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STATE OF ARIZONA

BEFORE THE ARIZONA COMMERCE COMMISSION

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| **In the Matter of the Application of** | ) | |
| **the Tucson Electric Power Company** | ) | ACC Docket No. U-1933-95-317 |
| **for a Rate Increase** | ) | |

# DIRECT TESTIMONY OF

# PAUL CHERNICK

# ON BEHALF OF

# THE RESIDENTIAL UTILITY CONSUMER OFFICE


Resource Insight, Inc.


January 5, 1995

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## EXHIBITS


Exhibit ____ (PLC-1) *Professional qualifications of Paul Chernick.*

Exhibit ____ (PLC-2) *Revision of Springerville #2 Used-and-Useful Calculation (Exhibit DBE-1)*

## I. Identification and Qualifications

**Q: Mr. Chernick, please state your name, occupation, and business address.**

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

**Q: Summarize your professional education and experience.**

A: I received a SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a SM degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, among other things, the prospective and retrospective review of generation planning decisions; ratemaking for excess and/or uneconomical plant entering service; conservation-program design; cost recovery for utility efficiency programs; the valuation of environmental externalities; rate design; and class-cost allocations. My resume is attached as Exhibit____(PLC-1).

**Q: Have you testified previously in utility proceedings?**

A: Yes. I have testified more than one hundred and thirty times on utility planning, ratemaking, and rate design issues before more than 25 regulatory, legislative, and judicial bodies, in local, state, federal, and Canadian jurisdictions. A detailed list of my previous testimony is contained in my resume.

**Q: Are you the author of any publications on utility planning and ratemaking issues?**

A: Yes. I am the author of a number of publications on rate design, cost allocation, power-plant cost recovery, conservation-program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

**Q: On whose behalf are you testifying?**

A: My testimony is being sponsored by the Residential Utility Consumer Office.

## II. Introduction and Summary

**Q: What is the purpose of your testimony?**

A: The purpose of this testimony is to review the Proposed Settlement presented by Tucson Electric Power Company ("TEP") and the Commission Staff. My review concentrates on two issues with immediate effects on the level of rates to be set in this case and three other topics with longer-term implications. The two issues affecting rate immediately are

- the used-and-usefulness of Unit 2 of the Springerville coal plant and
- the rate treatment of TEP's settlement with Southern California Edison (SCE), including the seasonal diversity exchange.

The other issues, each of which could have a significant effect on future costs and cost allocations, are

- the pricing flexibility proposed in the settlement,
- the design of residential time-of-use Rate 70,
- the potential for expanded use of DSM to achieve the goals of the settlement at lower total costs.

**Q: Please summarize your testimony on Springerville Unit 2.**

A: I find that the settlement is incorrect in asserting that all of Springerville Unit 2 is used and useful. My review of TEP's loads and resources for the 1994 test year indicates that TEP did not need all the capacity of Springerville Unit 2. Even with appropriate adjustments to avoid penalizing TEP for reducing loads with energy efficiency, about 70 MW of Springerville Unit 2 was excess. That is half the amount that is currently excluded from rate base. TEP's computations that support the usefulness of the unit are incorrect because they

- ignore short-term purchases,
- overstate the reserve TEP actually maintained,
- include the interruptible Air Liquid contract as a firm load,
- claim load reductions for audit programs.

**Q: Please summarize your testimony on the SCE settlement.**

A: The settlement provides for a $4 million annual credit to ratepayers, to ensure that they receive some benefits of the SCE settlement, since the shareholders took all of the cash settlement in 1992 and will keep all the operating savings of the diversity exchange until the next rate case. To equalize the split of benefits between ratepayers and shareholders, as required by Docket U-1933-93-006, the proposed SCE credit to ratepayers should be increased to $6 million. In addition, given the uncertainty in future benefits to ratepayers, compared to the certainty of the cash benefits already taken by shareholders, the division of the total benefits of the SCE settlement should be reviewed in any subsequent rate case.

**Q: Please summarize your testimony on flexible pricing.**

A: This section of the settlement should be rejected in its entirety. The present system appears to be working fine, and the settlement proposal would amount to radical deregulation of rate design and cost allocation. These regulatory responsibilities would be delegated to TEP and the Staff, working in secret; neither party has demonstrated that it is prepared to undertake such responsibility. The problems with the proposal are as follows:

- Only TEP and the Staff would have any significant input to the rate discounting process; the settlement appears to contemplate that Staff approval of a discount would *force* Commission approval, without hearings or consultation of other parties.
- The settlement would allow TEP to use rate discounts to discourage customer efforts to install renewable generation, increase energy efficiency, manage loads, or install economic cogeneration.
- The settlement would not require TEP to pursue energy efficiency investments, even where they would be less expensive than the rate discount necessary to achieve the same reduction in a customer's bill.
- The settlement allows TEP to discount rates to customers to fend off competitors within the service territory, creating discriminatory pricing, requiring further discounts, and/or reducing revenues without retaining any load.

- Flexible pricing requires a methodology for projecting marginal costs, to avoid sales below cost. Neither TEP nor the Staff has developed such a methodology, and TEP appears confused about what type of marginal costs should be included in the computation. The Commission should not delegate its ratemaking authority without knowing how rates would be set.
- The settlement allows rates to be set at marginal cost, without any margin to benefit other ratepayers or protect them from changes in costs. The parties to the settlement acknowledge that rates should be set above marginal cost, but have refused to specify a minimum margin, or a method for computing such a margin.
- The settlement discriminates against residential customers. It has a special provision to allow TEP to provide class-wide discounts to small commercial customers, without any showing of need, but prohibits any discount to residential customers, no matter how great their need.

In short, the settlement proposal for flexible pricing is unnecessary, premature, uncontrolled, and unfair. The settlement would allow TEP to favor one customer over another, discourage desirable resources, and create financial distress that would result in higher rates to residential and other ratepayers.

**Q: If, notwithstanding your recommendation, the Commission were to decide that it wished to move TEP toward greater pricing flexibility, how should this section of the settlement be changed?**

A: Given TEP's lack of preparation for granting of rate discounts, the Commission should not actually grant any flexibility at this time. It could establish a process for TEP to receive greater flexibility, once TEP presents the Commission with a detailed and workable framework for setting minimum rates, including:

- Limiting discounts to only those customers who would otherwise take clearly undesirable actions, such as relocation to another state, closing due to out-of-state competition, or installation of uneconomic cogeneration.
- Prohibiting discounts to compete with local competition, efficiency, load control, or renewables.
- Strengthening TEP's role in promoting efficiency, load control, and renewables as an alternative or supplement to a rate discount.
- Developing a methodology for determining marginal cost.
- Defining the minimum acceptable margin for various types of discounts.
- Including other parties in the review of discounts.

The proposals that TEP files with regard to these issues should be subject to full public technical review and hearings, to avoid repetition of the problems in the settlement.

**Q: Please summarize your testimony on rate design.**

A: Residential Rate 70, as proposed in the settlement, would have the following problems:

- The summer-peak and intermediate-weekday periods would not cover all the high-load hours that may contribute to system requirements for generation and transmission.
- Many of the weekday hours with the greatest residential loads would fall in the off-peak period, which would encourage larger class peak loads, increasing distribution costs and the residential allocation of costs.

- The entire weekend would be off peak, even though residential loads are greater on weekends.
- The settlement would increase the summer-winter differential in Rate 70, without any cost justification.

These problems would lead to greater total costs to TEP, increased allocations of existing costs to the residential class, and assignment of most of the benefits of Rate 70 to customers with electric heat who are out of the house during the weekdays.

In my discussion of time-of-use rates below (§VI), I derive a set of rates that would collect the same revenue as the settlement rate, discourage new peaks, and spread the benefits more broadly.

**Q: Please summarize your testimony on the enhanced use of DSM to achieve the goals of the settlement.**

A: In a number of situations—low-income discounts, the LIFE program, flexible pricing, Rate 21—TEP is attempting to reduce customer bills. As TEP acknowledged, it would often be less expensive for the Company to increase the efficiency of the customer's energy use than to achieve the same bill reduction through a rate discount. Improved efficiency is also likely to have other benefits, including increased customer satisfaction, productivity, and competitiveness.

The Company should be encouraged or required to seek out opportunities to use energy efficiency and related measures (such as rooftop photovoltaics) to achieve bill-reduction goals.

**Q: Do you have any other introductory comments?**

A: Yes. I have cited TEP responses to RUCO discovery as "RUCO DR __" and to Staff responses as "Staff DR __." Following the settlement, RUCO asked some discovery of the Staff, which I cite as "Staff's response to RUCO __."

In some cases, I make general comments supported by discovery responses that TEP has labeled as confidential. To avoid disclosing any legitimately confidential information, I do not identify my sources or otherwise provide specific information. If TEP waives confidentiality of these materials (many of which appear to contain no commercially sensitive information), I will discuss the details at the hearing.

## III. The Usefulness of Springerville Unit 2

**Q: Do you agree with the proposed settlement that Springerville #2 should be considered 100% used-and-useful?**

A: No.

**Q: What evidence have the Company and the Staff offered to support this treatment of Springerville Unit 2?**

A: The Company presented a comparison of the retail and firm wholesale demand on June 29, 1994 with available resources, removing from the analysis the sales of excess capacity, the effects of demand-side management programs (DSM), and the Liquid Air interruptible resource. From this comparison, TEP concluded that it was capacity-deficient in 1994 even with 100% of Springerville #2. According to the TEP analysis, even with 100% of Springerville Unit 2, the system was 68 MW short of what Company Witness

Erdwurm called the "primary criterion" reserve margin (Erdwurm Direct pp. 2-4 and Exh. DBE-1).[1]

The Staff did not provide any additional analysis.

**Q: Has the Company adequately demonstrated the used-and-usefulness of Springerville Unit 2?**

A: No. The 1991 Settlement (§13b) defined "useful capacity" as "capacity that is necessary to meet demand adequately and reliably." The Company's analysis has not met the conditions of the 1991 Settlement for the following two reasons:

- The Company did not need 100% of Springerville #2 in the test year to meet retail and firm wholesale demand.
- The Company purchased 114 MW of short-term capacity at prices lower than the annual cost of Springerville #2, and could have purchased more.

**Q: Did TEP actually operate at a 68 MW capacity deficiency on June 29, 1994?**

A: No. The Company's analysis, which indicates a 68 MW "deficiency," differs from actual conditions by

- reducing resources by 20.2 MW, TEP's estimate of the effect of DSM;
- including the Liquid Air interruptible load, but excluding the associated 6 MW interruptible load as a resource;
- excluding 114 MW of short-term purchases.

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[1]The Company's primary-reserve-margin criterion is the single largest hazard plus 5 percent of forecast peak demand.

As explained below, TEP appears to have operated only about 12 MW below the primary-criterion reserve margin.

**Q: Why do you find that TEP's calculation provides an unreasonable basis for determining the usefulness of Springerville Unit 2?**

A: The Company's analysis exaggerated the usefulness of Springerville #2 in the following ways:

- The reduction of resources for DSM overstates the effects of the audit programs.
- The exclusion of the Liquid Air Interruptible Agreement is an inappropriate interpretation of the Settlement.
- The Company inappropriately omitted actual 1994 short-term purchases from its analysis of need.
- Exhibit DBE-1 overstates the need for Springerville #2 by assuming a reserve requirement that is greater than the reserve TEP actually maintained in 1994.

**Q: Why is TEP's adjustment to peak for all DSM program savings inappropriate?**

A: Of the 20.2 MW savings claimed by TEP, residential and commercial audit programs account for 5.5 MW (Exh. CAM-1). No savings should be attributed to these audit programs, for three reasons.

- The Company has offered no derivation of this 5.5-MW value.
- The Company has never really determine whether these programs result in any energy efficiency investments, or save any energy or peak demand.

- Audit programs can be valuable as intake mechanisms for rebate, design and direct-installation programs, but are not likely to produce any appreciable energy or demand savings on their own.

**Q: Has TEP performed any evaluation of the load impacts of the audit programs?**

A: The only such evaluation appears to be a 1993 survey question asking participants which recommended measures they implemented (RUCO DR 3.1, Attachment 3, p. 133). Even these results do not appear to have been used in the savings estimates, and they have not been made up-to-date (Staff DR ER-113).

Impact evaluations are particularly important for audit programs. In rebate and direct-installation programs, the utility has some idea of the number of measures installed, because it tracks payments made for specific actions and requires documentation that the equipment was purchased or installed. Even so, impact evaluations are important for rebate and installation programs, to estimate free ridership (the share of participants who would have taken the action without the program), average efficiency increase, hours of usage, persistence, and other data that cannot be derived from the tracking system. For audit programs, the utility has no idea what percentage of recommendations are acted on, or how well the equipment is selected and installed. Since no incentives are provided to overcome market barriers, the small percentage of customers who act on the recommendations may be those that would have taken the same actions without the audit.

**Q: Then how did TEP derive the estimates of the load reductions?**

A: The Company apparently counted whatever savings it assumed for screening the programs in the first place, regardless of whether the audits actually resulted in any customer actions or savings.

For one residential audit program, the savings estimates come from the software vendor. For the other residential program, the estimates were provided by the Arizona Energy Office. There is no evidence that TEP even attempted to estimate free ridership, or otherwise reconcile these *a priori* estimates to actual results.

**Q: Why are audit programs unlikely to produce any appreciable energy or demand savings?**

A: As I noted above, audit programs have a number of features that limit their effectiveness:

- Since no incentives are offered, few of the recommendations are likely to be implemented.
- The utility has little opportunity for quality control.
- Free ridership can be very high.

Generally, the energy and demand savings from audit programs should generally be assumed to be negligible, unless a very careful impact evaluation indicates that the savings are appreciable.

**Q: Does TEP uniformly treat its audit programs as producing savings?**

A: No. TEP now treats the commercial program as producing zero savings (RUCO DR RI 3.6 CONFIDENTIAL). TEP has not provided any justification for counting savings from earlier commercial audits, or from similarly ineffective residential audits, in the used-and-useful calculation for Springerville Unit 2.

**Q: Why is TEP's adjustment for the Liquid Air agreement inappropriate?**

A: Only load reductions from TEP conservation efforts are to be excluded from the Springerville Unit 2 usefulness computation. The Liquid Air contract is not a conservation measure, and may not result in any load reduction.

In its last Order, the Commission allowed TEP to count the Liquid Air contract as conservation, but directed TEP to demonstrate in its next rate case that the interruptible agreement achieves "energy conservation and efficiency," as required by the 1991 Settlement. The Company made no attempt to comply with the Commission's Order. Instead TEP chose to pretend that the 1991 Settlement provision refers to "peak conservation" and "efficiency in use of generating facilities," instead of "energy conservation and efficiency." The utility then presented load data that purported indicate a decline in Liquid Air's on-peak demand and a shift in energy use to the off-peak periods (Erdwurm Direct, p. 3).

**Q: Does the Liquid Air load data be used to demonstrate energy conservation and efficiency?**

A: No, for several reasons. First, load shifting is not energy conservation or energy efficiency, and is not eligible for exclusion from the usefulness computation.

Second, it is not at all clear that the Liquid Air contract was ever intended even to reduce peak. The initial purpose of the special contract was to encourage Liquid Air to *increase* off-peak loads, not to reduce on-peak demand. Load-building is not conservation.

Third, the contract may well have resulted in a greater 1994 peak. Liquid Air is negotiating with TEP for a further rate discount for "competitive reasons" (Staff DR RWS-67 CONFIDENTIAL). Without the special contract, Liquid Air might well have left the TEP system, resulting in a zero capacity requirement. Therefore, the effect of the Liquid Air contract may be to retain about 6 MW of load, not reduce loads. Load-retention is not energy conservation.

Fourth, the Company should not receive special treatment for activities that are now standard practice: TOU pricing, interruptible rates, and favorable pricing arrangements for large customer. The purpose of the DSM provision in the Settlement is to reduce TEP's reluctance to promote conservation, not reward it for routine rate design activities. The Liquid Air contract is no more a conservation program than is every rate that includes an energy charge.[2] Rate design is not conservation.

**Q: What short-term purchases does TEP omit from its analysis of need?**

A: On the 1994 peak, TEP was purchasing 114 MW on a short-term basis (RUCO DR RI 4.10). TEP's used-and-useful calculation should be revised to include the short-term purchases that were used to meet firm demand. Adding the 114 MW of short-term purchases reduces the need for additional Springerville capacity from the entire 135 MW to 89 MW.

**Q: What actual reserve did the Company maintain on the peak day on 1994?**

A: To make the 80 MW of short-term sales on June 29, the Company operated about 12 MW below what it assumes in Exh. DBE-1 to be its *required* reserve level.[3]

**Q: Does that mean that TEP's system was unreliable in the test year?**

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[2]Imagine how much more energy TEP's customers would use if they were only charged an energy charge.

[3]Adding 114 MW of purchases to Exh. DBE-1 (giving a total of 2089 MW) and 80 MW of sales (for a total of 1,806.5 MW) gives a reserve margin of 282.5 MW, 11.8 MW short of the 294.3 MW required under the primary criterion.

A: No. It is not clear what effect the lower reserve level had on the reliability of the system. There are a number of possibilities, as follows:

- The system was operating at too low a reliability level and TEP was just lucky.
- The reserve required in the short term is smaller than that required for long-term planning, since the latter must account for the long-run uncertainty in the demand forecast and resource availability.
- Especially given the current regional surplus, TEP is easily able to rely on an additional 12 MW of regional system support to meet its reliability standard.

The responses to RUCO DR RI 11.4 and 11.5 indicate that TEP plans on meeting small deficiencies with short term purchases, supporting the third explanation.

**Q: Based on your revisions to Exh. DBE-1, what is the used and useful portion of Springerville #2?**

A: The Company's analysis overstates the 1994 need for Springerville #2 by

- excluding 114 MW of short-term purchases,
- counting about 12 MW more of reserve than it actually maintained,
- including a 6 MW credit for Liquid Air contract in the DSM adjustment,
- including 5.5 MW of savings from audit and informational programs in the DSM adjustment

The Company's comparison of load and available capacity in 1994, if corrected for these errors, would indicate that less than half of the currently excluded 135 MW of Springerville #2 is useful. This computation is shown in Exhibit____(PLC-2). I therefore recommend that 67.5 MW of

Springerville Unit 2 be excluded from rate base. This is slightly less than the 80 MW of what TEP calls "excess capacity" sold during the test year.

**Q: Was Springerville Unit 2 an economic source of power to TEP in 1994?**

A: No. Capacity and energy could have been purchased through short term contracts. The cost of these alternatives provides a reasonable measure of the economic value of the 135 MW of Springerville Unit 2.

**Q: What was the economic value of Springerville Unit 2 in 1994?**

A: That value was relatively small in comparison to its annual cost. The Company considers the contract with Texas-New Mexico Power Company (TNP) to be a reasonable proxy for the market value of peaking capacity in 1994. Under that agreement, TNP will pay only $3.50/kW-month for capacity in 1996 (RUCO DR RI 4.53 and RI 11.1 CONFIDENTIAL).

In contrast, the annual non-fuel revenue requirements of Springerville Unit 2 are $273/kW-year or almost $23/kW-month (RUCO DR RI 13.1).[4] Thus Springerville Unit 2 cost over six times as much as the market value.

**Q: Did Springerville Unit 2 have any fuel-saving value?**

A: Probably not, at present. The energy costs for Springerville #2, including its high fixed fuel costs, do not appear to be any cheaper than market energy prices. In 1994, the average fuel cost for Springerville 2 (including fixed fuel costs) was $24 or $25/MWh (RUCO DR RI 4.22). This was more than the average cost of TEP's 1994 economy purchases, at $23/MWh.[5] Therefore, Springerville #2 does not appear to have significant fuel savings compared to the market.

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[4]The energy costs in this contract are $26-31/MWh on-peak, $20-23/MWh off-peak, compared to $24–25/MWh for Springerville Unit 2.

[5]From TEP's 1994 FERC Form 1, p. 326-327: $13,161,558 ÷ 573,461 MWh = $23/MWh.

**Q: What revision to the Proposed Settlement do you recommend to reflect your analysis of the used-and-usefulness of the remaining 135 MW of Springerville #2?**

A: The Commission should allow into rate base about half of the remaining 135 MW of Springerville Unit 2. Half of 135 MW is 67.5 MW, but anywhere from 65 to 70 MW would be reasonable. For consistency, the Commission should probably eliminate the $4.3 million settlement credit to ratepayers for off-system sales margins, since these sales would be primarily from the excess capacity.

## IV. The SCE Settlement and Exchange

**Q: How is the SCE exchange treated in the proposed settlement?**

A: The settlement proposes a $4 million annual credit to TEP ratepayers. This is intended to represent the energy and capacity savings of the exchange, net of the reservation charges.

**Q: Is this treatment of the SCE exchange reasonable?**

A: No. The exchange is part of a settlement of TEP's lawsuit against SCE, in connection with SCE's interference with TEP's failed attempt to merge with San Diego Gas and Electric. In Docket U-1933-93-006, the Commission found that the present-value benefits of the SCE settlement, net of the cost of litigation, should be split evenly between shareholders and ratepayers. The Commission also ordered TEP to produce a plan to achieve this equal division of net benefits. The Company requested two extensions, and never prepared such a plan.

The shareholders have retained $27.6 million from the cash settlement from SCE; the only benefits to ratepayers flow through the power exchange.

If ratepayers receive $4 million annually for 1996 to 2004, the ratepayers would end up with a present value to 1992 (when shareholders received their payment) of just $17.3 million, or just 63% of the shareholder benefit.

**Q: How could this imbalance of benefits be corrected?**

A: If the rates from this case remain in place through 1999, and if ratepayer benefits in 2000-2004 are about $7 million annually, then a $6 million annual credit to ratepayers will produce a present value to ratepayers about equal to the benefits to shareholders, producing an even split. The $7 million annual benefit for 2000-2004 is roughly equal to TEP's projection of energy benefits in that period (Staff DR ER-1, Attachment 3), plus the benefit of deferring a new CT (at the costs estimated by TEP in Staff DR ER-1, Attachment 4).[6]

The split of benefits between ratepayers and shareholders could be made equal by increasing the current SCE credit to ratepayers from the $4 million proposed in the settlement to $6 million.[7] In addition, the Commission should clearly state that the current credit assumes that ratepayers will receive $7 million in net benefits annually in 2000-2004, and that the division of the total benefits of the SCE settlement will be reviewed in any subsequent rate case, if the annual net benefits at that time are significantly lower than the $7 million.

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[6]The utility treated the SCE exchange as avoiding the levelized costs of the first 10 years of a CT added in 1995. In fact, a new CT would be required at the end of the exchange, at a greater, inflated cost. I valued the SCE capacity in 2000-2005 with the savings from deferring a CT from 2000 to 2005.

[7]This level of benefits seems quite reasonable, given that TEP projects over $7 million in annual net benefits for ratepayers for 1996-1999 in DR ER-1.

## V. Pricing Flexibility

**Q: Are the pricing flexibility provisions in §B9 of the proposed settlement reasonable?**

A: No. The Commission should reject the flexible pricing proposal for the following reasons:

- The Company has not demonstrated that more flexibility in retail price negotiations is needed.
- The proposed settlement fails to provide sufficient and appropriate controls over TEP's implementation of pricing flexibility.
- The proposal is not ripe for review and approval, since TEP and Staff have not yet resolved important issues in flexible pricing.
- The proposal that discounts be limited to commercial and industrial customers is discriminatory.
- There is not adequate provision for review by the Commission and by interested parties other than the Commission Staff.

**Q: What is the Company's rationale for pricing flexibility?**

A: Company Witness Glasser (Direct, p. 11) simply states that unspecified "emerging competitive forces" and the needs of unidentified customers require quick response by TEP without Commission oversight.

**Q: Does the Company's rationale have merit?**

A: No. As the Company acknowledges, its original proposal would grant TEP a level of pricing flexibility that has not been requested by any other utility (DR Staff RWS-73). The Proposed Settlement, which sets up only a 30-day review period for the Staff, does not do much to constrain the Company. It is unclear what competitive forces and special customer needs would justify granting TEP this much additional latitude. The Company is already negotiating special rates for customers in the absence of flexible pricing and has not demonstrated that the existing process fails to meet its existing customers' needs.

**Q: In what respect does the proposed settlement give the Company too much latitude in the implementation of flexible pricing?**

A: The proposed settlement fails to address some fundamental policy questions. Rather than setting any limits on the Company's negotiations with customers, the settlement would leave most decisions to a case-by-case determination without Commission review. Without more specificity, the Commission cannot know what it would actually be authorizing by approving the proposed settlement.

The settlement would require Commission approval of all discounts that are consistent with the tariff. However, the settlement does not include the tariff, and the only real requirements in the settlement are that the Staff approve the discount. Hence, by approving the settlement, the Commission may be delegating its ratemaking authority to TEP and Staff.

**Q: What fundamental decisions does the proposed settlement leave to the discretion of the Company and Staff?**

A: The proposed settlement has the following deficiencies:

- It provides no guidance in estimating long-run incremental costs and provides no process for developing an estimation methodology.
- It fails to specify the minimum margin above marginal cost for which a sale would be worth the risks to the ratepayers and shareholders. The Company has not demonstrated that it has clearly thought through how to set the margin, or even that it understands why a margin is needed.

- The Proposed Settlement does not address the potentially adverse effects of its rate discounts on the competitive position of its other customers.
- There is no clear definition of what sort of "viable alternative" would make a customer eligible for a price discount.
- The Proposed Settlement does not limit the Company's price negotiations to the minimum discount necessary to prevent uneconomic loss of sales.
- The Proposed Settlement appears to extend pricing flexibility beyond the original Company proposal, to include re-allocations of entire class costs outside of a rate case, without benefit of a retail cost-of-service study.

**Q: Have the Company and Staff agreed on a long-run marginal-cost methodology for use in its price negotiations?**

A: No. The Staff and the Company did not discuss in detail or agree to a methodology for estimating long-run marginal cost (RUCO DR 17.6). They have agreed only on a short-run marginal cost estimate using production costing models—a method similar to that currently used to calculate the credit to the excess capacity deferral (RUCO DR 17.6 and Staff's response to RUCO 4.6).

**Q: Have the Staff and the Company adequately specified the basis for the short-run marginal cost estimate?**

A: No. Production costing models, such as PROMOD, can be useful computational tools. However, the marginal-cost estimate can only be as accurate as the inputs to the model. The marginal-cost methodology should specify all of the essential cost elements of the analysis, such as opportunities for economy purchases and sales. The Staff and the Company have not described how they would do this.[8]

**Q: Has TEP developed a long-run marginal cost methodology that could be used in price negotiations?**

A: No. The utility appears to have no idea how to estimate long-run marginal cost. The utility's responses to discovery in this proceeding indicate that TEP has no estimate of long-run marginal cost. The Company has not developed a marginal cost methodology, and apparently does not intend to do so. It has no estimate of the long-run market value of capacity and no projection of the year in which the market supply will be in balance with demand (RUCO DR RI 4.51, 4.54 and 4.55). The Company will only say that it would consider "the competitive environment" on a "case-by-case basis" (RUCO DR RI 4.64).

**Q: Has TEP explained how it would apply marginal cost concepts in setting flexible rates?**

A: No. The Company has not even provided a consistent statement of the role long-run marginal cost will play in its price negotiations. On discovery, TEP demonstrated confusion regarding the difference between short- and long-run costs, and was not clear about what costs needed to be covered in discounted rates.

**Q: Has the Staff provided any more guidance on this issue?**

A: Unfortunately, the Staff does not seem to have thought this through clearly either. According to its response to RUCO 4.6, the Staff would include in

[8]In using production costing modeling to estimate the energy savings from the TEP-SCE exchange, TEP omitted economy purchases and sales (RUCO DR RI 11.6(c)).

marginal cost "the present value of deferring future capacity additions (if such additions would have otherwise occurred during the time of interest)."

**Q: Why is the Staff's definition of long-run marginal cost inadequate?**

A: The Staff's definition might mean that discounted rates need to cover any capacity cost only at the point when TEP plans to add a new generation unit. This perspective fails to recognize that TEP is currently purchasing capacity, and is planning to buy more over time, without adding new units. Capacity has a market value immediately, either as the cost of additional purchases or the opportunity cost of foregone sales. Focusing on the addition of new units ignores the effects of retail price discounts on TEP's short-term wholesale purchase costs and sales revenues.

According to the Staff's own analysis, capacity currently has a significant value, even before any planned addition. For purposes of valuing the SCE-TEP diversity exchange, the Staff estimates of the market value of capacity are equivalent to about $60/kW-year (in 1995), close to the full annualized cost of a peaking unit (Staff's response to RUCO LA-3-1, Staff workpaper WP 3; testimony of G. Harpster in Docket No. U-1933-93-006, pp. 78-79, 84-85).

**Q: What should be included in the marginal costs used in setting rate discounts?**

A: The Company should use a consistent marginal-cost methodology that can be updated for current conditions and tailored to the particular characteristics of the customer. The methodology should include the following components:

- Short-run marginal energy cost, based on production costing model runs (such as PROMOD), including the opportunity for economy purchases and sales.

- Marginal generation capacity costs over time, reflecting
    1. market capacity costs for purchases and sales,
    2. an estimate of how quickly the regional bulk-power market will move towards a balance of load and resources, [9]
    3. any fixed fuel costs (or other fixed O&M) associated with capacity additions,
    4. the effect of energy sales on the type and cost of new capacity.[10]
- Long-run marginal transmission-and-distribution costs. Both retention of existing customers and addition of new customers can result in additional T&D costs. For new loads, the marginal cost analysis should consider (1) the new T&D investment necessary to serve that additional load, (2) the effect on the utility's future need of T&D capacity to serve other load growth, and (3) the effect of new load on useful life of existing equipment. Existing distribution equipment wears out faster if it is more heavily loaded. In setting the minimum rate to be charged for an existing load, the marginal cost analysis should consider the effect of retaining that load on items (2) and (3) above.

**Q: What position does the Proposed Settlement take on a minimum margin of price over marginal cost?**

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[9]The size of the surplus is essential to estimating the market value of capacity. It is difficult to see how TEP could develop a valid estimate of long run marginal cost when it has not even projected when the market will no longer be in a surplus condition (RUCO DR RI 4.51).

[10]Increased energy sales may result in construction of a combined-cycle unit rather than a less expensive combustion turbine.

A: The Proposed Settlement simply does not recognize the need for a minimum margin or a methodology for determining a minimum margin. It only requires that rates cover marginal cost:

> The authorized rate must *cover* TEP's marginal cost, considering the term of the contract and type of service offered. (Settlement §B9b, emphasis added)

Furthermore, an inconsistency in the proposed conditions may prevent TEP from charging rates that cover long-run marginal cost. The settlement provides that "[t]he negotiated rate cannot exceed the otherwise applicable rate." A long-term contract price based on marginal cost may at times be less than embedded cost; at other times it may be greater. Section B9b should therefore be revised to require that the "present value of the negotiated rate cannot exceed the present value of the otherwise applicable rate, over the term of the contract."

**Q: Has TEP developed a methodology for determining a minimum margin?**

A: No. In response to discovery, TEP was unable to specify a minimum margin that it would require of contracts of a given type and duration. Instead, TEP intends to negotiate each contract on a case-by-case basis.

**Q: Why is a minimum margin necessary?**

A: Price should include a margin above marginal cost to make the sale worthwhile and to protect the ratepayer and shareholder against potential losses. As the Company itself recognizes, there are risks that require that a margin be built into marginal-cost based prices. In Staff DR ER-5 [CONFIDENTIAL], the Company identifies cost risk as an important factor, particularly in longer-term contracts:

> The term of the contract would be one of many factors which would influence the minimum price that TEP would charge under its pricing flexibility proposal. TEP may not be willing to lock into a long-term contract at fixed prices that had only a small margin. Given the uncertainty of future prices..., the risk inherent in such arrangements becomes greater as the contract term increases. The required margin should increase as the term of the arrangement increases.

**Q: What are your concerns about the competitive effects of case-by-case price negotiations?**

A: Case-by-case price discounts can affect the market position of competing firms within the service territory. When the Company agrees to a special rate discount to help a struggling firm that is losing out to other competing firms in the local area, the *intent* of the discount is to alter the competitive balance in that market.

The competitive effects raise two basic concerns. First, special discounts can harm the participant's competitors in the service territory and elsewhere in Arizona. A utility should not be making these decisions without review by affected parties and guidance from the Commission.

Second, flexible pricing may not always have the desired effect of maintaining or attracting sales. For example, consider two neighboring supermarkets, one of which requests a rate discount to keep it in business. If TEP grants the rate discount, the other supermarket may be forced out of business, unless it gets its own discount. There may be no net increase in kW and kWh sales, just a net reduction in revenues to the Company.

In the absence of a process for identifying, evaluating and responding to the competitive effects of special price discounts, flexible pricing can harm the participant's competitors, while failing to provide clear benefits to ratepayers—or to shareholders, for that matter.

**Q: Does the Company intend to address the competitive effects of its pricing decisions?**

A: Essentially, it does not. The Company acknowledges that it would not have information necessary for identifying market effects (RUCO DR RI 4.71 and 4.72). For this reason, TEP intends to implement flexible pricing on "a case-by-case basis" without regard for the potential effects within a group of competing customers:

> TEP will probably not have the requisite information to address the competitive effects of any price discounts granted a customer or group of customers. In most cases...the Company intends to respond to competitive threats based on the economics and alternatives of each individual customer. (RUCO RI 4.71)

Even if TEP intended to deal with the competitive effects of flexible pricing, it would not be a simple matter. For example, to avoid adverse competitive effects, TEP could give the same discount to all competing firms; in fact, does mention this as a possibility (RUCO RI 4.71). However, if it did so, the cost in revenue losses could be substantial—and such a discount would not necessarily keep the struggling firms from going out of business.

**Q: Have the Staff and TEP proposed a clear eligibility standard for flexible pricing?**

A: No. Tucson Electric will only say that it will consider any flexible pricing option that benefits (or is not to the detriment of) the Company (RUCO DR 17.8). The Staff states (in its response to RUCO RI 4.7) that to be "viable," the customer's alternative should have lower cost than power under the regular tariff.[11] Beyond that, the Staff and Company have not agreed on a definition of a "viable" alternative. They have agreed only that they will

[11]The Staff also allows for some exceptions to this rule in its response to RUCO 4.6.

consider whether the customer qualifies for a rate discount on a case-by-case basis.

**Q: Is such an open-ended standard be appropriate?**

A: No. This standard as it is written would permit the Company to manipulate price to discourage *economic* alternatives to electric consumption, such as installation of cost-effective energy-efficiency measures, cost-effective load control, cost-effective cogeneration, and cost-effective photovoltaics (RUCO DR 17.8).

Specifically, TEP is unwilling to exclude even cost-effective DSM even though it "has supported, and continues to support cost-effective energy efficiency measures and cost-effective load control" (RUCO DR 17.8).

**Q: Has the Staff clarified its position on economic alternatives?**

A: Yes. The Staff (in its response to RUCO RI 4.8) takes the position that applying flexible pricing to discourage cost-effective alternatives would not be sound policy. It proposes that rate discounts not be permitted to compete with photovoltaics, economic or not, to be consistent with TEP's goals and Commission policy regarding renewables. The Staff also opposes using flexible pricing to discourage cost-effective energy efficiency, cost-effective load control, and cost-effective cogeneration.

**Q: Has the Staff included limits on eligibility on the Proposed Settlement to prohibit flexible pricing from deferring renewables and cost-effective alternatives?**

A: No. In the Staff's view, there is no reason for concern, because if the alternative is cost-effective, then its cost will be below the Company's marginal cost and the Company would be unable to negotiate a discount low enough to discourage the customer from making the investment (Staff's response to RUCO 4.8).[12]

**Q: Do you agree with the Staff that under marginal cost-based pricing, the Company will be unable to out-compete a cost-effective investment in energy efficiency or cogeneration?**

A: No, for at least two reasons. First, as discussed above, the proposed settlement does not give clear assurance that the Company will be unable to set prices below long-run marginal cost. Second, because of market barriers, the Company can discourage cost-effective investment at rates substantially *above* marginal cost.

**Q: Why is the Company able to underbid cost-effective alternatives with prices that are greater than marginal cost?**

A: Customers routinely decline alternative investments that, measured with a utility's economic yardstick, are extremely attractive. In spite of embedded cost-based rates—which often exceed estimates of long-run marginal costs—typical customers require efficiency investments that last 20 years or longer to pay for themselves within two years. This quick payback requirement, which leads utility customers to reject substitutes for supply that appear highly cost-effective if scrutinized under utility investment criteria, is the driving factor behind utility-funded conservation programs in the first place. Customers do not have sufficient incentives to invest under current rates. Flexible price discounting will only reduce customer's interest in pursuing cost-effective alternatives.

[12]In its response to RUCO 4.8, the Staff appears to distinguish between DSM and cogeneration, treating the former as a less appropriate target for rate discounts. The distinction, as phrased by Staff, is subtle and may be inconsequential.

**Q: What market barriers account for customers' short payback requirements?**

A: Short payback requirements are symptoms of market barriers to customer investment in cost-effective efficiency and cogeneration. The simplest reason that efficiency is so regularly passed over in favor of "business as usual" is that, as an investment, it is not available on the same pricing terms as electricity or fossil fuels already being purchased by customers. If it were—either through market innovation, utility market intervention, or both—even short-payback customers would be much more likely to choose efficiency whenever it was priced below electricity.

In addition, limited access to capital, institutional impediments, risk perception, inconvenience, and information scarcity all increase the costs and decrease the benefits of energy-efficiency improvements.

**Q: Does the Proposed Settlement include any conditions that place a limit on the size of the discount?**

A: The Proposed Settlement has no effective limitations. The Company should be explicitly required to limit the discount negotiated to the minimum necessary to retain the customer and avoid uneconomic alternatives. In particular, the customer should have to demonstrate that it has installed all cost-effective energy efficiency measures before it can be eligible for a rate discount. As the Company itself recognizes:

> TEP believes that DSM can be an important tool for attracting and retaining customers in a competitive environment. To be successful, DSM must address three critical customer issues: price, cost, and value. The cost of energy is obviously very important in a competitive market. Cost to the customer has two components: price and consumption. This is a simple but critical concept. Customers may have a mindset to compare energy prices, but they should also consider the amount of energy used to provide the required services. *For example, a 20% decrease in energy price may be very attractive for an industrial customer. However, the customer would be even better off with existing prices but a 30% decrease in consumption for the same level of production output.* TEP believes that it is critical to have the ability to negotiate prices with customers. We also believe that DSM services can be included in this process to deliver low energy cost. (CONFIDENTIAL Staff DR ER-7, emphasis added)

**Q: What conditions of the Proposed Settlement may permit class revenue re-allocations outside a rate case?**

A: There are two such provisions. First, §B9(f) of the Proposed Settlement allows standard contracts for commercial and industrial customers of less than 200 kW. This flexible standardized contract would be inconsistent with the conceptual basis of flexible pricing. The utility intends flexible pricing as a way to "respond to the customers' *individual* circumstances," not to give a whole group of customers a rate discount (Glazer Direct, p. 15, emphasis added). In addition, flexible pricing is intended to permit TEP to compete with uneconomic or undesirable alternatives (such as cogeneration or relocation) that are not currently available to smaller customers, and are unlikely to be available class-wide.

Second, the proposed settlement states:

> In addition to the flexible tariff described above for individual customers, TEP and Staff agree that TEP may lower rates for any rate schedule at any time upon Commission approval.

This provision allows for two interpretations.

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This provision allows for two interpretations.

- This provision may just preserve the potential for rate design filings pursuant to existing procedures and provision §B7. If so, the proposed Settlement should be revised to say so explicitly.
- This statement may be granting the Company new rights to unilaterally reduce rates to a favored class outside of a general rate-design case. If so, this provision should be eliminated entirely from the Settlement. The captive customers, including the residential classes, are likely to be disadvantaged by such special rate reductions.

**Q: What review process would the proposed Settlement establish?**

A: The proposed Settlement would effectively eliminate Commission oversight of special contracts and would place all of the regulatory responsibility with the Commission Staff. The Staff alone would decide whether special contracts meet the tariff conditions and must do so within 30-day review period. The Commission would review only the special contracts rejected by the Staff.

**Q: What review process do you recommend?**

A: The Commission should continue to have primary oversight over special contracts. Representatives of rate classes (including RUCO) should also be included in the review of the special contracts, because these customers may be affected if the discounts are allocated to them in the next rate case or if the loss of special-contracts customers results in stranded investment.[13] In addition, the review process should include other customers whose competitive position may be affected by the discount.

[13] The Company admits that discounts may result in stranded investment (RUCO DR RI 4.66).

**Q: What is your recommendation regarding flexible pricing?**

A: The Commission should reject the flexible pricing set forth in the Proposed Settlement, for two reasons. First, neither the Company nor the Staff has demonstrated clearly that the current special-contracts procedures provide inadequate flexibility. Second, the proposal is not well-developed and gives too much latitude to the Company.

If the Commission decides to grant TEP some discretion in negotiating special contracts, I recommend that the Commission should determine up-front that none of the discounts will ever be recovered from non-participant ratepayers. In addition, the Commission should set a limit on new price discounts at $1 million annually. This limit would allows TEP some negotiating room, but would reduce the risk that the Company will over-extend itself, particularly in long-term commitments.[14] Even if discounts are not directly recovered from non-participating customers, permitting unlimited price discounts can impose financial stress on the company and ultimately increase costs to ratepayers.

If the Commission decides to consider allocation of the discounts to the other ratepayers in the next rate case, I recommend that the Proposed Settlement be revised to include a number of ratepayer protections.

- The Commission should withhold approval until it is presented with a long-run-marginal-cost methodology that responds to the issues discussed above.

[14]By the end of 1999, this limit would still permit TEP to have committed to $4 million in discounts for the year 2000.

- The Commission should withhold approval until it is presented with a minimum margin of price over marginal cost and/or a methodology for determining that margin.
- To prevent flexible pricing from being used as a back-door means of class revenue re-allocation, the Commission should remove the provision that permit a standardized contract for customers under 200 kW.
- The review process should be open to all interested parties, including RUCO and competitors potentially affected by the special contract price discount.
- The Commission should explicitly exclude energy efficiency, load management, renewables, and cost-effective cogeneration from the list of potential viable alternatives.
- The Commission should provide that discounts should be granted only to prevent uneconomic cogeneration, self-generation, or relocation or closure due to outside out-of-state competition.
- The discount should be limited to the minimum necessary to retain the customer and avoid uneconomic alternatives assuming that the customer has implemented all cost-effective conservation measures.

## VI. Residential Time-of-Use Rate 70

**Q: Is the structure of Rate 70 proposed in the settlement appropriate?**

A: The general structure of the rate seems reasonable, but several details should be revised. Most importantly, the peak and intermediate periods should be extended, which will reduce the rates in those periods. In addition, revenue requirements should not be shifted so dramatically from winter to summer, compared to Rate 1.

**Q: What cost basis do TEP and the Staff offer for the settlement rates?**

A: The Company did not offer any cost basis for its original proposed rates, nor did either TEP or the Staff offer any cost basis for the settlement rates. The rate differentials were set to encourage switching, rather than to approximate cost patterns (RUCO DR RI 4.24).

**Q: What problems have you identified in the definition of the seasonal rating periods?**

A: I have identified three problems.

First, the peak and intermediate periods proposed in the settlement do not consistently cover high-load hours that may contribute to system requirements for generation and transmission.

Second, peak and intermediate periods do not cover the highest-load residential hours. The low off-peak rates at these times will encourage further increases in residential non-coincident peak (NCP) loads. High residential loads, even if they do not coincide with system peak, contribute to the peak loads on various parts of the distribution system, from the line transformer to the primary feeder, to the substation. Increased distribution peaks require the installation of additional equipment, increasing revenue requirements.[15] In addition, since TEP allocates distribution costs in proportion to NCP, the increase in residential NCP would increase the residential allocation of distribution costs.

[15]High loads around the time of distribution peak also increase costs, since heat build-up reduces the load-carrying ability of lines and transformers, and accelerates the aging of insulation.

Third, the settlement would increase the summer-winter differential in Rate 70, compared to the existing or proposed Rate 1, without any cost justification.

**Q: What are your concerns about the settlement periods for the summer weekdays?**

A: In the summer weekday, the settlement proposes an intermediate period of 6-8 PM, following a 1-6 PM peak. The system load data (DR ER-11, Attachment 1, p. 3) indicate that load is just as great in the period 11 AM–12 noon as in the 6-8 PM period. While these hours are not usually the peak hour, reliability problems can occur whenever a major outage occurs.

The residential peak continues to 9 or 10 PM weekdays (DR ER 11, Attachment 3, pp. 6-7; see also Attachment 4, pp. 2-3). The utility concedes as much in DR RI 4.27.

**Q: What are your concerns about the settlement periods for the summer weekends?**

A: Under the settlement, the entire weekend is off-peak. Residential loads are actually greater on the weekends than weekdays, so at least the distribution portion of the cost differential should be extended to the weekends.[16]

**Q: What are your concerns about the settlement periods for the winter weekdays?**

A: The settlement proposes a winter peak period of 7-11 AM and 6-9 PM weekdays. The Company does not provide any system-load data for the winter. There is obviously some value of generation in the winter, for resale

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[16]TEP did not provide separate load shapes for Saturday and Sunday.

to winter-peaking utilities, or for scheduling of maintenance, to ensure that all generation can be available for the summer peak.

The residential load data indicate that loads in the 6-7–AM hour are at least as high as in the 10-11–AM hour. The sharp increase in rates at 7 AM would encourage customers to set their clock thermostats to warm up the house earlier, shifting the morning peak to 6 AM. In the evening, loads fall after 9 PM, but remain above the morning levels through 10 or 11 (Staff DR ER-11, Attachment 3, pp. 6-7; see also Attachment 4, pp. 2-3). Given the ease of shifting certain loads (dishwasher, clothes washer, clothes drying) later in the evening, the evening peak period could slide into the proposed off-peak period.

**Q: What are your concerns about the settlement periods for the winter weekends?**

A: For winter, as for summer, the settlement proposes that the entire weekend be off-peak. Winter residential loads in weekends are close to, or greater than, weekday loads. The high-load evening hours closely match those of the weekdays; the morning peak starts an hour or two later.

**Q: Would an increase in residential winter loads increase costs to residential customers?**

A: Yes. Customers with electric heating experience their highest loads in the winter. In winter-peaking areas, with many electric heating customers on the block or in a subdivision, increased winter loads will require additional distribution equipment. Since TEP's cost-of-service study divides residential customers into non-heating (summer-peaking) and heating (winter-peaking) groups, and computes an NCP for each, increased winter loads will increase the residential allocation of distribution costs.

**Q: How does settlement Rate 70 increase the summer-winter differential, compared to Rate 1?**

A: The settlement Rate 70 would reduce the ratio of winter bills to summer bills, compared to settlement Rate 1, for typical customers (Staff response to RUCO 4.10 and Attachment). Since both Rate 1 and Rate 70 have seasonal rate differentials, there is no reason for the seasonal differential to be higher in Rate 70 than Rate 1. No cost justification for this increased differential is offered by TEP or the Staff.

The settlement would arbitrarily give disproportionate benefits to winter-peaking customers.

**Q: Have you prepared an alternative Rate 70, to avoid the problems in the settlement proposal?**

A: Yes. I propose retaining the settlement peak periods, while extending the weekday intermediate periods to cover more system shoulder hours and residential high-load hours, and adding intermediate hours on the weekend, covering the residential high-load hours. My proposed hours, compared to those of the proposed settlement, are

| | Peak Hours | Intermediate Hours | |
|---|---|---|---|
| | | Settlement Proposal | Revised Proposal |
| *Summer Weekday* | 1-6 PM | 6-8 PM | 11AM-1PM<br>6-9 PM |
| *Summer Weekend* | none | none | 11am-9pm |
| *Winter Weekday* | 7-11 AM,<br>6-9 PM | none | 6-7 AM, 5-6 PM,<br>9-11 PM |
| *Winter Weekend* | none | none | 8-11 AM<br>6-9 PM |

**Q: What rates would result from these extensions of the intermediate hours?**

A: I have determined a set of rates that

- maintain the same annual bill for the average non-TOU customer switching to Rate 70 as in the settlement;
- maintain the settlement's 4.5¢/kWh off-peak winter rate;
- keep the intermediate rates roughly equal to the average of peak and off-peak, as in TEP's original proposal and the settlement;
- keep the ratio of summer and winter bills close to Rate 1.

My proposed rates are as follows:

| | | Settlement Rat | Proposed Rat |
|---|---|---|---|
| *Summer* | Peak | 19.50 | 15.0 |
| | Intermediate | 12.75 | 10.0 |
| | Off-peak | 6.00 | 5.0 |
| *Winter* | Peak | 12.75 | 11.6 |
| | Intermediate | 4.50 [17] | 8.0 |
| | Off-peak | 4.50 | 4.5 |

My proposal would reduce summer rates, and the winter peak rate, compared to the settlement. These reductions would be offset by the creation of the winter intermediate period, and the addition of hours to the summer intermediate period.

## VII. Additional Uses of DSM to Fulfill the Settlement Goals

**Q: In what ways does the settlement refer to the use of DSM to achieve the goals of the settlement?**

[17]The settlement proposes no winter intermediate period; all of my intermediate hours are treated as off-peak in the settlement.

A: The only such reference is in the discussion of flexible pricing, which specifies that the recipients in discounted rates must undergo an energy audit.

**Q: What other applications of DSM would facilitate the goals of the settlement, while reducing costs?**

A: There are three areas in which DSM could be helpful. First, if flexible pricing is to be pursued at all, the provisions regarding DSM should be strengthened, to require that TEP ensure that all cost-effective DSM be undertaken prior to the granting of any discounts. A rate discount of, for example, 20% is equivalent to giving the customer 20% of its energy for free. If saving electricity is less expensive than producing the electricity (which is the definition of cost-effective DSM), TEP and its ratepayers will be better off paying to save power for the vulnerable customers than buying more expensive power to give those customers. The Company itself recognizes this benefit of DSM, as noted above.

Second, for customers with long-run difficulties in paying their bills, TEP funds, such as from the LIFE program, may be better spent reducing their energy usage than forgiving their bills.

Third, Rate 21 was created to provide relief to a group of high-use residential customers when declining-block rates were eliminated and has been left open for the same reason (Staff DR RWS-30), even though all parties acknowledge that the rate does not reflect TEP's cost structure. In future rate cases, the discount to Rate-21 customers will result in larger rate increases to other residential customers. This rate could be phased out by offering the customers on Rate 21, and those on the waiting list, a combination of Rate 70 and a reduction in energy use. The eligible customers would receive smaller bills, while other customers would bear reduced revenue requirements.

**Q: Does this conclude your testimony?**

A: Yes.