On the Complexity of Market Power Assessment in the Electricity Spot Markets

Poonsaeng Visudhiphan (IEEE student member), Marija D. Ilic (IEEE Fellow), and Mrdjan Mladjan*

Abstracts: In this paper we point out various factors which should be taken into consideration when assessing market power in the evolving electricity markets. Of particular interest are the effects of the electricity market design rules, type of software employed when computing electricity clearing price, and the generation technology-specific costs, such as start up and shut down costs. In this paper we propose a method of estimating a benchmark price which accounts for these factors unique to electricity markets; when assessing market power the actual price is compared to this benchmark price. The pros and cons of assessing market power using such aggregate benchmark price and/or more direct analysis of individual bids are illustrated using the New England market data.

Keywords: unit-commitment, economic dispatch, competitive market, (horizontal) market power, marginal centralized dispatch, and decentralized dispatch.

1. INTRODUCTION

An approach based on comparing market prices to the estimate short-run marginal costs or benchmark prices [2, 5, and 11] may not be sufficiently accurate to quantify market power exertion by the generators. A more credible measure is needed to capture the unique characteristics of electricity markets, which require that demand and supply balance in real time. With very few economically viable options to store electricity, this balancing means turning on and off many power plants in order to follow temporal demand variations. The interplay of market rules in place, software employed to select bids and the physical constraints inherent in various generating technologies creates continuously changing conditions. This approach obtained without taking these effects into consideration may generally lead to erroneous results. To start with, credible measures of market power should take into consideration that generating units cannot be turned on and/or off instantaneously to respond to demand variations and that there is an inherent start up and shut down cost. This frequently results in a counter-intuitive scenario characterized by lower prices during high demand, and vice versa. These inter-temporal factors play a critical role in characterizing a bid of a generator and also affect its strategic behavior [2 and 3]. Moreover, they impact the optimal selection of bids as demand varies over time.

Given this general observation, we propose in this paper an enhanced method for quantifying market power, which does account for the major unit-commitment (UC) related effects of interest. The method is based on using a simplified deterministic UC approach to identify benchmark prices from historic data and known load levels. This is computationally manageable and could be implemented for monitoring market power. (A much more complex approach would be to quantify market power under uncertainties in real time.) We, furthermore, analyze the challenge of differentiating between the effects of UC constraints and costs on the observed price of electricity, on one hand, and the strategic behavior, on the other.

2. MARKET MECHANISMS AND ALGORITHMS FOR BID SELECTION

In the United States two qualitatively different types of spot market designs have evolved over time. The first market is California (CA) style in which market rules

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require specification of convex supply functions, independent of the type of generation technology. The bids assume that the plants would be available at the hour for which the supply function is specified. It is up to the bidders to account for these constraints and to internalize their costs into generally time varying supply functions for bidding day ahead; this decision making process at a bidder's level could be viewed as decentralized unit commitment [1 and 6]. Not having to account for physical constraints when the bids are selected and the ECP is determined, allows for a straightforward stacking up of the supply functions, much the same way as the aggregate price is found in the economics textbooks (such as [7]). The software tool supporting this process is known as a simple economic dispatch (ED) method.

The second type of markets is an outgrowth of the centralized power pools in the Northeast US, such as Independent System Operators (ISO) of New England (NE), New York, and Pennsylvania-New Jersey-Maryland. Here the bidders explicitly provide generation specific constraints and costs, and the ISO uses centralized unit commitment to select bids so that total cost is minimized subject to operating constraints and costs [1].

Under the highly idealized assumptions, the two designs should result in the same ECP and total cost. However, we emphasize that even under such assumptions, the exercise of assessing strategic bidding should be carefully conducted as a function of how is the ECP obtained, i.e. as a function of market mechanism and software used to obtain the ECP. One of the critical assumptions for the two methods to lead to the same result concerns the way of internalizing UC constraints and their costs by the bidders themselves. In the next two sections we analyze more closely how the bidders create their supply functions keeping in mind the type of market mechanism in place, even when everyone is a price taker.

3. Bidding to California Style Markets (Decentralized UC and Centralized ED)

The basic decision making problem facing a bidder into a market which does not explicitly compensate for the technology-specific costs is to decide on the hours when to sell electricity, the amount and price, taking into consideration its own start up and shut down constraints and costs. This is known as a decentralized UC problem, and its complexity varies depending if price is assumed to be known or not [1]. Moreover, depending if the bidder acts as a price taker or it attempts to influence the market price, the bids will be different.

We propose here that bidding prices submitted to the markets requiring a portfolio bid without UC constraints would be higher than marginal costs even in the perfectly competitive markets. To explain this, consider two markets with identical load and available generation capacity. For a day-ahead market, in the first market, market I, a generator submits a set of bids with only prices and quantity for the next 24 hours ($k = 1,\dots,24$), while in the second market, market II, a generator is required to submit a set of bids with UC constraints (for $k = 1,\dots,24$). Suppose also that both markets are perfectly competitive, in the sense that generators are price-takers. Let us consider only a deterministic UC problem, which assumes known prices[1].
To start with, the total cost (TC) of the bidder is incurred independent of the type of market, i.e..

$$TC = \sum_{k=1}^{\overline{K}} \{u_k \cdot c(q_k)\} + SU + SD \qquad 1)$$

On the other hand, total return (TR) to the unit participating in Market I is

$$TR^{I} = \sum_{k=1}^{\overline{K}} \{u_k^{I} \cdot p_k^{I} q_k\} \qquad 2a)$$

Similarly, total return to the unit participating in Market II is

$$TR^{II} = \sum_{k=1}^{\overline{K}} \{u_k^{II} \cdot p_k^{II} q_k\} + SU + SD \qquad 2b)$$

Therefore, total profit (TP) made by the unit participating in Market I is

$$TP^{I} = \sum_{k=1}^{\overline{K}} \{u_k^{I} \cdot (p_k^{I} q_k - c(q_k))\} - SU - SD \qquad 3a)$$

Similarly, total profit made by the unit participating in Market II is

$$TR^{II} = \sum_{k=1}^{\overline{K}} \{u_k^{II} \cdot (p_k^{II} q_k - c(q_k))\} \qquad 3b)$$

Here u_k indicates the operating status of a generator ($u_k = 1$ when on, $u_k = 0$ when off), p_k^{I} and p_k^{II} are market prices in Market I and Market II respectively, q_k is the minimum operating capacity (low-operating limit or LOL), and $c(q_k)$ is operating cost of producing q_k (it could include environmental costs). SU is the start-up cost incurred when a generator changes from an off mode to an operating mode, and SD is the shut-down cost incurred when a generator changes from an operating mode to an off mode.

Since demand and available generation capacity in Markets I and II are assumed to be symmetric, total competitive profit that a generator obtained from either market should be the same (a generator with the same technology and capacity should obtain the same profits) or

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[1] A similar, slightly more complex analysis could be provided for stochastic prices.

$$\sum_{k=1}^{\overline{K}} \{u_k^{II} \cdot (p_k^{II} q_k - c(q_k))\} = \sum_{k=1}^{\overline{K}} \{u_k^{I} \cdot (p_k^{I} q_k - c(q_k))\} - SU - SD \qquad 4)$$

It follows from Eqn (4) that if a generator is scheduled the same q_k (in both market scenarios), it is essential to bid in order to recover all incurred costs according to:

$$p_k^{II} < p_k^{I}, \text{ when } u_k^{II} \ \& \ u_k^{I} = 1. \qquad 5)$$

If a generator does not bid according to (5) it may end up not recovering the short-run SU and SD costs. This depends on the relative position of the generator within the aggregate supply curve. In the case the unit is an infra-marginal unit, it could recover its fixed cost (which is a long-term cost-recovery and not included in this analysis) as well as its costs incurred due to start-up and shutdown process. If the unit is a marginal unit, this unit could not recover its fixed cost and costs incurred due to start-up and shutdown process. Moreover, an extra-marginal unit could not recover its fixed cost. The potential marginal (and also extra-marginal) units would rather bid higher than their true marginal costs so that once they are scheduled to operate all incurred operating costs, including the SU and SD costs, are recovered. This does not imply market power exertion although generators intentionally bid higher than their marginal cost.

A. An example of unit commitment based bidding

Here we give a numerical example to illustrate the effects of UC constraints on decision to bid to be scheduled. Assume that a generator is a price taker and that it knows forecast demand and prices for the next trading period with 100% accuracy. In order to offer set of bids day-ahead for each hour $k = 1, \ldots, 24$, the unit needs to decide when it would be scheduled according to some criteria. If the criteria do not account for SU and SD costs, this amounts to solving a decentralized ED [4]. If the UC constraints are accounted for, this amounts to solving a decentralized UC [1]. Here we illustrate that, depending on which method is used, the decision to bid is quite different. In Fig. 1, anticipated profits received using decentralized UC and ED approaches, respectively, are presented. For illustration, marginal cost chosen equals to 48 $/MW, the start-up cost is1000$/hour, capacity is 50 MW, and the generator is in the off mode at hour 0, and it knows forecast prices shown in Fig 2. The start-up time of the unit is assumed to be 4 hours. When the UC constraints are accounted for, it is not optimal to turn the unit on for the first five hours, to be turned off again at the sixth hour. This is contrary to the plot in Fig 1 obtained when using ED. Therefore, to bid to a day-ahead market, a generator would increase the bidding prices so that it would not be turned on in the first five hours, and to be turned on during hour 19. These bidding prices are such that once the plant is turned on, the total SU costs are recovered (Fig. 2).

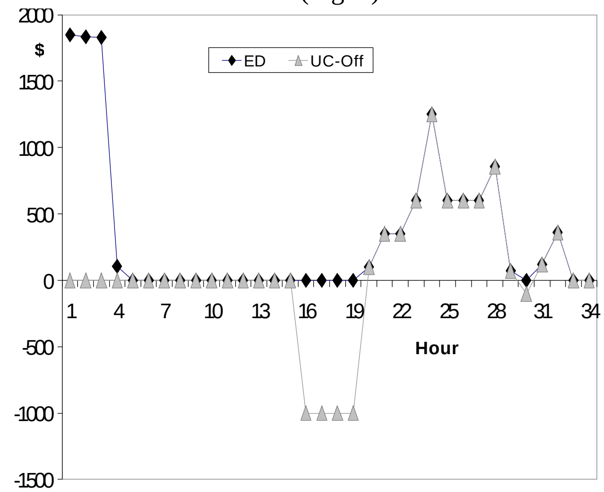

Fig. 1. Profits in each period obtained by assuming dispatch with no UC constraints or ED dispatch, and dispatch with UC constraints.

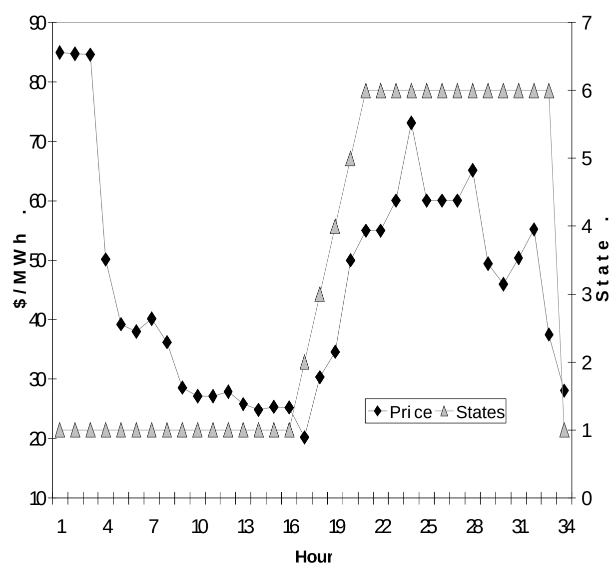

Fig. 2. Market prices and optimal state-transitions as a result of solving UC problem.

4. Bidding into New England Style Market (Centralized UC)

In contrast to the CA style market where the ECP is simply obtained by finding the intersection of the given demand and the aggregate supply curve (by solving a coordinated ED), the NE style market computes the ECP by accounting for SU and SD costs in a coordinated way. This implies that in order to reconstruct the actual ECP using publicly available bids, one should carefully assess the effects of technology specific bids on the resulting ECP. This is not the case in CA style market in which the technology specific constraints get internalized at a bidders' level. To illustrate the complexity of reconstructing the ECP in a market where the bids are publicly available (but without any technology data), the hourly market prices are determined for given demand by using a coordinated ED method. Any publicly available data obtained from [13] (such as LOL, high-operating limit (HOL), uplift quantity due to transmission constraints, and net interchange) were used to account for the dispatch rules[2]. However, since the SU and SD costs are not publicly available, it is impossible to run coordinated UC program and reconstruct the actual price. Figs 4 and 5 show observed market prices and calculated prices, given total net demand (actual demand minus uplift capacity and plus net interchange) for June 1, 2000 and March 26, 2000. Net demand for both dates are shown in Fig. 3. From Figs. 4 and 5, one could observe that an ED-based computation of the ECP using available bid data is not sufficiently accurate to reconstruct the hourly market prices. Moreover, the calculated prices could be higher or lower than observed market prices.

To start with the observed market prices could be higher than the calculated prices using ED because of effects of the UC constraints (including SU and SD times and costs), and furthermore, because of the presence of bilateral contracts. According to the unique NE market rule in [13], when external bilateral contract purchases are committed and the five-minute real-time market price (RTMP) is lower than the hourly dispatch price of any external bilateral purchase, the RTMP is set at least equal to the most expensive external purchase price. Additional important factors are related to the characteristics of the market supply functions (technology mix, steepness of the supply function, and to the load factor (maximum and minimum daily load, rate of load variation).

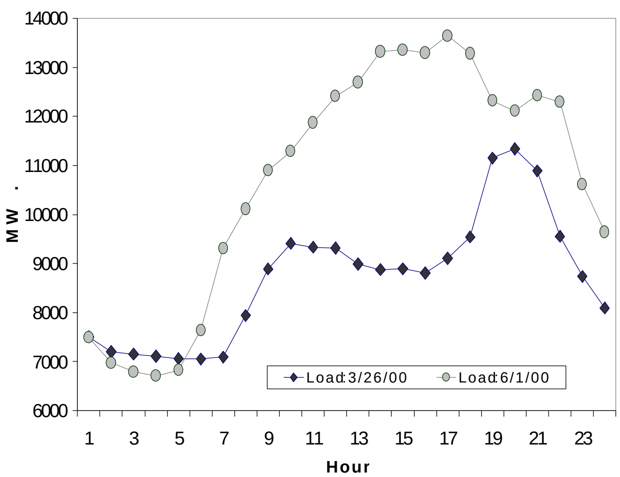

Fig. 3. Net demand during March 26, 2000 and June 1, 2000

2 Algorithms for accounting for other effects, such as transmission constraints imposing out of merit scheduling are not discussed in this paper. They are accounted for, whenever available.

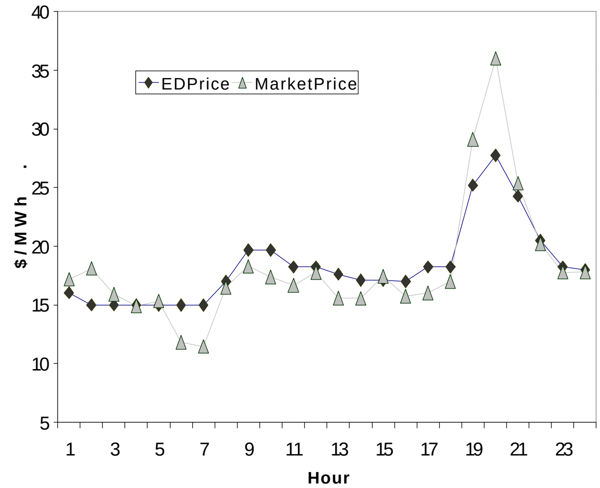

Fig. 4. Observed market prices and calculated prices for March 26, 2000

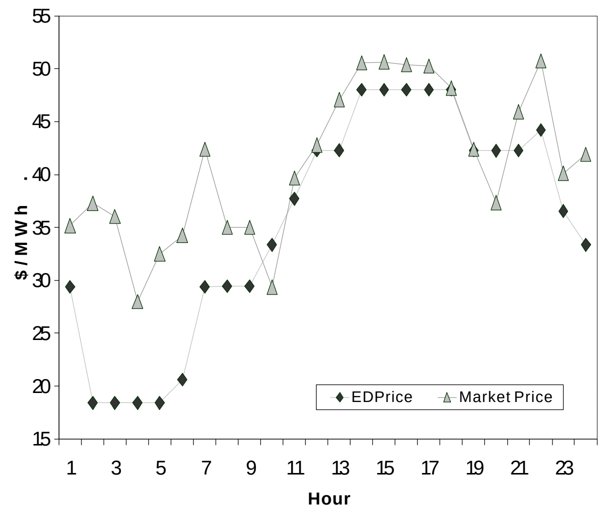

Fig. 5. Observed market prices and calculated prices for June 01, 2000

If there are many (marginal) units with expensive SU costs, marginal-cost prices plus additional charges due to SU costs tend to be high. Steep aggregate supply functions in a market with high load factor (maximum to minimum load), prices could deviate substantially from marginal. This is because very flexible units, which might have high marginal costs, would be called on to operate as the load varies unexpectedly. The load profile will affect the frequency of turning-on and turning-off units which are needed to respond to time-varying load increments. As a result of all these effects jointly market prices could be also be lower than the ED based prices, as one could see from Figs. 4 and 5. Generally, market prices resulting from coordinated UC calculations could be lower than marginal-cost prices due to inter-temporal effects related to SU and SD times and their costs. This is true even when there is no strategic bidding. The generators simply lower their bids in some periods to avoid being turned off.

5. PROPOSED BENCHMARKING METHOD FOR ASSESSING MARKET POWER

When attempting to assess strategic bidding and exertion of market power in the evolving electricity markets, one should keep in mind complexities created by the UC type constraints, as discussed in previous Sections 2, 3 and 4. A particular challenge comes from not being able to differentiate between the offset of the actual ECP from the ECP computed using publicly available bids and a handful of rules unique to each market. As pointed out in Section 4, it is impossible to run a coordinated UC program using publicly available data to compute the ECP, particularly because the SU and SD times and costs of the bids are not publicly known. This means that the offset between the actual ECP and what is computable using publicly available data in a NE style market would always exist. As a consequence, it will not be possible to clearly differentiate the effects of UC-type constraints from the effects of strategic bidding.

In order to systematically assess strategic behavior while take into consideration UC constraints and costs, we propose two possible methods for benchmarking. One method is similar to the measures used in [2, 5, and 11] but it accounts for the UC constraints when estimating the benchmark accounting price. The second method is based on the comparison of generator bids to their costs after accommodating for UC constraints (such as [10]).

A. Benchmarking aggregate prices for market power assessment

Based on the unique issues related to the UC constraints and costs, described in Sections 2, 3, and 4, we account for the fact that the benchmark aggregate price is obtained differently in the CA style markets from that in the NE style markets. The following reflects these differences.

1. Market power assessment method in the CA style markets

The benchmark ECP in a CA style market characterized by the use of ED for computing electricity prices is obtained as follows:

- For each bidding period, d, (a one-day period for a day-ahead market) and for each generator, determine cost functions including SU and SD costs (internalized costs).
- Select bids using coordinated ED method from the obtained cost functions and given load during that period (d).
- Determine benchmark prices resulting from this computation for each d over T. These prices are the proposed benchmark prices.
- Compare market prices to the benchmark prices, and determine existence of market power based on the difference of market prices and benchmark prices.

2. Market power assessment method in the NE style markets

The benchmark ECP in a NE style market characterized by the use of centralized UC for computing electricity prices is obtained as follows:

- Define the market power assessment interval, T, (i.e. one month or one season).
- For each bidding period, d, (a one-day period for a day-ahead market), select bids using a coordinated UC to meet given demand in this period.
- Determine benchmark prices resulting from this computation for each d over T. These prices are the proposed benchmark prices.
- Compare the average of market prices to the average of benchmark prices during T, and determine existence of market power. Depending on the magnitude of difference between the average of market prices and the average of benchmark prices, one could assess the degree of market power exertion. This method is similar to [2, 5 and 11], excepting that the benchmark prices account for the UC constraints.

B. Direct assessment of market power based on cost/bid comparison

If a generator in the market is asked to submit the bids that include SU and SD costs, bidding prices and quantities could be different from marginal-cost bids. On the other hand, if these costs are accounted for separately (not included in the bids), bidding prices and quantities should be close to the marginal-cost bids. Hence, one should note that *when SU and SD costs are included in bidding prices, in the competitive market bids of each generator should be close to its internalized costs*. Also, on the other hand, *when SU and SD costs are not included in bidding prices, in the competitive market bids of each generator could be close to marginal costs*.

These proposed methods could be implemented by the entity in charge of computing ECP, a system operator, for example. Those who only have publicly available information in current ISOs cannot exactly implement these, since they require knowledge of the SU and SD costs, as well as the SU and SD times, generally not available outside an ISO.

6. POSSIBLE STRATEGIC BEHAVIOR WITH UC CONSTRAINTS

In the actual markets, strategic bidding to reap more profits by the generators is inevitable. Suppose generators are required to submit a bid with the UC constraints specified. In this case potential strategic bids could result from the following:

1) Lowering bidding prices in some low-demand hours and increasing bidding prices in other high-demand hours

This strategy is likely to be practiced by a generator avoiding to be shutdown and to restart again. Moreover, for an infra-marginal unit, decreasing bidding prices increases probability of being scheduled.

2) Submitting inexpensive bidding prices for part of capacity and expensive bidding prices for the rest of capacity. A generator partially withholds its capacity by bidding high prices and maintains its tendency to be scheduled to operate by bidding inexpensive prices of some bidding blocks. This will benefit a generator if load deviation is substantial. In this situation, the probability of being scheduled when demand increases is high.

3) Lowering bidding quantity in some low-demand hours and increasing bidding quantity in other high-demand hours

Lowering bidding quantity, particularly LOL, while keeping bidding prices unchanged and lower than marginal-cost price (of forecast demand) would increase probability of being scheduled. It was noted in [9] that the probability mass function of prices for a given demand is shifted to the right (higher prices) when infra-marginal generators submit bidding quantities smaller than their maximum available capacity. Hence, at the same bidding price, lowering bidding quantity increases the chance of being scheduled.

The effect of LOLs can be explained by using the following hypothetical example. Assume that the perfectly inelastic electricity demand curve were placed to the right hand side from the point where S1 and S2 start coinciding (in our example, the point with coordinates (6,3)). Let the demand curve correspond to x=7. This makes the price result in aggregate supply curve S1resulting in S2, the same P1=P2=4. The total revenue is 7*P=$7*4.

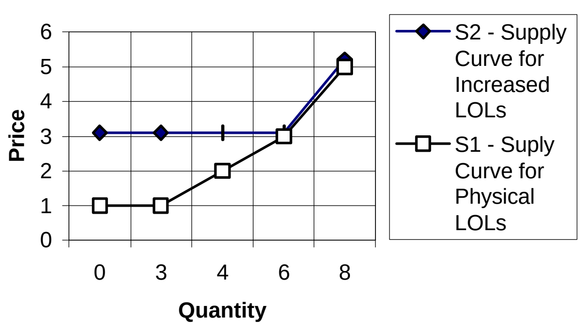

Fig. 6. Implications of Changing LOL on Anticipated Revenue

Assume that the demand curve is to the left-hand side of the point where S1 and S2 start coinciding (6,3). Let the demand curve correspond to x=3.5. This makes P1=1.5 and P2=3. Thus, the revenues achieved corresponding to S1 and S2 supply curves differ. Revenue obtained from supply function S2 is higher than the one obtained from supply function S1 , x*P2>x*P2 ⇔ $3.5*3 > $3.5*1.5.

This behavior could be observed in the NE market. As shown in Fig. 7, the shift of aggregate LOL supply function is observed during higher demand periods (i.e. H # 20) compared to low demand period (i.e., H # 6).

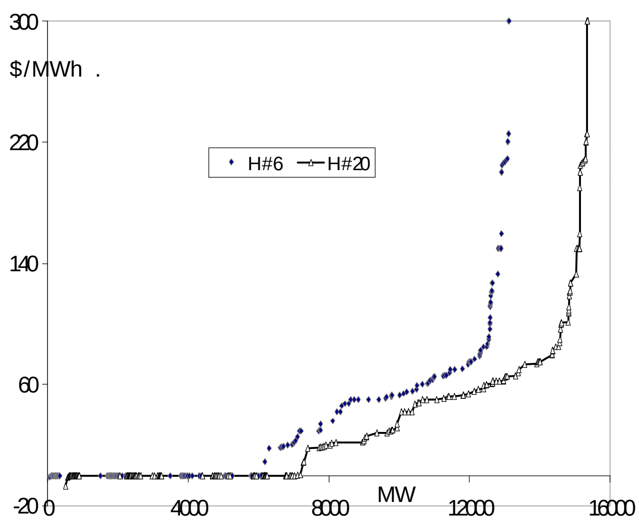

Fig. 7. Aggregate supply function accounting for only LOL of June 01, 2000 during hour 6 and hour 20

8. Conclusions

In this paper we briefly review the process of bid selection and the algorithms used for the electricity spot price (ECP) calculation. We analyze next how the type of spot market design chosen affects the bidding process itself even under the assumption that all bidders are price takers. We conclude that one should exercise caution when defining a benchmark ECP to which the actual ECP is generally compared in order to assess the degree of strategic bidding. In particular, two methods are proposed for defining such benchmark bids and/or data. The first method assesses presence of market power by estimating aggregate benchmark ECP. The second method is a direct comparison of bids to the benchmark costs of bidders themselves; based on the results obtained, we suggest that the benchmark costs are no longer routinely used short-run marginal costs. Instead, these are modified to account for the effects of technology-specific constraints and costs. Finally, we suggest that the detection of market power and strategic behavior in which bidders are no longer price takers greatly depends on the type of benchmarking method used.

Note that in this paper, the impact of bidding to reserve markets and reserve requirements is not considered. Although market prices might include costs due to UC constraints, this price does not incorporate fixed costs. Infra-marginal units in a single price market could recover their fixed cost, but marginal and extra marginal units might not be able to. To ensure capacity adequacy, one must consider a criterion that accounts for long-term investment aspect as well. If this factor is included, one should expect to observe without market power exertion, market prices rise above competitive prices. Also strategic behavior such as capacity withholding is not emphasized. This particular issue is extensively analyzed in [8].

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APPENDICES

A. A method for reconstructing hourly market clearing prices from the NE (6-month delay) bid data using an ED approach

From http://www.iso-ne.com/historical_bid_data/, one obtains bidding information on each generator which includes: masked Lead Participants and Asset ID, LOL and HOL, self-scheduling capacity, energy limit, and bid blocks containing unit price in $/MW and associated power. This hourly information could vary from hour to hour.

The aggregate supply function is a combination of bid blocks of all generators. A generator is scheduled at least its LOL. Load engaged in an out-of-merit order (such as associated with transmission constraints) is subtracted from actual demand in each hour. This approach creates an error since it limits not to schedule only marginal generators due to transmission constrains. Additionally, (positive) net interchange in each hour is subtracted from the actual load. Hence, the load used to calculated market clearing price equals:

$$\text{Net Load} = \text{Observed Load} - \text{Uplift} + \text{Interchange}$$

Note that the method used in this study is slightly different from the Market-Clearing Rule of the NE-ISO because of the following:

a) The calculated price is the marginal price of hourly actual demand, while market price is time-weighted average of the real-time marginal prices (every 2-5 minutes).

b) An energy limit (such as pumped storage) and several specific operation constraints (such as ramping rate) of a generator are discarded in calculated prices.

BIOGRAPHIES

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