Feb. 2, 2016

Mr. Michael Osbourne, Chairman
Electric Utility Commission
City of Austin
Austin, TX

Dear Mr. Osbourne and members of the Commission:

I appreciate the invitation to participate as an expert advisor to the Commission. I regret that I am not able to appear in person before the Commission; this Feb. 22 meeting conflicts with an American Council for an Energy Efficient Economy conference at which I am a speaker.

RAP is a global non-profit that provides training and technical assistance to utility regulators. For a municipal utility, that role is vested in the City Council, and for Austin, shared with the Commission. We normally do not advise utilities or intervenor parties. We consider your invitation to be in the role of regulator, and our advice is available to you on that basis.

In lieu of an appearance and presentation, I have prepared a brief written report, based on only a few hours of review of the AE cost of service study and rate design report. I hope it is useful to you.

It should be possible for me to join the meeting remotely, by telephone, Skype, or GoToMeeting if that is desirable. We can discuss that option once you have reviewed this brief written report. We can use the RAP GoToMeeting platform, leaving the Commission only to connect to a website if that is of interest.

Should Austin's utility regulators desire a deeper involvement of RAP as advisors, we can discuss how that activity can be arranged and funded.

I look forward to discussing this with you in any way it is helpful.

Sincerely,

Jim Lazar, Senior Advisor
Regulatory Assistance Project

Observations on Austin Energy Cost of Service and Rate Design Report.

The following observations are the result of a few hours examining the cost of service and rate design reports to the EUC and the City Council. They should not be considered an exhaustive review, and there may be errors in my interpretation of the methodology that AE has employed that can be corrected.

Based on this limited review, I do not think that the AE cost of service study represents a reasonable basis for allocation of costs between customer classes or the design of rates within classes.

Customer-related costs and demand-related costs appear to be significantly overstated. Energy-related costs seem to be significantly understated. Smart Rate Design for a Smart Future, and particularly Appendix A to that report, provide a more detailed discussion of a modern approach to cost allocation and rate design.

I recommend that, ideally, the EUC and City Council convene a multi-day set of workshops to allow presentation of modern rate design principles that could guide policy makers in directing the utility how to move ahead with a modern cost allocation study. I have done this on several occasions with utility regulators. In my experience, when I have worked with policy makers in these types of workshops, a more logical classification and allocation of costs results.

Cost of Service Study

A brief series of observations on the cost of service study, divided by the types of costs evaluated. In the simplest of terms, this cost of service study uses some obsolete methods, and probably should not be relied on for either cost allocation between classes or rate design within classes. Our industry has evolved rapidly, and new methods are needed.

This study is what is known as an “embedded cost” study – one that looks at current costs and apportions them based on customer and usage factors. Many utility regulators also consider “marginal cost” studies that look at the cost of replicating the utility system at today’s costs; these can produce very different results. And within the “embedded cost” and “marginal cost” categories, there are literally hundreds of different methods used.

There is no “correct” method for apportioning utility costs. The role of the regulator is normally to consider multiple methods, and make a reasoned judgement based on what they learn.

It is in that context that I make some specific observations on the AE staff study, and recommend consideration of alternative approaches.

Customer-Related Costs

The study appears to classify all metering and billing costs as customer-related. Customer related costs should include only those costs that vary with the number of customers served. This approach appears to be inconsistent with the discussion in the Austin Energy Rates Policy Statement in at least two ways, and inconsistent with sound practice for at least two additional reasons:

a) As the Rates Policy document states at page 188, Austin Energy operates the **3-1-1 system** for Austin, which the Rates Policy Document states handles more than 1 million calls and 170,000 service requests; some of these costs should not be considered electric utility costs, and if they are electric utility costs, many are not related to the incremental cost of serving an additional electric consumers. These costs should not be classified as customer-related. I was unable to find in the workpapers where these costs are apportioned between utility-related and non-utility, and within the utility, between costs associated with incremental numbers of customers served.

b) Austin energy has installed extensive **smart grid** components, including smart meters. As the Rates Policy document states at page 187:

   Smart Grid/Advanced Metering Infrastructure – Austin Energy began building its smart grid system in 2003 and its service territory is now completely served by advanced meters. This advanced system will improve system security, allow for greater system control by the utility and its customers, lower the number and length of outages, and provide new opportunities for customer management of energy use and new electricity pricing models.

   This clearly recognizes the benefits of smart meters and smart grid components in reducing peak loads (demand-related), improving reliability of service, and reducing line losses and providing time-varying energy benefits (energy-related).

   The costs of the smart grid components should be allocated between the customer, energy, and demand classifications in the COSS. Absent other detailed analysis of benefits, there is no basis for other than equal one-third classification to each category.

c) It appears that 100% of **billing and collection** costs have been classified as customer-related. Utilities bill customers monthly or bimonthly because their usage is significant, and less frequent billings would result in high (and potentially unmanageable) bills, higher uncollectible expenses, higher working capital requirements, and other costs. If customers used only a few kilowatt-hours per month, it would not make economic sense to bill customers more frequently than annually (as most magazines do). The cost of more frequent billing and collection than is required by law should be classified as usage-related costs because they are incurred do to the level of energy usage, not the presence of customers.

d) **Uncollectible expense** has apparently been classified as customer-related. The majority of uncollectible expense is due to the accumulation of usage-related costs (power supply and distribution), not the accumulation of customer-related costs. Uncollectibles should be classified as usage-related.

It appears that customer-related costs have been overstated by a factor of two or more by the inclusion of usage-related costs for smart grid, billing, collection, uncollectibles, and perhaps the costs associated with the 3-1-1 system. There are two different issues here. First, are these primarily “residential” costs (as opposed to commercial and industrial). The second is whether these costs are “customer-related” even if attributable to the residential class. These are separate issues, and this needs to be considered in the cost classification and allocation process.

One important issue is the choice of customer classifications. The utility cost of service for multi-family dwellings is significantly lower (on both a per-customer and a per-kilowatt-hour basis) than the cost of serving single-family residents. Multi-family dwellings have less distribution investment, better transformer utilization, and lower line losses than single-family dwellings, simply because primary-voltage power is normally delivered to the premises, rather than at remote line transformers. In addition, where manual meter reading is used, these costs are lower for grouped meters. AE has consolidated all of these into a single “residential” class. This has the effect of over-charging multi-family dwellings relative to single-family dwellings; depending on the purpose of the inclining block rate design, it may (inadvertently) tend to offset this equity issue.

Power Supply Costs

Power supply costs have been divided into fixed and variable components, and the fixed costs classified almost entirely as demand-related as shown in Workpaper F-2. This was a common practice many decades ago, but evolution in the industry makes this no longer a logical or appropriate approach.

Within ERCOT, all power supply costs are ultimately manifest as time-varying energy charges. In my opinion, since AE has smart meter data available, it should be able to apportion all power supply costs to the classes based on the usage by each class in each hour. This may or may not result in a material change in the ultimate cost allocation, but it is a cost-based approach that more accurately tracks how the mix of baseload, intermediate, and peaking power supply costs are associated with different periods of usage. This would be a significant improvement on the current, somewhat subjective, demand and energy classification scheme.

I have performed several rate studies that use this approach, apportioning all power supply (fixed and variable generation and transmission costs) based on nodal time-varying energy costs. I recommend that AE be requested to divide all class usage into hourly periods, and price that usage based on ERCOT market clearing prices for the most recent 12 months. That result should provide a “proportion” of the power supply (generation and transmission) revenue requirement applicable to each class.

My experience in both California and New England is that this generally results in lower costs to residential customers (who have significant night and weekend usage) and higher costs to commercial (particularly office) customers, whose usage is concentrated in the higher-cost hours of the year due to lighting and air-conditioning loads dominating usage.

Examples of why the AE staff prepared study is not appropriate any longer include:

a) Nuclear generation has very high capital costs, justified by expected lower fuel costs over time; many regulators have recognized this, and classified the majority of nuclear investment and fixed operating costs as energy-related;
b) Coal plants have significant pollution control costs, which are incurred to reduce emissions during all operating hours; these costs need to be properly assigned to all operating hours, not classified as demand-related and allocated only to peak period usage;
c) Peak loads are best managed with a combination of pricing options (TOU, Critical Peak Pricing; Seasonal Pricing) and Demand Response measures (air conditioner, water heater, and other controls). AE recognizes this both through seasonal rates and through operation of the nation's largest chilled water ice storage system, but the costs allocated to peak hours appear to greatly exceed those incurred to serve peak demands with ice storage.
d) Remote baseload generation, primarily coal and nuclear, require construction of high voltage transmission lines to deliver that power to the load centers. These costs should be considered a part of the baseload power plants, and classified primarily on an energy basis; the COS does not do this.

Administrative and General Costs

AE has allocated most A&G costs based on the underlying subtotals of how production, transmission, and distribution costs are allocated. If the production costs are moved from demand to energy, and the billing, collection, and smart grid costs are reclassified from customer to usage-related classifications, the subtotals upon which these are based will shift.

Variable Energy Costs

Variable energy costs include fuel, economy energy purchases, and long-term purchased power costs such as wind and solar contract costs. These are a mix of on-peak, off-peak, and as-available resources.

AE consolidates all variable energy costs into a single total, and allocates this across all usage, collecting them through a single tariff adder on top of base rates.. This has the effect of averaging peaking, intermediate, and baseload fuel costs. Just as it is important to assign the capital costs and maintenance costs for these different types of resources to the hours when they are relied upon for service, the fuel costs should also follow this same pattern.

The approach suggested earlier, apportioning all power supply costs (fixed and variable) based on time-varying usage by class addresses this issue. Alternatively, if a demand and energy framework is retained (and baseload and intermediate costs classified as primarily energy-related), then these variable costs should be apportioned to seasons and time periods on an as-incurred basis.

The EUC and City Council should consider elimination of the separated energy charge, and incorporate this into seasonal and time-varying rate elements for each class of customers.

Rate Design Issues

The AE staff proposal includes a flattening of the rate blocks by applying the base rate decrease disproportionately to the end blocks of the 5-block rate design.

In the previous rate review, I advised the City Council in favor of a three-block rate design, suggesting that five blocks is more complex than is really understandable by consumers.

There are several justifications for an inclining block rate design, and the AE staff study does not really address the basis for their recommendation within this context. This is addressed in Smart Rate Design in Appendix B.

Load Factor: Customers with higher usage consume a larger share of their usage during peak periods as air conditioning is a bigger share of total usage.

Resource Allocation: Utilities that own generating resources have a limited supply of older, lower-cost resources, and augment this with higher cost new resources. An inclining block rate fairly apportions the limited low-cost resources to each customer.

Conservation: Allowing each customer a limited amount of power at a lower price, with increased usage at a higher price, makes incremental energy efficiency more financially attractive. As long as the initial block is well below the average usage level, the vast majority of customers using the overwhelming majority of electricity will experience the higher block rates.

In addition, because there is a correlation between income and electricity usage, an inclining block rate provides a benefit to most (but not all) low-income consumers.

The Austin Rate Policy reflects all three of these principles, so it is logical that a steeply inclining block rate design is appropriate. The goal to reduce CO_2 emissions is consistent with the resource allocation principle, since AE's lowest-cost resources are hydro and nuclear. The cost of service element within the "fairness" principle is supported by both the load factor and resource allocation functions of inclining block rates. The goal of 800 MW of incremental efficiency is supported by the Conservation function of inclining block rates. Simply put, an inclining block rate is entirely consistent with Austin's rate design principles. The issue is whether the current relatively steep 5-block rate is appropriate. That is a matter well beyond the scope of this limited review.

Summary Observations

1) The Cost of Service Study prepared by AE is inadequate to support a differential allocation of the base rate changes between customer classes. The shortcomings in classification of costs including smart grid, billing and collection, and administrative & general costs are significant. The fundamental approach to power supply cost allocation merits a bottoms-up review in the context of the ERCOT market pricing design and Austin's growing renewable energy supply.
2) An across-the-board decrease is the "normal" response of a utility regulator when faced with an unacceptable cost allocation study. In this case, that would be a uniform percentage adjustment to base rates for all customer classes.
3) It is my understanding that a portion of this "base rate decrease" is amortization of an over-collection in the energy tariff rider; if that is the case, that portion should probably be refunded in the manner in which it was collected, and ideally from the customers who paid these excess amounts.
4) The current AE customer charge of $10/month greatly exceeds the cost of periodic billing and collection and other customer-specific costs properly attributable to the customer charge. Once the smart grid, monthly billing, 3-1-1, and administrative costs are properly allocated, my experience has been that these costs approximate about $6.00/month for urban utilities. One approach for the residential portion of this base rate decrease would be to restore this charge to the previous level. Another approach would be to bifurcate the rate design between multi-family and single-family homes, recognizing the dramatically lower cost of service associated with serving multi-family buildings. Either would allow the preservation of the current block rates, so that large customers do not see an increased incentive to consume, an action that is contrary to the rate principles to encourage conservation.
5) I have not reviewed the commercial or industrial rate proposals in any detail. A detailed review would include this.

   I will observe, simply, that the energy-constrained demand charge proposed for the commercial demand-metered customers is a simplified way to address a well-recognized problem – that low load-factor customers can "share capacity" with other similar customers, and should not be apportioned a full demand charge. The better way to address this is to eliminate demand charges entirely for recovery of shared distribution facilities, and instead recover these in time-varying energy charges. By that approach, customers like school stadium lights, houses of worship, and public assembly halls that have sporadic usage are charged appropriately for the service they receive, and are no longer required to subsidize customers that use capacity on a continuous basis but pay the same demand charges. Demand charges should be limited to customer-specific capacity, such as distribution line transformers; they should not be used to recover shared capacity now that we have the ability to measure time-varying consumption.

6) I recommend that the AE cost of service study <u>not</u> be a foundation for either cost allocation or rate design. The EUC and City Council should convene workshops to consider modern cost allocation methods that recognize time-variation, the difference between dispatchable and as-available resources, and the multiple uses of smart grid assets. A new approach to cost allocation should result from that inquiry.

I hope this brief written report is an acceptable substitute for my inability to attend the February 22 scheduled workshop. I am able to join that meeting by phone or GoToMeeting if that would be helpful. RAP would be receptive to participating on a more detailed basis if the resources are available to support that activity.