum load.

PG&E Energy Services expects to sign contracts that run into the tens and hundreds of millions of dollars of cost exposure over several years, with very thin margins. Many of these contracts present risks which if unmanaged can easily liquidate our entire capitalization, but which contain a very small margin potential. On the other hand, there are entities that are willing to take on these risks for a fee as described previously.

This discussion illuminates several aspects of restructuring in Arizona and elsewhere. First, it gives one reason for why divested generation assets sell for values above book: purchasers reduce their risk when they own generation capable of being delivered to its customers. Second, it demonstrates the over compensation to APS by allowing APS both recovery of 100% of its stranded costs (as in the Settlement) and to allowing the transfer of its entire owned generation assets to an unregulated affiliate. Once transferred, APS will be free to use that generation to reduce its risks or to sell the assets at that time to a new owner for a premium that will likely not be subject to refund to customers.

Q. 11. Does the Settlement recognize any of these price risks?

A. Interestingly enough, the Settlement contains one provision to mitigate price risk, but only a risk faced by APS. If the spot and forward prices diverge, APS will be deemed to over- or under-collect its stranded costs and is permitted to increase its rates as necessary. In other words, the Settlement effectively gives APS an option on the price of energy – but doesn't recognize the need for risk mitigation in the MGC.

Q. **12. You mentioned transmission and distribution costs as a necessary component of the MGC. Aren't they already included in direct access rates?**

A. One would hope so, but the language is not specific enough to assure us. First, ESP's may be subject to transmission and, perhaps, distribution charges in **excess** of the approved retail transmission and distribution tariffs. Although APS' unbundled retail tariffs contain a component for what can be charged to retail customers as transmission and distribution charges, APS' actual transmission charges to ESP's will occur via charges to schedule coordinators. For transmission, such charges will be as per their OATT. Schedule Coordinators, in turn, will charge ESP's. Unless explicitly addressed in APS' unbundled retail tariffs, we would expect APS' actual transmission charges to exceed what APS is approved to collect from retail customers via retail unbundled rates.

APS' retail direct access tariffs include transmission components that appear comparable to the rates for "Retail Network Integration Transmission Service" in Schedule 11 of APS' OATT (although if APS transfers its transmission assets to TEP, then the TEP OATT would apply). However, I have not yet found a definition of Retail Network Integration Transmission Service that includes ancillary services. In other words, ESPs may be separately liable for ancillary service costs, and this interpretation is borne out by Staff's testimony, and language in the TEP settlement, to the effect that the 3 mill adder is intended in part to cover ancillary service costs.

In fact, APS' tariff DA-GS1 states:

> "When the customer is load-profiled and Company provides Metering, Meter Reading and Billing, customer will be charge as shown below. When Metering, Meter Reading or consolidated Billing are provided by an ESP, customer is not charged for each respective service. Transmission charges are billed to customer's Schedule Coordinator."

> "Services Acquired From Certificated Electric Service Providers – Customers served under this rate schedule are responsible for acquiring their own generation, transmission and any other required competitively supplied services from an ESP or under the Company Open Access Transmission Tariff."

The above language could be read to create the means for differential transmission charges to any customer taking any competitive service. This is clearly a discriminatory result. If APS can offer distribution service to bundled and unbundled customers at the same charge, then it need not charge differential charges for transmission service.

There should be explicit language in APS' tariffs addressing this issue. We recommend that provisions along the following lines be incorporated into APS' and TEP's unbundled retail tariffs:

- In order to serve load at retail, an ESP has to have energy *delivered to* an APS (or TEP) tie point in an amount equal to its load (or load * (1 + loss rate).[2]
- APS (or TEP) will transmit and distribute the energy. It will be the utility's responsibility to recover any costs associated with transmission and distribution, whether from the Open Access Transmission Tariff (APS' *or* TEP's) or otherwise, out of the transmission and distribution components of retail customer rates.
- There will be no additional charges, whether for transmission, distribution, ancillary services, grid administration, "neutrality", unaccounted-for energy, etc., assessed against the energy supplier.
- There will be no additional charges -- e.g., from any of the categories above -- assessed against direct access customers that are not also assessed against bundled customers.

If explicit assurances such as these are not incorporated into the Settlement the MGC will need to be increased to include a component for excess T&D charges.

[2] It is important for the language to say "deliver to" a tie point, not "deliver onto" APS' (or TEP's) system; in some cases utilities charge for putting the energy onto their system.

Q. **13. Please continue identifying the major categories of additional cost for an ESP above the raw cost of energy.**

A. An additional component of costs has to do with the commercial costs of serving retail load. Some of them are characteristic of any retail business, and are usually built into the wholesale-retail spread. Some examples are collection costs, reserves for bad debts and accounts payable, customer acquisition costs, call centers, office overheads, etc. Others are specific to the electricity business, such as load forecasting and profiling. APS certainly sees a value in load profiling, since they refused to give us load profiles when we asked for them. Utilities bear these costs also, but they are usually buried in transmission and distribution charges. They can easily add 3 mills to the costs.

Q. **14. In your answer to question 5 you suggested that an MGC should include a reasonable profit for an ESP. Are you suggesting that the credit should include a subsidy to marketers?**

A. Not at all, and I find the implication rather peculiar. As I outlined above, an MGC should represent the price of competitive supply. No competitive business will offer electricity to the marketplace out of a sense of charity; investors would not permit it. The Commission has not expected utilities to do so, and regulators consistently allow public utilities the opportunity to earn a profit.

In order to justify the level of profit allowed it is usually put in terms of a return on capital invested in hard assets, but that is an accounting construct. Part of the profit ought to be attributed to each aspect of the utility's business, including the merchant or supply function.

Staff's consultants have expressed concern that an MGC could provide "too much" to competitive ESPs. For example, Ms. Smith's testimony states:

> A shopping credit that is set "too high" may also, until the market is fully developed, allow suppliers to make additional profits. In other words, if there initially were very few competitors, rather than providing their "best" price they might be able to acquire load by offering prices just below the shopping credit.

This displays a lack of faith in the workings of the competitive market: if you don't expect competition why go to the trouble of opening the market?

If initially there were very few competitors earning excessive profits, additional competitors would very quickly be attracted. Experience to date in California, Massachusetts and Pennsylvania has shown that the opening of a competitive retail electricity market attracts a large number of potential competitors, who find that they cannot set a price that allows them a reasonable profit. In other words, it is more likely that any excess will be more than competed away (so that suppliers are forced to cut costs or lose money) than that suppliers will receive windfalls.

Q. **15. How does the MGC under the Settlement compare with the MGC under the Aug. 21 proposal?**

A. The APS August 21, 1998 proposal would have covered only the basic cost of raw energy shaped to serve a retail customer and nothing more. (Hence, there was already a need to increase this proposed MGC to cover costs beyond raw energy). On a first reading of the Settlement, we believed the negotiated 3 mill/kWh adder was in, in fact, in addition to the August 21, 1998 proposed formula and would have made a partial contribution toward those costs. However, upon a detailed review of the Exhibit A we noticed the adder was included at the expense of other important components in the formula. We presented APS with several data requests on this issue. APS presented us with MGC calculations under identical assumptions (based on a customer with a usage pattern and size selected by APS) using the two MGC methods: August 21, 1998 and the Settlement method from Exhibit A. By APS' own estimates, the MGC in the August 21, 1998 proposal was greater (MCG equaled $31,000 for the month) than the Settlement MGC ($29,000 for the same month), almost completely wiping out the 3 mill adder to the latter.[3] We believe this general conclusion will hold under a wide range of different customer usage assumptions.

[3] The revised response to question 1, as received Nov. 24, indicates a total MGC, absent the adder, of $29.289.76 for 595.768 kWh of load, or an average MGC of 49.16 mills/kWh based on the 11/5 settlement. The response to question 2i indicates a total MGC of $31,013.76, or an average MGC of 52.06 mills/kWh based on the 8/21 proposal, for a difference of 2.9 mills/kWh.

Q. **16. Do you believe Staff intentionally negotiated a smaller MGC?**

A. No. My colleague Mr. Broderick has told me that he believes Staff intended to negotiate a *superior* MGC that was at least 3 mills greater than APS' August 21, 1998 proposal. Otherwise, why settle? It would have simply been better to accept APS' proposal. However, he concedes that Staff has the say on what they intended.

A reader cannot easily discern the intent of the parties because the APS Settlement Agreement is internally inconsistent on this point. Page 2, Section II, second paragraph, second sentence states, "The peak and off peak prices shall be determined by shaping the Palo Verde Nymex futures price by actual hourly prices from the California spot price index." However, APS Exhibit A on-peak and off-peak MGC formulas clearly lack any hourly shaping by the California PX. Only the "LLR" component of the off-peak formula contains the California PX price.

Q. **17. So overall, how large an adder do you feel is appropriate?**

A. I feel that it is appropriate to include an adder of 8 to 10 mills/kWh. It breaks down as follows:

- Shaping: 1.5 to 2 mills
- Risk premia: 4 to 5 mills
- Commercial costs: 1.5 to 2 mills

- Transmission, distribution and ancillary services: Ensure all costs are incorporated in wires charges; otherwise an additional 4 to 6 mill adder would be needed
- Reasonable profit margin: 1 mill.

Furthermore, this adder should *not* be adjusted for load factor. Most of the component costs (risk premia for serving retail load, commercial costs) are not very sensitive to load factor except in extreme cases (for example a customer with a 100% load factor would entail no shaping risks).

Q. **18. If the 3 mill adder were maintained, how much load do you expect that PG&E ES will serve in Arizona?**

A. If the Settlement were approved unchanged, I would recommend to our management that PG&E ES not seek to serve *any* retail load in Arizona.

Q. **19. Are there any other clarifications you wish to point out?**

A. Yes. We believe it was the Staff's intent that the monthly CTC not be capped at APS or TEP's embedded generation cost. We request Staff clarify their position on this issue. We expect there to be a number of months in the year when the MGC will exceed APS and TEP's embedded generation costs. The MGC in such months should lead to customer refunds or be carried over to subsequent months without limit in order to reduce the CTC in those months. This should be allowed to occur for the duration of CTC recovery. This is a fair solution. Load that switches away from APS and TEP will free up generation requirements for those companies from what they otherwise would be. That generation can then be sold at market prices which will on occasion exceed their embedded generation costs as described above.

Second, the language in the Settlements is clear that the adder should be inside the brackets and subject to increase for loss factors. Third, its clear from the Settlement language that when a true-up of an under-collection in MGC occurs in excess of $5 million that generation rates for all tariffs including standard offer will increase. In other words, the under-collection would be recovered from all customers not just competitively serviced customers.

Q. 20. Earlier you mentioned that the variable component of the adder should be larger and adjustments should occur more quickly.

A. Yes. The Settlement currently contains a provision for increasing the adder by 0.5 mils after two years if switching is below an identified amount. In concept, this is an excellent approach. However, we recommend that the adder begin at 8 to 10 mills/kWh and be increased or decreased every quarter based on actual switching results if this concept is embraced. If there is interest in this concept, it could easily be fleshed out at hearing.

Q. 21. Does that conclude your testimony?

A. Yes.

Attachment JJ-1

Professional Background and Experience
of
Jonathan Jacobs, Ph.D.

Jonathan M. Jacobs is employed by PG&E Energy Services as Director - Market and Financial Modeling. In that position he has responsibilities in the areas of load forecasting, load modeling, price forecasting (especially as it impacts the difference between flat and hourly prices), product development and the development of computer models and tools for pricing electricity at retail. On behalf of Energy Services Dr. Jacobs and his staff have evaluated emerging electricity markets across the country.

Prior to joining PG&E Energy Services in June 1997, Dr. Jacobs worked for seven years for Pacific Gas & Electric Co., the utility serving Northern and Central California, where he developed mathematical models and computer tools for electricity supply planning. Dr. Jacobs also participated on behalf of PG&E in the development of the market structure for the California Power Exchange.

Prior to joining PG&E, Dr. Jacobs was a Senior Analyst for General Research Corp. in Vienna, VA.

Jonathan Jacobs holds the degrees of Master of Science and Doctor of Philosophy from the University of Wisconsin - Madison as well an S.B. from the University of Chicago, all in mathematics. He has published in technical journals such as the *IEEE Transactions on Power Systems* and the *Annals of Operations Research* and has testified before the California Energy Commission.