IEEE Power Systems Conference and Exposition
October 10-13, 2004
New York, NY

“Self-Regulating Markets for Electricity: Letting Customers into the Game”*

Richard E. Schuler, P.E., Ph.D.
Prof. of Economics
Prof. of Civil and Environmental Engineering
Cornell University
Ithaca, NY 14853-3501
res1@cornell.edu

Imagine going to the supermarket twice a week without having to stand in line for check-out (your purchases are simply scanned as you pull them off the shelf and recorded on a computer), returning home, cooking gourmet meals and enjoying the products you’ve hauled away, and then at the end of the month (or two) receiving a bill for your purchases. So far, this is not unlike credit card purchases, but suppose in addition, the prices you’re charged for each category of product, whether gourmet or generic brand, is the same average price per ounce for all buyers. Furthermore, suppose there are no coupons or “specials” to entice purchase in “off-days” or “slack-seasons”? In that case, most shopping would take place at the buyer’s convenience and there would be a tremendous bias toward buying up-scale items because of the uniform average price charged, regardless of the costs imposed on the system of supply. Economists would label this merchandising scheme a “moral hazard” , since it has many features analogous to insurance for health care, and there would be a continual bias toward forcing prices up because customers would always opt for the high quality products bought at the most convenient time for them. This is because those costs for ever-larger stores and parking lots, stocked with more and more up-scale produce are averaged over all buyers and purchases, and are assessed at the end of the month, long after the purchase decision.

What’s different between electricity markets and the purchase of food and produce, of course, is that with produce some alternative super-market is likely to spring up offering only generic brands at lower prices, plus discounts for off-hours shopping. The primary reason why retail competition offering alternative bundles of electricity services hasn’t happened is that there is only one way to transport electricity, and everyone in the neighborhood served off of the same network of wires and cables will get the same

* This research has been sponsored by the Power Systems Engineering Research Center (PSERC) and the Consortium for Electricity Reliability Technology Solutions (CERTS). We express our appreciation for the support provided by PSERC’s industrial members, by the National Science Foundation’s Industry/University Cooperative Research Program under Grant NSF EEC-0118300, and by CERTS, supported by the United States Department of Energy.

quality of service. The cost of setting up two or more parallel electricity distribution systems is simply too costly (and unsightly if the lines are overhead) to have two or more separate physical providers at the point of delivery to the customer. Where competition has emerged in this industry is among the generators feeding power into this system, but the amount of electricity to be purchased is determined by the ISO/RTO responsible for maintaining system reliability and, in most cases, running the wholesale market for electricity. Furthermore, those load estimates are usually mere aggregations of the projected demands submitted by the utilities that own and operate the wires connecting the ultimate customers to the system.

Why don't those utilities install time-of-use meters on all of their customers and charge for usage based upon the actual hour-by-hour wholesale cost? Answer: in part because investing in meters is expensive, and in part because they don't want to risk irritating their customers with a more complicated billing scheme. Even worse, suppose the customers were to respond as violently to a heat-wave electricity price spike as they do now to a twenty percent hike in gasoline prices? And, despite the fact that the cost of providing electricity during peak heat-wave periods may be ten to twenty times as expensive as the average price, who wants to be the bearer of bad tidings? The answer is no one because very few professionals in this industry have grown up as entrepreneurs, well-versed in the marketing of cost-saving, autonomy-enhancing opportunities to their customers. Besides, among the utilities there's little incentive to take a chance since they are highly unlikely to be allowed to reap any reward if they are successful. But, they are certain to be criticized highly and publicly if the outcome is less than a smashing success.

So why don't independent marketing entrepreneurs enter and provide this broker service for customers? Answer: they need to have the necessary meter installed, and they don't own the lines in which it has to be inserted; nor do they have the right to insert a meter independently. So, some further institutional re-arranging may be required in order to afford the customers an opportunity to get into the game, but following the continual political battles over the past decade over, first, open access, second, mandatory RTOs, third, implementing standard market design (SMD) and now, enforced mandatory reliability requirements, who has the stomach for even more re-structuring that isn't voluntarily agreed to by the utilities?

Only those of us who are dismayed by the creeping retrenchment we see across the country toward a re-regulation of the industry (in fact many regions of the country really never experienced any effective de-regulation) are still ready to debate. Examples of expanding re-regulation include: all markets across the U.S. have price caps, and in most cases computer-automated, market-power-mitigation procedures (AMPs) have been implemented. But to counter the resulting reduced revenue flows to generators so that some promise of making money is offered to potential investors in new facilities, ad-hoc mechanisms like an ISO-constructed demand curve for capacity are imposed, where capacity markets exist. In this case the load-serving-entities (LSE) are required to make advanced capacity purchases in accordance with this regulatory-imposed demand relationship, but in effect it is a proportional tax scheme to support capacity.

If a demonstrated trend in cash flow is required to elicit funds for new capacity from investors, why not structure forward markets so buyers can match their long-term concerns that adequate capacity may not be available down the road to meet their needs with the suppliers' need to have some assurance that the new capacity they are planning will have an adequate market to utilize the facility upon its completion? But by and large, that is not how deregulation has proceeded. When a problem emerges, the first impulse seems to be to devise a regulatory band-aid, rather than to return to market fundamentals and to revise and update the markets. While these regulatory interventions may be a necessary correction to maintain public trust, they should be viewed as short run crutches to be used only until long run structural improvements can be found, tested and implemented.

Yes, many mistakes were made in the initial structuring of electricity markets throughout the U.S. as economists applied their far-too-simple theoretical constructs to devise markets for this far more complicated commodity whose delivery obeys the laws of physics, not of contracts. That is why a team of engineers and economists at Cornell have developed a realistic, simulated non-linear a.c. power grid with line capacity and voltage constraints upon which we can perform operational and market structure experiments, using human participants whom we pay in proportion to their performance. Although expensive, we find our experiments in the laboratory to be orders of magnitude less costly than the "experiments-of-the-whole" that have been inflicted upon the American public over recent years.

Currently we are working on a variety of reliability related issues, including how do you clear markets so that the least cost combination of reserves and energy is dispatched from each supplier in order to meet both demand and the list of contingencies the system needs to withstand? These truly co-optimized market-clearing solutions that select the provision of energy and reserves by particular location, rather than satisfying some pre-determined reserve margin, can lead to quite different and lower-cost supply solutions than traditional approaches. Furthermore, early experimental results suggest that they tend to snuff out speculative offering behavior by the suppliers, since the selection of a supplier to provide energy hinges on the combination of their energy and reserve offers (the same is true for reserve selection). If , as an example, a generator were to offer low energy but very high reserve prices (in the hope it might be needed for reserves in an extreme emergency and set a very high price), it risks not being selected for either. The same two-edged sword seems to moderate offered prices for energy when if selected for reserves, generators are paid the lost-opportunity-cost of the generation backed-down to provide reserves. In that case, the higher the energy offer, the lower the reserve payment will be, and vice-versa. Of course while these schemes would enhance the operating and economic efficiency of electricity markets, they would also result in smaller total cash flows to many suppliers; thereby, attenuating the need for well-established, longer-term forward markets to reduce the perceived risk of new investment in capacity.

Furthermore, the co-optimization methodology used to achieve a least-cost dispatch that satisfies a list of contingencies can also be extended to address an efficient "virtual" dispatch across several control areas. This solution to the "seams" problem is not ad-hoc since prices and dispatch across all borders would be included, and all generation, load, line-flow and voltage constraints in neighboring control areas would be satisfied by treating them as other contingencies.

We are also conducting experiments of alternative forms of demand-side participation in the market to understand to what extent electricity markets might be more self-regulating (require fewer regulatory interventions like price caps and AMPS), were customers to become more actively involved. As a beginning benchmark, an analytic model of electricity supply and demand was developed to understand which components might be solved in theory by markets, and which would have to rely upon regulatory oversight. Three conclusions result. First, since all the customers in a neighborhood served from the same electrical network receive the same level of reliability, regardless of differences in their individual preferences for reliability, the determination of that optimal level of reliability is a public function and must be set by a regulatory authority. Individual private expressions cannot be relied-upon, if a price is attached, because of free-rider problems. Second, while some customers may be willing to interrupt or reduce their level of demand in response to a pre-announced request with a specified credit per kWh of reduction, the optimal response will not be forthcoming from customers unless the credit they receive is equivalent to the forgone reserve and capacity payments that would have been incurred were that reliability provided by additional generation, plus they must save the real-time energy price for electricity not used. In short, efficient demand side participation requires both demand response programs (DRP) and real time pricing (RTP). Third, unless the loss in consumer value from an unanticipated interruption is identical to their loss in value for a planned demand reduction through DRP, the customers' willingness to participate in DRP programs cannot be used to infer the value of reliability. Reliability is a public good and its level can only be set and enforced by a regulatory body; however, once set, that standard can be met efficiently through market mechanisms made available to both suppliers and customers.

Guided by these principles, experiments were then designed and conducted to represent end-use customers in electricity markets who can substitute part of their usage between day and night. The demand relationships of individual buyers differ among each other, and are represented by a two-step value function for each period. However these demand relationships for individual customers are disaggregated from observed market demand relationships. In these experiments, demand varies between day and night and during heat waves. Three alternative demand-side market structures were evaluated: 1) customers pay the same fixed price (FP) in all periods, the base case, 2) a demand response feature (DRP) is added in periods of supply shortages, wherein buyers receive a pre-specified credit for reduced purchases, and 3) a real time pricing (RTP) case where prices are forecast for the upcoming day/night pair, then buyers select their quantity purchases sequentially and are charged the actual market-clearing prices.

Initial experiments were conducted with active demand-participants, but with a predetermined typical hockey-stick supply structure that was varied randomly, over eleven day-night pairs that included heat waves and supply shortages. The RTP structure resulted in the greatest market efficiency, despite the more difficult cognitive problem it poses for buyers. Furthermore, a preference poll comparing DRP and RTP was conducted after each trial, and while 64% of the participants said they preferred DRP before RTP experiments, 76% selected the RTP structure afterwards, a statistically significant reversal of preferences.

Subsequent experiments using full two-sided markets with six active sellers and seventeen buyers demonstrated the ability of both DRP and RTP market structures to curb price spikes in comparison to FP market structures for buyers. In these experiments, experienced graduate students who had learned how to speculate successfully were used as suppliers, but new undergraduate students were used as buyers. Each buyer was assigned a different set of valuations for their electricity purchases, so over a wide range of prices only about 20% of the buyers should have had an incentive to adjust their consumption in response to price swings. All experiments were conducted without price caps or AMPs.

Under the traditional FP structure used by most utilities, even six suppliers were able to force prices up by learning to withhold capacity from the market, thereby demonstrating the need for intensive market monitoring and/or price caps under traditional pricing. However, both DRP and RTP lead to a redistribution of market power, without regulatory intervention, and RTP leads to the greatest market efficiency and in the end was preferred by a majority of all participants, including buyers and sellers. With these full two sided markets, 74% of all participants claimed they preferred DRP before trying RTP, but after experiencing RTP and having been given the chance to participate in additional experiments with additional rewards under the scheme that a majority selected, 64% opted for RTP, a statistically significant reversal. In a second identical trial with a similar group of participants, preferences again reversed as experience with RTP was gained, from 47% saying they preferred RTP before trying it, but 68% preferring it afterward.

An added advantage of RTP is that payments by retail customers just match the market-clearing revenue required by suppliers. Under FP and DRP, a forecast average market-clearing price is set and fixed for a specified future period for the buyers, but if either side of the market behaves strategically and drives price above (or below) the efficient level, rate increases (decreases) are required in subsequent periods to balance the utility's/ISO's/RTO's budget. In the first experimental trial, a 39% increase in bulk power costs would have been passed on to customers under FP and a 51% increase would have been implemented under DRP in order to balance the budget. In the second trial those wholesale cost increases would have been 38% and 20% respectively. By comparison, the wholesale cost budget is always balanced under RTP.

System operators may also find value in the widespread implementation of demand side participation. As Robert Thomas has shown, under the former regulated pricing regime there is a systematic proportional relationship between power flow on any line and overall system load; however, under market-based dispatch with a pre-set demand, based upon FP retail pricing, virtually no correlation exists between system load and line-flows because of speculative behavior by suppliers. In our preliminary analysis of line flows under DRP and RTP, the positive correlation appears to re-emerge.

So there appears to be beneficial outcomes for everyone from encouraging widespread customer participation in these markets: less volatility in prices and line flows and greater overall efficiency. But that's not surprising because whoever heard of a market where the customers weren't allowed to play? The only other widespread example was in the former Soviet Union where economic chaos reigned. Surely we don't want the same outcome for electricity in the United States; we simply cannot afford the attendant unreliability.