# Dependence of Generation Market Power on the Demand/Supply Ratio: Analysis and Modeling

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**Abstract:** In an electricity market with a power-pool structure, total generation capability and forecasted demand are the critical factors for generators attempting to strategically bid into the market or to exert their market power. Some power plants might be under their maintenance schedule and/or forced outage. Electricity demand generally increases during the high-temperature days. To diagnose, in advance, the existence of market conditions under which generators are able to exercise their market power, a forecasted demand and total available supply ratio is proposed as a possible index to indicate such conditions. This index is different from the Lerner and the HHI indices, which are standard in analysis of market power and market concentration. The forecasted information used here concerns demand and power plant status instead of generators' market shares and elasticity of demand. The New England market data is then analyzed to test the proposed index. Subsequently, this ratio is applied to formulate a generator's strategic bidding model which is aimed at explaining market dynamics.

**Keywords:** Electricity market, market power index, demand-supply ratio, strategic bid.

## I. Introduction

An electricity market has its own characteristics which are different from other commodity markets. Electricity cannot be stored. Demand for electricity is almost inelastic, and varies with seasons and daily weather. This may change in the future, as more systematic facilitation of retail competition is pursued. Supply for electricity also varies with time as a result of planned maintenance and forced outages, as well as a result of installing new plants and closing some older plants. Previous research (for example, [5], [11], and [13]) has shown that existing electricity markets such as the UK, California, and New England markets, are not perfectly competitive and that generators have some market power.

Previous studies concerning the market power issues provide several indices, such as the Lerner index and the $HHI$ index, used to identify the existence of market power. Both Lerner index and $HHI$ assume that the market shares and elasticity of demand in a market of interest are known. However, in an electricity market in which energy trading via a power pool by bidding processes from suppliers and customers occurs in advance, information about the elasticity of demand, market shares, and market clearing prices is unlikely to be known before bidding takes place. Hence, the Lerner index and the $HHI$ might not be directly applicable.

Therefore, we propose a simplified method to detect a market condition which encourages generators to exert their market power in advance, by taking into consideration both the available generation capacity or total supply and the demand level. We suggest that a demand-supply ratio or a supply-demand ratio is a key to indicating such a condition. Once this condition does exist, generators might be able to use it to strategically bid into the market and reap their extra profits in daily trading, and they might learn to game in the market when this condition is omitted. Generally, not only generators could benefit from detecting this condition, but a regulator could also notify this condition ahead of time and try to prevent generators from "making" high market clearing prices.

## II. An overview of market power indices

The term "market power" refers to an ability of a firm (or a group of firms, acting jointly) to raise prices above the competitive level without a rapid loss of an ability to sell [1]. Similarly, market power is an ability to profitably maintain prices above competitive levels (or marginal cost) by restricting output below competitive level [8]. Two well-known methods are widely used as a measure of market power. The first method is a so-called *Lerner index,* which measures the proportional deviation of price at the firm's profit-maximizing output from the firm's marginal cost at that output [1]. The Lerner index is defined as the following:

$$L_i = \frac{P_i - mc_i}{P_i} = \frac{1}{\epsilon_i^d} \qquad (1)$$

where $L_i$ is the Lerner index for firm $i$; $P_i$ and $mc_i$ are price and marginal cost at the firm's profit-maximizing output, respectively; and $\epsilon_i^d$ is the elasticity of demand seen by the firm. From eqn (1), the larger the Lerner index, the higher the deviation from the marginal cost. One can observe that the higher the elasticity of demand, the smaller the index, which means that the price is closer to the competitive price. Theoretically, the Lerner index includes the effect of other fringe firms' elasticity of supply in the form of the market clearing price $P$.

The second index, generally used to determine the market concentration[1], is a so-called *Herfindahl-Hirschman*

[1]This index is used by the Department of Justice and the Federal Reserve in the analysis of the competitive effects of mergers, for example see [4], [7].

*index HHI*, which is defined as:

$$HHI = \sum S_i^2, \quad \sum S_i = 100\% \tag{2}$$

where $S_i$ is market shares of each firm in a market. $HHI$ ranges between 0 and 10,000. $HHI = 0$ refers to a market with a monopoly, while $HHI = 10,000$ refers to a competitive market. The inverse of thedu -k du an $HHI$ measures an effective number of firms in a market. For a market comprised of $n$ equal-sized firms or firms with market shares $S_i = 1/n$, $1/HHI$ equals $n$.

## III. The New England Market

We use the New England market (NEPOOL) as our case study. This market is a pool-type market, which opened on May 1, 1999. Market participants with positive net generation capability bid to sell the electricity to the Independent System Operator (ISO). Customers of the pool buy electricity[2] from the pool without bidding. In this paper we mainly focus on the market for energy, in which generators submit their energy bids one day in advance for the next day dispatch (at 12.00 pm today for a schedule starting at 1.00 am tomorrow). The ISO schedules power producers to operate by applying the total cost minimization criterion. Hourly market clearing prices, and hourly total scheduled generation or hourly demand are posted for public information [16]. In addition, forecasted demand and (forecasted) total available generation capacity are also available four days in advance. The (planned) maintenance schedule of participating generators is posted publicly as well.

From the testimony submitted to the Federal Energy Regulatory Commission (FERC) entitled "New England Pool (NEPOOL): Market Power Analysis," [9] the New England market is workably competitive[3]. According to NEPOOL, the markets for all products are moderately concentrated, and for those few products and time periods the markets are more highly concentrated. NEPOOL claims that the significant excess capacity increases competitiveness, and argues also that entry of new generation would mitigate market power [15].

To verify the claim by NEPOOL, let us observe the actual market clearing prices obtained from the New England ISO [16] for four months (May to August) in Figure 1.

Let us also observe average operating expenses of hydroelectric, nuclear, fossil steam, and gas turbine and small-scale power plants made available by the Department of Energy [14] listed in Table I.

[2]Seven products including energy, automatic generation control (AGC), ten-minute spinning reserve (TMSR), ten-minute non-spinning reserve (TMNSR), thirty-minute operating reserve (TMOR), operable capacity, and installed capability (ICAP) are traded.

[3]Workable competition is not a perfect competition. It is an explicit recognition that in markets with relatively free entry and a lack of explicit collusion, consumers are made as well off as they are likely to be, since government interference in these markets is more likely to decrease welfare than to increase it [10].

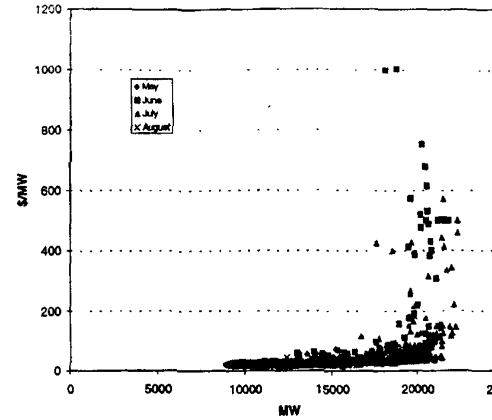


Fig. 1. Market Clearing Prices and Demand in the NEPOOL market (May to August, 1999)

Average operating expenses for major US. investor-owned electricity utilities, 1993-1997 (mills per KWh)

| Plant Type | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|
| Nuclear | 21.80 | 20.86 | 20.39 | 20.65 | 24.80 |
| Fossil Steam | 22.97 | 21.80 | 21.11 | 21.25 | 21.34 |
| Hydroelectric | 6.47 | 7.43 | 5.89 | 5.95 | 5.73 |
| Gas Turbine and Small Scale | 40.38 | 32.16 | 28.67 | 40.64 | 32.94 |

TABLE I

AVERAGE OPERATING EXPENSES FOR MAJOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES, 1993-1997 (MILLS PER KWH)

In addition, the total generation capacity[4] in each type[5] of available technology is listed below:

July 1999: Summer season net claimed capacity

| Plant Types | HD | HW | PS | F | N |
|---|---|---|---|---|---|
| Capacity (MW) | 652.1 | 882.0 | 1684.5 | 9038 8 | 4342.6 |
| % of Total Capacity | 2.8 | 3.8 | 7.2 | 38.8 | 18.6 |
| Plant Types | CC | D | G | GF | J |
| Capacity (MW) | 2541.6 | 105.6 | 684.4 | 2524.5 | 837.1 |
| % of Total Capacity | 10.9 | 0.5 | 2.9 | 10.8 | 3.6 |
| Total (MW) | 23293.3 | | | | |

TABLE II

JULY 1999: SUMMER SEASON NET CLAIMED CAPACITY

One can see in Figure 1 that market clearing prices fluctuate over a wide range, particularly when demand exceeds 19,500 MW. Although the average marginal expenses presented here are not updated and there are more than four types of plants in the NEPOOL, one can speculate that the market prices during the high demand level (exceeding 19,500 MW) are very unlikely to reflect the

[4]Data presented in this table, the Summer Season Claimed Capacity, the month of July 1999, is excerpted from [16].

[5]Unit Categories: CC-Combined Cycle, D-Diesel, F-Fossil, G-Gas, GF-Gas or Oil, HD-Daily Hydro (Normally No Pondage), HW-Weekly Hydro (Pondage), J-Jet Engine, N-Nuclear, and PS-Pumped Storage.

system marginal cost[6]. Moreover, although one might argue, as shown in [10], that no market is perfectly competitive, in order to judge whether market power exists, one should compare the actual market outcome to the imperfect situation of the regulated condition of that market. However, as observed, some hourly prices during months of June and July went above 100% of the most expensive marginal operating expenses shown in Table I. From this observation we are convinced that strategic bids from generators are likely to happen in the New England market. Subsequently, market conditions which tend to allow generators to exert their market power will be identified in the next sections.

## IV. Supply and Demand in Electricity Markets

In this section we explain the effect of supply and demand levels on the imperfect condition in an electricity market by using a simple market set-up. This market set-up is aimed to mimic the New England market. The model includes a group of generators with limited generation capacity. Lack of demand-side bidding is formulated by making the assumption of having an inelastic load. In addition, to simplify our analysis, we ignore the effect of transmission constraints and the start-up or shut-down costs.

### *A. A market with constant marginal-cost generators*

Demand $Q_{L,t}$ at time $t$ in the market is assumed to be inelastic and time-varying. A market of interest consists of three generators with different constant marginal cost $\{mc_1 = c_1 > mc_2 = c_2 > mc_3 = c_3\}$ and the same generation capacity $q_m$. Suppose we consider only the net load and net generation capacity of market participants trading electricity in a power pool[7]. Two examples are analyzed (as shown in Figure (2)). In the first example (Figure (2:A), the total generation capacity $Q_T = 3q_m$. Two scenarios are considered:

1. The maximum forecasted demand is 80% of total generation capacity, $2q_m < Q_{L,t} < 3q_m$. In this case, all generators will be scheduled to operate no matter how high their bidding prices are. The generator with the most expensive marginal cost, and also generators with cheaper marginal cost, can raise their bidding prices (theoretically) to infinity. Note that a generator is not required to know other generators' marginal costs[8].
2. The maximum forecasted demand is 60% of total generation capacity, $Q_{L,t} < 2q_m$. In this case, only two generators are sufficient to serve the load. With no collusion, in principle, two cheaper generators could raise their bidding prices no more than the highest marginal cost $c_1$ [6].

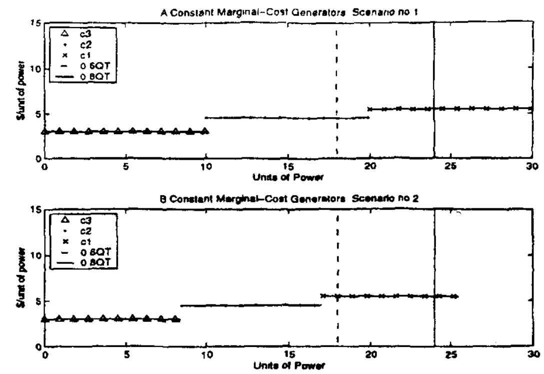


Fig. 2. A Market with Constant Marginal Cost Generators

In the second example (Figure 2:B), the capacity of each generator is reduced by 5% of total generation capacity ($0.05Q_T$), hence, total available generation capacity $Q_R = 0.85Q_T$.

1. The maximum forecasted demand is 80% of total generation capacity, $2q_m < Q_{L,t} < 3q_m$. In this case, all generators will be scheduled to operate no matter how high their bidding prices are[9].
2. The maximum forecasted demand is equal to 60% of total generation capacity ($0.6Q_T$). All generators have to be scheduled during the maximum demand period. This allows all generators, especially the most expensive generator, to raise their bidding prices in an unlimited manner.

This example explains why a generator can increase its bidding price easily when demand is high, and why generators are able to game in the market easily when plants are on maintenance schedule[10].

### *B. A market with linear marginal-cost generators*

Next, we analyze a market in which generators have a linear operating-cost function and limited generation capacity, and one generator cannot supply the maximum demand. Assume also that bids submitted to the market are a linear supply function. A generator is able to bid strategically according to different methods as shown in Figure 3. The first strategy is to shift the slope of marginal-cost function[11] (Figure 3:A). The second strategy is to shift the marginal-cost curve upward and either shift or not shift the slope (Figure 3:B).

For given total available capacity, if a single generator bids by shifting its slope from marginal-cost function and is scheduled during a high-demand day, it will gain extra profits. Similarly, when total available generation

[6]See Appendix A.

[7]In this paper we assume that bilateral contracts from outside the pool of interest are subtracted, or no presence of bilateral contracts.

[8]If generators submit the same bidding prices, each generator's market share is equal to 33% (and the *HHI* equals 3333.33). If they bid differently, two cheapest generators have the same market shares equals $\frac{q_m}{Q_L}$ and the other's market share equal to $\frac{Q_L - 2q_m}{Q_L}$.

[9]Although total generation capacity changes, the HHI could remain constant at HHI = 3333.33, if generators submit a similar bid.

[10]In addition, this example also shows that the *HHI* no longer provides the information that indicates gaming in this market.

[11]For example, see [13].

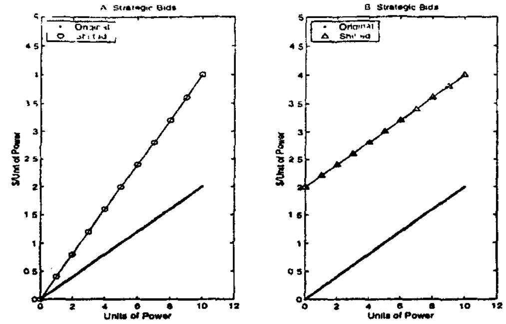

Fig. 3. A Market with Linear Marginal Cost Generators:Strategic Bids

capacity is reduced, generators could consider changing (shifting) their supply curves from the marginal-cost functions and gain extra profits. Hence, for the shifted supply function to be scheduled, demand in the market must be large or the surplus capacity (the difference between total capacity and forecasted demand) small.

Let generators have a limited capacity $q_m$, and linear marginal-cost functions of the form

$$mc = aq$$

where $mc$ refers to the marginal cost (dollars per unit power) of producing $q$ units of power[12].

If all generators bid at their marginal cost and their supply functions equal $p = aq$, where $p$ refers to the bidding price, the system supply function is

$$P = \frac{a}{n}Q$$

where $P$ refers to the market clearing price at the load level $Q$.

Suppose that $k$ generators ($k < n$) bid strategically to the market by shifting their bids upward $aq_m$ in the form of

$$p = aq + aq_m$$

One might ask a question concerning the number of k generators required to bid strategically in order to raise the market clearing prices given the forecasted demand equal to $Q_L$. The integrated supply function of $k$ generators is

$$P = \frac{a}{k}Q + aq_m$$

The total supply function is

$$P = \tfrac{a}{n-k}Q, \quad 0 < Q \leq (n-k)q_m$$

$$P = \tfrac{a}{k}(Q - (n-k)q_m) + aq_m, \quad (n-k)q_m < Q \leq nq_m$$

If these $k$ generators are scheduled, they produce equally $\bar{q} = \dfrac{Q_L - (n-k)q_m}{k}$. The profit from bidding strategically exceeds the profit from marginal-cost bidding namely,

$$\frac{1}{2}a\bar{q}^2 + aq_m\bar{q} > \frac{1}{2}aq^2 \tag{3}$$

where $q = \frac{Q_L}{n}$ refers to amount of energy scheduled to each generator when all generators bid at their marginal cost. It follows from eqn (3) that

$$\frac{1}{2}\Big[\frac{Q_L - (n-k)q_m}{k}\Big]^2 + aq_m\Big[\frac{Q_L - (n-k)q_m}{k}\Big] > \frac{1}{2}a\Big(\frac{Q_L}{n}\Big)^2 \tag{4}$$

This condition is true when $Q_L > (n-k)q_m$. Let us next define $R = \frac{Q_L}{nq_m}$. Hence,

$$R = \frac{Q_L}{nq_m} > \Big(1 - \frac{k}{n}\Big) \tag{5}$$

and

$$\frac{k}{n} > 1 - R \tag{6}$$

The intuition behind the expression in eqn (6) is that when $R$ increases, or demand increases while generation capacity is held constant, the minimum $k$ to satisfy eqn (6) decreases. This means that a number of generators required to strategically bid to (game in) the market decreases. Similarly, when the available generation capacity ($nq_m$) decreases, or $R$ increases, the minimum $k$ decreases. However, the formulation in eqn (6), does not guarantee that profits from strategic bids will increase. We then further analyze this example in more details.

Rewrite eqn (4) as:

$$[Q_L - (n-k)q_m]^2 + 2\frac{k}{n}q_m[Q_L - (n-k)q_m] > \Big(\frac{k}{n}\Big)^2 Q_L^2 \tag{7}$$

Further, dividing eqn (7) by $(nq_m)^2$, and replacing $\frac{Q_L}{nq_m}$ by $R$, leads to,

$$1 - \frac{(R - \sqrt{(}R^2+1) + 1)}{(2 + \sqrt{(}R^2+1))} < \frac{k}{n} < 1 - \frac{(R + \sqrt{(}R^2+1) - 1)}{(2 + \sqrt{(}R^2+1))} \text{ and } \frac{k}{n} > 1 - R \tag{8}$$

Eqn (8) shows the relationship between a demand-supply ratio and a number of firms strategically bidding to the market.

Consequently, the results from the constant marginal-cost and the linear marginal-cost market set-ups lead us to conjecture that, for a power producer who desires to exert its market power, information relating to forecasted demand and total available capacity is significant.

[12]Note that the cost function equals: $C(q) = \frac{1}{2}aq^2$.

## V. THE PROPOSED MARKET POWER INDEX: DEMAND-SUPPLY RATIO

In contrast to using forecasted demand and available generation capacity as shown in the previous sections, to calculate the Lerner index and the $HHI$ to measure market power, one must consider the following:

### A. Demand Elasticity

In general, elasticity of demand is not known in advance. Although historic data can provide a guideline, due to variation in demand over time, this data might not be generalizable. Hence, it is complicated to determine the Lerner index. Note that lacking the knowledge of demand elasticity has no direct effect on calculating the $HHI$.

### B. Market Shares

Market shares are also complicated. There are at least two possible ways to calculate market shares. First, generator $i$'s market share indicates what percentage of electricity is generated by the generator $i$[13][9]. Second, generator $i$'s market share is the percentage of generator $i$'s capacity compared to the total system capacity[14]. When either one of these definitions are used, the information from the market will not be complete to determine the market shares. For using the first definition of market shares, the information of each generator's dispatch schedule is not public. Generator $i$ knows its share but not the shares of the others. For using the second definition of the market shares, one would need the information about individual maintenance which is typically not available; instead, only total maintenance schedule is a public information. Total generation capacity of a generator reduces if some units are on maintenance schedule. Hence, the information used to compute the Lerner and the $HHI$ by the second method is not complete.

### C. Market Clearing Prices and Marginal Costs

The Lerner index can be calculated by using price, at the profit-maximizing output [1], and marginal cost. The available prices are the Ex Post prices $P$. However, if a generator is an intra-marginal unit, market clearing prices are higher than the bidding prices. The Lerner index of this generator will be misleading. In addition, in the real market in which a power producer bids to sell its power in advance (a day in advance in a day-ahead market), yesterday's market clearing prices can be irrelevant to today's market clearing price if the demand patterns of both days are very different. Consequently, the Lerner index is not valid to predict market condition for the next trading day

We have already elaborated on the reasons why the available indices to measure market power tend not to be valid in an electricity market such as the NEPOOL market. To understand when generators exert their market power in the electricity markets and the consequence due to an existence of gaming, we propose to define an alternative index indicating market power. This index is named a *demand-supply* ratio $\Gamma$[15], and defined as:

$$\Gamma = \frac{Q_L}{Q_A} \tag{9}$$

where $Q_L$ is the forecasted demand, $Q_A$ is available generation capacity in the market[16].

If a market consists of many generators, when $Q_L \rightarrow Q_A (\Gamma = 1)$, generators can (implicitly) collude behaving like a monopoly. On the other hand, when $Q_A \rightarrow \infty$, or the market is perfectly competitive (all generators are price-takers), $\Gamma = 0$. Therefore, the higher the ratio or the closer the conditions to the monopolistic market, the more possibility for a generator to exert a market power. The smaller the ratio or the closer the conditions to the competitive market, the less possibility for a generator to exert market power.

An alternative index is a supply-demand ratio $\Delta$, defined as:

$$\Delta = \frac{Q_A}{Q_L} \tag{10}$$

Note that $\Delta$ approaches 1 for a market condition leading to a monopolistic case and increases when there is more competition (more capacity) in the market. Index $R$ compared with index $\Gamma$ is more sensitive to the variation in each generator' capacity than $\Gamma$. However, $\Gamma$ is more sensitive to the demand variations than $\Delta$ [17].

## VI. THE NEW ENGLAND MARKET: ANALYSIS

As mentioned earlier, generators can determine the demand-supply ratio or supply-demand ratio to detect if market conditions are convenient for exerting market power. The major factors accounted for the deviation of generation capacity from the net claimed capacity are the maintenance schedules and the imported energy from outside the area. These two factors change over time[18].

[13]Dr. Hieronymus [9] "The GEMAPS model simulates system operations, and determines, for each 2-hour period, which units are dispatched for energy ... These modeling outputs provide the basis for calculations which derive, for each product market, the market shares of each participant and the associated HHIs."

[14]If each generator has the same marginal cost function, and generators are rational, the generators should submit their bids such that they maximize profits. Consequently generators submit the same bids (such as generators in [11]). This results that generators have the same market shares calculated from both methods described previously.

[15]Similar to $R$ in eqn (5).

[16]Also, $\Gamma_m$ is defined as:

$$\Gamma_m = \frac{Q_{L,m}}{Q_A}$$

where $Q_{L,m}$ is the maximum forecasted demand. Forecasted demand varies in each hour, hence, in one day 24 $\Gamma$s are calculated (for each hour). If a generator submits a single bid for a single hour dispatch, $\Gamma$ of each hour can be used. On the other hand, if a generator submit a single bid for a one-day dispatch, $\Gamma_m$ might be used for simplification instead.

[17]See explanation in Appendix C

[18]For example, see appendix D.

In the next figure we show a relation between the demand-supply ratio and the market clearing prices. We perform the calculation of demand-supply ratio from the forecasted demand and available generation capacity, obtained by subtracting the generation scheduled for maintenance (Table III) and the interchange from the summer net claimed capacity. We assume here that the interchange during the entire months of May, June and July is equal to 2,400 MW[19].

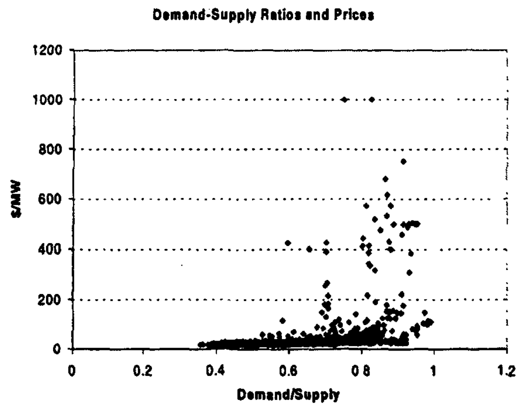


Fig. 4. Demand-Supply Ratio and Market Clearing Prices

The plot of the hourly (forecasted) demand-supply ratios and market clearing prices of May, June and July in Figure 4 shows that when the ratio is smaller than 0.8, market clearing prices tend to vary proportionally to this ratio. However, when the ratio exceeds 0.8, the proportionality is no longer valid. Therefore, the 0.8 ratio could be considered to be a good cut-off value for the current NEPOOL market.

## VII. Learning Model

Next, we attempt to apply our demand-supply ratio or $\Gamma$ index to elaborate on the market power issues. Because the energy trading occurs on a regular basis (hourly and/or yearly), to analyze bidding behavior and also gaming decision of generators, a dynamic model representing bidding decision is proposed. In our previous research [12], we have formulated a dynamic model representing a generator's bidding behavior. A generator is assumed to learn the market daily and to use the observed information to update its next bid. The result shows that in a three-generator market, generators learn the market so that they always submit strategic bids and reap extra profits by bidding (high) above marginal cost.

However, in our previous model, we assume that generators use only market clearing price information to construct their next bid. We neglected the important factors concerning the total available generation capacity and demand variation. Moreover, we assume also that load follows a weekly pattern. To fulfill the previous model by including the total generation capacity and demand information using our proposed index in this paper, an upgraded dynamic model representing a generator's bidding behavior is formulated.

The difference between the new model and the previous one is that this new model consists of two parts. The first part is designed for a so-called normal operating condition or the low demand-supply ratio[20] $\Gamma$. The other part represents the switching behavior when the market allows generators to (tacitly) bid excessively. This part represents that the market is in a so-called critical condition[21]. The learning process is preserved during normal and critical operating conditions. In our market model, we assume that the marginal cost functions of generators are not necessarily public. During the normal condition, the learning process is proposed to have the following form (eqn (11)):

$$X_n[k+1] = X_n[k] + B_n[k]U_n[k] \tag{11}$$

The tomorrow's bid $X_n[k+1]$ is today's bid $X_n[k]$ plus the adjustment due to generators' learning from today's market represented by $B_n[k]$ and $U_n[k]$, which includes market clearing prices, forecasted demand and available generation capacity.

The critical condition is another learning process which is represented in the following form:

$$X_c[k+1] = X_c[k] + B_c[k]U_c[k] \tag{12}$$

Hence, the overall model is in the form:

$$\begin{aligned} X[k+1] = {} & \beta[X_n[k_n] + B_n[k_n]U_n[k_n]] + \\ & (1-\beta)[X_c[k_c] + B_c[k_c]U_c[k_c]] \end{aligned} \tag{13}$$

In eqn (13), $k_n$ and $k_c$ are used instead of $k$, because of the switching between the two conditions. When the switching occurs, the previous condition is considered as an initial condition to the current condition. $\beta$ indicates the condition in which a generator switches its bidding behavior.

Although the ratio derived in previous sections has a closed-form solution (as shown in eqn (8)), this solution is valid only in the case when generators have the same marginal cost functions and capacity limits. Moreover, the strategic bidding is to shift the marginal-cost function upward. In the other market-setup, this formula is not applicable. In addition, there exists an uncertainty due to the deviation of actual and forecasted demand, and unplanned outages. Consequently, a decision of each

[19]The best publicly available information is based on the (assumed) average of interchange equal to 2,400 MW (around 60% of (supposed) maximum transfer limits, NYPP = 1100 MW, NB = 700 MW, and HQ = 2200 MW).

[20]Because, as mentioned previously, the existing markets are imperfect, the normal operating condition no longer implies that market clearing prices equal system marginal cost or $\Gamma = 0$.

[21]For example, in the New England market, the Operating Procedure 4 is exercised [16].

generator to choose between $\beta = 1$ or $\beta = 0$ is an estimation problem in a stochastic process. This is the subject to future research.

## VIII. Conclusion

In this paper we analyze electricity markets power pool-type with respect to the conditions that allow power producers or generators to exert their market power. The effects of transmission constraints are not studied. Only shorter-term effects of maintenance and forced outages are analyzed. The analysis could be generalized to include the longer-term effects. A simplified method to indicate such conditions, proposed here, is to determine a forecasted demand-supply ratio ($\Gamma$). This method is applicable to an electricity market in which energy trading by bidding processes occurs in advance and only information about forecasted demand and total generation capacity is publicly available. This ratio is used to analyze when generators are likely to exert their market power. The higher the ratio, the more tendency for generators to game in the market. This method is very useful for both generators who want to game in markets and a regulator who wants to prevent gaming. This ratio is further applied to formulate a dynamic bidding model containing two separate processes. One process refers to a market during periods with low tendency to gaming, and the other process refers to a market during periods with high tendency to gaming.

## IX. Appendices

### A. Appendix A

Assume that all hydroelectric power, fossil-fuel, nuclear and gas turbine or small-scale (such as jet-engine and combined-cycle) power plants have marginal cost equal to the 1997 average operating expenses shown in Table I. The system marginal cost function should look like the function shown in Figure 5.

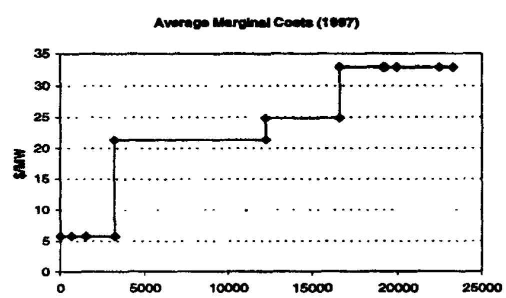


Fig. 5. An (Average) Marginal Cost Function of the NEPOOL market

### B. Appendix B

From eqn (7),

$$[Q_L - (n-k)q_m]^2 + 2\frac{k}{n}q_m[Q_L - (n-k)q_m]$$

$$> (\frac{k}{n})^2 Q_L^2 \qquad (14)$$

Further, dividing eqn (14) by $(nq_m)^2$,

$$[\frac{Q_L}{nq_m} - (1-\frac{k}{n})]^2 + 2\frac{k}{n}[\frac{Q_L}{nq_m} - (1-\frac{k}{n})] > (\frac{k}{n})^2(\frac{Q_L}{nq_m})^2$$

and replacing $\frac{Q_L}{nq_m}$ by $R$,

$$[R - (1-\frac{k}{n})]^2 + 2\frac{k}{n}[R - (1-\frac{k}{n})] > (\frac{k}{n})^2(R)^2$$

leading to,

$$(R - (1-\frac{k}{n}))(R - (1-\frac{k}{n}) + 2\frac{k}{n}) > (\frac{k}{n})^2(R)^2$$

Let next $(1 - \frac{k}{n}) = W$, or $\frac{k}{n} = 1 - W$. This results in

$$(R-W)(R-W+2(1-W)) > (R)^2(1-W)^2$$

$$(\frac{(R-W)}{(1-W)} + 1)^2 > R^2 + 1$$

Hence,

$$\frac{(R-W)}{(1-W)} + 1 > \sqrt{(}R^2+1), \text{and}$$
$$\frac{(R-W)}{(1-W)} + 1 < -\sqrt{(}R^2+1)$$

Hence,

$$1 - \frac{(R - \sqrt{(}R^2+1) + 1)}{(2 + \sqrt{(}R^2+1))} < \frac{k}{n} <$$
$$1 - \frac{(R + \sqrt{(}R^2+1) - 1)}{(2 + \sqrt{(}R^2+1))}, \text{and} \qquad \frac{k}{n} > 1 - R$$

### C. Appendix C

1) Sensitivity of $HHI$ (Assume that the $HHI$ is calculated from the total capacity (the second definition).)

$$HHI = \sum_{j=1}^{n} S_j^2 = \sum_{j=1}^{n}\{\frac{q_{m,j}}{(\sum_{i=1}^{n} q_{m,i})} \times 100\}^2$$

Hence,

$$\frac{\partial HHI}{\partial q_{m,j}} = 2\frac{q_{m,j}}{(\sum_{i=1}^{n} q_{m,i})^2} \times 100^2 - 2\frac{\sum_{i=1}^{n}(q_{m,i} \times 100)^2}{(\sum_{i=1}^{n} q_{m,i})^3}$$

$$\frac{\partial HHI}{\partial q_{m,j}} = 2\frac{(100S_j - HHI)}{(\sum_{i=1}^{n} q_{m,i})}$$

Hence, when $(\sum_{i=1}^{n} q_{m,i})$ is very large, although $S_j$ is large, $\frac{\partial HHI}{\partial q_{m,j}}$ is small.

In addition, $\frac{\partial HHI}{\partial Q_L} = 0$ where $Q_L$ represents system load.

2) Sensitivity of Demand-Supply Ratio Index

$$\Gamma = \frac{Q_L}{Q_A} = \frac{Q_L}{(\sum_{i=1}^{n} q_{m,i})}$$

Hence,

$$\frac{\partial \Gamma}{\partial q_{m,j}} = -\frac{Q_L}{(\sum_{i=1}^{n} q_{m,i})^2}$$

In addition,

$$\frac{\partial \Gamma}{\partial Q_L} = \frac{1}{(\sum_{i=1}^{n} q_{m,i})}$$

3) Sensitivity of Supply-Demand Ratio Index

$$\Delta = \frac{Q_A}{Q_L} = \frac{(\sum_{i=1}^{n} q_{m,i})}{Q_L}$$

Hence,

$$\frac{\partial \Delta}{\partial q_{m,j}} = \frac{1}{Q_L}$$

In addition,

$$\frac{\partial \Delta}{\partial Q_L} = -\frac{(\sum_{i=1}^{n} q_{m,i})}{Q_L^2}$$

### *D. Appendix D*

The maintenance schedule as shown in Table (III).

**A sample of maintenance schedule data (1999)**

| Dates | 5/01 -5/07 | 5/08-5/14 | 5/15-5/21 | 5/22-5/28 | 5/29-6/04 | 6/05-6/11 | 6/12-6/18 |
|---|---|---|---|---|---|---|---|
| Maintenance Capacity (MW) | 5100 | 5700 | 4800 | 4300 | 3300 | 3400 | 3600 |
| Dates | 6/19-6/25 | 6/26-7/02 | 7/03-7/09 | 7/10-7/16 | 7/17-7/23 | 7/24-7/30 | 7/31-8/06 |
| Maintenance Capacity (MW) | 2600 | 2300 | 1400 | 800 | 800 | 500 | 0 |

TABLE III

A SAMPLE OF MAINTENANCE SCHEDULE DATA

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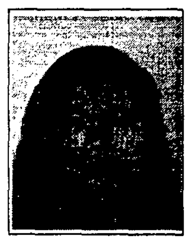

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