Chapter 73

ENERGY, RESERVE AND ADJUSTMENT MARKET BEHAVIOR WITH INDUSTRY NETWORK, DEMAND AND GENERATOR PARAMETERS

MARK A. OLSON, STEPHEN RASSENTI and VERNON L. SMITH

In this chapter we report results from experiments using a complex 9-node network market with parameters supplied by the electric utility industry (see Olson et al., 1999).

1. Modeling Generators

Generator companies (Gencos) consist of portfolios of generator units of various types (coal, oil, gas, hydro, nuclear), including portfolios of identical units. Parameters of each type and companies that own portfolios, are shown in Table 1. Large coal and nuclear units are represented by high capacity, low marginal costs, large start-up costs, large minimum loads (50% and 100% of maximum capacity, respectively), large fixed costs per hour, and long start-up times (10 and 60 hours, respectively). Gas and oil fired turbines vary considerably in capacity and cost, but generally have high marginal costs, low fixed cost, and low minimum loads (5% of maximum capacity or less), but represent quick-start sources of reserve power in the event of unscheduled outages (see Figure 1 in Olson et al., 1999 for the supply schedule implied by Table 1).

A portion of the screen display for the Genco at node 7 is shown in Figure 1. (The screen also displays the network and the Genco's location in the network, but this is shown separately in Figure 2). Genco 7 controls seven classes of generator units designated A7, B7, ..., G7. Each class consists of one or more individual units, each unit represented by its own lightning icon. By clicking on the icon, the essential data for that generator is displayed in the box titled "A Costs." For example, the 5th unit in A7 is highlighted in the upper panel, and the data for that unit is indicated in the left lower panel. (The data are identical for all other class A units in Genco 7's A portfolio). The first box displays the startup cost of this unit, 1500 (measured in ¶ units of experimental "pesos"). Then the ramp (start up) time, 10 h, followed by the fixed (sunk) cost 389 ¶/H, pesos per hour. Under Fuel Cost, the first box lists the fuel cost, 15 (¶/MWH), for the unit's minimum loaded capacity step, 80 MW. Subsequent capacity steps, up to the maximum loaded capacity, are listed next. In this example, there is one additional step at the same fuel cost and capacity, the unit having a capacity of 160 MW at a constant fuel cost up to capacity.

Handbook of Experimental Economics Results, Volume 1

DOI: 10.1016/S1574-0722(07)00073-X

Table 1

Eight Gencos each own a portfolio of generator units listed in the rows with parameters shown in the columns. Reading from the left, company 1, row 3, owns large coal facilities consisting of 4 generators, each with maximum capacity of 530 MW, with variable operating cost of 12.9 ¶/MWH, minimum load capacity 265 MW, start up cost 1500, requiring 10 hours to ramp up to its minimum capacity. One of these units is precontracted for full capacity at low off peak demand, 2 for 620 MWH at shoulder demand, and 2 for 820 MWH on peak demand

Company	Type of unit	# units	Max capacity (MW/unit)	Var. op. costs (¶/MWH)	Min load (MW)	Start cost (¶)	Ramp time (hours)	Precontracted supply		
								Low MWH (# units)	Shoulder MWH (# units)	Peak MWH (# units)
1	Hydro	1	70	2.500	3	10	0			
1	Nuclear	1	180	7.825	180	25,000	60	180 MWH (1)	180 MWH (1)	180 MWH (1)
1	Large coal	4	530	12.900	265	1500	10	530 MWH (1)	620 MWH (2)	820 MWH (2)
1	Small coal	2	10	17.100	3	400	3			
1	ct/ic/je	1	10	46.400	1	40	0			
Totals		9	*2400*					*710 MWH (2)*	*800 MWH (3)*	*1000 MWH (3)*
2	Hydro	1	270	1.830	5	10	0			
2	Nuclear	1	550	11.520	550	25,000	60	550 MWH (1)	550 MWH (1)	550 MWH (1)
2	Large coal	1	620	16.350	310	1500	10			
2	Small coal	1	80	20.110	10	400	3	10 MWH (1)	10 MWH (1)	80 MWH (1)
2	Oil ct	10	20	37.300	1	40	0			
Totals		*14*	*1720*					*560 MWH (2)*	*560 MWH (2)*	*630 MWH (2)*
3	Hydro	1	90	7.900	3	10	0			
3	Large coal	3	210	13.230	105	1500	10	105 MWH (1)	105 MWH (1)	105 MWH (1)
3	Small coal	1	40	19.230	3	400	3			
3	Steam turbines oil/gas	1	20	40.000	3	400	3			
Totals		6	*780*					*105 MWH (1)*	*105 MWH (1)*	*105 MWH (1)*

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Table 1
(*continued*)

Company	Type of unit	# units	Max capacity (MW/unit)	Var. op. costs (¶/MWH)	Min load (MW)	Start cost (¶)	Ramp time (hours)	Precontracted supply		
								Low MWH (# units)	Shoulder MWH (# units)	Peak MWH (# units)
4	Nuclear	1	60	11.520	60	25,000	60	60 MWH (1)	60 MWH (1)	60 MWH (1)
4	Large coal	1	160	14.700	80	1500	10			
4	Small coal	1	30	20.100	10	400	3			
4	ct/ic/je	1	10	87.900	1	40	0			
Totals		4	*260*					*60 MWH (1)*	*60 MWH (1)*	*60 MWH (1)*
5	Hydro	1	30	0.000	5	10	0			
5	Large coal	4	190	12.900	95	1500	10	95 MWH (1)	95 MWH (1)	190 MWH (1)
5	Nuclear	1	260	14.550	260	25,000	60	260 MWH (1)	260 MWH (1)	260 MWH (1)
5	Small coal	2	30	17.100	3	400	3			
5	Steam turb	1	10	26.000	3	400	3			
5	ct/ic/je	2	20	105.000	1	40	0			
Totals		*11*	*1160*					*355 MWH (2)*	*355 MWH (2)*	*450 MWH (2)*
6	Hydro	1	150	3.040	5	10	0			
6	Nuclear	1	290	12.230	290	25,000	60	290 MWH (1)	290 MWH (1)	290 MWH (1)
6	Large coal	10	60	14.500	30	1500	10	240 MWH (8)	360 MWH (8)	480 MWH (8)
6	Small coal	1	10	16.400	10	400	3			
6	Steam turb	10	10	18.660	3	400	3			
6	ct/ic/je	10	20	33.220	1	40	0			
Totals		*33*	*1350*					*530 MWH (9)*	*650 MWH (9)*	*770 MWH (9)*

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Table 1
(*continued*)

Company	Type of unit	# units	Max capacity (MW/unit)	Var. op. costs (¶/MWH)	Min load (MW)	Start cost (¶)	Ramp time (hours)	Precontracted supply		
								Low MWH (# units)	Shoulder MWH (# units)	Peak MWH (# units)
7	Hydro	1	190	2.010	5	10	0			
7	Nuclear	1	1010	12.230	1010	25,000	60	1010 MWH (1)	1010 MWH (1)	1010 MWH (1)
7	Large coal	10	160	15.400	80	1500	10	1000 MWH (10)	1600 MWH (10)	1600 MWH (10)
7	Small coal	1	170	18.870	10	400	3	10 MWH (1)	155 MWH (1)	150 MWH (1)
7	Combined	1	100	24.135	40	1000	1	40 MWH (1)	40 MWH (1)	100 MWH (1)
7	ct/ic/je	10	90	52.100	1	40	0			
7	Steam turb	10	90	55.000	3	400	3	15 MWH (5)	15 MWH (5)	15 MWH (5)
Totals		*34*	*4870*					*2075 MWH (18)*	*2820 MWH (18)*	*3310 MWH (18)*
8	Hydro	1	300	1.830	5	10	0			
8	Nuclear	1	480	12.230	480	25,000	60	480 MWH (1)	480 MWH (1)	480 MWH (1)
8	Large coal	10	230	17.400	115	1500	10	1150 MWH (10)	1620 MWH (10)	2260 MWH (10)
8	Small coal	1	90	22.600	10	400	3			
8	ct/ic/je	10	30	49.500	1	40	0			
8	Steam oil/gas	10	10	64.940	3	400	3			
Totals		*33*	*3570*					*1630 MWH (11)*	*2100 MWH (11)*	*2740 MWH (11)*

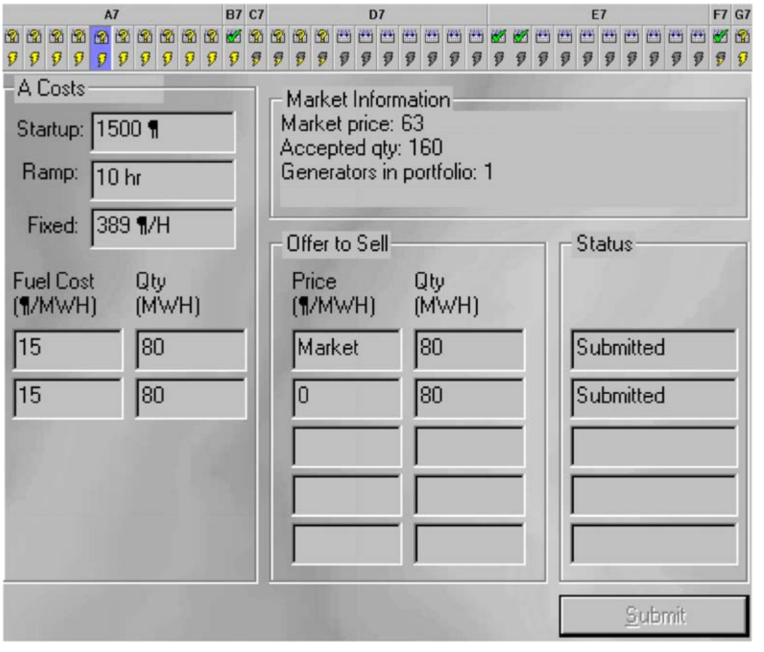

Figure 1. This is the screen display for a Genco at node 7 for the SBO energy market. Generator units are represented by the lightening icons for power generator classes: A7, B7, . . . , G7. Multiple units are indicated by the number of icons in each class. A green icon indicated the generator was turned on the previous period; blue it was off; red (not shown) it is out of commission. The parameters for a generator in class A are shown: startup cost; 1500 ¶ ("pesos"); Ramp time 10 h from startup to minimum loaded capacity; fuel cost 15 ¶/MWH for the minimum capacity, 80 MWH; and 15 MWH for the next 80 MWH (capacity, 160 MWH). The minimum loaded capacity (80) is offered automatically "at market" (0 price). Up to four additional (price, quantity) steps may be used to offer the remaining capacity (shown all offered at 0 price).

All loaded generators are assigned forced outage rates based on industry-supplied data for units of different types. If an outage is realized, its duration is then specified, and during such periods that unit cannot be offered to the market.

2. Modeling Demand

Demand cycles from a low off-peak period, through a middle level shoulder period to a peak period, and back to a shoulder period. The four periods are repeated in a series of 5 market days during each experiment, for a total of 20 energy trading periods. Each period each wholesale buyer is assigned a large spike of "must serve" demand that he can resell at a fixed regulated price. In these experiments no portion of the demand can be interrupted voluntarily. The must-serve spike in demand is uncertain. There was a "day-ahead" forecast with + or −8% confidence interval error, then a new forecast at + or −2% error an "hour ahead" of spot market execution.

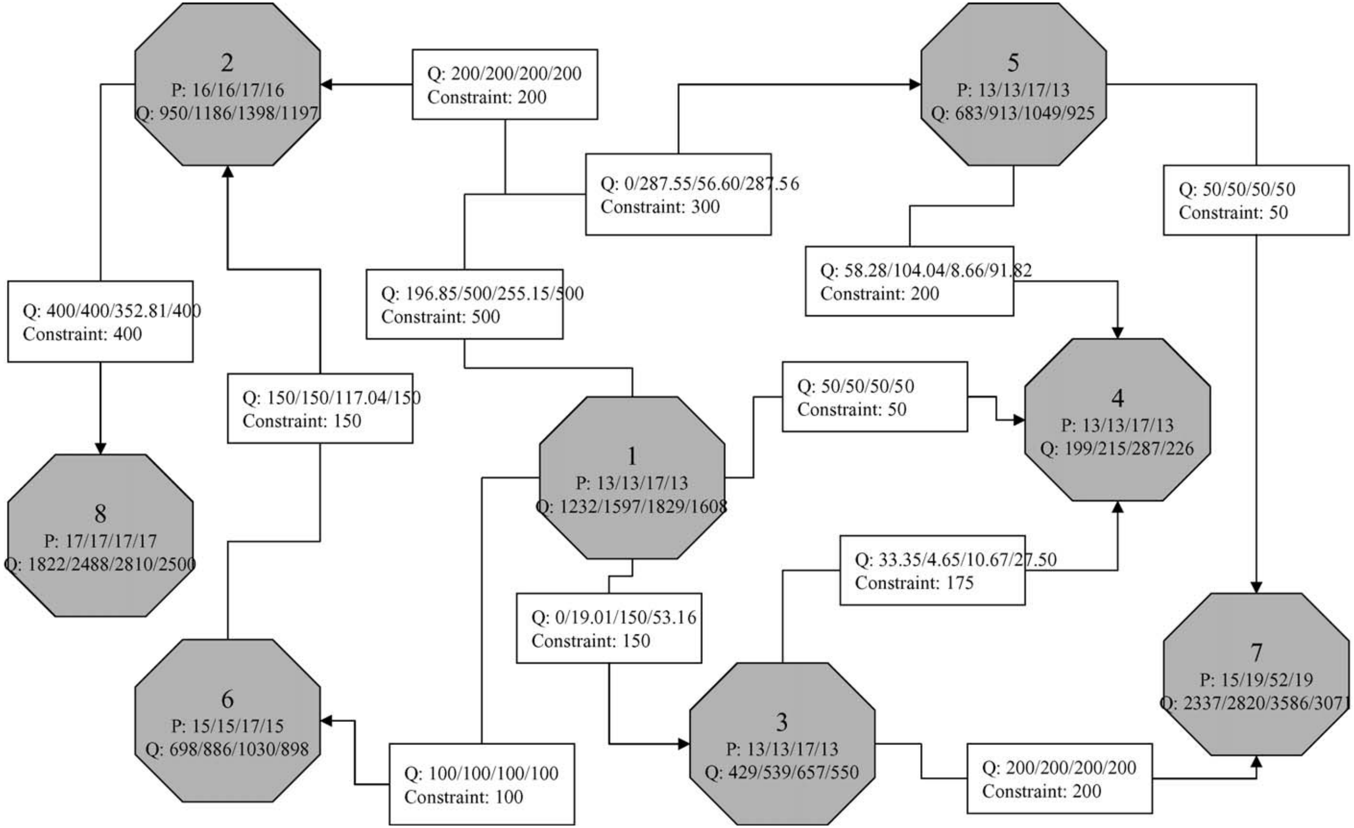

Figure 2. The eight demand and generator supply nodes are represented by the numbered octagons. The average CE prices are indicated after (P:) for the off peak, shoulder, peak and shoulder demands; The average corresponding CE quantities of energy consumed are indicated after (Q:). Similarly the CE flow quantities, are indicated on the power lines (first row of each box) connecting the nodes after (Q:). The maximum flow constraint is shown on the second line in each box.

3. Market Design

The power market consists of three sequential auction submarkets: (1) an energy market for generator supply commitment, which either employs sealed bids to buy and offers to sell based on day-ahead demand forecasts, or continuous bilateral double auction trading up until the hour-ahead forecast is delivered; (2) a market for spinning and quick start reserves conducted after the results of auction (1) are completed; (3) a load adjustment (often called the increment/decrement) market, based on hour-ahead forecasts, under which the terms of (1) are to be incrementally or decrementally adjusted based on the deviation of realized demand from the forecast demand. This market allows Gencos to make marginal adjustment after learning the commitment outcome of (1). Also, to the extent that bilateral contracts have been entered into, (privately, or) in the continuous double auction public version of the energy market, such Gencos could supply their adjustment terms to the Center to enable priorities to be established among all Gencos in the event of line congestion. Such congestion requires the higher cost generators upstream from a constraint to be throttled back and the lowest cost available downstream units to be ramped up.

4. Sealed Bid Day-Ahead Energy Market

The objective of this market is to marshal generator commitment in advance of more exact information on demand. The baseline mechanism for this market is the two-sided sealed bid-offer (SBO) auction. Generator commitment means that any Genco unit with a must-run minimum load requirement is offered as follows: the minimum loaded capacity is offered as the first quantity step at a zero price to the auction; subsequent steps are offered at any prices selected at the discretion of the Genco's owner, except that the center ranks the steps in increasing order of price, whether or not they are submitted in that form.

Buyers submit bids for all their demand, which consists of all must-serve loads, none of which can be voluntarily interrupted. All demand and supply are channeled through a central exchange market. To the extent that Gencos contract directly with buyers, those contracted amounts are subtracted off of both the demand and the supply, but such contracts are simulated and are not a treatment variable in the experiments reported here. For example, we assume that all nuclear units are completely contracted, and that something between minimum and maximum capacity of several of the large coal units are also contracted. The columns on the far right of Table 1 show the number of contracted generators from each Genco, and total contracted capacity of those generators for off, shoulder and peak periods are indicated in summary rows for each seller. Such contracted amounts are subtracted from demand at each local distribution node, and are never under threat of being constrained off. Capacity not contracted is comparable in magnitude to the export capacity of each node. This still creates congestion due to stochastic and cyclical demand variation, and the variance in the marginal prices for generating additional power at various nodes in the system.

As the experiment proceeds from period to period, the status of each generator is indicated by the color of its lightning icon (see Figure 1): green indicates that the generator was providing power in the previous period; blue indicates that it was off; and red indicates that it was unavailable (due to an outage). If a generator was off, offered into the market, and the offer accepted, then the Genco incurred the start-up cost in addition to the fixed and fuel costs. If it was on, and the offer accepted in the market, only the fixed cost and fuel cost are incurred.

The sealed bid procedure for entering energy offers for a generator is illustrated in Figure 1. On his computer monitor in the window entitled "Offer to Sell," each generator's capacity can be offered to the market in up to five asking price steps. In the illustration for a unit in class A, Genco 7, there is automatic entry of the first minimum loaded capacity step (80 MWH) "at market." This is defined as commitment. This can be viewed as an expert system local control over the offer entered, not necessarily a rule of the Exchange Center. In the example, Genco 7 chose to offer the remaining capacity, 80 MWH, at zero. This assures that all the capacity of the unit will be accepted at the ruling market price, unless there is excess minimum base load capacity in the system, as can occur, and the price is zero. (The California PX has produced zero prices in portions of the 1–3 AM interval.) Having entered the offer prices, the subject clicks on the submit button at the bottom right of Figure 2, and each offer step under Status is marked as Submitted. At the close of the market, if the offer is accepted, the Status changes to Accepted.

By clicking one generator and then dragging the mouse across several icons in a class while depressing the mouse button, a portfolio of identical generators is combined into a single offer, i.e., the one representative offer was cloned for all the like units in the portfolio. If the offer was only partially accepted, a local expert system algorithm managed the generators by turning on the minimum cost subset needed to meet the output requirement. Consequently, units must be offered individually if the subject wants to force any unit to be kept on when the offer would not be fully accepted. This algorithm freed the subject to give thought to the intertemporal management problem.

Sellers whose generator offers to the energy market were accepted at less than full capacity are free to offer that capacity, or any surplus capacity, either to the reserve market or the load adjustment market. Only generators with a zero ramp time, or already minimum loaded in the energy market, are eligible.

5. Reserve Market

The reserve market accepted seller offers of capacity as spinning or quick start reserves in the event of an unscheduled outage, or in the event that a buyer falls short of purchasing his forecast requirements in the energy market. Each offer from a generator owner has two parts: (i) the first is a capacity supply price representing the Genco's minimum required payment for maintaining the capacity's readiness to supply temporary reserves; (ii) the second is an energy charge in megawatt hours for drawing upon the capacity until the reserve was no longer needed.

The buyers and sellers are told that the probability of unscheduled outage is about .06 for any generator. Required reserve capacity is always set at 12% of the forecast load in the entire system. In addition to the required reserve, RR, for outages, we treat individual buyers as imposing a buyer reserve requirement, BR, on the system if they did not purchase enough power to cover their forecast demand in the primary energy market. A sudden large increase in load above the energy market allocation is viewed as economically equivalent to a generator going down.

Allocations were made as follows: the capacity supply prices (i) were ordered from lowest to highest; if RR + BR was the total required reserve capacity in megawatts, the lowest RR + BR units of capacity offered were accepted at the lowest rejected offer. Buyers pay for the first RR units in proportion to their forecast demand. Individual buyers, who had fallen short in the energy market, pay for BR, since (in this study) they had no interruptible demand.

The set of RR + BR accepted reserve offers were then sorted from lowest to highest energy asking prices (ii) at which each unit was offered. Now suppose a stochastic failure occurred, requiring OC_i units of reserves to be drawn to replace a failed generator owned by seller i. Then i paid the reserve energy price to all those Gencos supplying the reserve energy, until the next energy market period. However, an expert system automatically substituted any ready but uncommitted capacity owned by i for the reserve market supply, if the fuel cost of that capacity was less than the energy reserve market price. Thus, quick start units not committed to any of the three markets, still served the Genco by placing an upper bound on the cost of replacement power due to an outage.

In similar fashion buyers who failed to purchase enough power through the energy market, were obligated to pay the second tier of energy prices supplied in the reserve market. The buyer's residual demand was automatically satisfied by recourse to the reserve market to incentivize buyers to cover their must-serve demand.

6. Load Adjustment Market

Quick responding generator capacity not accepted (or offered) in either the energy or the reserve market can be offered for load adjustment to realized demand (load following). At this point we model demand as known with a confidence interval of + or -2%. Realized demand may have been either above or below the total capacity of generators accepted in the energy market.

In the load adjustment market, Gencos submit their supply price for providing additional energy above that accepted in the energy market; also the price they are willing to pay to supply less power. Contractually they will be paid their supply price in the energy market based on the day-ahead forecast (hence, generating less than this saves fuel). This information, when supplied after the energy and reserve markets have been run and demand becomes better known, allows substitutions between downstream and upstream generators on either end of a constrained line for congestion management. All Gencos in the energy market are free to supply this information for congestion management, and as a tertiary source of supply for forecast load not yet contracted in the energy or reserve markets.

7. Continuous Double Auction Energy Market

We executed a single major experimental treatment variation on the day-ahead sealed bid energy market described above, keeping constant our treatment of the auction procedures for the reserve market and the load adjustment market. This was the continuous double auction (CDA) energy market.

In this variation we followed the proposal in California under which all buyers and sellers are free to contract via a double auction market that runs continuously down to the hour-ahead spot market. There was no day-ahead energy market, only a day ahead forecast with + or −8% confidence. (Other demand related events could be publicized at any time.) Shortly before the double auction energy market closed, a new forecast was publicized with + or −2% confidence. Following the energy market, we ran the reserve and load adjustment markets as above.

The convention employed was that the acceptor of a CDA bid (offer) agreed to deliver (or take) power from the submitter's location. If the energy could not ultimately be delivered or taken because of line constraints, the acceptor suffered the cost of rectifying the situation. The acceptor had to purchase locally available energy to satisfy the buyer's load and avoid the constrained line, and he could attempt to unload his previously contracted remote energy source in the adjustment market.

A time line for the energy, reserve, and load adjustment markets is provided in Olson et al. (1999, Figure 8).

8. The Network

A chart of the 8-node network we used for the experiments is shown in Figure 2. Each node is a control area connected to other nodes so as to correspond to an aggregated version of a portion of the grid in the Mid-Atlantic, South and Midwest. In this figure are presented the set of surplus maximizing competitive equilibrium allocations based on the demand in the four periods on the final day of trading. These allocations are based only on marginal costs of energy, assuming all the right generators are available to inject power into the system. The competitive equilibrium line flows and sector costs and profits are computed by applying the optimization to simulated fully revealing bids/offers; i.e., each simulated buyer bids his resale value schedule, and each seller her marginal cost schedule for each generator unit as if it is currently running. The equilibrium allocations are shown for periods 17–20 (Day 5). On other days the realization of demand was different, though of the same pattern, so the corresponding equilibrium allocations were somewhat different.

Under each node name is a vector of prices (P:) above a vector of quantities (Q:). These represent the equilibrium prices for power (rounded to the nearest peso) in the Off-peak, Shoulder, Peak, and Shoulder average demand periods, and the corresponding quantities buyers would consume. Each transmission line, which shows a direction of flow and a maximum flow constraint, also shows a vector of quantities indicating the amount of flow that would occur in each of the four periods if the competitive equilibrium allocation were achieved.

Each control area (node) had demand and supply capacity that was large relative to the transfer capacity of the lines connecting it with other control areas. This meant that the control areas were sealed off from substantial inter-connect contestability. We imposed local bilateral contracts in sufficient quantity to allow contestability through imports and exports loosely matched in volume to the capacity of the transmission lines. This allowed us to study a reasonably competitive market structure, but public policy must ultimately address the issue of creating more competitive conditions within each control area. The transmission system is inadequate to rely on export–import contestability.

9. Optimization

In the experiments conducted, we used a DC model with quadratic line losses to compute the real power flows in the aggregated network.

10. Subjects

More than 100 undergraduate students were recruited from business, engineering and economics classes. Subjects received a fixed fee of \$15 for arriving on time for each experiment, and their accumulated earnings in the experiment after they have finished. Where subjects were recruited for several experiments, including training sessions, all payments were withheld until they completed the series. All trading was denominated in experimental "pesos," and each agent was provided a private exchange rate that was used to convert pesos earned to American dollars at the end of the experiment. The exchange rates were calibrated to provide each subject with competitive equilibrium earnings of approximately \$25 for his two hours of effort, depending on how well he and other members of his group traded. Subject earnings varied from \$0 to \$180 during various individual trading sessions.

Each subject was originally recruited for a series of four 2-hour training experiments. The first session consisted of the delivery of written and oral instructions, followed by a question and answer period concerning the experimental environment in which they would trade. That was followed by a training session in which subjects traded in a symmetric star network with no losses, line constraints or reserve and adjustment markets. Losses and line constraints were added in session three, and the auxiliary markets in session four. Across the four sessions subjects earned up to several hundred dollars.

Through self and experimenter selection for the best traders, the original 100 were reduced to 44 who participated in the series of three experiments reported here. Therefore, all subjects had participated in at least four previous trading sessions.

11. Data Analysis: Questions and Answers

Running an SBO versus CDA variation in the energy market allowed us to compare the two different auction institutions in terms of efficiency, the distribution of surplus between buyers and sellers, the effect of location on prices and profitability, and the effect on profitability of Gencos with varying mixes of generators who can offer portfolios of like units to the market. In this comparison we note that the CDA provides continuous feedback of information, and permits Gencos to lock in some individual generators in advance, while others are committed later when more information is available. These advantages, relative to the day-ahead SBO, must be weighed against the latter's optimization support advantages.

For the sake of conciseness and clarity in reporting the experiment results, we chose four representative measurement nodes in the network. In equilibrium, they represented the major sources: Node 1, one transhipment point, Node 5, and the major sinks at opposite ends of the stylized trading network, Node 7 and Node 8. Results are reported separately for each of four super-experienced groups in each environment, and then summarized with averages.

11.1. What is the Competitive Efficiency of the Two Markets Based on Marginal Energy Costs?

The primary measure of market performance will be efficiency measured as the realized proportion of total competitive equilibrium surplus per period; i.e., the ratio of actual to equilibrium earnings attributable to producers, wholesale buyers and transmission. Table 2 gives a summary of Total Efficiency for the SBO and CDA environments. Overall efficiencies are high (well above 90%) in both markets, but the results here indicate that post energy market efficiencies of the day ahead SBO markets are on average 2.5% more efficient than those of the CDA markets.

Moreover the difference grows to 3.4% in the post adjustment market. These differences can only be due to the lack of coordination in the CDA, and the consequent reduced potential to fix inefficiencies in the auxiliary markets.

How effective are buyers in meeting their energy requirements? How cost effective is generation? Consider the fact that in equilibrium we know which is the most economical set of generators to supply the power and which buyers should buy. We observed:

Table 2

The results realized for sellers' % equilibrium costs, buyers' % equilibrium quantity of power delivered (post energy and post adjustment markets) are shown for each of four distinct super experienced subject groups, under both the SBO and CDA trading rules. The average across the four groups is listed at the bottom of each column for SBO and CDA. Observe that on average sellers incur costs of 112.56% of the equilibrium cost following the adjustment market in SBO, but 122.56% in CDA. Buyers fill 98.76% of their demand quantity, post adjustment, in SBO and 97.03% in CDA. Similarly total efficiency is 97.01% in SBO, 93.79% in CDA

Auction	Group	Sellers' % equilibrium costs		Buyers' % equilibrium quantities		Total efficiency	
		Post energy Mkt	Post adjustment Mkt	Post energy Mkt	Post adjustment Mkt	Post energy Mkt	Post adjustment Mkt
SBO	1	106.63%	109.72%	97.39%	98.87%	96.21%	97.49%
	2	104.04%	112.15%	95.78%	98.96%	94.73%	97.28%
	3	103.10%	118.45%	94.07%	98.61%	92.92%	96.09%
	4	104.90%	109.93%	96.50%	98.61%	95.43%	97.19%
	Ave.	104.67%	112.56%	95.94%	98.76%	94.82%	97.01%
CDA	1	120.80%	125.25%	95.00%	96.89%	91.72%	93.29%
	2	124.04%	126.91%	97.80%	98.85%	94.46%	95.28%
	3	118.95%	125.46%	93.55%	96.66%	90.32%	93.02%
	4	110.55%	112.60%	94.79%	95.71%	92.78%	93.56%
	Ave.	118.59%	122.56%	95.29%	97.03%	92.32%	93.79%

(1) the proportion of expected energy consumption that was actually realized by buyers (% Equilibrium Quantities), and (2) the cost of producing that energy for the sellers (% Equilibrium Costs). This information, also contained in Table 2, indicates that the major cost of inefficiency was due to a higher than expected total average cost of producing energy, and not so much due to buyers missing consumption. But again, the CDA environment produced seller costs that averaged 10% in excess of the SBO.

11.2. Do SBO Prices and CDA Weighted Average Prices Converge to Comparable Levels?

CDA prices are maintained at a higher level than SBO prices. This is borne out by Table 3 that provides absolute energy trading prices observed at the four measurement nodes at the four demand levels. The average CDA prices dominate the uniform SBO prices in 14 of 16 cases, usually by a factor between 1.5 and 2. Moreover SBO prices dominate the competitive equilibrium price prediction in 14 of 16 cases (cf. the competitive equilibrium prices at the bottom of each average price column). Table 3 also provides quantities consumed, which varies little by group and treatment, and quantities imported or exported which reinforces the notion of high group variance and the unpredictability of flow patterns in a network where similar marginal costs are distributed well throughout the network.

11.3. What are the Profitability Levels for the Various Agents in the System?

If generation costs and trading prices are systematically higher, and quantity traded systematically lower in CDA than SB, then the consequence can only be that buyers suffer lower profitability: they paid 1.5 times as much for 4% less energy. However, the potential for increased seller profitability is contingent on whether sellers negotiate price increases that more than cover the cost of their increased inefficiencies, and whether sellers gather enough demand and value information during the double auction feedback to behave more strategically in the reserve and adjustment markets.

Comparing CDA with SBO, the energy prices recorded (Tables 3a–3b) indicate that sellers' CDA prices tend to be much above SBO prices, while power deliveries are reduced only modestly. But from Table 2 we have seller costs in the energy market increasing by only 10%. Sellers are able therefore to capture some of the buyers' surplus in the CDA energy market where there is more opportunity to explore the "willingness to pay" and less risk to bear in having an offer refused. In some sense they are blessed by the fact that higher priced inefficient generators trade to bolster the prices, and buyers are more cautious in buying close to home to avoid the risks of congestion.

11.4. Do Nodal Prices Reflect Distance Sensitivity and Line Constraints?

For the sake of clarity, because buyers and sellers were quoting prices in integers, nodal prices were always displayed as rounded integers on the network diagram that agents

Table 3

Average prices at nodes 1 and 5 (3a) and nodes 7 and 8 (3b), are listed by subject group in columns 3, 6, 9 and 12 for four sequential demand levels: off peak, shoulder, peak and shoulder. Average prices are followed by the quantity of power consumed (QC), followed by the quantity imported (+) or exported (−) under QIE. The top 5 rows are for SB, the last 5 rows for CDA. Observe that for most nodes and demand condition, the average price is higher in CDA trading than SBO. In parentheses below the average price column for each node is contained the competitive price (Figure 2)

(a) Energy market prices and quantities (price, quantity consumed, quantity imported (+) or exported (−))

Node 1

Auction	Group	Off peak			Shoulder			Peak			Shoulder		
		Price	QC	QIE	Price	QC	QIE	Price	QC	QIE	Price	QC	QIE
SB	1	16.8	1209.0	150.3	19.2	1606.0	−259.4	36.6	1618.4	140.4	32.8	1606.0	314.7
	2	13.8	967.0	84.7	19.8	1551.0	215.0	19.8	1621.0	−64.6	20.0	1574.8	30.5
	3	14.8	1209.0	−128.4	20.4	1562.0	−220.5	30.8	1419.2	147.2	32.8	1505.8	325.8
	4	15.4	1209.0	226.8	24.0	1606.0	26.5	30.2	1803.0	−13.9	28.8	1606.0	75.6
	Ave.	15.2	1148.5	83.4	20.9	1581.3	−59.6	29.4	1615.4	52.3	28.6	1573.2	186.7
CDA	1	19.7	1176.8	91.8	44.2	1587.8	−106.6	81.9	1608.4	178.2	47.9	1485.8	129.2
	2	23.1	1209.0	158.4	39.6	1606.0	−20.4	47.0	1756.8	−172.1	45.1	1546.2	−42.0
	3	39.3	1170.8	307.4	27.1	1606.0	223.2	41.2	1694.6	214.0	22.5	1476.9	500.7
	4	55.8	1164.2	13.8	46.4	1606.0	−256.8	33.6	1803.0	−55.7	42.6	1601.8	18.3
	Ave.	34.5	1180.2	142.9	39.3	1601.5	−40.2	50.9	1715.7	41.1	39.5	1527.7	151.6
		(13)			(13)			(17)			(13)		

Table 3
(*continued*)

Node 5													
Auction	Group	Off peak			Shoulder			Peak			Shoulder		
		Price	QC	QIE	Price	QC	QIE	Price	QC	QIE	Price	QC	QIE
SB	1	16.8	658.0	56.4	19.6	923.0	181.0	38.6	909.3	120.9	32.8	923.0	113.8
	2	14.0	658.0	−79.3	19.8	920.0	−90.6	19.8	946.4	−147.2	20.0	883.0	−193.7
	4	15.4	658.0	120.2	24.8	920.3	321.2	30.2	1023.0	214.3	28.8	923.0	249.8
	Ave.	15.3	658.0	21.8	21.2	920.1	130.6	29.9	904.8	36.1	28.6	885.0	45.5
CDA	1	27.0	653.6	33.0	38.1	865.3	58.5	47.6	892.6	41.9	48.2	785.3	45.4
	2	53.8	658.0	−69.8	39.4	915.3	53.6	41.9	963.6	56.8	45.4	901.8	−11.4
	3	15.9	550.1	92.3	31.1	915.7	24.9	59.3	977.8	56.6	39.9	852.9	93.9
	4	15.7	615.0	−101.4	29.5	923.0	154.1	30.3	1023.0	38.4	27.4	923.0	102.2
	Ave.	28.1	619.2	−11.5	34.5	904.8	72.8	44.8	964.3	48.4	40.2	865.8	57.5
		(13)			(13)			(17)			(13)		

Table 3
(*continued*)

(b) Energy market prices and quantities (price, quantity consumed, quantity imported (+) or exported (−))

Node 7

Auction	Group	Off peak			Shoulder			Peak			Shoulder		
		Price	QC	QIE	Price	QC	QIE	Price	QC	QIE	Price	QC	QIE
SB	1	17.2	2310.8	199.8	30.8	3064.1	223.3	60.0	3376.2	238.3	53.0	3042.4	149.7
	2	15.2	2311.0	167.1	20.0	3069.0	94.7	48.0	3559.0	238.3	29.0	3069.0	238.3
	3	18.6	2308.9	123.9	24.6	2923.3	28.0	35.0	3143.3	−104.5	31.0	2745.7	−147.7
	4	15.4	2311.0	98.2	26.2	3066.7	157.0	43.0	3407.1	158.2	30.8	2979.7	104.8
	Ave.	16.6	2310.4	147.3	25.4	3030.8	125.8	46.5	3371.4	132.6	36.0	2959.2	86.3
CDA	1	19.5	2307.6	−210.7	40.4	2991.2	−115.1	51.2	3354.1	−183.8	48.3	2919.5	−139.4
	2	4.0	2286.3	167.3	33.7	3016.2	20.2	47.9	3362.1	109.0	37.4	3058.5	77.8
	3	23.3	2311.0	−112.2	30.2	3009.6	15.8	47.6	3455.9	197.1	42.3	2884.9	91.9
	4	16.2	2280.6	−187.3	27.7	3015.2	−10.2	32.6	3465.3	125.3	29.5	3019.0	−7.9
	Ave.	15.8	2296.4	−85.7	33.0	3008.1	−22.3	44.8	3409.4	61.9	39.4	2970.5	5.6
		(15)			(19)			(52)			(19)		

Table 3
(*continued*)

Node 8

Auction	Group	Off peak			Shoulder			Peak			Shoulder		
		Price	QC	QIE	Price	QC	QIE	Price	QC	QIE	Price	QC	QIE
SB	1	13.2	1797.0	−133.0	18.4	2498.0	−264.8	20.0	2784.0	−287.2	18.8	2498.0	−384.2
	2	12.8	1797.0	−133.0	19.2	2498.0	−0.7	20.0	2784.0	−214.5	21.4	2498.0	40.4
	3	14.4	1797.0	167.0	22.6	2493.7	324.7	21.4	2783.0	−66.2	27.4	2493.7	−274.3
	4	13.6	1797.0	−127.4	23.8	2498.0	127.3	24.8	2784.0	−196.2	37.4	2495.7	185.0
	Ave.	13.5	1797.0	−56.6	21.0	2496.9	46.6	21.6	2783.8	−191.0	26.3	2496.4	28.9
CDA	1	20.2	1756.0	−3.0	39.4	2462.6	154.4	52.2	2753.0	−116.0	49.2	2395.0	−35.8
	2	26.3	1787.7	−64.1	35.9	2467.8	49.4	66.9	2758.4	−147.3	51.7	2356.7	11.9
	3	16.0	1670.2	−66.0	30.3	2201.6	−118.8	47.7	2718.1	−129.9	40.6	2185.2	−122.1
	4	6.9	1746.1	33.1	27.4	2454.3	80.1	30.5	2768.1	−157.7	31.3	2453.4	3.2
	Ave.	17.4	1740.0	−25.0	33.3	2396.6	41.3	49.3	2749.4	−137.7	43.2	2347.6	−35.7
		(17)			(17)			(17)			(17)		

could observe. This meant that minor price differences were frequently undetectable. However, the exact nodal prices, taking into account the marginal losses along network transmission lines, were always used to count realized profits.

Since average line loss on every line was scaled from 2.5% at maximum capacity, the largest price difference due to losses could be 5%. (Marginal loss price differences are approximately twice the average loss.) Whenever the upstream and downstream prices differed by at least 5%, there was line congestion. Genco production cost differences between control areas yielded lines often loaded to constraint in our calculated competitive equilibria (see Figure 2). Notice, however, that even though several lines are frequently up to constraint, there is just one large equilibrium congestion price difference in this network, which occurs at Node 7 during peak demand. In equilibrium the constraints are just barely binding.

Larger price differences due to congestion were frequently realized during the trading, and the observed flow was often the reverse of the equilibrium direction. These price differences really did not reflect the physical reality of the production cost differences, but are artifacts of strategic bidding in a very delicately balanced system. Generators with similar cost characteristics were disbursed throughout the system, and only the offers determined which direction the power flowed.

We conclude that with intensive training and screening subjects can handle very complex and demanding environments when assisted by local expert system algorithms similar to the support needed by practitioners in the field. Moreover they engage in extensive, successful manipulation attempts to take advantage of the regulatory "must-serve" restrictions on the ability of the local distribution monopoly to interrupt demand to discipline seller withholding of supply. Sellers, however, are much more consistently successful in this respect under the CDA trading rule condition. These findings contrast sharply with those of other experimental studies in which modest proportions of peak consumer demand could be interrupted by wholesale buyers, enabling the latter to discipline seller attempts to raise clearing prices.

Reference

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