Structuring Electricity Markets for Demand Responsiveness: Experiments on Efficiency and Operational Consequences

Final Project Report

Power Systems Engineering Research Center

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Power Systems Engineering Research Center

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Executive Summary

Efficient markets require the active participation of many buyers and sellers who have complete information. Unfortunately, the characteristics of electricity markets in those regions of the U.S. that have them fall far short of this theoretical ideal. In electricity markets instead of active participation by end-use customers, utilities or load serving entities (LSEs) merely estimate the quantity demanded by all of their customers and enter that quantity bid into the wholesale market for energy. The result is a one-sided market that clears where the total quantity demanded intersects the ascending array of the price-quantity offer structure. As a result, the wholesale price varies, but the buyers pay an averaged fixed price that is forecast ahead of time and does not vary with changing supply and demand conditions. Under this market framework, suppliers have demonstrated their ability to exercise market power; that is why most market-operators in the U.S. now impose stringent rules about and oversight of the suppliers' offers.

This analysis explores the extent to which active customer participation in these markets might improve efficiency with less oversight. An experimental approach is used because economic theory cannot predict how buyers will actually respond to alternative demand structures (it can only specify how they <u>should</u> react), nor can theory specify how many buyers are required to achieve efficient outcomes. An experimental demand-side structure is established that represents end-use customers in electricity markets who can substitute part of their usage between day and night. Each customer's demand relationship is represented by a two-step value function for each period that can, however, vary between day and night, and during heat waves. These individual demand patterns are different for each buyer, but they are disaggregated from observed market demand relationships. Three alternative demand-side market structures are evaluated: 1) customers pay the same fixed price (FP) in all periods - the base case; 2) a demand response feature (DRP) is added to the fixed price case 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, but are charged the actual market-clearing price, period-by-period. The values of electricity assigned to buyers was such that at most 20% of the buyers would benefit by altering their usage over a wide range of anticipated prices.

After demonstrating the ability of buyers to understand and use each of these three market structures effectively, six representative sellers with experience in exercising market power were paired with seventeen buyers over twenty- two auctions (eleven day-night pairs) that included heat waves and unit outages. The same twenty-two periods were repeated under each of the three different market treatments. Overall, the RTP structure resulted in the greatest market efficiency, despite the difficult cognitive problem it poses for buyers. A major and statistically significant change in customer behavior under RTP was the modest but consistently larger electricity purchases at night than under FP or DRP; this was the largest source of welfare gain under RTP. In addition, the level of price spikes that appeared under FP were reduced in most cases under RTP and DRP.

Since the pre-determined prices in the FP and DRP cases were set at a level representing a competitive market, because of the exercise of some market power under both FP and DRP, a retail rate increase ranging from 1.5 to 2.1 ¢/kwh was required to balance the ISO's budget. By comparison, under RTP, the buyers always pay the exact cost of acquiring supplies so no rate adjustment was required.

A preference poll comparing DRP and RTP was conducted after each treatment. In one experiment, 74% of the participants said they preferred DRP before trying RTP, but 64% chose RTP afterward, a statistically significant reversal of preferences. In a second experiment, 53% preferred DRP initially, but 68% selected RTP after experiencing both treatments. Finally, the relationship between total system load and line flows was examined under each of the three market treatments and for a simulated fully regulated regime. The strong positive correlation demonstrated under the regulated regime deteriorates under markets with customers paying FP, but the predictability is re-established under the DRP and RTP market structures.

The shortcoming of single-sided markets was emphasized through the initial testing of the demand-side structure developed for these experiments. Those first runs with active buyers used a pre-determined, hockey-stick-shaped offer function that varied randomly. In that case, buyers were able to extract too much of the market surplus from the sellers which is the exact opposite of outcomes in existing single-sided markets where only the sellers are active. This result suggests a cautionary note for the widespread implementation of demand-side participation. If efficient market outcomes and adequate investment in new supplies are to be obtained, regulatory restrictions on the offering behavior of suppliers may need to be loosened if a large fraction of customers participate in DRP/RTP programs.

Nevertheless, these experimental results strongly support the implementation of demand-side programs, both as a way of increasing market efficiency and economic surplus and of improving the ability of system operators to predict line flows on their systems. Furthermore, having tried DRP and RTP systems after having been trained first on the traditional FP system, the majority of participants in these experiments selected RTP for their future use.

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1. Introduction

Can electricity markets be more self-regulating if we encourage customers to enter the game as active participants? Existing markets for electricity in the United States emphasize wholesale exchanges between generators and marketers and/or utility distribution companies that act as intermediaries between generators and retail customers. Furthermore, the existing market structures are usually just a variation of the least-cost, optimal power flow dispatch paradigms that were used before deregulation by the utilities' power pool managers. What has changed is that offers are substituted for cost schedules on the supply-side, and an ISO/RTO clears the market and determines the dispatch. However, demand is still an aggregation of schedules submitted by the load serving entities that are the buyers in the wholesale energy market, with very little, if any, price response associated with their forecasted demand quantities.

Effectively, these wholesale electricity markets are single-sided. In previous experimental studies in the laboratory (see Bernard, et. al. [3] and Mount et. al. [5]), and in the experiments-of-the-whole conducted on electricity markets in California, the ability of a number of suppliers to drive prices well above competitive levels is demonstrated in markets where offers are repeated frequently. Consequently, routine regulatory interventions like price caps and automatic market protection (AMP) mechanisms have been introduced in most jurisdictions. Rarely are customers active participants. Where retail competition exists, it usually is between aggregators who offer a constant price for electricity in all periods. Typically, customers are not exposed to the real-time cost of their buying decisions.

Suppose a larger portion of customers were confronted with the fact that in some periods their cost of acquiring electricity spikes anywhere from five to twenty times their average price? Would they be willing to alter their consumption patterns, and if so, might that mute some of the suppliers' potential market power? To what extent could some of the regulatory band-aids that have been applied to these markets over the past several years be reduced or removed? Would a power exchange with active demand-side participation be harder or easier to operate than existing systems? To address these questions, we studied simple mechanisms that permit customers to participate actively in electricity markets. Then, through experimental analyses where the customers' valuation of electricity in different periods is calibrated according to historically observed usage patterns, we analyze the buyers' collective ability to perform efficiently and to offset attempts at exercising market power by generators. The relationship between flows on individual lines and total system load is also explored for these different market structures.

While theoretical constructs suggest that the overall efficiency of any market should be improved with both active buyers and sellers, the theory does not prescribe how many participants are required to achieve that efficiency, nor how the number of required sellers varies as the number of active buyers increases. In fact, all benchmarks about the number of participants required to achieve efficient markets are empirically-based. For example, the Herfindahl-Hirschman Index (HHI) is frequently used by the Antitrust

Division of the U.S. Department of Justice to gauge potential market power in an industry. Furthermore, these guidelines are all developed from experience with industries whose characteristics are unlike the unique aspects of electricity markets: there's only one way to transport electricity on a system subject to congestion; transport feasibility is governed primarily by physical, not commercial laws; and production and usage must be matched in real time (inventories are not economically feasible) or else the entire system will collapse (a blackout).

Questions to be asked include: (1) how do buyers actually perform under different demand-side structures, (2) which structure might they select voluntarily, if given a choice, and (3) to what extent do different demand-side structures succeed in muting the exercise of market power by suppliers and lead to self-regulating markets? These are practical questions that are amenable to experimental analysis; game-theoretic analyses of repeated markets where sellers have multiple units that they can choose to supply are too complex to develop definitive conclusions. And while promising large-scale tests of alternative demand-side structures have been conducted by some utilities with their customers, the results are frequently difficult to generalize because of the diversity of customers and the elapsed time of the tests during which other things can change. As an alternative, a representative demand-side structure is developed and used in controlled laboratory experiments with human participants.

2. Laboratory Experimental Analyses

Rassenti, Smith and Wilson [7] have conducted illustrative two-sided market experiments to represent what might occur in electricity markets were customers let into the game. Their experimental market structure clears price and quantity, using bids and offers that are made simultaneously into a real-time energy market with four buyers, five sellers, and one computer-simulated buyer. The participants face three different demand periods in a day (peak, shoulder and off-peak periods). As in all laboratory experiments with buyers, the actual valuation of purchases must be pre-assigned (induced valuations) and the participants must be paid in proportion to the difference between the assigned valuation for the electricity purchased and the price paid. In Rassenti, Smith and Wilson's experiment, buyers were assigned a multi-step demand relationship, calibrated so that the maximum possible combined reduction in the quantity demanded was 16 percent. Their results [7] illustrate the potential for an active demand-side to completely eliminate the exercise of market power by suppliers.

Using an alternative methodology of "pre-programmed" autonomous agents in a numerical simulation of a two-sided market, Talukdar, et. al. [8] have shown how buyers' and sellers' propensity to "learn" how to maximize their gains can offset each other. This agent-based simulation methodology has the advantage of being able to replicate hundreds of market periods with a large number of participants much more rapidly and at a lower cost than in laboratory experiments with human subjects. As an example, human subjects must receive appreciable compensation in proportion to their performance in order for the experimental outcomes to be valid. The suspicion about numerical simulations, particularly when not preceded by controlled experiments with humans that reveal their cognitive processes, is that the outcomes are biased by the agent's "learning" mechanisms that are pre-programmed, and that these simulations may not accurately reflect the cognitive insights and/or limitations that are inherently human.

In this analysis, therefore, a demand-side platform was constructed and tested that is representative of the decisions that electricity customers would have to make in real-time markets, and whose valuations are calibrated to reflect previous statistical analyses of aggregate buyer behavior. In particular, since much of the response by customers to demand response programs and real time pricing has been to shift a portion of their usage to adjacent time periods, it was essential to incorporate this inter-temporal decision-making into the demand-side platform. As a consequence, the demand-side representations that are tested can be used to address many other important issues in the future, including tests on markets for reserves, forward markets, etc. However, the current experiments are designed to demonstrate that a representative mechanism is available for future analyses of three alternative (and/or in various combinations) forms of demand-side participation in electricity markets: (1) a pre-announced Demand Response Program (DRP), (2) a Real Time Pricing (RTP) program, and, as a base case for comparison, (3) a pre-specified identical Fixed Price (FP) charged in every usage period (the form used by most utilities today). This analysis also tests the relative efficiencies of the three alternative demand-side treatments, as well as the participants' subjective preferences in a sequence of before and after polls.

3. Experimental Structure

The demand-side structures that were selected for experimental analysis resulted in part from an earlier analytic model of electricity supply and demand. This model was developed to understand which components of electricity supply might be solved in theory by markets, and which would have to rely upon regulatory oversight. Both DRP and RTP structures emerged as mechanisms for partial de-centralization of electricity supply through markets (Mount, Schulze and Schuler [6]). Three conclusions resulted. 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 of their valuation of reliability cannot be relied-upon, if a price is attached, because of free-rider problems.

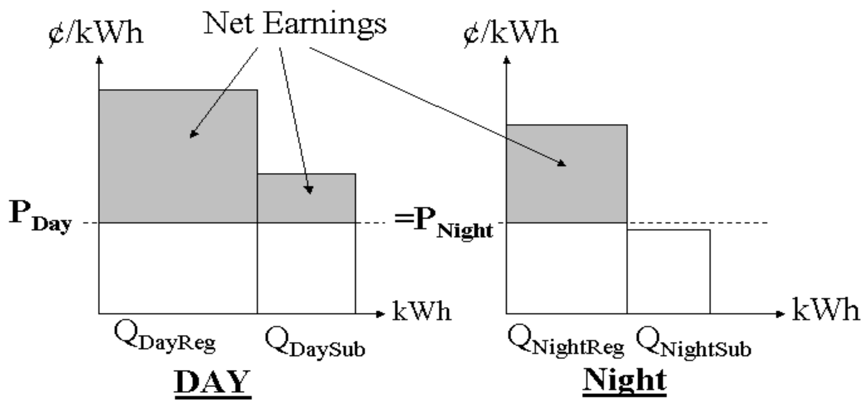
Second, while some customers may be willing to interrupt or reduce their level of demand in response to a pre-announced request with a specified credit per kWh of reduction, the optimal response will not be forthcoming from customers unless the credit they receive is equivalent to the forgone reserve and capacity payments that would have been incurred were that reliability provided by additional generation. In addition, 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 the 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. These analytic results support the experimental evaluation of both DRP and RTP demand-side structures.

3.1 Demand-Side Representation

To keep the demand-side decisions simple for the participants, each buyer is assigned a simple two-step discrete demand function with separate valuations for day and for night usage, as shown in Figure 3.1. In fact, these individual demand relationships are decomposed from an aggregate demand function, shown in Fig. 3.2, that has a retail price elasticity of demand at the mean price of -0.3 (Faruqui and George [4]). Furthermore, the overall demand function, ranging from very low prices to the reservation price, was given the inverted S-shape suggested by Schulze's work (reported by Woo, et. al. [9]) on consumer value loss for interruptible service. Customer day valuation is higher than their night valuation. Furthermore, there is an additional "substitutable" block of energy that customers can choose to buy either during the day or the subsequent night period. Unused substitutable energy cannot, however, be carried over to the next day/night pair of periods. Typically, substitutable electricity purchases are valued less than the regular purchases in each of these periods, and substitutable night energy is valued less than if it is used during the day. These substitutable blocks were also decomposed from the aggregate demand curve that has an elasticity of substitution between day and night usage of +0.3 (Faruqui and George [4]).

Thus, the buyer is confronted with an inter-temporal optimization problem. In addition, these induced valuations are increased substantially in pre-specified periods called "Heat-Waves" to reflect the added value of electricity in extreme climatic conditions. The buyer's problem is to maximize the spread between assigned valuation for each quantity of electricity purchased, and the price paid for it.



In this Example: $Q_{Day} = Q_{DayReg} + Q_{DaySub}$

$Q_{Night} = Q_{NightReg} + 0$

$Q_{DaySub} + Q_{NightSub} \leq Q_{SubMAX}$

Figure 3.1. Buyer's Problem under a Fixed Price System

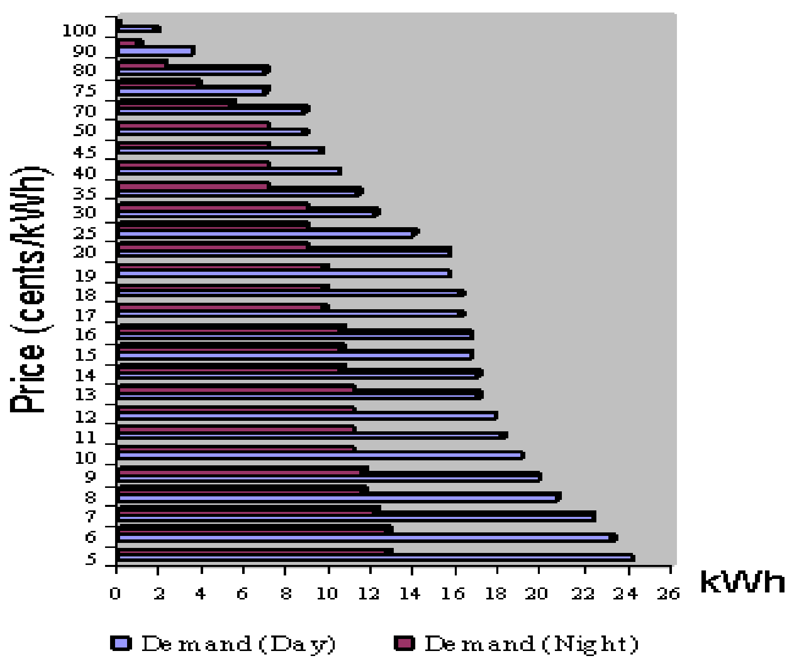


Figure 3.2. Average Demand Curve

3.2 Alternative Demand-Side Market Structures Considered

The experiments are designed to test the efficiency of two alternative forms of active demand-side participation in electricity markets. As a base case for comparison, all subjects participate in an initial experiment that reflects typical utility pricing where buyers pay a pre-determined fixed price (FP) in all periods and merely determine how much electricity they wish to purchase in each period. In the second treatment, buyers are alerted before consumption periods when supply shortages are anticipated. In those periods, customers are given the opportunity to reduce their consumption below their normal benchmark purchases in similar periods, and, by doing so, they can earn a pre-specified credit per kWh for each unit of electricity less than their benchmark that they choose to buy. This treatment is analogous to the NYISO's Emergency Demand Response Program (DRP). All electricity actually purchased under this DRP scheme is priced at the same fixed price used in the base case. However, total customer payments are reduced by any DRP credits earned. The third treatment is a simple real-time pricing (RTP) scheme where price forecasts are announced for the next day and night periods, and, based upon these forecasts, buyers decide how much electricity to purchase. However, buyers must pay the actual market-clearing price in each period for their actual purchases, and that price may differ from the forecasted price. This mechanism approximates a scheme used in France where customers are notified a day ahead by color code whether electricity prices are anticipated to be high, moderate, or low. Based upon that information the customers make their quantity purchases, but are charged the actual average clearing price for the day (Aubin, et. al. [2]).

In early pilot experiments, a second type of RTP market structure was also tested. That alternative asked participants to submit a price that represented their maximum-willingness-to-pay for each block of electricity demanded. Each participant’s performance was compared under the four market structures, FP, DRP, RTP and RTP with limit-price, in that order, for three identical day-night pairs that included heat waves and supply outages. Undergraduate students with prior experimental experience were used as subjects in these pilots, but they did not perform as well in the RTP runs where they specified a limit price as they did in the quantity-only RTP trials. Average earnings of buyers under RTP with limit prices were 94.9% of optimal, as compared with 98.7% under the simpler, quantity-only bid structure. Because the full experimental runs were to be much longer than the pilots, and participant fatigue was a concern, only the simple form of the RTP market structure was tested in the full experiments.

3.3 Experimental Tests of Demand-Side Structures (Single-Sided Market)

Before undertaking experiments on full two-sided markets, the three selected demand-side platforms were tested with two separate groups of students against a predetermined supply-side that was varied randomly (Adilov et. al. [1]). The buyers in these experiments were 21 Cornell graduate students in professional programs who were divided into two groups. They received cash compensation in proportion to their individual earnings that was computed as illustrated in Figure 3.1. However, since each buyer was assigned different valuations for their purchases, a different exchange rate was applied to each participant's earnings so that each subject had a fair chance of earning the same amount of money in the experiment despite different costs and valuations. The exchange rate was always less than one to keep the cost of the experiments within the researchers' budget. The actual average earnings per player ranged between $38 and $48 in these experiments with an active demand-side only.

The supply configuration was based upon previous supply-side experimental results at Cornell University (Mount, et. al. [5]) and upon actual offer structures observed in wholesale electricity markets. Thus, the typical "hockey-stick" shaped offer function shown in Figure 3.3 was applied in all cases. Randomly-selected outages of particular generators caused this offer curve to slide back and forth horizontally in some market periods. Furthermore, to insure that the market always clears, regardless of buyer behavior, sufficient external supplies are always available to meet demand at the highest offered price.

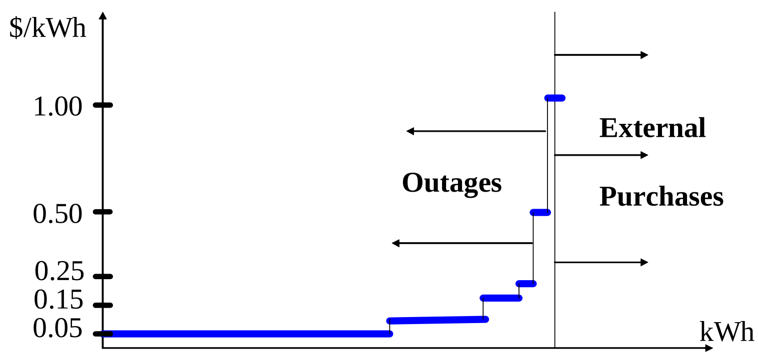


Figure 3.3 Typical "Hockey-Stick" Offer Curve

In all treatments, the market is conducted for the energy component of electricity supplies only. Thus, the retail price paid by customers has a $0.04/kWh wires charge added to it, since demand valuations were calibrated at retail prices. In the FP treatment, the retail price was set at $0.11/kWh (with $0.07/kWh for the average energy price for electricity), based on the stochastic offer structure that was predetermined, and the assumption of optimal bidding strategies by the buyers whose valuations are known by the designers of the experiments.

For the Demand Response Program, the price for retail purchases of electricity remained at $0.11/kWh. However, whenever a randomly pre-determined supply shortage occurred, a DRP period was announced and buyers received a credit of $0.25/kWh for the difference between their benchmark consumption (that is, what they would have bought in that period without the DRP credit under fixed-price purchases, had they behaved optimally) and the amounts they actually bought. The DRP credit was computed to include both the estimated savings in the actual wholesale price of electricity for their reduced consumption, and the pro-rated savings experienced by the market. Under both the FP and DRP treatments, the actual payment by buyers may not equal the cost of purchases from suppliers, unless the actual participants behave optimally since that was the basis for setting the fixed prices and DRP credit.

Under the RTP treatment, the buyers were given an accurate estimate, based upon optimal performance, of the energy price plus the $0.04/kWh wires charge before they made their quantity purchases. The buyers were also told (given our experience with earlier experiments) that they could expect the actual clearing prices to vary by 20% and that they would pay the actual market-clearing price. Thus, for the RTP treatment, the prices paid and costs of purchases should be identical.

Participants demonstrated their ability to understand the three alternative buying structures acceptably in these experiments. Each treatment was tested over the identical eleven day-night pairs (or 22 periods in total). Those periods included heat waves during which the buyers' valuations are increased, and occasional supply shortages. All three demand-side structures were tested.

RTP resulted in the greatest overall market efficiency, measured as the sum of consumers' and producers' surplus. Under the RTP treatment, participants attained 99.6% of the socially-optimal level, despite the more difficult cognitive problem RTP poses for buyers. By comparison, FP efficiency was at 98.7% of the optimum, and DRP attained only 96.9% of the socially-optimal benchmark. Under FP, the aggregate consumers' surplus portion of the total surplus was only at 95.7% of the optimal level. That level increased to 97.2% under DRP and to 101.8% under RTP.

These results emphasize an inherent problem with single-sided markets. In most existing electricity markets that have primarily active suppliers, the suppliers have an advantage. In these experiments with only active buyers, the consumers benefit and acquire surplus from the sellers. This explains how consumers' surplus can exceed 100% of the socially-optimal level.

Table 3.1 reports the results of pair wise statistical tests on the differences in each participant's consumer surplus for each demand-side treatment and the theoretically optimal level. Paired t-tests were used, with a separate test conducted over the distribution of the subjects' differences in surplus over each of the eleven day-night period pairs. The first three columns in Table 3.1 show that in most cases, the consumers' surplus obtained from these market experiments deviated significantly from the socially-optimum level. In fact, RTP resulted in greater than optimal consumers' surplus in 8 of 11 pairs; whereas both FP and DRP resulted in significantly less than optimal consumers' surplus in 7 of 11 pairs. However, in 2 of 11 remaining pairs, the consumers' surplus for FP was significantly greater than the optimal level and the same was true for DRP in 4 of 11 pairs. Comparing the consumers' surplus between FP and RTP, RTP is significantly better in 7 of the 11 periods and worse in 2 of 11 periods. In comparison with DRP, RTP yields significantly greater surplus in 7 of 11 periods and less in 4 of 11.

A poll comparing preferences between 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. Thus, the opinion poll seemed to reflect the observed differences in consumers' surplus.

Table 3.1 Single-Sided Market: Paired t-tests on Weighted Individual Consumer Surplus Differences, Active Demand-Side/Preset Cost-Based Supply.

Period Pairs	**FP - OPT**		**DRP - OPT**		**RTP - OPT**		**FP - DRP**		**FP - RTP**		**DRP - RTP**		**Conditions**
	sign	significance	sign	significance	sign	significance	sign	significance	sign	significance	sign	significance	
1&2	-	100.00%	-	100.00%	+	27.20%	-	63.49%	-	100.00%	-	100.00%	N
3&4	+	70.13%	+	96.65%	+	90.58%	-	96.30%	-	45.95%	+	96.65%	S, DRP
5&6	-	100.00%	-	99.30%	+	100.00%	+	67.09%	-	100.00%	-	99.30%	H
7&8	-	100.00%	-	100.00%	+	100.00%	0	0.00%	-	100.00%	-	100.00%	N
9&10	-	100.00%	-	100.00%	+	100.00%	-	68.99%	-	100.00%	-	100.00%	N
11&12	-	100.00%	-	100.00%	+	100.00%	+	67.07%	-	100.00%	-	100.00%	N
13&14	+	100.00%	+	99.70%	+	100.00%	-	91.86%	+	99.99%	+	99.70%	H+S, DRP
15&16	+	100.00%	+	99.69%	+	54.05%	-	91.55%	+	99.99%	+	99.69%	H+S, DRP
17&18	-	100.00%	-	100.00%	+	100.00%	-	67.07%	-	100.00%	-	100.00%	N
19&20	+	86.89%	+	96.63%	+	99.95%	-	95.63%	+	29.62%	+	96.63%	S, DRP
21&22	-	100.00%	-	100.00%	+	100.00%	-	67.07%	-	100.00%	-	100.00%	H

(N=Normal, H=Heat Wave, S=Generator Outage, DRP=In Effect)

Figure 3.4 illustrates the effects that these alternative demand-side and market-clearing schemes had on wholesale energy prices for the first group of buyers. The price pattern was similar for the second group over each of the same 22 market periods. In periods where there are significantly higher wholesale prices (optimally so, according to the theoretical simulations shown in the figure), they are highest under the FP treatment and lowest under DRP. However, customers may not be exposed to price spikes in these single-sided markets that are as high as they might be were active participants also representing suppliers. That analysis is left to the next section on two-sided markets where participants acting as generators might speculate and/or withhold capacity from the market. In this section with pre-determined, cost-based offers, these price spikes simply reflect the varying marginal cost of meeting demand in different periods. Figure 3.4 shows that under RTP, market-clearing energy prices are closest to the theoretical optimum. Also, RTP prices are generally lower than for FP and DRP in low load periods.

These experimental results are consistent with intuition; DRP is shown to be an effective way of curbing price spikes. Unfortunately, it does so inefficiently by resulting in too little price variation. Furthermore, once participants in these experiments experienced RTP and reaped its benefits, they voluntarily switched their preferences and selected RTP as their preferred buying mechanism for the future.

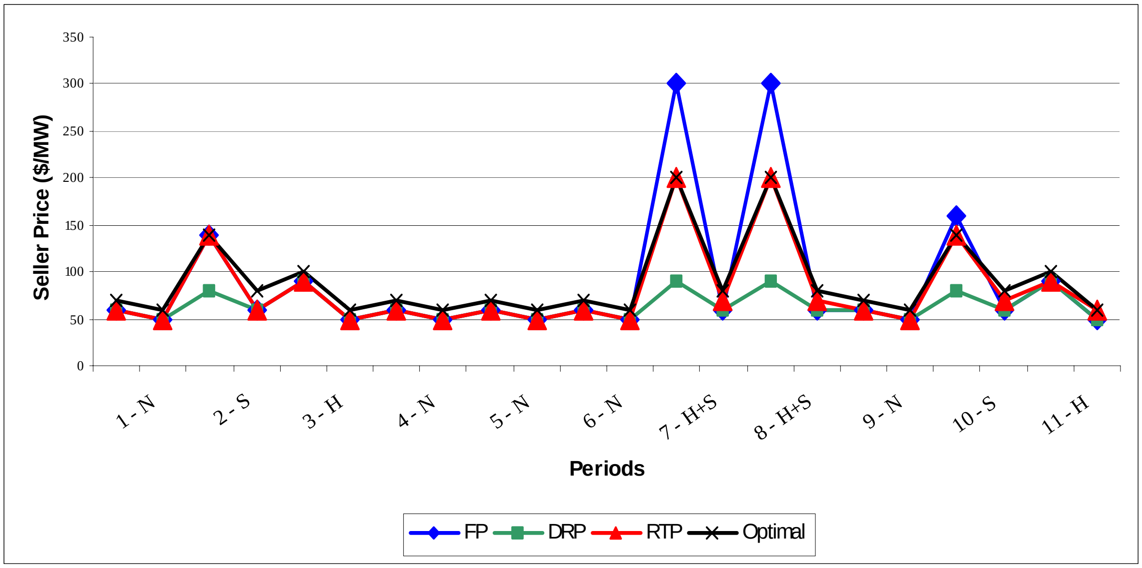


Figure 3.4 Experimental Prices: Active Demand/Preset Cost-Based Supply with Random Shift (Group 1)

Currently there are many regulatory restrictions on seller behavior in most electricity markets in the U.S. Examples include: price caps, prohibitions on withholding of supplies except for maintenance and necessary repairs, and the automatic substitution of historic "reference" offers if a supplier's current offer is higher and computed to have a significant impact on raising the current market price (AMPs). Therefore, the actual market-clearing prices may be close to the suppliers' costs in most U.S. electricity markets. The analysis in this section, therefore, might represent the consequences of introducing widespread customer participation in electricity markets where all existing supply-side regulations are retained. What these single-sided experiments do not reflect is the effect that those regulations may have on the suppliers' incentives to reduce their costs or to invest in additional, more efficient generation capacity.

4. Two-Sided Market Experimental Structure

In the following experiments, the supply-side regulatory restrictions are eliminated, and six active sellers are substituted for the pre-determined, random, cost-based offers. Furthermore, there are no restrictions on the suppliers' offering behavior; they may offer as much or as little capacity as they want at whatever price they want in all periods. The only behavioral restriction is a prohibition on talking to each other and/or discussing their offers (thereby resulting in no anti-trust violations).

4.1 Supply-Side Representation

Each of the six active suppliers is assigned three generating units, each with a different constant incremental production cost (that is, 20 MW at $22/MW, 15 MW at $50/MW and 20 MW at $61/MW). In addition, there is a fixed cost of $20 per market period per generating unit, or $60 per supplier, associated with each supplier's total capacity. The fixed cost must be paid regardless of the supplier's level of activity. Suppliers are free to offer as much or as little capacity into the market as they desire, up to the total capacity limit of their generation. They can specify a different price for each of the three different blocks of power that they offer into the market. Offers may be made at prices lower or higher than incremental production costs.

A discretionary cost each supplier chooses is associated with how much capacity is offered into the market. Each MW offered bears an opportunity cost of $5.00, regardless of having been selected to generate. This opportunity cost represents the commitment of resources and/or cost of foregone maintenance that is associated with planning to have those units available, as reflected in making an offer.

The seller's problem is illustrated in Figure 4.1. Since the market in each period clears at the highest offer needed to meet the market demand, all suppliers with offered prices at or below that level are paid the same last (and highest) accepted offer. Each seller earns a profit in each period equal to the market price times the quantity sold, minus the incremental cost of generating the electricity, minus the $5.00 opportunity cost times all of the energy offered into the market, and finally, minus fixed costs.

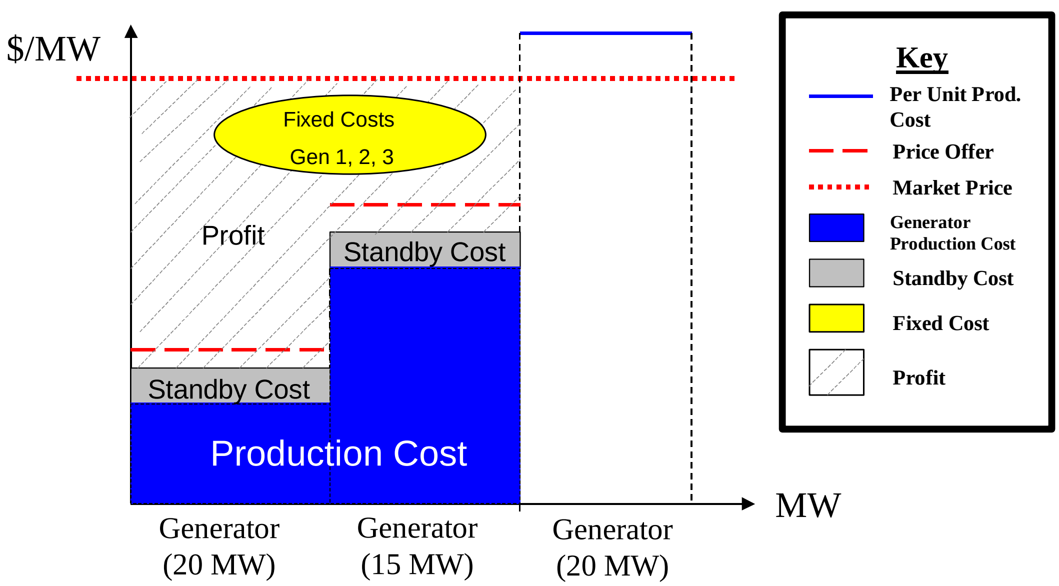


Figure 4.1 Illustration of Seller's Problem.

4.2 Market Structure and Calibrations

In these two-sided markets, 19 buyers and 7 sellers were included. However, the seventh seller was represented by a computer-simulated agent with a single 30MW block of low-cost $25/MW generation (representing a base-load unit) that is always offered at cost. The $5/MW opportunity cost of making offers is already included in the $25/MW. This unit was the only generator subject to random outages, and its behavior was simulated numerically. Otherwise, had the infrequent outages been assigned randomly to any of the six active participants, those who experience an outage may have felt that their earnings were biased by a random phenomenon.

Each of the buyers was assigned a different set of valuations for the energy they could purchase. Those valuations were the same as for the single-sided market experiments, and for approximately 80 percent of the buyers, those values were set very high but realistically, based upon previous empirical work (Woo et. al. [9]). Therefore, the optimal quantity purchases would not change for the majority of buyers unless the market-clearing prices reached levels many times higher than those anticipated. Given the popular sentiment that "most' buyers are not interested in altering their electricity consumption, this assignment of values acknowledges that assertion. It also provided experimental flexibility when some anticipated subjects did not appear for assigned sessions; they were replaced by numerically-simulated agents that were assigned valuations that were well above the anticipated prices. Thus, human subjects always played the role of the twenty percent of buyers with valuations that appeared at the margin in one or more periods. In fact, the number of human buyers ranged from 13 to 17 out of a total of 19 in each of these two-sided experiments.

In the two-sided market experiments, the same three demand-side treatments were tested as in the single-sided experiments: FP as the base-line, DRP, and RTP. Each treatment was run over the identical eleven day-night pairs (22 periods in total) with the same sequence of combinations of normal periods, heat waves and unit outages, as listed in Table 3.1. Here, however, DRP was triggered by any predicted retail price that exceeded $0.106/kWh (or $66/MW energy price). As a result, speculative behavior on the part of suppliers was also able to initiate DRP. The average market demand in these experiments was designed to be approximately 200 MW (lower at night, higher during the day, and during heat waves), and 330 MW of active supply was available. There was an additional 30 MW provided by the numerically-simulated base load unit (when not subject to a random outage).

The wholesale market was cleared at and all accepted suppliers were paid the uniform price of the highest (and last) accepted offer. Demand was always met, despite supply withholding, because of the availability of purchases from the 30 MW external source. All participants were aware of the external generator. What subjects were not told ahead of time was: (1) precisely in which periods those sources would be used and (2) at what price (thus external purchases were to represent economic market purchases from outside the system). All participants were informed of the market-clearing energy price after each period. In fact, whenever demand could not be met from internal supplies, or whenever the estimated wholesale price exceeded $150/MW, the external purchases were invoked from the generator outside of the system. The external generator's cost was $72/MW. However, whenever that import generator was called upon, the wholesale market price was set at the lower of 1) $150/MW, or 2) the last accepted internal offer plus an increment ranging between $5 to $15 (that was selected randomly in each instance). The objective was to avoid having suppliers withhold capacity specifically in order to have the import generator set the wholesale price at a known level (in effect, transforming a hidden price cap into a price floor).

4.3 Market Sequence

Each market period began with the auctioneer (ISO/RTO) providing fair load forecasts (quantities) for the upcoming two (day-night pair) periods. All buyers and sellers were told before each day-night pair whether the upcoming period had normal or heat-wave conditions, and whether a unit outage had occurred. Next, the suppliers submitted their price-quantity offers for both of the day-night periods. Then, either price forecasts or firm prices and/or anticipated market conditions were given to the buyers. Under FP, the retail price was always set at $0.085/kWh, regardless of energy market conditions.

Under the DRP treatment, the same fixed price of $0.085/kWh was charged for all purchases. When DRP was announced to be in effect, a $0.079/kWh credit was provided for purchases below each buyer's announced benchmark consumption level. These fixed prices and DRP credits differed from the amounts in the previous single-sided market experiments because of the fewer increments of cost assigned to suppliers in these two-sided experiments. The range of demand valuations remained the same.

Under the RTP treatment, a fair forecast of market clearing prices for the next day-night pair was announced, based upon market conditions and the suppliers' offers. The buyers then made their quantity purchases, suppliers were committed and the market-clearing energy prices were declared. In the case of RTP, buyers were told the actual price they were assessed for their purchases in each of the previous day-night periods. The actual prices did not vary more than twenty percent from the forecast prices for those periods. Finally, each seller was told their earnings, and each buyer was apprised of the net value of their purchases, including DRP credits where applicable. The process was then repeated for the next day-night pair until all eleven pairs were completed.

Load forecasts were always based upon buyers' performing optimally at the fixed or forecast prices. The $0.085/kWh retail price was based upon an estimate of cost-based offers by suppliers and optimal purchases by buyers. The DRP credit reflected the saving in supply, at production cost, to the reacting customer plus a pro-rata share of the cost-based savings to the market. The price forecasts for the RTP treatment used the suppliers' actual offers and presumed the buyers would behave optimally.

Since retail prices and/or DRP credits were pre-specified and fixed under the FP and DRP treatments, there is no guarantee that the revenues collected from the buyers, minus the $0.04/kWh wires charge, would match the energy market obligations to the sellers.

Therefore, after each of the first two treatments (that is, FP and DRP), the change in retail price that would have been required to balance the ISO/RTO's budget was announced. In the case of RTP, no rate adjustment is required since buyers pay the actual market-clearing prices for their purchases.

4.4 Preference Polls

A poll was conducted after each of the three treatments. Participants were asked which of two treatments they preferred: DRP or RTP. The poll was conducted and results tabulated before the subjects had any experience with either treatment, again after they completed the DRP treatment, and then again after they completed the DRP and RTP treatments. The required adjustments in retail prices were also announced after the FP treatment, and again after the DRP treatment, but before the respective preference polls were conducted. What differed about the final poll is that the participants were told that based upon a majority vote, they would play four additional day-night pairs using the treatment (DRP or RTP) they selected. Furthermore, in this final round they were told that their exchange rates would be adjusted so that they might anticipate earning as much money for this final four period round as they had in the earlier sessions that covered eleven day-night pairs.

4.5 Selection of Subjects, Training, and Compensation

A primary issue addressed in the experiments is the extent to which the introduction of active demand-side participation in electricity markets might reduce the exercise of market power by suppliers. Therefore, it was essential to have the subjects who represented generators know how to speculate and lift prices. In previous experiments undergraduates and graduate students demonstrated that they could raise prices substantially above competitive levels. Given sufficient experience, even six subjects acting as competing generators were able to raise prices without colluding explicitly. In all experiments, participants only received market-clearing information (not bid and offer data), and suppliers were told that the other generators had costs and capacities similar to theirs.

Initial pilots were conducted with faculty and industrial sponsors who were experts in the electric industry. The pilots showed that the decision-making time was so long for these professionals (approximately 15 minutes per period) that a total requirement of two days was projected for running all three treatments over 22 periods. While each trial could have been restricted to a shorter time duration, it was evident that in doing so, many of the subjects would have continued to learn how to perform more effectively as the experiments proceeded. This was particularly important for the suppliers' behavior. For example, in one pilot run with an abbreviated number of day-night pairs, it was evident that most of the generators were only beginning to try to speculate during the third (RTP) treatment after having already experienced FP and DRP. Therefore, unless the subjects were available for prolonged training, it appeared that comparative behavior between the three demand-side treatments would have been subject to severe order effects that could have been controlled for only by conducting many more experiments in permutated sequences, a costly proposition. Since the purpose of these experiments was not primarily to test scientifically for cognitive lags, the choice was made to use students with prior experience as subjects, and to give additional advance training to those students who would represent sellers to be sure they understood how to lift prices before any of the experiments began!

Even after separate training sessions for prospective sellers, several trial runs were conducted on each market treatment before the actual experiment was begun. In addition, all questions by buyers and sellers were answered and communicated to all subjects before the experiments began. Questions that arose during the experiments were answered privately. The entire experiment lasted several hours on each of three separate evenings: one session for training, one to run FP and DRP treatments, and one for RTP plus the final four high payment rounds using the treatment selected by the subjects through the preference poll.

All participants were paid in proportion to their total earnings. In the first experimental run conducted late in 2003, 17 active buyers and 6 sellers participated. They earned an average of $49.27 in their training session and $66.15 in the two experimental sessions, combined. $91.47 was the highest payment and $10.53 was the lowest. Only one buyer did not complete all trials; however, since that buyer's assigned valuation of purchases was extremely high and their purchases were never on the margin, a computer agent was substituted when the buyer was absent. All 13 active buyers and 6 sellers who began the April 2004 identical experiment completed it. In all cases, extra subjects (who were trained as sellers) were paid to appear at each experiment, but they were never called upon to participate. In the second experimental run, the average payment during the training round was lower, $22.32. The average payment during the two experimental sessions was $62.09, nearly identical to the earlier payments, although the range was smaller; $74.09 was the highest payment and $34.55 was the lowest.

5. Experimental Results for Two-Sided Markets

5.1 Overall Efficiency and Wholesale Prices

Consumers' surplus, producers' surplus, and total market efficiencies are summarized in Table 5.1 for the DRP and RTP treatments as a percentage of the wholesale revenues under the FP treatment. These efficiency measures are provided separately for each experiment and in combination. As a benchmark, the socially-optimal levels of available efficiency are also presented, and the combined data indicate that a 6.75 % overall gain in efficiency, compared to a FP system without regulatory controls on suppliers, is theoretically possible. That potential gain in overall efficiency is net of a large gain in the buyers' surplus and an enormous decline in producers' surplus because subjects acting as suppliers were able to raise prices and earn large profits under the FP regime. As compared to this theoretical benchmark, improvements in overall market efficiency were also obtained with RTP, compared to the FP regime, but with a smaller transfer of surplus from sellers to buyers. In contrast, DRP leads to an overall loss in market efficiency compared to FP, but consumers gain substantially at the cost of an even greater loss to

Table 5.1 Two-Sided Market Experiment Results: Differences in Consumer Surplus (CS) Adjusted for Budget Deficit, Producer Surplus (PS) and Total Surplus (TS) from Fixed Price Regime Levels as Percent of Wholesale Market Revenue

	Adjusted CS Difference from Fixed Price	PS Difference from Fixed Price	TS Difference from Fixed Price
	Experiment 1 (November, 2003)		
Demand Reduction Program (DRP)	8.97%	-12.71%	-3.73%
Real Time Pricing (RTP)	7.22%	-4.57%	2.65%
Socially Optimal (SO)	31.12%	-21.88%	9.25%
	Experiment 2 (April, 2004)		
Demand Reduction Program (DRP)	18.67%	-22.27%	-3.60%
Real Time Pricing (RTP)	10.79%	-9.38%	1.41%
Socially Optimal (SO)	27.55%	-23.25%	4.30%
	Combined Experiments		
Demand Reduction Program (DRP)	13.86%	-17.52%	-3.66%
Real Time Pricing (RTP)	9.02%	-6.99%	2.02%
Socially Optimal (SO)	29.32%	-22.57%	6.75%

producers. Although the percentage differences varied between the two separate experimental groups, the qualitative results were similar.

Figures 5.1 and 5.2 illustrate wholesale energy price patterns for each experimental trial and for each market period. Prices are shown for the FP, DRP, and RTP treatments. Also shown is the socially-optimal marginal-cost-based price. Both figures demonstrate the ability of suppliers to generate price spikes under a FP retail regime. In general, wholesale prices are the highest under FP, followed in descending order by RTP, DRP and the socially-optimal prices.

There are exceptions. Suppliers were able to generate a severe price spike under DRP in the November 2003 experiments and under RTP in the April 2004 experiments. In fact, this speculative behavior by suppliers may not have been in their self-interest under the RTP regime, and the DRP price spike came at night during normal weather conditions! What these graphs may reflect is lagged learning; in these experiments, subjects representing suppliers who had learned how to speculate and to lift prices in a FP retail market were slow to learn about circumstances when it no longer paid to speculate under RTP. Nevertheless, despite the persistent speculative behavior by suppliers, overall efficiency improvements are reaped through the RTP treatment as shown in Table 5.1. What Figures 5.1 and 5.2 confirm is that all prices should be and are higher in heat waves and during supply shortages, with the exceptions noted, including the socially-optimal price. DRP and RTP tend to follow that optimal pattern. However, in the April trials, the

DRP prices were lower than the socially-optimal level in several instances, indicating a real welfare loss in those periods.

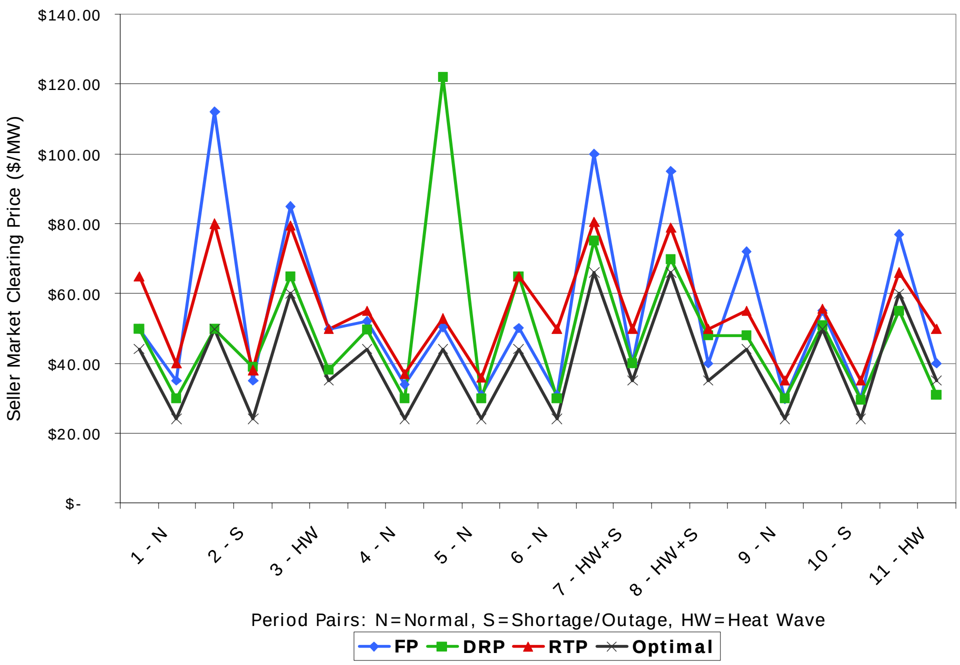


Figure 5.1 Prices by Treatment in Two-Sided Market Experiment (November 2003)

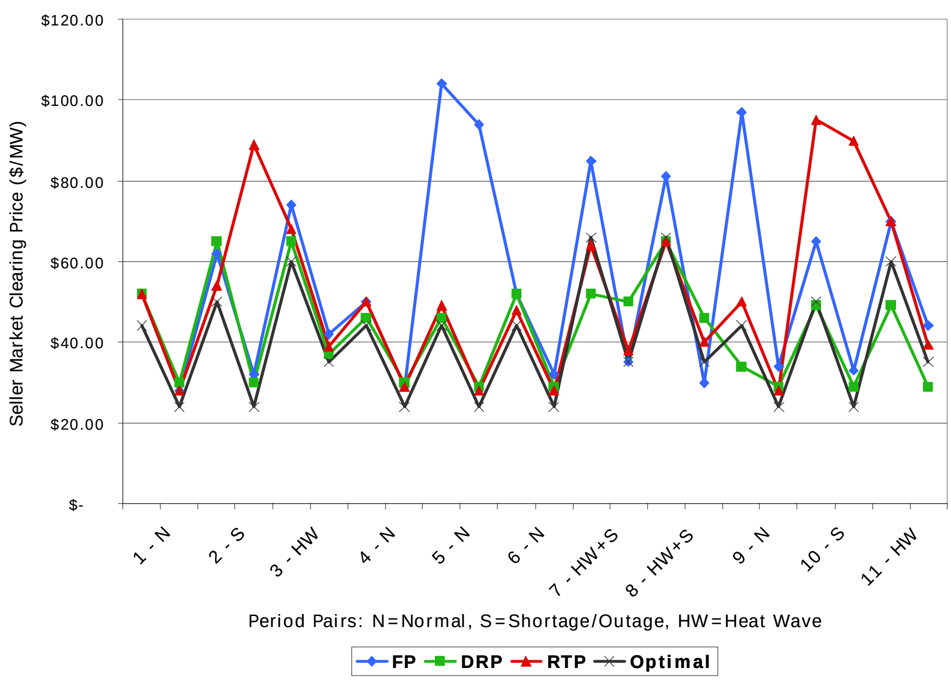


Figure 5.2 Prices by Treatment in Two-Sided Market Experiment (April 2004)

5.2 Statistical Tests on Differences in Surplus and Quantities

Because this experiment was repeated only twice, statistically-valid inferences may not be drawn about overall changes in welfare. However, if each subject is viewed as an observation, then the distributions of surplus and of quantities transacted can be estimated for each treatment. Then, a t-test can be conducted on the differences in surplus and the differences in quantities among all buyers and all sellers between treatments. These pair-wise comparisons for both buyers and sellers are summarized in Table 5.2 for surplus differences and in Table 5.3 for quantity differences.

Furthermore, the individual buyer's consumers surplus needs to be adjusted under the FP and DRP regimes to reflect the effect of the rate changes that would have had to be implemented in order to balance the ISO/RTO's budget. In the case of FP, that increase would have been \$0.0155/kWh and \$0.0152/kWh, respectively, in the two sets of experiments. Under DRP, that increase would have been an even larger \$0.0205/kWh in the November 2003 experiment, but a much smaller \$0.0081/kWh for the April 2004 group. The buyers' surplus was adjusted both on the basis of these per kWh charges and by an equal lump-sum allocation, as reported in the statistical summary in Table 5.2.

Comparing buyers' surplus adjusted for the rate increase on a per kWh basis between FP and either DRP or RTP, customers are better off with active participation under RTP at the .95 level and nearly so under DRP. In this case, the differences between DRP and RTP are not statistically significant. When consumers' surplus is adjusted on an equal per customer basis, the conclusions regarding buyers are less concrete except DRP is still significantly better than FP at the .95 level. Sellers are significantly better off under FP as compared pair-wise with either DRP or RTP, but they should prefer RTP to DRP based upon the effects on their earnings.

Table 5.2 Two-Sided Markets: Statistical Analysis Using Paired t-tests of Differences in Surplus Between Treatments (Pooled Data)

Buyer Surplus (29 Buyers, Balanced Budget)						
A) Surplus Adjusted on per Customer Basis						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
P-Value	**0.000**	**0.025**	**0.000**	**0.047**	0.128	0.084
Sign	**(+)**	**(+)**	**(+)**	**(-)**	(-)	(+)
B) Surplus Adjusted on Quantitity Purchased Basis						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
P-Value	**0.000**	0.188	**0.000**	0.054	**0.048**	0.216
Sign	**(+)**	(+)	**(+)**	(-)	**(-)**	(+)
Seller Surplus (12 Sellers)						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
P-Value	**0.000**	0.086	**0.049**	**0.000**	**0.003**	**0.003**
Sign	**(-)**	(+)	**(-)**	**(+)**	**(+)**	**(-)**
P-Values Associated with t-test Performed on Pooled Data for Participants in Experiments 1 and 2						

Table 5.3 illustrates the substantive behavioral differences in quantities consumed by buyers under the three treatments. Buyers consume less electricity in all periods under DRP, as compared to FP; whereas, under RTP, customers buy more electricity at night and less during the day than under FP. Furthermore, the last column emphasizes the overall conservation effect of DRP since it results in a statistically significant reduction in purchases both during the day and at night, as compared to RTP. Unfortunately, this is inefficient as highlighted by the quantity comparisons between DRP and RTP with the socially-optimal level of consumption. Under DRP too little electricity is purchased in all periods whereas consumption under RTP was not significantly different than the socially-optimal levels, except during normal day periods when too little was purchased. Similar results are shown for the suppliers' quantities, since supply always equals demand, but the statistical tests are somewhat less significant for sellers because of their smaller number.

Table 5.3 Two-Sided Markets: Statistical Analysis Using Paired t-tests of Differences in Quantities Between Treatments (Pooled Data)

Buyer Quantities (29 Buyers)						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
Normal Day	0.234	**0.001**	**0.017**	**0.000**	**0.013**	**0.009**
	(-)	**(+)**	**(+)**	**(+)**	**(+)**	**(-)**
Normal Night	**0.036**	**0.001**	0.641	**0.017**	**0.039**	**0.000**
	(+)	**(+)**	(+)	**(+)**	**(-)**	**(-)**
Heat Wave Day	**0.008**	**0.000**	0.267	**0.000**	**0.004**	**0.000**
	(-)	**(+)**	(+)	**(+)**	**(+)**	**(-)**
Heat Wave Night	0.165	**0.046**	0.665	**0.180**	**0.160**	**0.043**
	(+)	**(+)**	(+)	**(+)**	**(-)**	**(-)**
Combined Day	**0.029**	**0.000**	0.051	**0.000**	**0.005**	**0.001**
	(-)	**(+)**	(+)	**(+)**	**(+)**	**(-)**
Combined Night	**0.016**	**0.002**	0.535	**0.048**	**0.033**	**0.001**
	(+)	**(+)**	(+)	**(+)**	**(-)**	**(-)**
Seller Quantities (12 Sellers)						
	SO - FP	SO - DRP	SO - RTP	FP - DRP	FP - RTP	DRP - RTP
Normal Day	0.989	0.087	0.575	**0.007**	0.356	0.180
	(-)	(+)	(+)	**(+)**	(+)	(-)
Normal Night	0.799	0.462	0.984	0.401	0.555	0.237
	(+)	(+)	(+)	(+)	(-)	(-)
Heat Wave Day	0.281	**0.025**	0.782	**0.001**	**0.021**	0.100
	(-)	**(+)**	(+)	**(+)**	**(+)**	(-)
Heat Wave Night	0.726	0.352	0.992	0.635	0.663	0.525
	(+)	(+)	(+)	(+)	(-)	(-)
Combined Day	0.519	**0.023**	0.669	**0.002**	0.051	0.111
	(-)	**(+)**	(+)	**(+)**	(+)	(-)
Combined Night	0.768	0.384	0.987	0.436	0.350	0.221
	(+)	(+)	(+)	(+)	(-)	(-)

P-Values Associated with t-test Performed on Pooled Data for Participants in Experiments 1 and 2

5.3 Participant Preferences

The results from the polls comparing preferences between DRP and RTP are summarized in Table 5.4. In both groups, there is a reversal of stated preferences between DRP and RTP between the initial poll taken before either treatment was tried, and after experience was gained with both. The first group switched from 74% preferring DRP initially to 64% preferring RTP afterward, a statistically significant reversal. The second group's reversal was less appreciable and not statistically significant, changing from 53% thinking they preferred DRP ahead of time to 68% stating they preferred RTP after having tried both, a similar final fraction to group one. Furthermore, the final preferences reflected learned self-interest since the results of the poll were used to select the treatment that was used in the last four rounds with high-stakes payoff potential for the participants. In particular, all suppliers in both groups selected RTP as their preferred market-clearing mechanism after having tried both, consistent with their self-interest as illustrated in Table 5.2.

Table 5.4 Two-Sided Markets: Participant Expression of Preferences (DRP vs. RTP) After Each Trial

	Experiment 1		Experiment 2	
	Raw Vote (%)			
	DRP	RTP	DRP	RTP
1. After FP				
Buyers	17 (100)	0 (0)	7 (54)	6 (46)
Sellers	0 (0)	6 (100)	3 (50)	3 (50)
Combined	17 (74)	6 (26)	10 (53)	9 (47)
2. After DRP				
Buyers	5 (29)	12 (71)	6 (46)	7 (54)
Sellers	1 (17)	5 (83)	0 (0)	6 (100)
Combined	6 (26)	17 (74)	6 (32)	13 (68)
3. After RTP				
Buyers	8 (50)	8 (50)	6 (46)	7 (54)
Sellers	0 (0)	6 (100)	0 (0)	6 (100)
Combined	8 (36)	14 (64)	6 (32)	13 (68)
Note: P-Value for Differences in Preferences between Stages 1 and 3 by Binomial Proportions Test				
Experiment 1: P = 0.0113				
Experiment 2: P = 0.1890				

5.4 Line Flow Predictability

Results from early power market experimentation showed that under a regulated regime with cost-based dispatch, there is a systematic proportional relationship between power flow on any line in the system and overall system load; however, under market-based dispatch with single-sided markets and a pre-set demand, based upon FP retail pricing, virtually no correlation exists between system load and line-flows. This result is due to the speculative behavior by suppliers. In an analysis of line flow implications from these experiments, the positive correlation appears to re-emerge under DRP and RTP. Figure 5.3 illustrates the PowerWeb 30 bus electrical transmission network that underlies these experiments. The location of all generators is shown, including the import generator that cleared the market when insufficient internal supplies were offered. The buyers are distributed across the remaining busses, and since these experiments were conducted on an uncongested network, a Monte-Carlo analysis was performed so that the results would not be biased by the arbitrary assignment of a buyer with a particular behavior to a key node. Therefore, the resulting analysis of line flows are obtained from 30 different random assignments of particular buyers to nodes, followed by a least cost optimal power flow dispatch in order to estimate flows on individual lines. In all cases, however, the location of sellers is as indicated in Figure 5.3

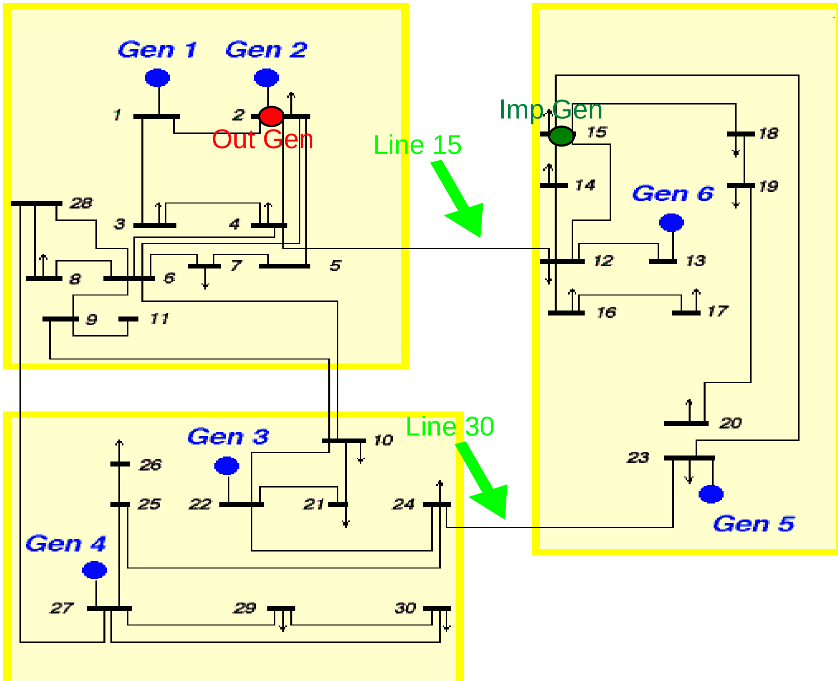


Figure 5.3 Power Web Simulated Electricity Network with Monitored Lines

The variation in power flows on each of the 39 transmission links in this network are plotted in Figure 5.4 for each of the three demand-side treatments. Both the socially-optimal line flows and an estimate of those flows that would have been observed under the former regulated regime (characterized by cost-based dispatch to meet the demand represented by the FP system - the demand structure widely employed under a regulated regime) as the benchmark, are also added. Line 15 has the greatest variability under all regimes, since that is the location where the import generator feeds into the network when there are shortages. Also, that line is linked to the generator that experiences random outages. In general, greater variability is associated with the market-based FP treatment, but those swings seem to be lower on most lines for DRP and RTP, approaching the levels of the former regulated regime. It is interesting to also note the high overall variability in line flows under the simulated former regulatory regime, due primarily to less damping of demand swings in comparison to the price-induced response under DRP and RTP.

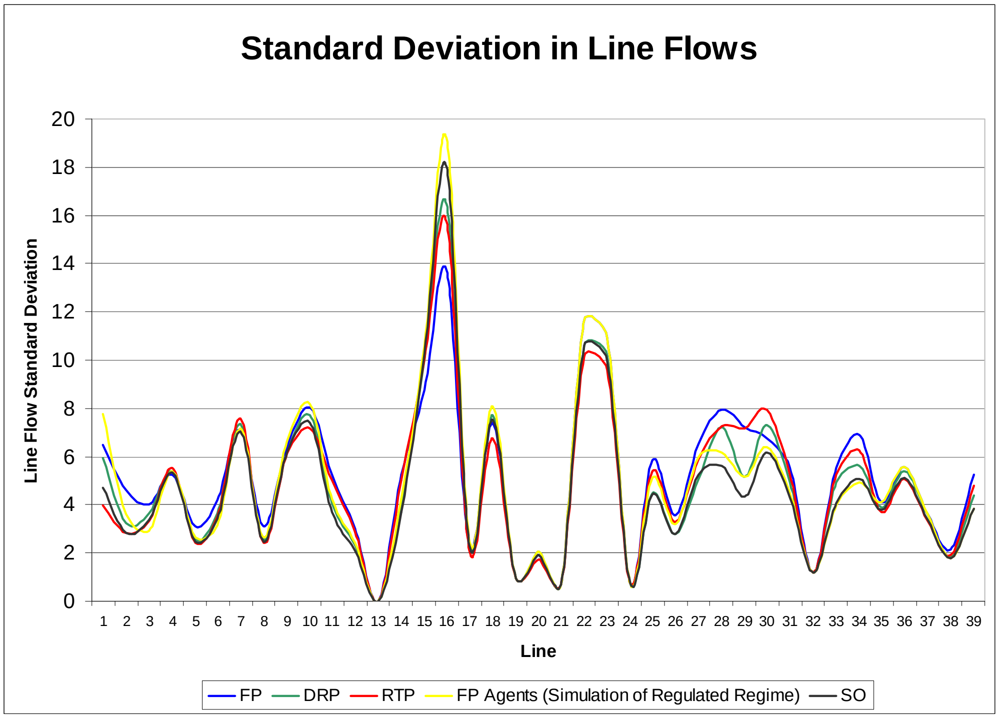


Figure 5.4 Two-sided Markets: Line Flow Standard Deviation by Treatment Using Pooled Data From Experiments 1 and 2

Two of the lines were selected (line 15 with the greatest variability and the more typical line 30), and a statistical test was performed on the correlation between system load and line flows on those links, for all five cases illustrated in Figure 5.4. These regression results are summarized in Table 5.5. Because of the location of the import generator, there is actually a negative correlation between system load and the flow on line 15. As system load increases, the probability of calling on imports increases which serves the load in the right-hand side of the system and reduces flow on that particular line. The negative relationship exists under all five regimes. What is different is the magnitude and the degree of statistical significance of that relationship. The relationships are nearly identical under the socially-optimal, previously regulated, and RTP regimes; the association is weakest under the FP market case, but improves somewhat under DRP.

In the case of a more typical transmission link, such as line 30 where there is a positive relationship between system load and line flow in all five cases, the socially-optimal and former regulated regimes yield almost identical results once again. Here, the relationship becomes much weaker under the FP market regime, and becomes almost identical in magnitude, but not in statistical significance, under DRP, and becomes even stronger under RTP, although still not as significant statistically. Thus, operators of electric systems may also find value in the widespread implementation of demand side participation if it strengthens the predictability of flows on any particular line.

Table 5.5 Two-Sided Markets: Statistical Relation between Line Flows and System Load

	Social Optimum	(Reg. Regime) Fixed Price with Regulated Sellers	*Results with Active Participants* Fixed Price	Demand Reduction Program	Real Time Pricing
		Regression Results for Tie Line 15			
Intercept	39.2810	37.6458	16.9847	28.5928	31.9242
Std Err	1.1134	0.8766	1.0616	1.2885	1.2343
Slope Coefficient	(0.1661)	(0.1539)	(0.0694)	(0.1381)	(0.1573)
Std Err	0.0061	0.0047	0.0057	0.0079	0.0070
R-Squared	0.5277	0.6199	0.1846	0.3189	0.4375
F-Statistic	735.09	1,073.15	148.94	308.15	511.75
P-value	0.0000	0.0000	0.0000	0.0000	0.0000
		Regression Results for Tie Line 30			
Intercept	(16.5565)	(16.0076)	(6.8518)	(11.8052)	(16.1431)
Std Err	0.8339	0.7325	0.8789	1.0581	1.1226
Slope Coefficient	0.0697	0.0603	0.0301	0.0627	0.0953
Std Err	0.0046	0.0039	0.0047	0.0065	0.0063
R-Squared	0.2599	0.2640	0.0585	0.1251	0.2567
F-Statistic	231.03	236.03	40.85	94.08	227.23
P-value	0.0000	0.0000	0.0000	0.0000	0.0000

Note: The following linear regression equation was estimated with OLS.
Line Power Flow = Bo + B1 x System Load
N = 660 for all regressions

6. Conclusions

The experimental results demonstrate the successful construction of a realistic demand-side platform that can be used to test a variety of hypotheses about buyer and supplier behavior in two-sided electricity markets. Optimal decision-making in electricity markets is not straight-forward, so substantial training was required to get subjects representing six sellers to lift prices well above competitive levels under the fixed, constant retail price regime that is used in most locations around the country. All markets were conducted without price caps, prohibitions on withholding supplies, or automatic mitigation mechanisms employed by an ISO/RTO. Nevertheless, when pitted against these trained sellers, less sophisticated buyers with fairly simple demand-side mechanisms, representing pre-set demand response programs or real time pricing regimes, were able to mute much of the suppliers' exercise of market power without any regulatory interventions. Not only did real-time pricing lead to the highest overall efficiency of these three market regimes, after having gained experience with that system, a majority of participants opted to use real-time pricing going forward. This choice was a reversal in a stated preference for DRP before experience was gained with both DRP and RTP.

Policy inferences can also be drawn from the results of the initial trials with active demand participation but with cost-based supply. This situation is analogous to introducing widespread buyer participation into existing electricity markets that have many restrictions on the suppliers' offering behavior. In this case, RTP and DRP both improved consumers' surplus as compared to a FP market regime, but too much so in the case of RTP. This experimental result emphasizes a cautionary note: if substantial active customer participation is attained in electricity markets, the current restrictions on suppliers' offering behavior may have to be loosened in order to enhance overall market efficiency. Both sides of the market need to be active participants, but if they are, less-regulated.

Finally, the predictability of electricity flows on several transmission lines was explored as a function of overall system load for the three two-sided market regimes and under a simulation of the former cost-based regulatory regime. That relationship deteriorates substantially under the FP market regime, is partly re-established under DRP, and under RTP once again resembles the predictability that was previously available to system operators under regulated power pool operation. What is intriguing in this simulation is that although line flow is highly predictable under the former regulated regime with customers paying known fixed price, as shown in Figure 5.4, that regulated scenario also results in larger variations of line flows on some links. This suggests that a conceivable benefit of deregulation requiring further study is the extent to which active customer participation can reduce the design capacity of many lines for a given average load.

References

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