# Market Design and Motivated Human Trading Behavior in Electricity Markets

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**ABSTRACT**

*This paper is based on a series of controlled experiments in the trading of wholesale electricity that expands substantially the scope of the research program reported previously. (Backerman, Rassenti and Smith, 1998; Backerman, Denton, Rassenti and Smith, 1998; Denton, Rassenti and Smith, 1998). The experiments employed cash motivated students and rented computer laboratory facilities of the University of Arizona. The primary objective of these experiments was to compare two alternative institutional arrangements for the trading of electric power. The first employed day-ahead sealed bid trading of energy for all periods in the subsequent day; the second employed simultaneous continuous double auctions for bilateral trading of energy up to the hour before delivery. All trading was executed on an eight-node network with limited transmission capacity. Each node was to be thought of as a control area, with one large wholesale generator company and one large distribution company resident there.*

## 1. Modeling Generators

Generator companies (Gencos) consisted of portfolios of generator units of various technological types (coal, oil, gas, hydro, nuclear), including multiple generator units of the same type. Parameters that characterized each type of generator, and the companies that owned them, are shown in Table 1. Large coal and nuclear units were 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 varied considerably in capacities and costs, but generally had high marginal costs, low fixed cost, and low minimum loads (5% of maximum capacity or less), but represented quick-start sources of reserve power in the event of unscheduled outages. If all generators in the network were arrayed from lowest to highest, according to their marginal cost and corresponding capacities, the resulting step function was the minimum willingness-to-accept supply schedule of power in the network, as shown in Figure 1 which abstracts from losses and transmission constraints.

A portion of the screen display for the Genco at node 7 is shown in Figure 2. (The screen also displays the network and the Genco's location in the network, but this is shown separately in Figure 6 below). Genco 7 controlled six classes of generator units designated A7, B7,…, G7. Each class consisted of multiple individual units, each unit represented by it's own lightening icon. By clicking on the icon, the essential data for that generator was displayed in the box titled "A Costs". For example, the 5$^{th}$ 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 money, "pesos"). Then the ramp (start up) time, 10 hr, followed by the fixed (sunk) cost 389¶/H, pesos per hour. Under Fuel Cost, the first 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 160MW at a constant fuel cost up to capacity.

All loaded generators were assigned forced outage rates based on NERC data for units of different types. If an outage was realized, it's duration was then specified, and during those periods that unit could not be offered to the market.

**Table 1. Genco information**

| 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 | 25000 | 60 | 180 MWH (1) | 180 MWH (1) | 180 MWH (1) |
| 1 | large coal | 4 | 530 | 12.900 | 265 | 1500 | 10 | 530 MWH (2) | 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 (3)* | *800 MWH (3)* | *1000 MWH (3)* |
| 2 | hydro | 1 | 270 | 1.830 | 5 | 10 | 0 | | | |
| 2 | nuclear | 1 | 550 | 11.520 | 550 | 25000 | 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)* |
| 4 | nuclear | 1 | 60 | 11.520 | 60 | 25000 | 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 | 25000 | 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 | 25000 | 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)* |
| 7 | hydro | 1 | 190 | 2.010 | 5 | 10 | 0 | | | |
| 7 | nuclear | 1 | 1010 | 12.230 | 1010 | 25000 | 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 | 25000 | 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 turbines oil/gas | 10 | 10 | 64.940 | 3 | 400 | 3 | | | |
| *Totals* | | *33* | *3570* | | | | | *1630 MWH (11)* | *2100 MWH (11)* | *2740 MWH (11)* |

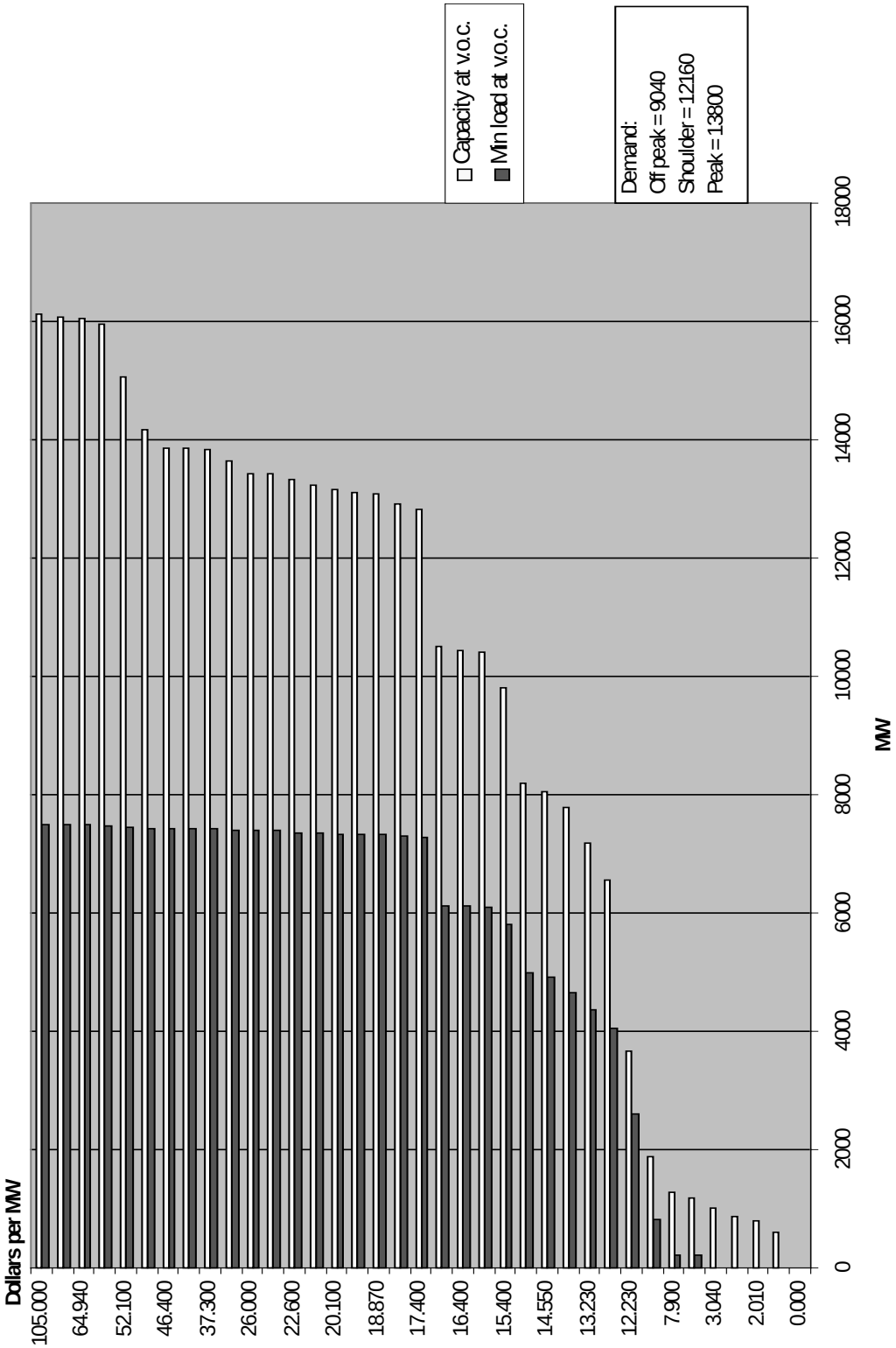


**Figure 1. Power supply curve (no losses)**

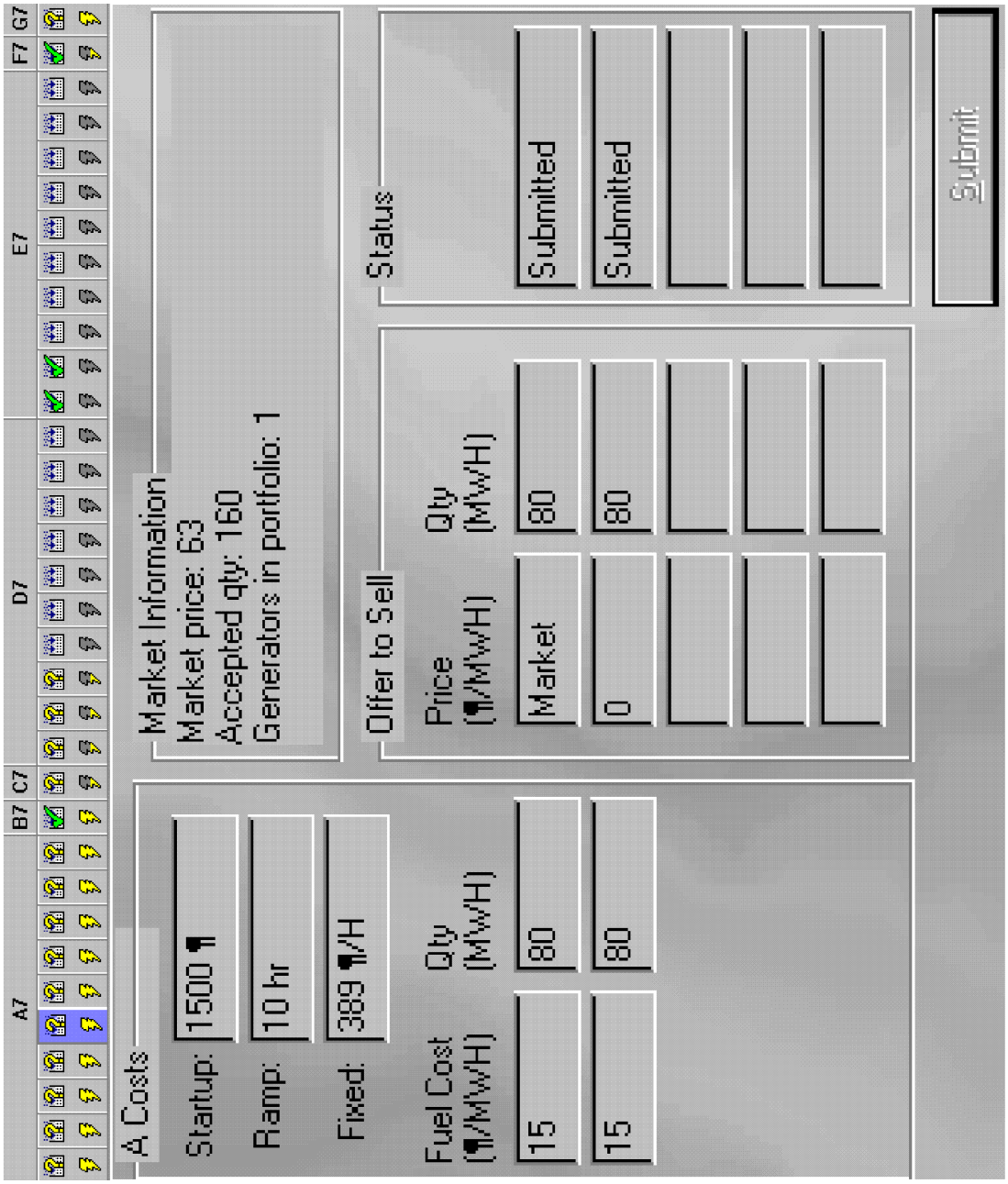


**Figure 2. Genco screen display SB**

## 2. Modeling Demand

Demand cycled 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 were repeated in a series of 5 market days during each experiment, for a total of 20 energy trading periods. Each period each wholesale buyer was assigned a large spike of "must serve" demand that he could resell at a regulated price as shown in Figure 3. In these experiments no portion of the demand could be interrupted voluntarily. The "must-serve" spike in demand was uncertain. There was a day-ahead forecast with + or – 8% confidence interval error, then a new forecast at + or – 2% error an hour ahead at "spot time" (the load adjustment market discussed below).

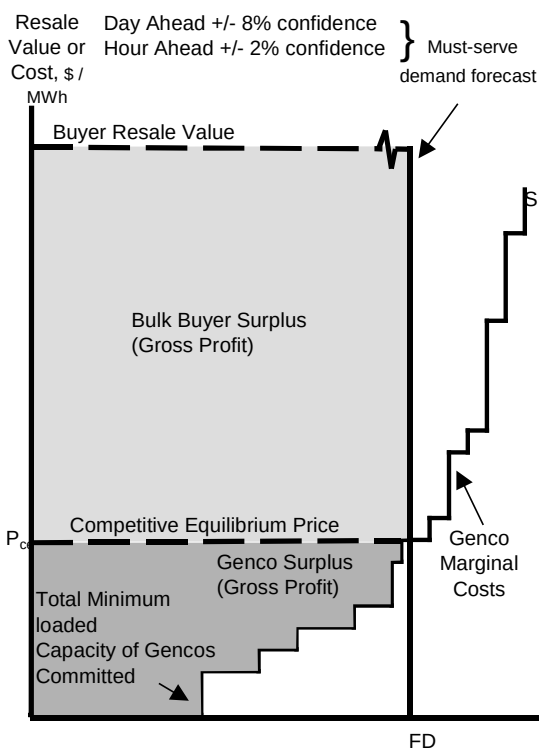


**Figure 3. Representation of demand, supply**

## 3. Market Design

The power market consisted of three sequential auction submarkets: (1) an energy market for generator supply commitment, which either employed 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 was delivered; (2) a market for spinning and quick start reserves conducted after the results of auction (1) were 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.

### 3.1: Sealed Bid Day-Ahead Energy Market

The objective of this market is to marshal generator commitment in advance of more exact information on demand. We modeled the day-ahead demand forecast with a + or – 8% confidence interval. The baseline mechanism for this market was the two-sided sealed bid-offer auction. Generator commitment meant that any Genco unit with a "must-run" minimum load requirement was offered as follows: the minimum loaded capacity was offered as the first quantity step at a zero (or negative, if there is a risk of surplus baseload capacity) price to the auction; subsequent steps were offered at any prices selected at the discretion of the Genco's owner, except that the center ranked the steps in increasing order of price, whether or not they were submitted in that form. A hypothetical set of Genco offers, S, is shown below in Figure 4.

Buyers submitted bids for all their demand, which we assume consisted of all "must serve" loads, none of which could be voluntarily interrupted. All demand and supply were channeled through a central exchange market. To the extent that Genco's contracted 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 experiment reported here. For example, we assumed that all nuclear units were completely contracted, and that something between minimum and maximum capacity of several of the large coal units were 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 were subtracted from demand at each local distribution node, and were never under threat of being constrained off. Capacity not contracted was 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.

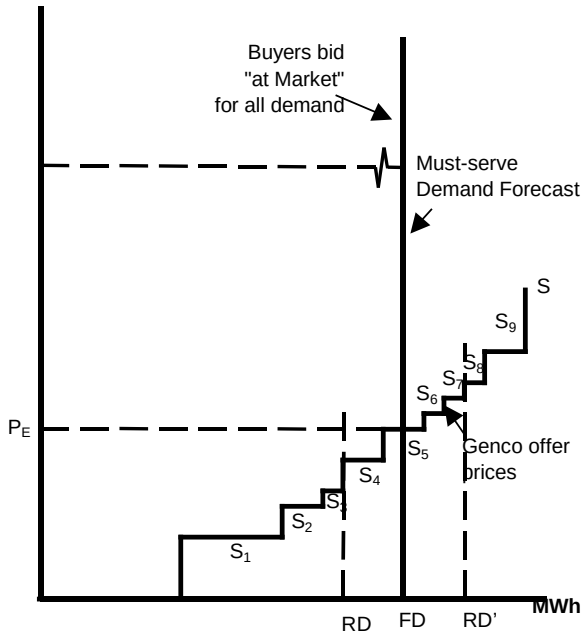


**Figure 4. Energy market offers, bids and clearing price**

As the experiment proceeded from period to period, the status of each generator was indicated by the color of it's lightening icon (see Figure 2): yellow indicated that the generator was providing power in the previous period; gray indicated that it was off; and red indicated 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. If it was on, and the offer accepted in the market, only the fixed cost and fuel cost are incurred.

The sealed bid procedure to enter energy offers for a generator is illustrated in Figure 2. In the window on his computer monitor entitled "Offer to Sell", each generator's capacity could be offered to the market in up to five asking price steps. In the illustration for a unit in class A, Genco 7, there was automatic entry of the first minimum loaded capacity step (80 MWH) "at market." This is defined as commitment, and guaranteed that a partial acceptance would not require a unit to run at less than minimum load. 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 MHW, at zero. This assured that all the capacity of the unit will be accepted at the ruling market price, unless there was excess minimum base load capacity in the system, as can occur, and the price was zero. (The California PX has often produced zero prices in portions of the 1-3AM interval). Having entered the offer prices, the subject would click on the submit button at the bottom right of Figure 2, and each offer step under Status would be 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 could be 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 should have been offered individually if the subject wanted 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 were 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, were eligible.

### 3.2: 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 fell short of purchasing his forecast energy requirement in the energy market. Each offer from a generator owner was a two part offer: (i) the first was a capacity supply price representing the Genco's minimum required payment for maintaining the capacity's readiness to supply temporary reserves; (ii) the second was an energy charge in $/MWh for drawing upon the capacity until the reserve was no longer needed.

The buyers and sellers were told that the probability of unscheduled outage was about .06 for any generator and therefore to accommodate 99.9% of all emergency circumstances the required reserve capacity in MW needed to be 12% of the forecast load in the entire system. (Unknown to the buyers and sellers, in these experiments we did not actually stress anyone with unscheduled outages, though they bid with full expectations of encountering them.) In addition to the required reserve, RR, for outages, we treated 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 was 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 MW, the lowest RR+BR units of capacity offered were accepted at the lowest rejected offer. (See Figure 5a). The cost of the first RR units of reserve capacity was shared by all buyers in proportion to their forecast demand. The next BR units of reserve capacity was paid for by the individual buyers who had fallen short in the energy market, since we have assumed in this study that they had no interruptible demand.

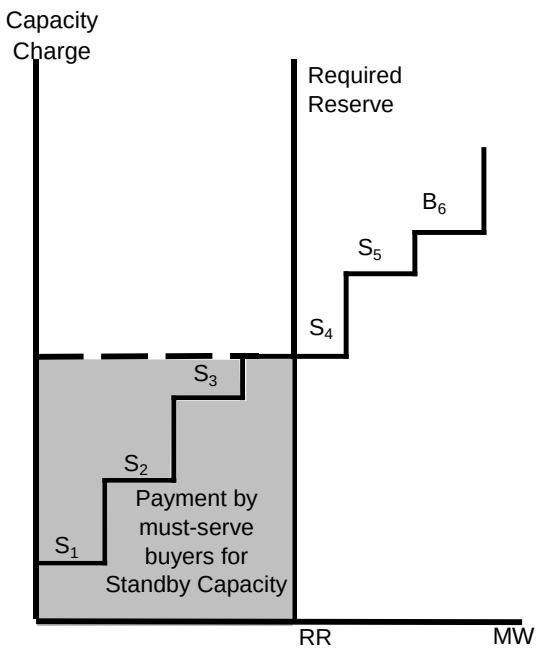


**Figure 5a. Reserve market**

The set of RR+BR accepted reserve offers were then sorted from lowest to highest based upon the energy 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, as illustrated in 5b. 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.

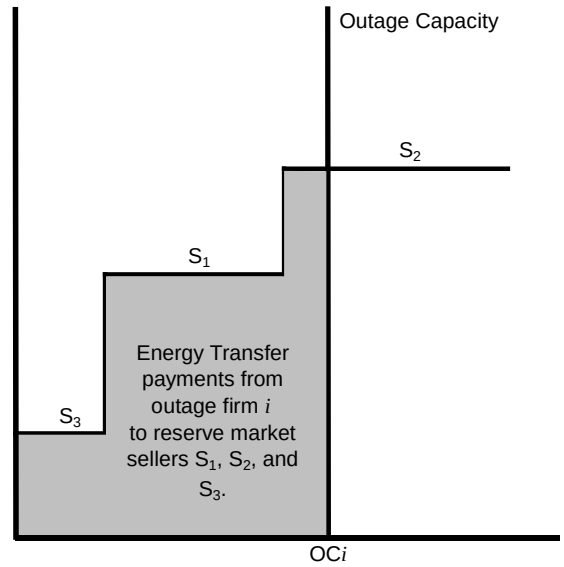


**Figure 5b. Energy supply to replace**

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. We can observe the extent to which residual demand drew on reserves.

### 3.3: Load Adjustment Market

Quick responding generator capacity not accepted (or offered) in either the energy or the reserve market could be offered for load adjustment to realized demand (load following). At this point in the time line sequence, we modeled 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 were 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.

The load adjustment market is illustrated in Figure 6. If realized demand, RD < FD, forecast demand, then, in the example illustrated in Figure 6, the load adjustment market substitutes generators willing to pay more for generators willing to pay less to reduce output. Thus, in the energy market, shown in Figure 4, $S_5$ is the marginal generator at FD, while $S_4$, $S_3$ and $S_2$ are the next lower generators in the merit order. But in Figure 6, it is seen that $S_2$ and $S_5$ are willing to pay more to throttle back than $S_3$ and $S_4$. Thus $S_2$ and $S_5$ win the decrement auction, with $S_2$ paying $S_4$ for the right to reduce delivered power, and $S_5$ (in effect) paying himself. Observe that the decrement market is concerned only with the possibility of substitution among committed generators; all generators accepted for the forecast demand, FD, receive payment from buyers who are billed on the basis of the demand as it was forecast.

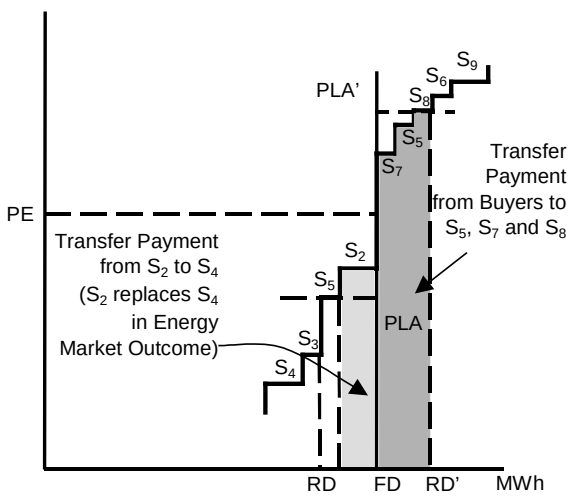


Figure 6. Load adjustment market

In the version of the experiments run, the load adjustment market was restricted to adjustments for energy shortfalls, so that buyers and sellers did not require training in both roles. When the demand realization was below the amount of energy purchased by buyers, this was viewed as a windfall for sellers who were arbitrarily cut back but received payment. Sellers could also not purchase power for the purpose of economy interchange, and were required to produce from the generators they had committed. Since the main objective was to test the consequences of rule changes in the primary energy market, this was done to avoid a more difficult training program and a more complicated experimental environment which would have generated more noise in the data. The full implementation of the adjustment market is possible with the current version of the software, and we plan future experiments that use all these features.

### 3.4: 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 relevant part of the seller's screen corresponding to the double auction trading is shown in Figure 7. The queue of standing offers (lowest to highest) sat above the queue of standing bids (highest to lowest). Any offer to sell in square brackets was an all or none offer, enabling Gencos to tender bids that guarantee minimum load coverage on their first step. Other bids and offers could be accepted in any part. An asterisk to the left of a bid or offer indicated it belonged to the agent who was observing it. An arrow to the left indicated that any change would be made to that bid or offer. The number to the right of the bid or offer indicated which node the submitter was at. An agent would enter a bilateral trade when he accepted someone else's bid or offer, or when his standing bid or offer was accepted by someone else.

**Figure 7. Genco screen display CDA**

The convention employed was that the acceptor 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 shown in Figure 8. Note that the reserve and load adjustment markets are identical in the two alternative scenarios. In the first, generator commitment is determine in a day-ahead SBO auction based on the day-ahead forecast, while in the CDA trading is continuous with the energy market closing just before the beginning of the reserve market.

## 4. The Network

A graph of the 8-node network we used for the experiments is shown in Figure 9. Each node is a control area connected to other nodes so as to correspond very roughly to an aggregated version of a portion of the grid in the Mid-Atlantic, South and Midwest, but we make no concerted effect at precise representation. 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 her resale value schedule, and each seller his 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 slightly different, though of the same pattern, so the corresponding equilibrium allocations were slightly 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, and there was a strong likelihood of the execution of monopoly market power by local suppliers when local buyers could not import enough. As a stopgap solution to this problem 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. There remained the potential for line congestion to arise, but the opportunity for local price escalation was greatly diminished in volume, and the Gencos did not need to devote task energy to bidding and scheduling much of their base load.

## 5. Optimization

In the experiments conducted, we used a DC model with quadratic line losses to compute the real power flows in the stylized network. XA (copyright Sunset Software Technology), a callable library for solving linear and integer programs, provided the horsepower to solve for the optimal (surplus maximizing) power flows given the bids and offers from all agents. A full nonlinear AC optimization program will be imported into the software package at the next stage of the research.

## 6. 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.

**Continuous Double Auctions (CDA)**

Step 0: Set I=1 and k=1. Publish forecast energy demands (+ or – 8%), then simultaneously open DA energy markets for periods I1, I2, I3, and I4 for 7 1/2 minutes.

Step 1a: Draw energy demand (+/- 2%) for period Ik. Announce the energy market for Ik will close in 2 1/2 minutes.

Step 1b: Close energy market Ik. Publish forecast demand (+ or – 8%) and open energy market for period (I+1)k.

Step 2: Conduct 1 minute SB reserve market for period Ik.

Step 3: Draw exact energy demand for period Ik, then conduct 1 minute SB inc/dec market for period Ik. Use inc/dec to balance demand and supply.

Step 4: Draw generator and line failures for period Ik. Use reserve to deal with failures. Do accounting, report results.
Allow subjects 1/2 minute to view.

Step 5: If k<5, set k=k+1. Otherwise, set I=I+1, k=1. Go to step 1a.

**Sealed Bid Day Ahead Auctions (SB)**

Step 0: Set I=1 and k=1.

Step 1: Publish forecast energy demands (+ or – 8%), then sequentially conduct SB energy markets for periods I1, I2, I3, and I4 for 10 minutes.

Step 2: Draw energy demand (+ or - 2%) for period Ik. Conduct 1 minute SB reserve markets for period Ik.

Step 3: Draw exact energy demand for period Ik, then conduct 1 minute SB inc/dec market for period Ik. Use inc/dec to balance demand and supply.

Step 4: Draw generator and line failures for period Ik. Use reserve to deal with failures. Do accounting, report results. Allow subjects 1/2 minute to view.

Step 5: Set k=k+1. If k<5 go to step 2. Otherwise, set I=I+1, k=1, go to step 1.

**Figure 8. Trading timelines.** The above flowcharts describe the institutional trading sequences. Let Ik indicate day I period k (e.g. I3 is day 1 in peak period). DA represents the Double Auction, and SB the Sealed Bid auction.

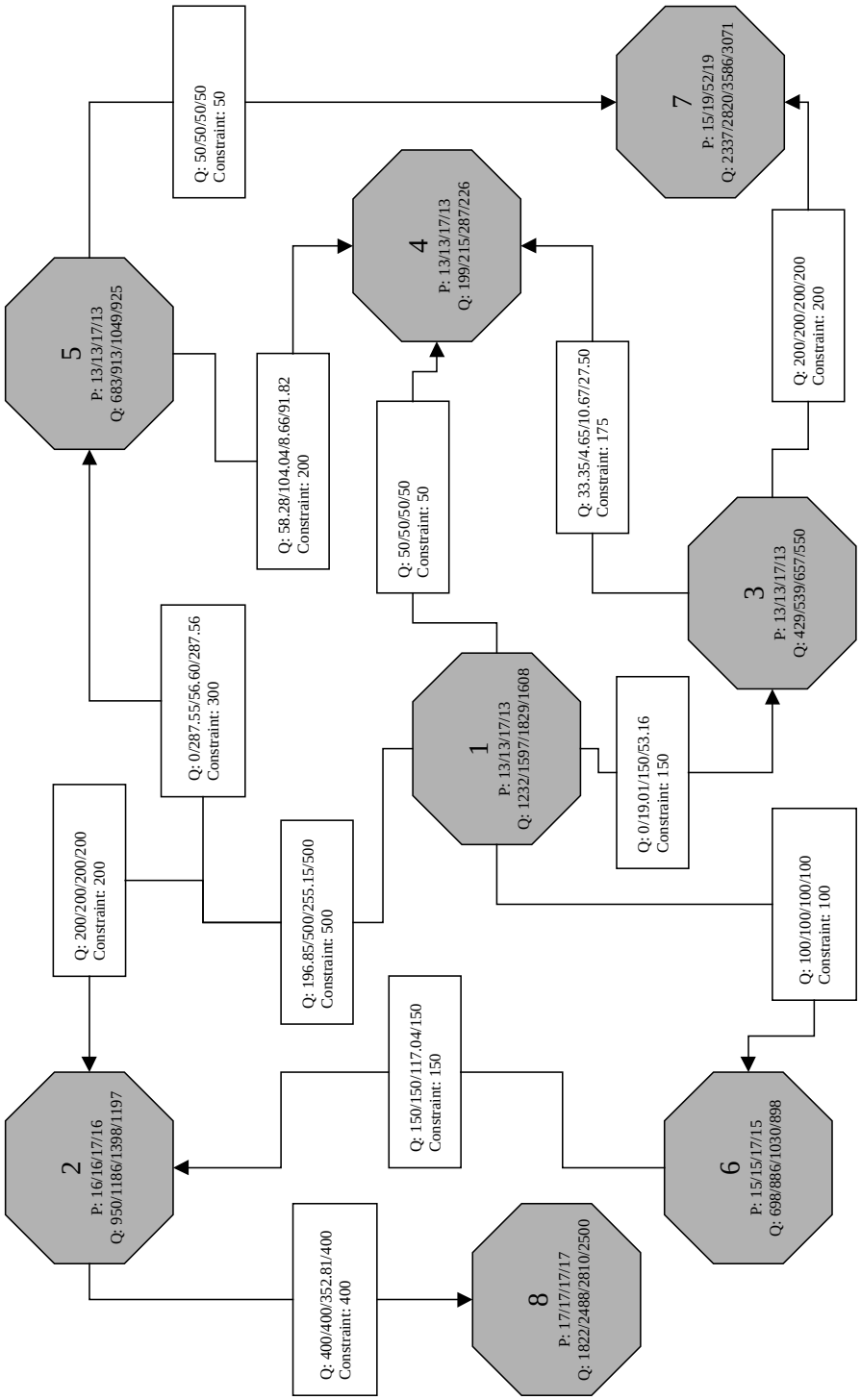


**Figure 9. Network representation**

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 whittled down to 44 subjects who were retained to participate in a series of three experiments in the test environment to be studied. As much as possible, we ensured that subjects retained their roles throughout these experiments. The results of the first of those experiments is ignored in reporting the data collected, as it provided subjects the opportunity to learn the parameters of the new and more complicated test environment. Therefore, all the data reported was generated by subjects who had participated in at least four previous trading sessions.

Each test environment trading session was conducted in a network where there were eight wholesale buyers and eight generating companies. The buyer's role, which required no participation in the auxiliary markets, unless inadequate purchases were made in the energy market, was much simpler than the seller's, who had to manage a complicated inter-temporal planning problem in offering his portfolio of generators. We used one subject for two buyer roles at two dispersed locations in the network. Two of the seller roles were fairly unimportant as they represented very small participants in the import and export of electric power in the network. The way the environment was parameterized, those sellers would not trade much power, and, in fact, one of them would lose money in the competitive allocation. In the sealed bid environment we simply robotized those sellers to reveal their costs, and played with 10 rather than 12 human subjects. We could not do this in the CDA environment because there is no simple and efficient strategy to use to simulate CDA behavior.

It is sometimes suggested that experimental results may be sensitive to the monetary stakes and the sophistication of the participant bidders. For this reason there have been many studies designed to determine the effects of experience, monetary rewards and subject pools on experimental outcomes. Such consideration has led us to replicate some of our previous, simpler, power experiments with industry subjects, with no real distinction in outcomes. But with the recent emergence and growth in the design and application of auctions for frequency spectra, spot markets in power, transmission rights, and so on, industrial bidders have often hired economic theorists, experimentalists and other professionals to assist then in developing sophisticated bidding strategies and experimental training exercises. Since our software will enable experiments to be run on the Internet, it would be feasible to conduct experiments similar to the ones reported over an extended period of time with industry participants/consultants.

## 7. Data Analysis: Questions and Answers

Running a sealed bid (SB) versus continuous double auction (CDA) variation in the energy market allowed us to compare the two different auction institutions in terms of efficiency (the proportion of the theoretical surplus captured by the participants); 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 SB, must be weighed against the latter's aggregation advantages.

We use a question and answer format to organize the presentation of the experimental results. 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.

<u>What is the competitive efficiency of the two markets based on marginal energy costs?</u> 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. Consequently, if the potential profit for all participants is $100 in a period, and they realize earnings of $90, the market is 90% efficient. Table 2 gives a summary of this Total Efficiency for the SB 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 SB markets are on average 2.5% more efficient than those of the CDA markets. This would represent a considerable margin in real dollar terms, and is statistically significant given the number of periods of observation (80).

**Table 2. System efficiency**

| Auction | Group | Sellers' % Equilibrium Costs | | Buyers' % Equilibrium Values | | Total Efficiency | |
|---|---|---|---|---|---|---|---|
| | | Post Energy Mkt | Post Adjustment Mkt | Post Energy Mkt | Post Adjustment Mkt | Post Energy Mkt | Post Adjustment Mkt |
| SB | 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% |

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Moreover the difference grows to 3.2% 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.

Distributional efficiency is normally measured for each industry sector as the percentage of that sector's competitive equilibrium share that is realized in any period. Thus, if at the competitive equilibrium, $40 (of $100 total surplus) would be earned by Gencos, who actually earn $32, then Genco, efficiency is (32/40)100 = 80%. In the test environment created there was a large gap between the resale values of the buyers and the marginal costs of the sellers, which created a natural lack of stability in the sector surplus predictions. The amount of surplus realized by each sector, in any given experiment, was a variable characteristic of the strength of the sector as a cooperative bargaining entity. But there is a measure that can shed some light on the efficiency predictions for each sector. Consider the fact that in equilibrium we know which is the most economical set of generators to supply the power which buyers should buy. In fact, we observed: (1) the proportion of expected energy consumption that was actually realized by buyers (% Equilibrium Values), 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 an average of 10% in excess of the SB.

Do SB prices and CDA weighted average prices converge to comparable levels? CDA prices are maintained at a higher level than SB prices. This is borne out by Table 3 which provides absolute energy trading prices observed at the four measurement nodes at the four demand levels. The average CDA prices dominate the uniform SB prices in 14 of 16 cases, usually by a factor between 1.5 and 2. 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.

What happens to prices and efficiency when demand side bidding is removed? Several other experimental economic investigations have tested the effect of having real buyers who can negotiate actively versus posting a fixed demand. The results indicate that when a fixed demand is posted, buyers are at the mercy of the sellers' abilities to tacitly collude in the one sided competition. With the expectation that the same might be true for the test environment, but no guarantee because of it's complexity, we created a sample run in which there was no active demand side bidding. We report a single SB run with subjects experiencing the test environment for the first time. Sellers were told that they would encounter a posted demand quantity. Our results suggested that it was not particularly worthwhile to pursue the issue any further. Post energy market efficiency was the highest observed (99%) in all experiments because buyers could not withhold demand at any price. The market prices at two of the measurement nodes reached more than twice as high as the largest otherwise observed in peak and shoulder periods. An alternative pricing strategy, which works equally well in any experiment where active buyers have no role in the adjustment market, was observed at the other two nodes: withhold supply from the energy market and charge high prices in the adjustment markets. It is likely that these tendencies would have continued to develop as all sellers learned that there was no push back from the demand side.

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.

It is clear from observing the price cycles in Figures 10a-i that reserve and adjustment prices in the CDA matched much more closely the closing prices in the energy market, and were not subject to as much volatility as in the day ahead SB. That might be expected, and did not allow CDA sellers as much opportunity to negotiate windfall profits from reserve and adjustment activity. On the other hand the energy prices recorded (Table 3a-b) indicate that sellers' revenues increase by an average of 45%, while from Table 1 we have their costs in the energy market increasing by only 9%. Sellers are able to capture some of the buyers' surplus in the CDA energy market: there is more time 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.

**Table 3a. 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 |

| 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 |
| | 3 | 14.8 | 658.0 | -10.0 | 20.6 | 917.0 | 110.6 | 30.8 | 740.6 | -43.8 | 32.8 | 810.9 | 11.9 |
| | 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 |

**Table 3b Energy market prices and quantities**
**(price, quantity consumed, quantity imported (+) or exported (-)**
**Continued**

| 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 |

| 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 |

Is Genco profitability subject to improvement through portfolio bidding? It was clearly the case that some subjects would have been better off with the opportunity to bid generically (from their portfolio), then subsequently engage an expert system to schedule their generators. This was not particularly a characteristic of the treatments, but of the individual's ability to forecast his output and, given the complexity of his portfolio, manage his inter-temporal planning problem. This matter is further discussed below under recommendations.

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 which agents 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 9). Notice, however, that even though several lines are frequently up to constraint, there is only 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.

However, 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 didn't reflect the physical reality of the production cost differences, but are the artifact 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.

Are there any indications of market power? Do generators upstream from constrained lines raise their prices? We observed many instances of upstream generators raising their prices, especially in the CDA where they observe price formation in a sequence of inter-regional trades. In SB it is much riskier to attempt to anticipate and game the size of the congestion price differential.

For example, it was most often the case that the flow from Node 2 to 8 was contrary to the direction predicted by the equilibrium outcome. The local large Genco was often able to export, up to constraint, due to several coincident price manipulation attempts by Gencos in the heart of the network. While at node 7 at the other end of the network, the production cost was high enough and demand was strong enough to ensure the import of power. This augmented the ability of the generators in the heart of the network to raise their prices, and consequently they drew power from the Node 8 Genco. This also meant that the buyers were paying more than expected, especially in the heart of the network where congestion could be taken advantage of in whatever direction it arose. It was also the case that the closer a Genco was to the upstream end of a constrained line with a high price differential, the higher his price tended to rise above the competitive price. Thus gaming by Gencos upstream from constrained lines is common, as has already been documented in a simple 3-node network. (Backerman, Rassenti and Smith, 1998).

## 8. Further Study

We suggest two treatments which might prove fruitful for further experimentation.

Accommodate Interruptible Elastic Demand Side Bidding. In addition to the spike of must-serve demand, buyers should hold multiple resale value steps, defining prices and corresponding quantities that can be voluntarily interrupted at prices above each step. The wholesale buyer would be allowed to interrupt the demand at her discretion so long as the charge to the customer at each step is not above the specified price. Previously, we have shown that such an implementation of demand side bidding enables highly competitive prices and efficiencies in the 95-100% range to be achieved with as few as 6 sellers and 4 buyers. We envision such demand interruption technologies as a likely response to full peak pricing in spot markets. For example, in June 1998, price spikes of $400 to $500 per MWh were experienced in Georgia, Ohio, etc. on the first hot day. Such spikes, if they persist, are likely to help incentivize the implementation of interruption contracts. The purpose of this exercise would be to estimate the value, in terms of efficiency improvement, of such a development. We could also measure the redistribution of surplus that might occur.

In this treatment, individual wholesale buyers would each have an expert system for forecasting their own demand. Each buyer would be strictly accountable for covering his own demand with the bids he submitted: there would be no automatic Center imposed coverage in the reserve or adjustment markets. If a buyer purchased more power in the energy market than his load realization, all excess could be sold in the load adjustment market: if his bid acceptances were insufficient then he could purchase the short-fall in the load adjustment market.

Finally, each buyer participates in the reserve market by selling any interruptible capacity whose bid was accepted in the energy market. Such capacity is, of course, a direct substitute for spinning and quick start reserves in the event of a failure. Thus, the cost of supplying reserves is borne by those buyers whose must-serve demand requires reserves to be made available while the flexible demand buyers escape the cost of this service. In this manner reserves are supplied by the lowest cost sources in a free choice scenario.

Allow portfolio offers with smart scheduling assistance. This would enable the overall efficiency of system allocations to increase, and the tendency for prices to inflate because of inefficient scheduling would diminish. The Genco agent would be presented with a much simpler task in which he simply offered to sell generic power from a specific node. He would be required to forecast his own output in future periods, and would have a dynamic program algorithm automatically minimize his production costs for the scheduling horizon, once it was informed of the contractual outcomes of each energy market.

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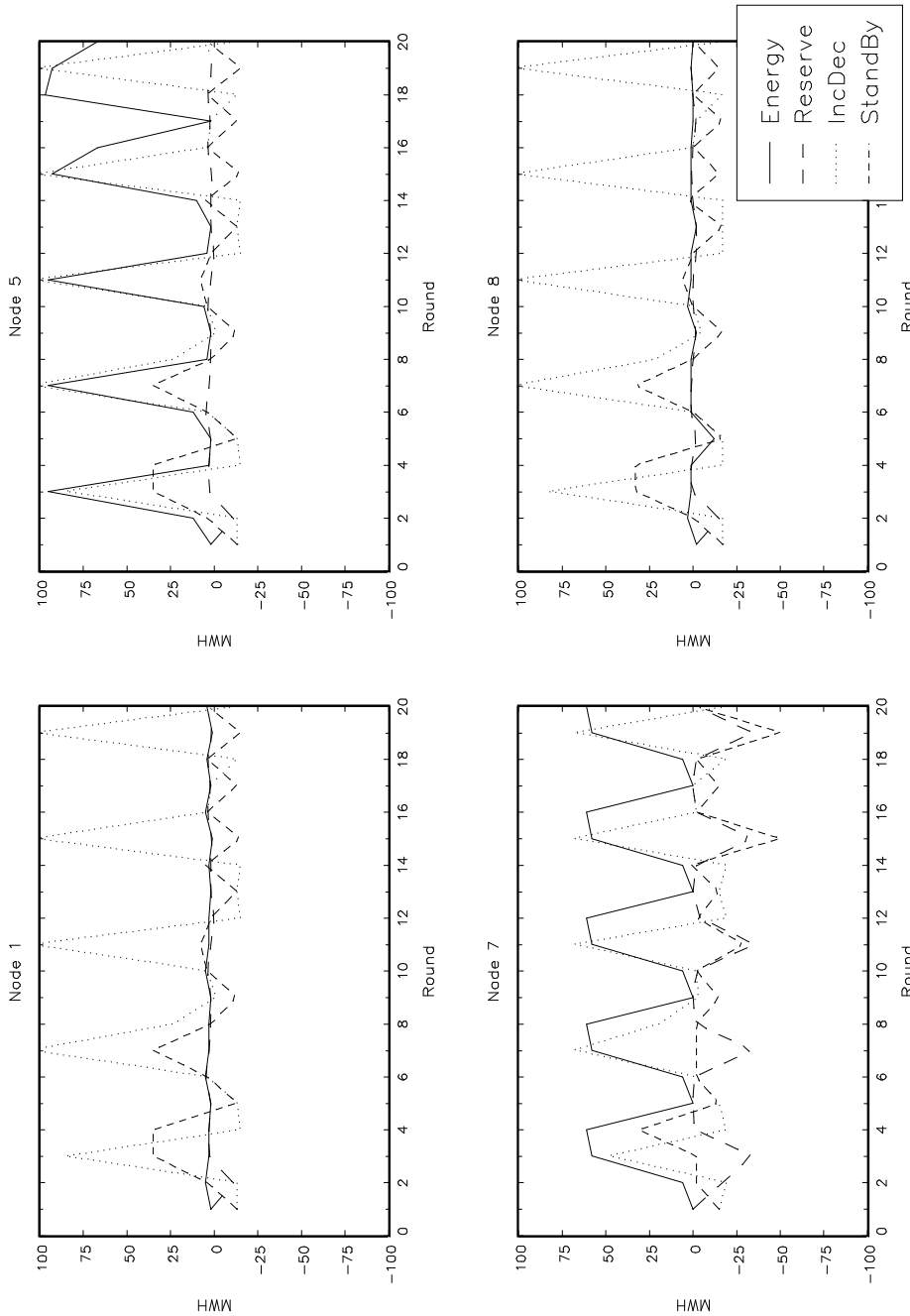


Figure 10a: Price series SB (All dummy Buyers).

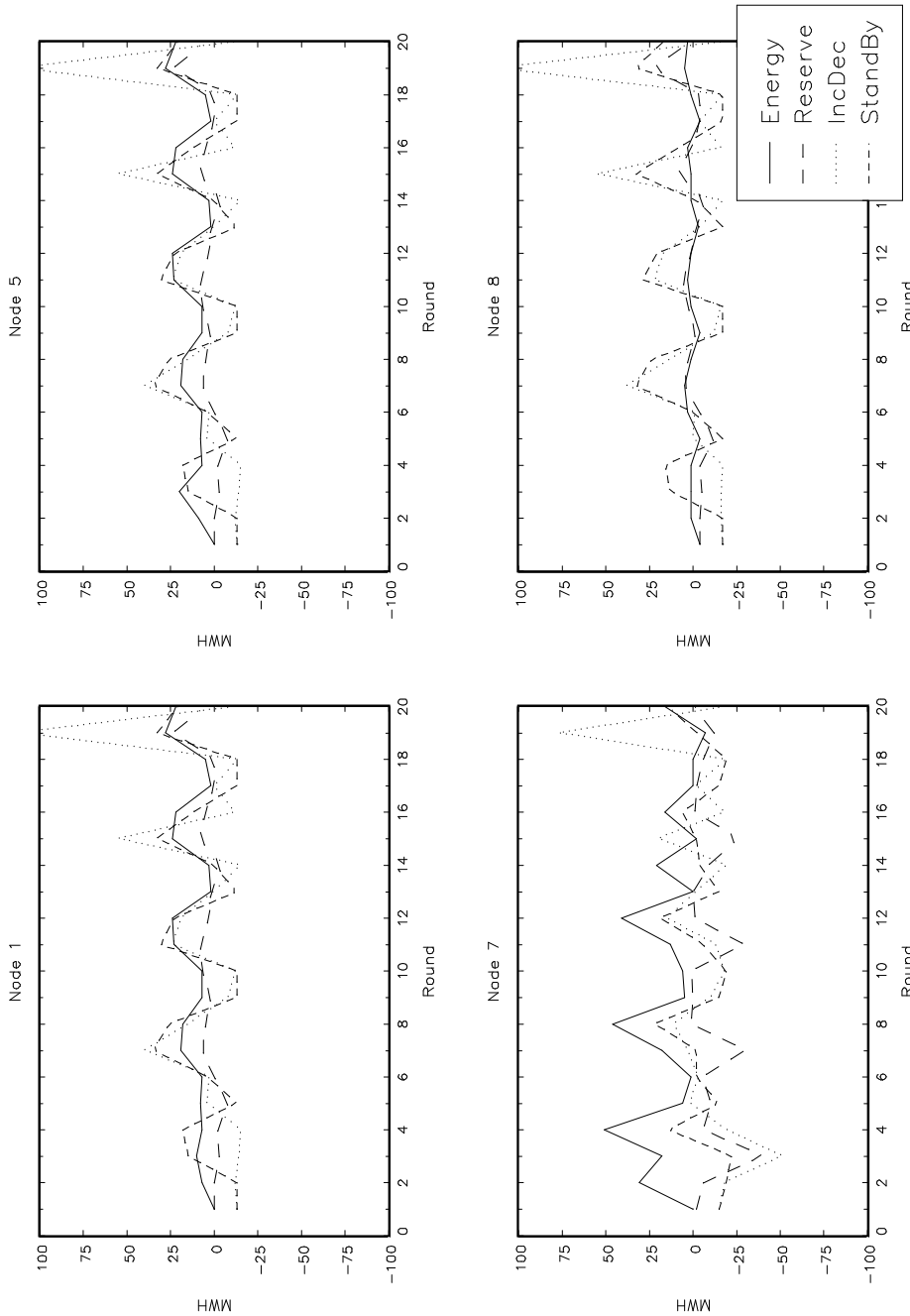


Figure 10b: Price series SB1

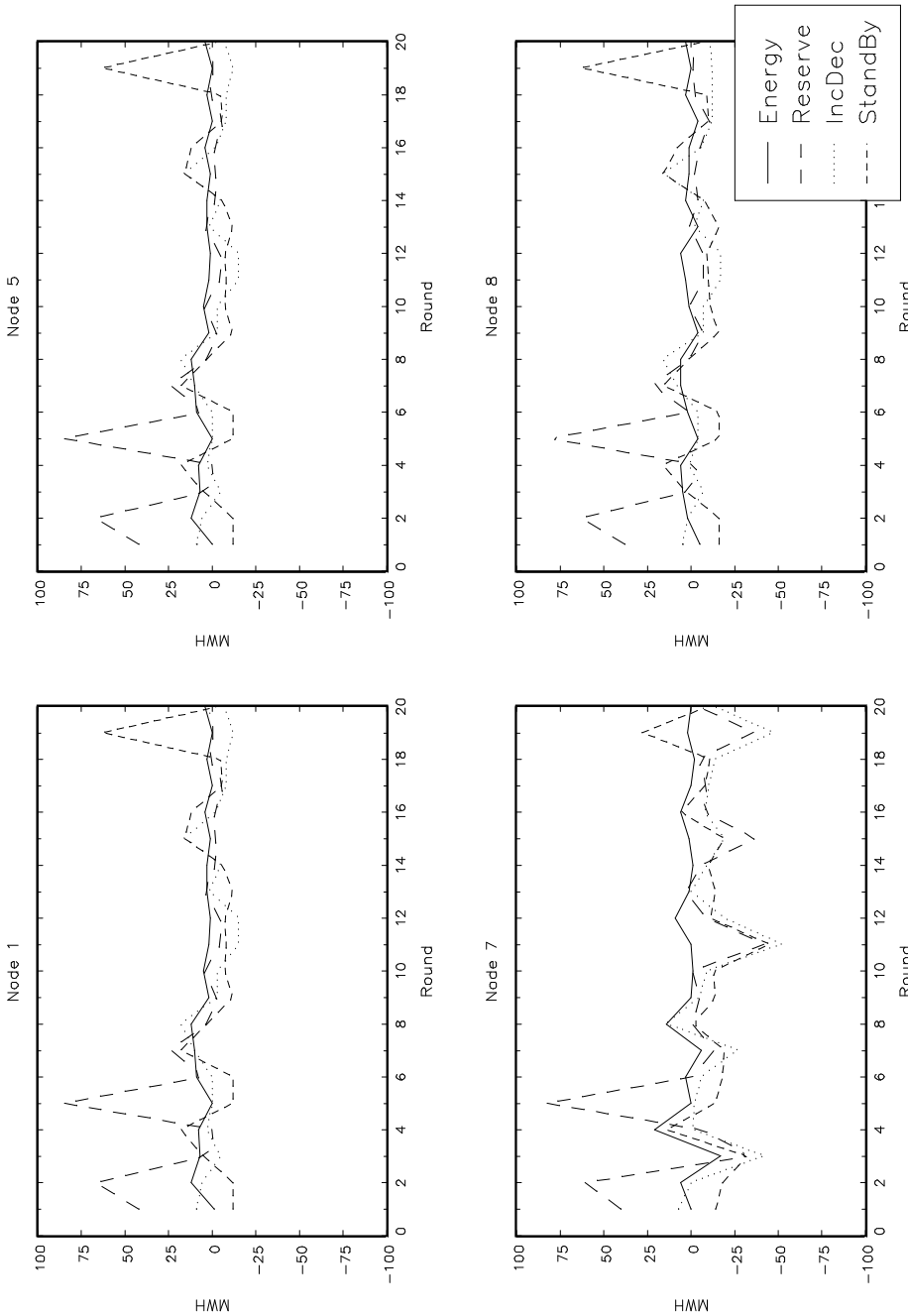


Figure 10c: Price series SB2

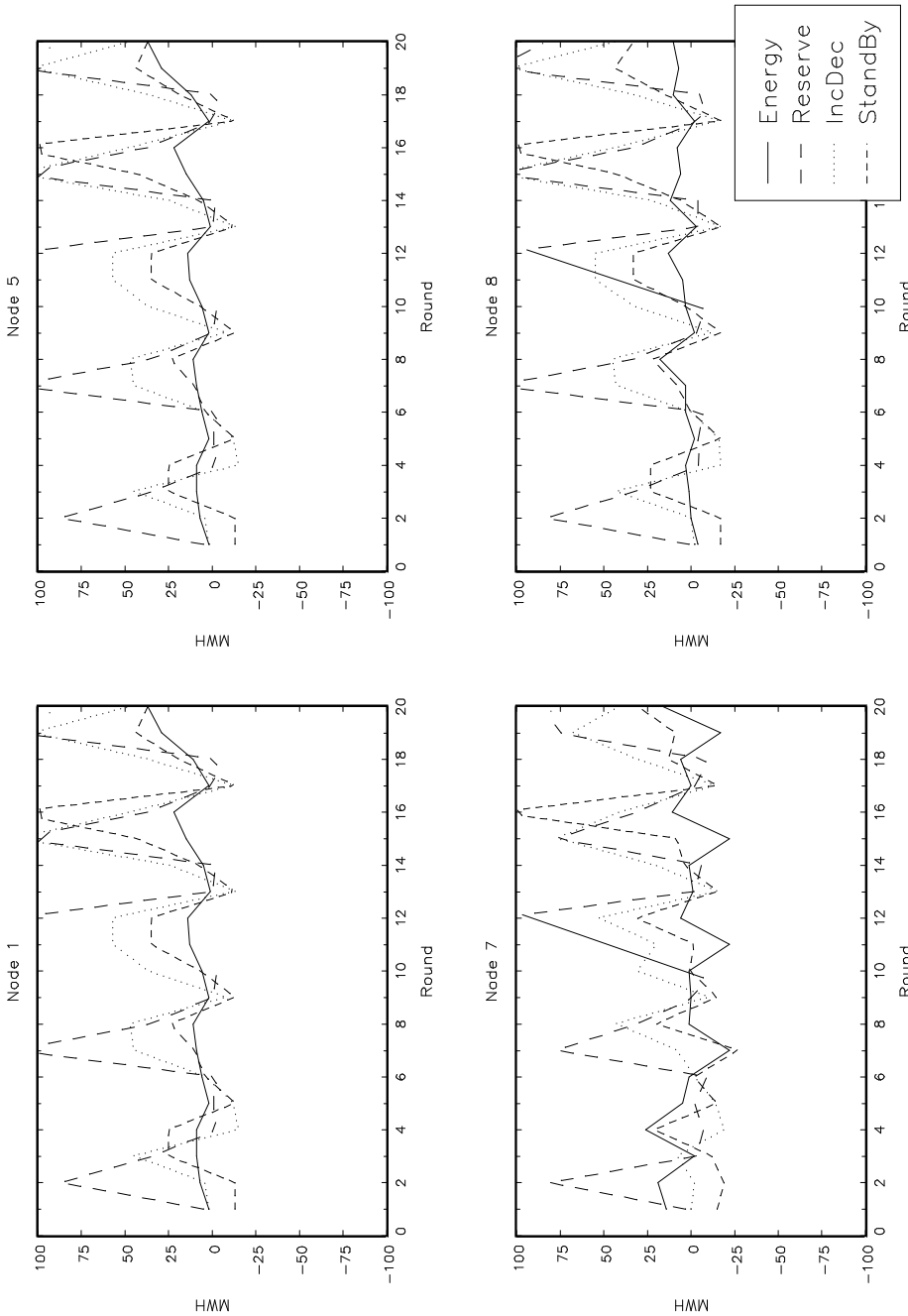


Figure 10d: Price series SB3

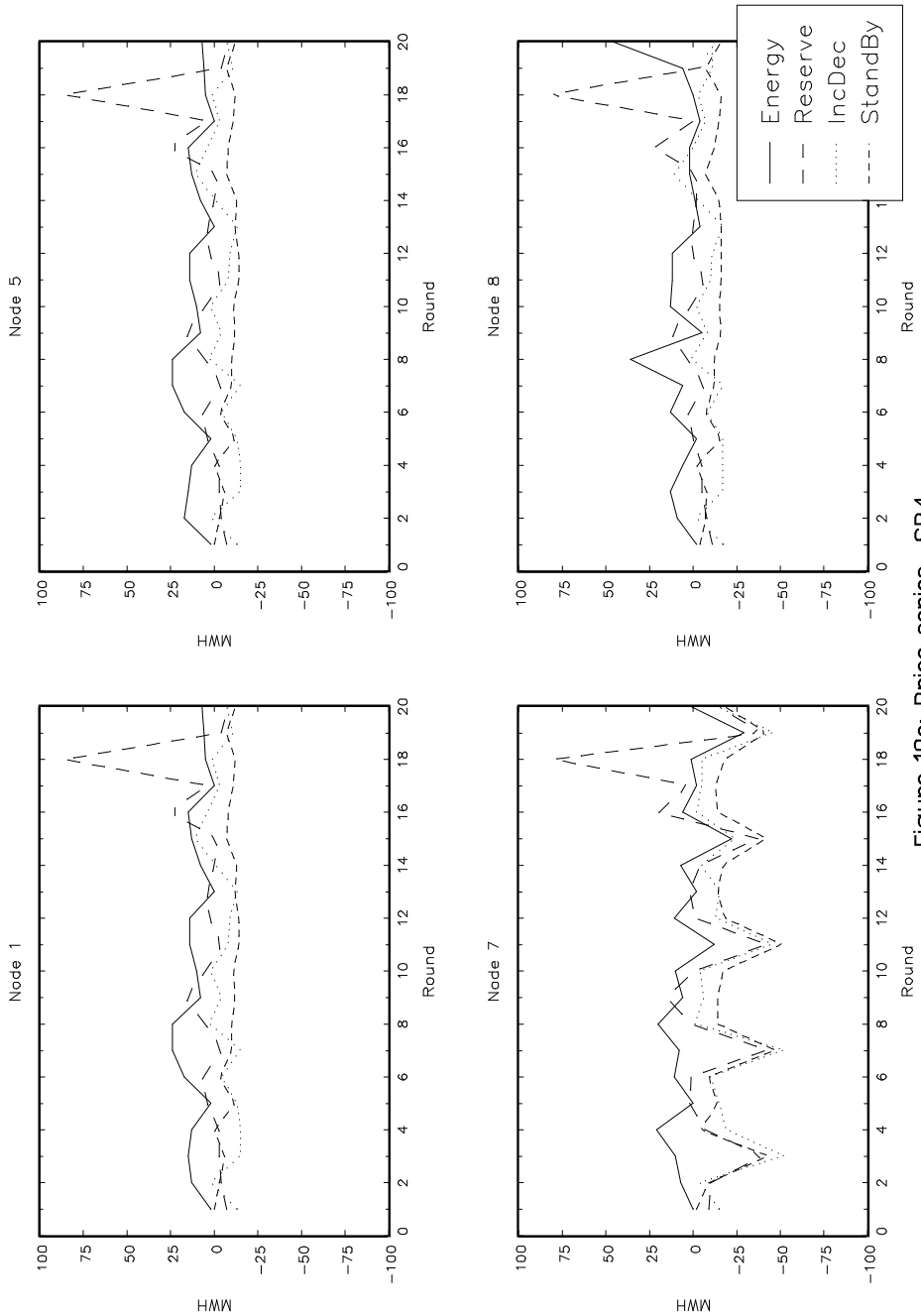


Figure 10e: Price series SB4

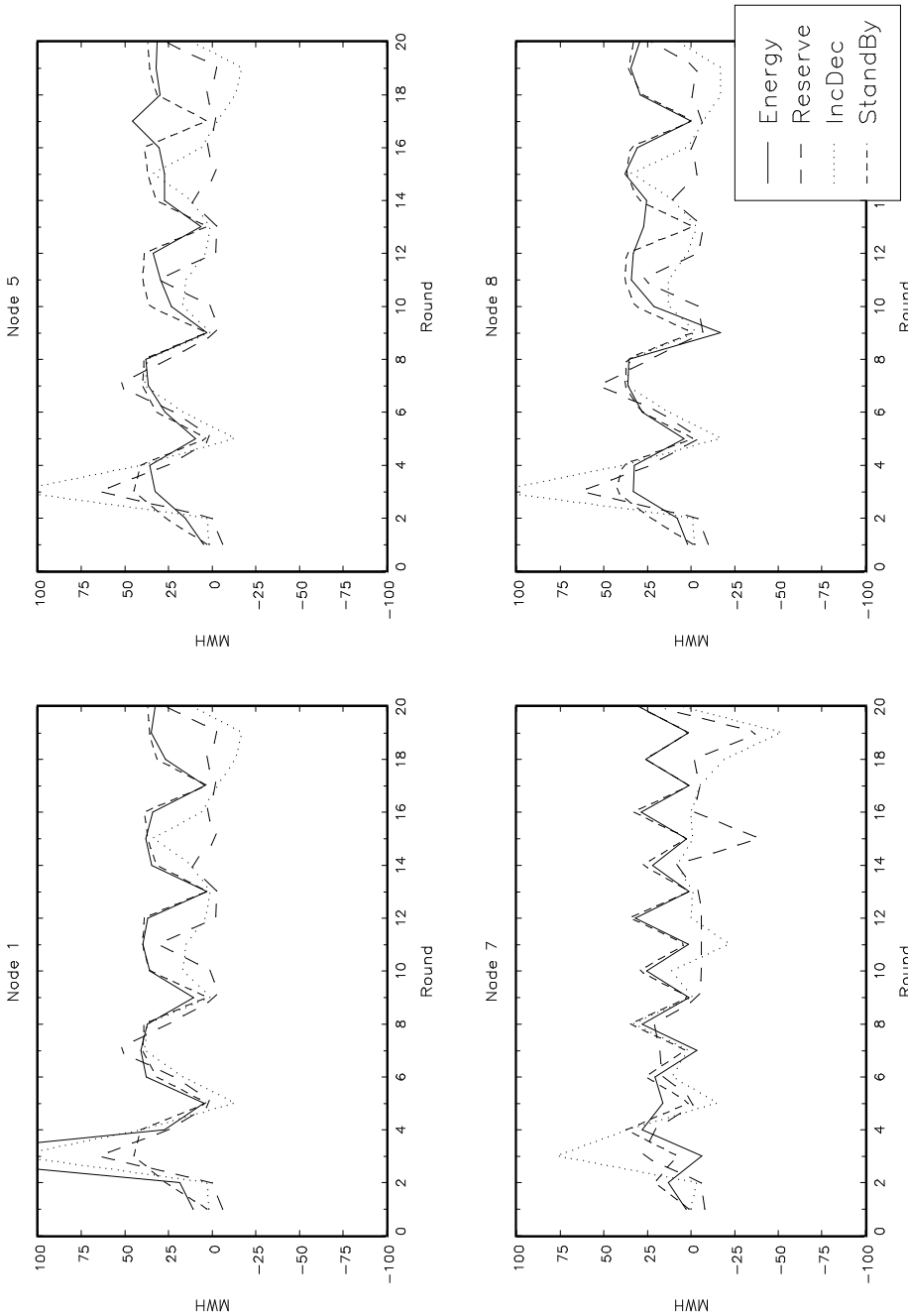


Figure 10f: Price series CDA1

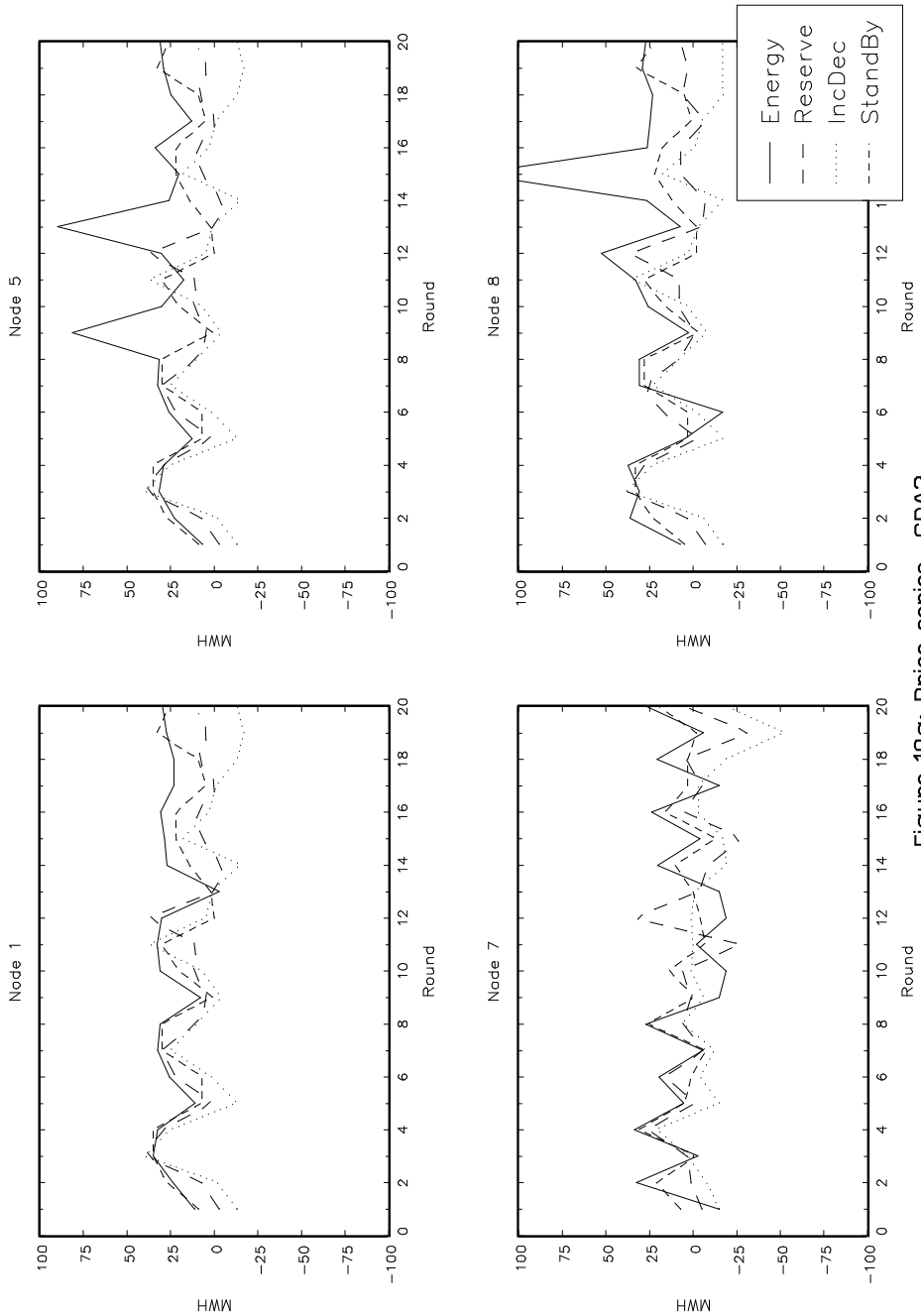


Figure 10g: Price series CDA2

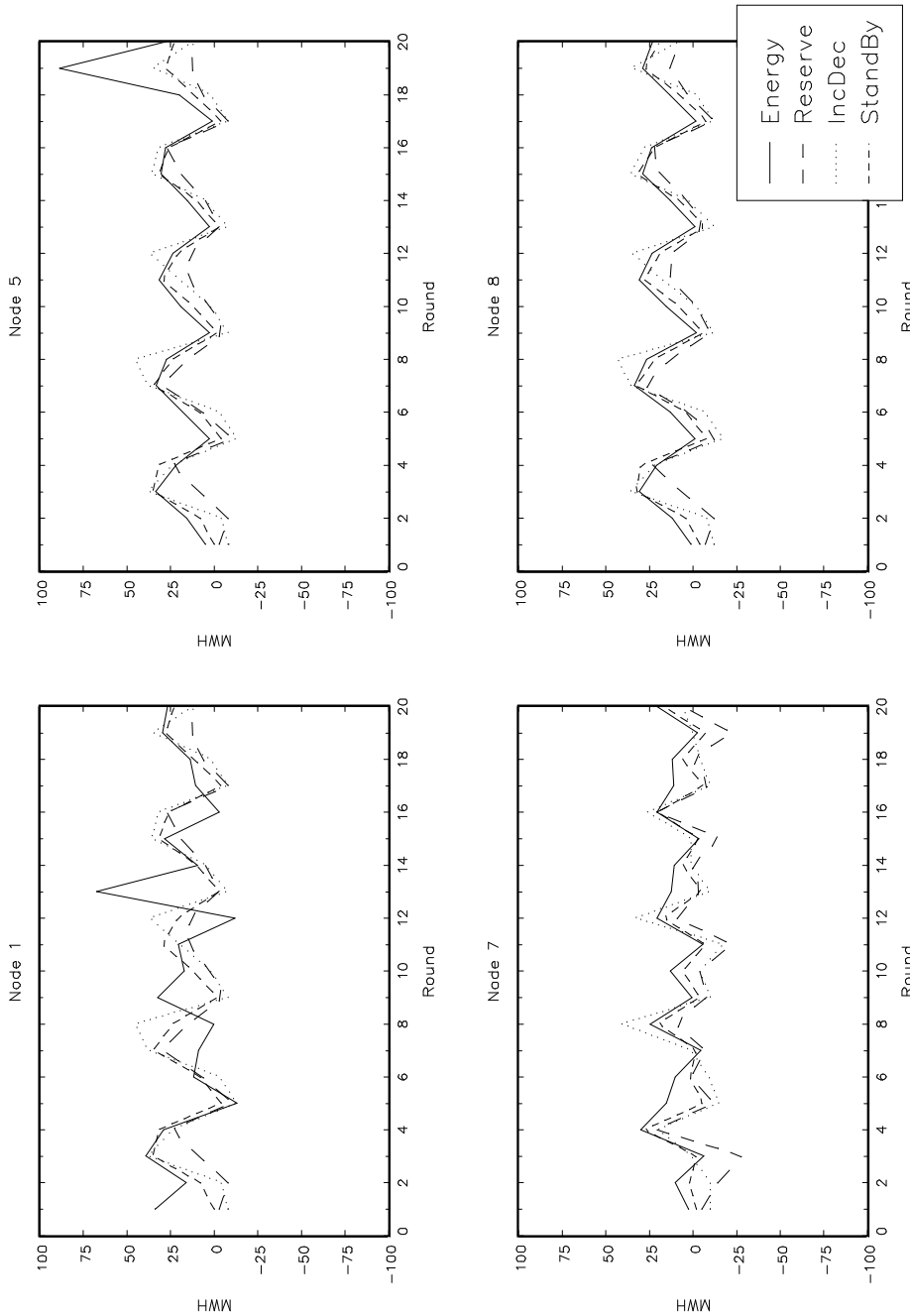


Figure 10h: Price series CDA3

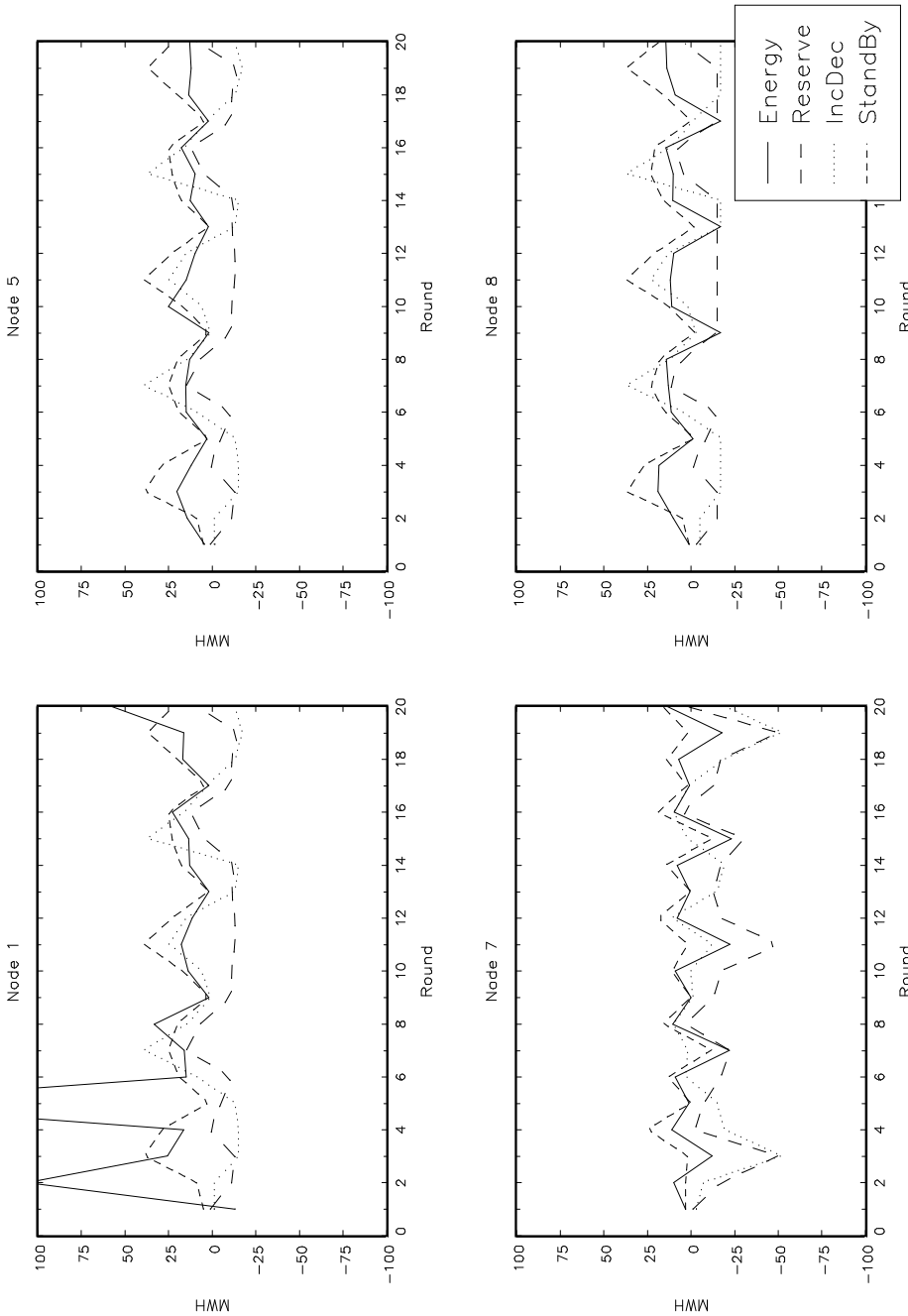


Figure 10i: Price series CDA4