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ACC Commissioners
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Arizona Corporation Commission (ACC)
1200 W. Washington Street
Phoenix, AZ 85007
Via eMail

Subject: *Value and Cost of Distributed Generation Docket No. E-00000J-14-0023*

I am writing to convey observations and suggestions in response to the Commission's inquiry and Tucson Electric Power Company's (TEP) comments.

TEP Comments regarding Unsubstantiated Claims of DG Benefits (paragraph 2 of their comment document)

As the ACC and TEP classify much of TEP Financial and special Customer contract information as confidential, requiring Non-Disclosure Agreements to acquire, it is neither possible nor appropriate to expect that most public speakers or those making comments to quantify and substantiate their claims of benefit-cost. As necessary, the utilities and ACC employ competent staff whose compensation is funded by ratepayers to identify and substantiate the concepts, benefits and costs provided by those responding the ACC's inquiry.

It is also appropriate to recognize that TEP, and APS, comments are similar to those of others that they criticized; they do not comprehensively and reliably substantiate and quantify the magnitude of their claims regarding system costs, benefits and net benefits of DG.

Cost Shifting Equity

Cost shifting equity, a major principle being debated in this docket, is not new to ratemaking; there are multiple customer classes each with a different set of rates, surcharges and riders, shifting costs from one customer class to others.

If the utilities and Commission are sincerely concerned with "fairness" and equity they should not restrict their scrutiny to shifting of costs within just a single class, Residential, they should address all cost shifting, consider elimination or reduction of multiple classes, and have most all ratepayers pay a similar cost per kilowatt-hour.

At minimum the Commission is encouraged to address the significant inequity that exists with the TEP Industrial and Mining class of ratepayers wherein 43 customers receive 22% of the common system production (TEP/Roshka October 11, 2010, page 9, correspondence to Commissioner Newman) and the major use customers receive special contract rates of 3 to 4c/kWh, less than cost, shifting recovery of millions of dollars of costs to all other customers who pay about 13c/kWh. Based on the above, a rate of about 11c/kWh (20% x 3.5c/kWh + 80% x 13c/kWh) for all customers would generate a 15% reduction in costs, optimizing benefits to almost all ratepayers, a primary constitutional responsibility of the Commission.

The resulting equity and increased rates for some Customers could be used to fund the development and accelerated cost maturity of storage solutions that would eliminate the need to sell the electricity at less than cost, lower base load run rates and related fuel and emission costs and purchase of expensive natural gas peaker generating equipment and inherent commitment to operate for decades; related fuel and emission costs increase significantly each year.

Current Ratemaking Principles & Cost Origin

- Comprehensive system NET cost-benefit analysis

Current ratemaking practices require that all system costs and benefits be considered. It is not appropriate to make any rate decision on this Residential DG system component until all costs and benefits to the system are comprehensively and reasonably projected, validated and quantified for the life of the relevant system assets.

To perform that analysis all generation, and the resulting transmission and distribution system technology options required to deliver the electricity from the generation point, must be considered and the optimal cost option configuration determined.

For example, utility and DG Commercial & residential scale solar electric generation has no fuel, emissions, transmission line loss, transmission capital or water loss to evaporation costs, and displaces fossil fueled generation which do incur those costs; water, fuel and related emission costs are expected to increase significantly over the life of the generating asset. Utility driven five-year programs to accelerate the deployment and cost maturity of emerging storage technology to address and reduce historical supply-demand(cascading black/brown-outs) and solar intermittency issues may well be much less expensive and provide greater benefit than expensive natural gas peaker equipment and the consequent costs identified above for the life of the fossil fueled "spinning reserve" assets.

To my knowledge, no utility has provided any comprehensive cost and benefit study that considers lifetime projected costs and identifies the optimal cost system configuration (Utility Generation mix, DG generation, Storage development/deployment, and the resulting transmission & distribution requirements and costs).

- **Ratemaking Practice revisions**

TEP comments in large part rely on no modification of existing ratemaking rules, claiming that: "Utility rates should reflect only known and measurable service costs, not speculative future expenses, projected savings"…..

Considering the amount of change that has occurred within our Utility markets and the Commission's constitutional responsibility to optimize benefit to ratepayers, to set rates that allow recovery of *reasonable* costs and profit, it is reasonable to expect and require that the ratemaking process evolve and adapt.

For example, the current regulated market is absent competitive price controls which encourage continuous improvement, fair and full evaluation of all options, and cost reduction. The current rate structure, cost plus guaranteed profit as a percentage of cost, provides significant disincentive, not incentive, for Arizona utilities to aggressively and willfully reduce costs, as that would reduce shareholder profit.

Utilities enjoy the highest average wage of any industry in Arizona. They employ, or could employ, the best and brightest, most competent Staff; a major ratepayer cost component AND available resource capable of reducing costs if properly focused, led and managed.

The Commission should consider rate structure revisions that would eliminate guaranteed profit, that rewards, not penalizes, utilities and their management to implement a continuous improvement culture, to identify, nurture and responsibly utilize emerging technologies to establish and continuously improve and sustain an optimal cost system.

In prior dockets I've suggested some version of a "Pay for Performance" rate structure that would allow recovery of current costs but fund and pay the Return on Rate, profit or fee, based on actual delivery of value, sharing of cost reductions with ratepayers, while maintaining acceptable quality and service standards.

- **Costs(Rates) are the product of the Integrated Resource Planning (IRP) Process**

TEP's comment that rates should be set based on known costs actually incurred by the utility are appropriate as the costs are the results of Commission approved Integrated Resource Plans (IRP).

However, the Commission should consider immediate and significant improvements to the current IRP process and decisions that results in avoidable costs and capital investments and may limit the capacity to adopt new technology, reduce and mitigate future costs for several decades.

Regulated utilities should be required to identify and reliably substantiate cost-benefit assumptions and simulations of best, worse and median case generation mix and delivery(transmission/distribution) options, consider emerging technologies, for the projected life of the assets, recommending the optimal cost mix and delivery of value to Ratepayers for review and approval by ratepayers and commission staff.

Greater emphasis should be placed on the *Integrated Resource Plan* process to assure that the 'measurable service costs" of the generation mix (transition), storage, and consequent transmission and distribution technology approved for implementation is minimized and optimal.

The IRP process should also recognize that costs historically considered external to the utility cost model but created by the chosen generation and delivery technology eventually find their way into the rates, charged to ratepayers; i.e., PPFAC, ECA.

Of immediate concern is TEP's current IRP and decision to expend a significant amount of capital to purchase natural gas peaker plants, without comprehensively costing and comparing those costs for the lifetime of those assets to other alternatives such as multiple local utility scale PV facilities and distributed storage components (Metropolitan Micro-Grid (MMG)). The natural gas "spinning reserves" will require incremental transmission capital and O & M costs, and the costs of fuel, water lost to evaporation, transmission energy losses and emissions will increase significantly over the operating life of those assets. While solar electric facilities have no such costs. California has mandated that their utilities purchase 1.3GW of storage; a two-state short-term (5-year?) Utility scale demand, and local subsidy program, for storage solutions would provide regulatory certainty and accelerate rapid cost reduction and product maturity similar to that generated by solar electric local subsidy programs that are no longer necessary. Federal CleanTech funding to support the development of storage, Tucson MMG, for potential deployment by other western states may also be available.

Sincerely,

M. Finefrock

Mr. Terry Finefrock, CPIM
TEP Ratepayer