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Research Article

Simulation on Bidding Strategy at Day-Ahead Market

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In an electric power day-ahead market, market prices are not always cleared at marginal cost caused by the strategic bidding of generators. This paper presents the results of day-ahead market simulation by using a simple three-generation-companies' model for the case of demand with price sensitivity and analysis of the profits depending upon bidding strategies. The results show that, without a demand response, generation companies with diverse generation can increase their profit by strategic bidding. Moreover, under this condition, even if the demand response is made sensitive, these characteristics do not change. It is clarified that one of these factors is the operating constraint of power generators. If the generation company's low-cost power generators decrease, the company's profit monotonically decreases as the speculated capacity increases. However, realizing this case requires an unreal demand response and many small companies without diverse generation. Unless the conditions above are satisfied, the wholesale power transactions only through a day-ahead market without price-sensitive demand mechanisms would create a sellers' market, where the sellers can easily manipulate the price.

1. Introduction

Conventionally, electric utilities have tried to reduce the costs of general services which include the construction and operation of facilities, while maintaining a certain level of reliability, based on the premise of regional monopoly under the vertically integrated system covering the processes from generation to supply. The introduction of the market mechanism to the electricity industry has caused companies to diversify. Generation and distribution companies run businesses to minimize risks and maximize profits, while transmission companies have a commitment to provide the generation and distribution companies with fair business opportunities, while maintaining a certain level of reliability.

Various papers have pointed out that the market clearing price in the day-ahead electricity market is not always equal to the marginal cost and is highly volatile because of the strategic bidding by generation companies [1–3]. Even in the US's PJM (Pennsylvania, Jersey, and Maryland: the Independent System Operator (ISO) whose control area covers Pennsylvania plus five other states), which is considered the best practice of deregulation, analyses reveal that one company controls prices and the prices hover at a high level [4]. In particular, the analysis results show that day-ahead electricity market prices are determined by the speculative bidding price, which significantly exceeds marginal costs during periods of high demand. The authors have already clarified reasons for these results by using dynamic simulations [5].

It is pointed out that, for these phenomena, price sensitivity of demand works effectively [6–8]. In fact, some ISOs in the US have introduced DRP (Demand Response Program). In the present paper, in order to quantitatively determine such effectiveness, the effect of strategic bidding will be analyzed taking factors such as price sensitivity of demand into account.

Section 2 states the purpose of simulation and its method including calculation algorism. Then it also explains input variables and bidding strategy. Section 3 gives the results of simulations. They show the effect of price sensitivity of

demand on the strategic bidding and the effect of operational constraint on generators on strategic bidding. Section 4 states the structural problems of an electric power day-ahead market, where prices could be easily manipulated in a comprehensive manner.

2. Analysis by Simulating Bidding Behavior

In the day-ahead electricity market, in order to examine price control and maintenance of high prices by one company in the day-ahead market in which companies bid for entire generation capacities, we examine through dynamic simulation the profit characteristics of generation companies corresponding to their bidding strategies. We used the MAPS (Multiarea Production Simulation) program developed by GE of the USA and applied market rules similar to those of PJM. As thermal power generators for which bidding is mainly made have various limits such as minimum run-time and minimum down-time, it is necessary to take account of those limits in order to calculate profits corresponding to bidding strategies by simulating the hourly market clearing price in the day-ahead electricity market. Since the MAPS program takes into consideration those limits and can simulate cost minimization, we used the program for this simulation.

Furthermore, the hourly demand used for this simulation was created based on the hourly actual demand of one whole year (1999) in PJM. Specifically, annual maximum demand power was specified so that the market reserve margin became a certain value relative to the total generation capacity used for the simulation, and based on the value, a ratio to PJM's maximum power was then calculated. Next, the ratio was multiplied by PJM's one-year hourly demand, thereby obtaining a demand curve.

2.1. Simulation Method and Input Variables. The unit commitments and load dispatching of generators have to be determined based on the bid price by taking into account the limits (e.g., transmission limits, reserve margin, minimum run-time, and minimum down-time) so as to minimize the amount of payment. The objective function is shown below.

Objective function:

$$\text{Min}\left(\sum_{h,i}\text{Sup}\,C_i+\sum_{h,i}\text{Min Gen}\,C_i+\sum_{h,i}\text{Inc}\,C_i-\sum_{h,j}\text{Dec}\,C_j\right), \tag{1}$$

where Sup C: cost of start up, Min Gen C: generation cost of minimum output, Inc C: incremental energy cost (bid price), and Dec C: decremental energy cost (bid price).

Limit conditions:

(1) $\sum_i \text{Gen}_i = \sum_j \text{Load}_j$,

(2) $\sum_i \text{Spin}_i \geq \text{Spin Requirement}$,

(3) $\sum_i(\text{Spin}_i + \text{Other Reserve}_i) \geq \text{Total Reserve Requirement}$,

(4) $\text{flow}_k \leq \text{limit}_k$ for all transmission facilities k,

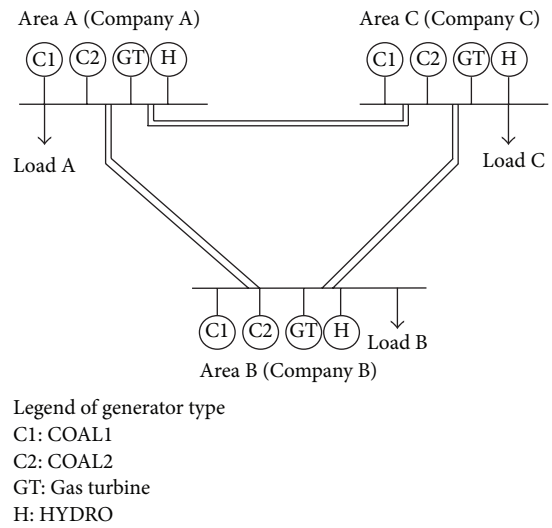


Figure 1: System configuration.

where Gen: amount of generation, Load: demand, Spin: spinning reserve, other Reserve: other reserve, flow: power flow on the line, and limit: Flow limit.

Herein, $\{h\}$ denotes 24 hours, $\{i\}$ is a set of generation bids, $\{j\}$ is a set of demands, and $\{k\}$ is a set of power flows.

The system conditions are three companies' loop systems as shown in Figure 1, and the available transmission capacity and wheeling tariff of each tie line is as shown in Table 1. Since this simulation does not require an analysis of the effect of transmission limits, we set a sufficiently large value for the transmission capability so that congestion will not occur and also set a sufficiently small value for the wheeling tariff between busbars.

Each company's power sources consist of one 250 MW hydropower generator, one 400 MW and one 300 MW coal generator, and one 250 MW gas turbine generator. The input variables of the generators are as shown in Table 2. Thermal power stations have some kind of operational constraints due to high temperature and pressure steam turbines and boilers. As these particular constraints are associated with the minimum output, the minimum downtime and the minimum run-time may have an impact on price formation in an electric power day-ahead market; they are considered in this simulation. Furthermore, a hydropower generator is to be economically operated under the limit amount of monthly generation. Loads are to be set by the method mentioned above such that the reserve margin becomes 15% and is distributed equally to each area.

Moreover, each company's profit is calculated by subtracting the generation cost obtained by using the variables shown in Table 2, from the revenue calculated by multiplying the hourly market clearing price by the contract amount of generation successfully bid. In other words, forward dealings are not taken into consideration. Therefore, it should be noted that depreciation cost is not subtracted.

Furthermore, to simplify the analysis, emergency outage and maintenance cycles are not simulated in this study.

Table 1: Available transfer capability and wheeling tariff.

Item	Unit	Tie-line A-B	Tie-line B-C	Tie-line C–A
Available transfer capability	MW	1200	1200	1200
Wheeling tariff	$/MW	0.01	0.01	0.01

Table 2: Input variables for each type of generator.

Item	Unit	Coal 1	Coal 2	GT	HYDRO
Maximum generator rating	MW	300	400	250	250
Minimum generator rating	MW	90	100	0	25
Minimum down-time	Hours	24	24	2	0
Minimum run-time	Hours	8	8	4	0
Variable O and M	$/MWh	5	7	10	0
Variable fuel cost	$/MBTU	1.5	3	4	0
Fuel input, minimum power	MBTU	765	850	0	0
Start-up energy	MBTU	3000	4000	0	0
Start-up time constant exponent	Hours	5	5	5	0
Energy charge	$/MWh	0	0	0	5
Monthly energy	MWH/month	—	—	—	90000

Table 3: Variable demand with price sensitivity.

Type	Start of sensitivity	Rate of sensitivity
Demand curve 1	$20	$0.6/%MW
Demand curve 2	$0	$1.5/%MW

Next, the price sensitivity of demand is simulated by dividing the demand in area A into ten sections and allowing these divided sections of demand to decrease in turn as the market clearing price increases. Two patterns are considered, which are shown in Table 3 (hereafter, referred to as demand curves 1 and 2). As an example, a supply curve in which all generators offer their bids on a cost base and demand curves in which the maximum demand (one-hour value) has price sensitivity are shown in Figure 2. The gradient of bidding prices of each generator in each company is set in such a range that, for each generator, the volume of output from the minimum output to the rated output is divided into six portions, for which the prices are set in steps, not overlapping the bidding prices of other generators. (Since the magnitude of this gradient does not have a large impact on the conclusion obtained from the simulation result, it is omitted from Table 2.) The magnitude of the price sensitivity of demand is assumed to be one-third of the demand. Also, the price sensitivity is set such that the gradient of the supply curve on a cost base would come between $0.6/%MW and $1.5/%MW which are much greater than actual values for the price sensitivity of demand. It is because the effect of actual values of price sensitivity of demand is too small to analyze price formation in an electric power day-ahead market structurally. Moreover, at the time of the maximum demand, the share of generating capacity of Company A is 33% (rounded off to the nearest integer) and its reserve is 15%. Therefore, in the case of zero price sensitivity of demand, if the supply of Company A is missing, then the portion of demand that cannot be satisfied becomes 18%, which is called residual demand. The residual demand is defined to be that which is obtained by subtracting the supply of other suppliers (Companies B and C) from the demand of the entire market. If it becomes a negative number, it is considered to be zero. Therefore, in the case where there is price sensitivity in Figure 2, the maximum demand of the entire market is 2,400 MW (67%), and the residual demand becomes zero.

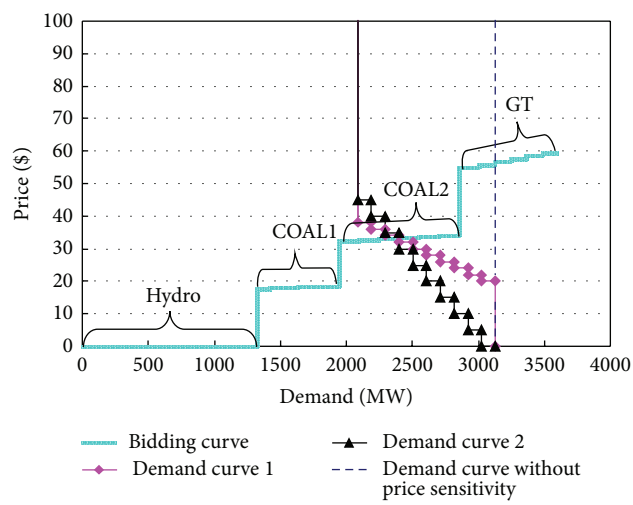


Figure 2: Supply and demand curve on the day of maximum demand.

2.2. Bidding Strategy. In the simulation, it is necessary to study each company's strategy and establish the pattern for its bid price. The authors' analysis of past records [4] revealed that each company bids for low-cost portions on a cost base but significantly increases bid prices for high-cost portions. Therefore, it is necessary to check the effects on

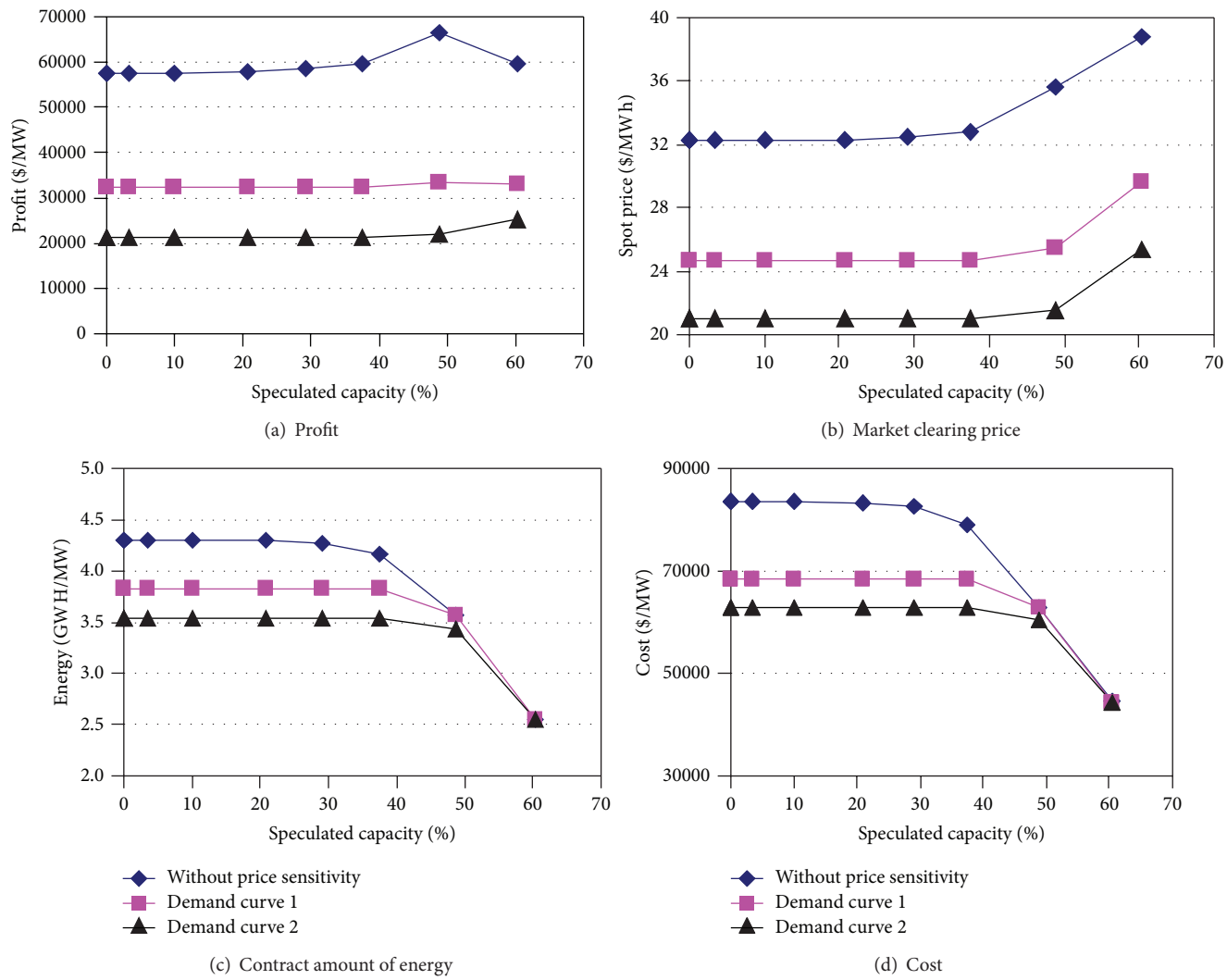


Figure 3: Effect of speculation by Company A.

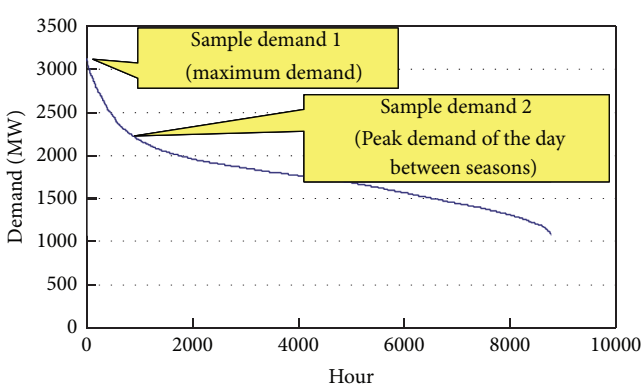


Figure 4: Duration curve of demand and sample demand.

the market clearing price and the contract amount due to changes of generation capacity (hereafter referred to as "speculated capacity") from the maximum price to the price at an inflexion point of the supply curve. According to the analysis results, bidding strategies for thermal power generators would be evaluated in comparison to the profit by cost-base bidding as a benchmark, and there are seven cases in which speculated capacities are changed strategically from 3% to 60% of the entire generation capacities including hydropower only in Company A. We calculated each company's profit by using these bidding strategies. Furthermore, although it can be assumed that each company could change its bidding strategy according to the supply and demand situation, we consider the strategies constant during the simulation period (one year) to simplify the analysis.

3. Results of Simulations

The simulations here examine how the market clearing price and companies' profits change in response to the price sensitivity of demand and the presence or absence of operating constraint of power generators and the like.

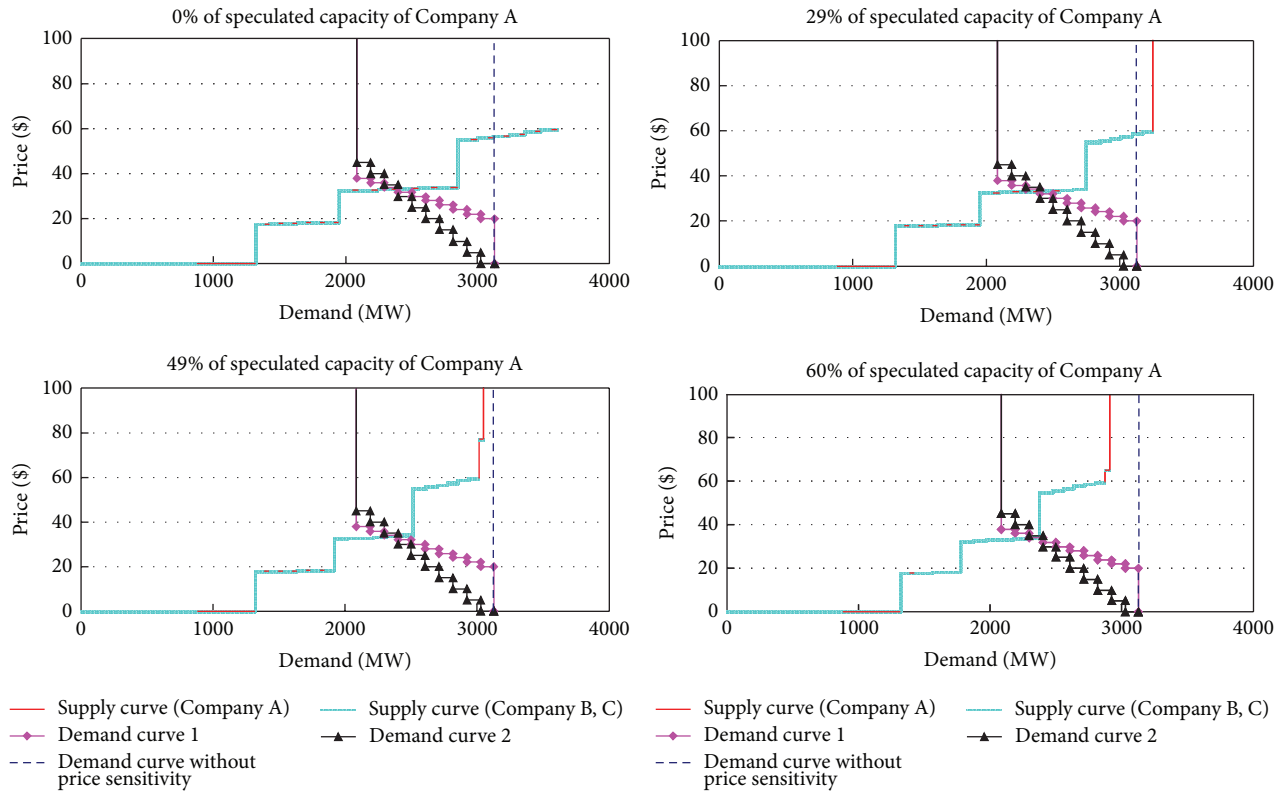


Figure 5: Supply and demand curve. (Sample demand 1: maximum demand.)

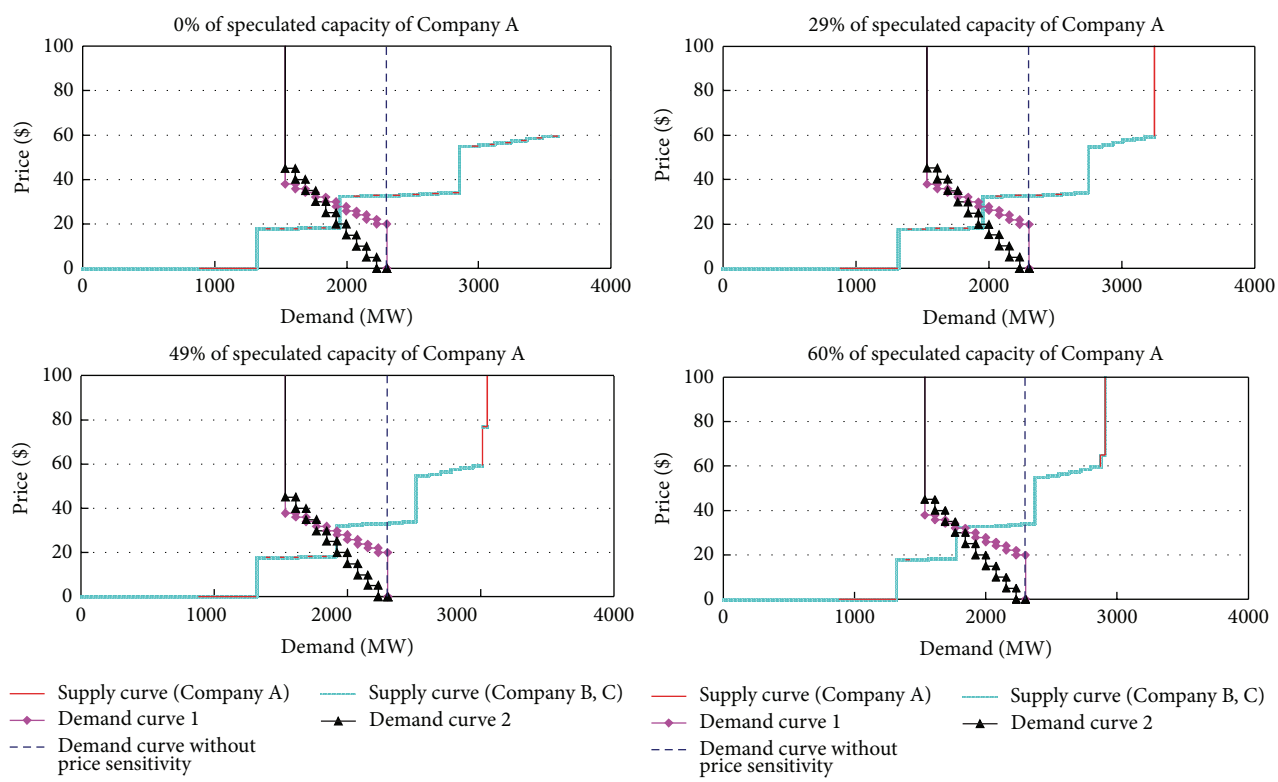


Figure 6: Supply and demand curve. (Sample demand 2: peak demand of the day between seasons.)

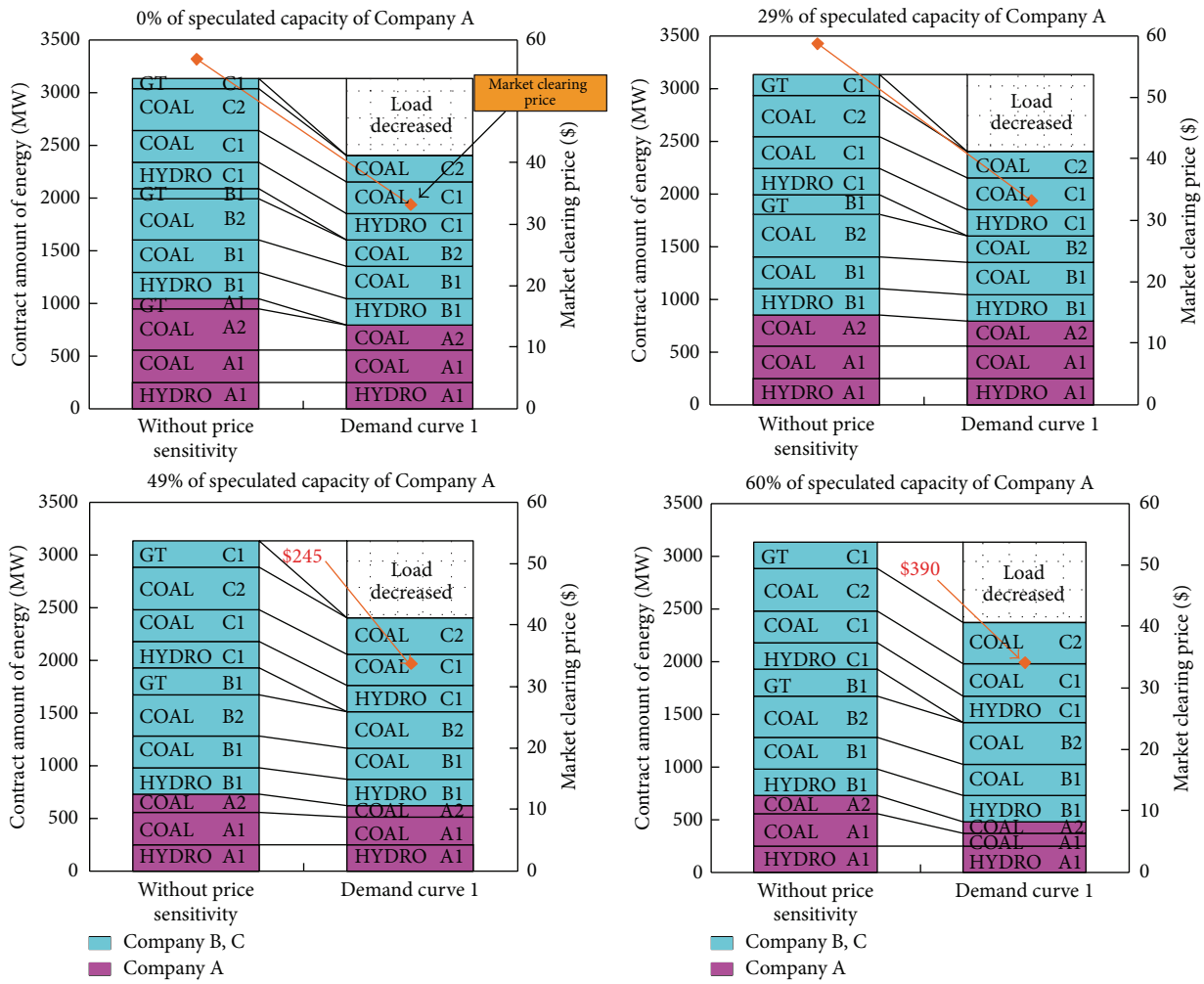


Figure 7: Load dispatching of generators at demand curve 1 and demand curve without price sensitivity. (Sample demand 1: maximum demand.)

3.1. Effect of Price Sensitivity of Demand on the Strategic Bidding. A case of strategic bidding was simulated according to the above conditions, and the results such as the profits of Company A, market clearing price, contract amount, and cost were as shown in Figure 3.

In the case where the demand has price sensitivity, the profit decreases, compared to the case where there is no price sensitivity. Furthermore, in the case where the percentage of strategic bidding is increased, although the profits do not increase in comparison to the bidding on a cost base, the profits do not decrease either, and the risk due to the strategic bidding is considered to be small. Even in the case where the price sensitivity of demand has a larger gradient (supply curve 1), because of the strategic bidding, the profits do not monotonically decrease. It should be noted that, since the profits monotonically decrease as the percentage of strategic bidding increases, the principle of competition seems to be working.

Next, the contract amount of energy will be considered. In the case of cost-based bidding or a lower amount of speculated capacity, the contract amount becomes small due to the price sensitivity of demand, showing a difference depending on whether price sensitivity exists or not. However, the difference in the contract amount due to the existence or nonexistence of price sensitivity decreases as the percentage of strategic bidding increases.

In order to briefly explain this phenomenon, a supply curve for strategic bidding of one percent to another or a breakdown of contract generation of Company A will be verified at sample demands (one hour each of the maximum demand period and the peak hours between seasons). Figure 4 shows the duration curve of demand used for the simulation and the sample demands.

Figures 5 and 6 show the supply and demand curves for sample demands 1 and 2, respectively, for cases where the speculated capacity is 0% (cost-based), 29%, 49%, and 60%. The supply curves in the figures are provided in such a manner that a generator of Company A and generators of Companies B and C are represented by different colors and can be distinguished for easy identification of any changes in the contract amount of Company A due to the presence or absence of price sensitivity of demand.

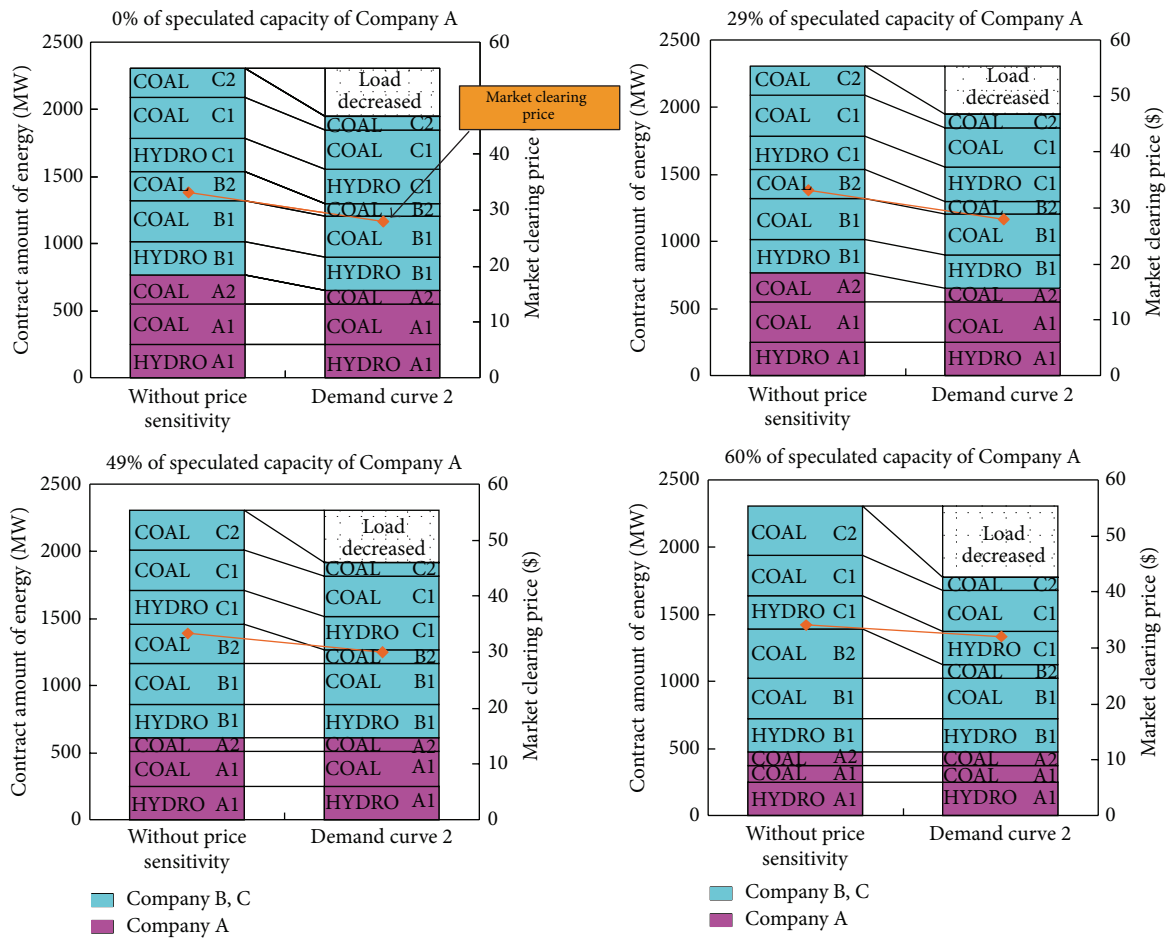


FIGURE 8: Load dispatching of generators at demand curve 2 and demand curve without price sensitivity. (Sample demand 2: peak demand of the day between seasons.)

First, in Figure 5 (the maximum demand), it can be seen that as the speculated capacity increases from the cost base, the bid of the generator of Company A shifts to the right side of the supply curve. In the case of cost-based bidding, up to COAL1 and COAL2 and a part of GT of Company A are contracted when there is no price sensitivity of demand, but only COAL1 and a part of COAL2 are contracted when the price sensitivity is present. On the other hand, in the case of the speculated capacity of 60%, generators up to a part of GT are contracted at a high price strategically set by Company A when there is no price sensitivity of demand, but only a part of COAL1 is contracted when price sensitivity is present. As observed above, in the high demand zone, the contract amount of Company A decreases because of the price sensitivity associated with the demand regardless of the percentage of speculated capacity.

Next, in Figure 6 (peak demand between seasons), in the cases where the speculated capacity percentage is zero and 29%, the contract amount of Company A decreases when the demand has price sensitivity as in the case of the high demand zone. However, in the cases where the speculated capacity percentage is 49% and 60%, the contract amount of Company A does not change even when the demand has price sensitivity. This can be explained from the fact that there are no generators of Company A between the demand curve with no price sensitivity (a straight line) and the demand curve with price sensitivity. More specifically, as the speculated capacity percentage of Company A becomes large, differences in the contract amount due to the presence or absence of demand price sensitivity become small. On the other hand, the extent of increase in the contract amount associated with an increase in the speculated capacity percentage hardly changes regardless of whether there is demand price sensitivity or not. This tendency remains the same even if the market share or power generation mix (fossil fuel classification) of Company A changes.

Furthermore, since, in Figure 4, an intermediate demand zone accounts for the majority, the characteristics of Figure 6 are more prominent than those of Figure 5 when seen throughout a whole year. Therefore, although the contract amount of Company A decreases as the speculated capacity percentage increases as discussed in Figure 6, the extent of such a decrease is smaller for a case with demand price sensitivity, and its value tends to converge to the contract amount in a case with no price sensitivity. Hence, the extent of decrease in the revenue associated with an increase in

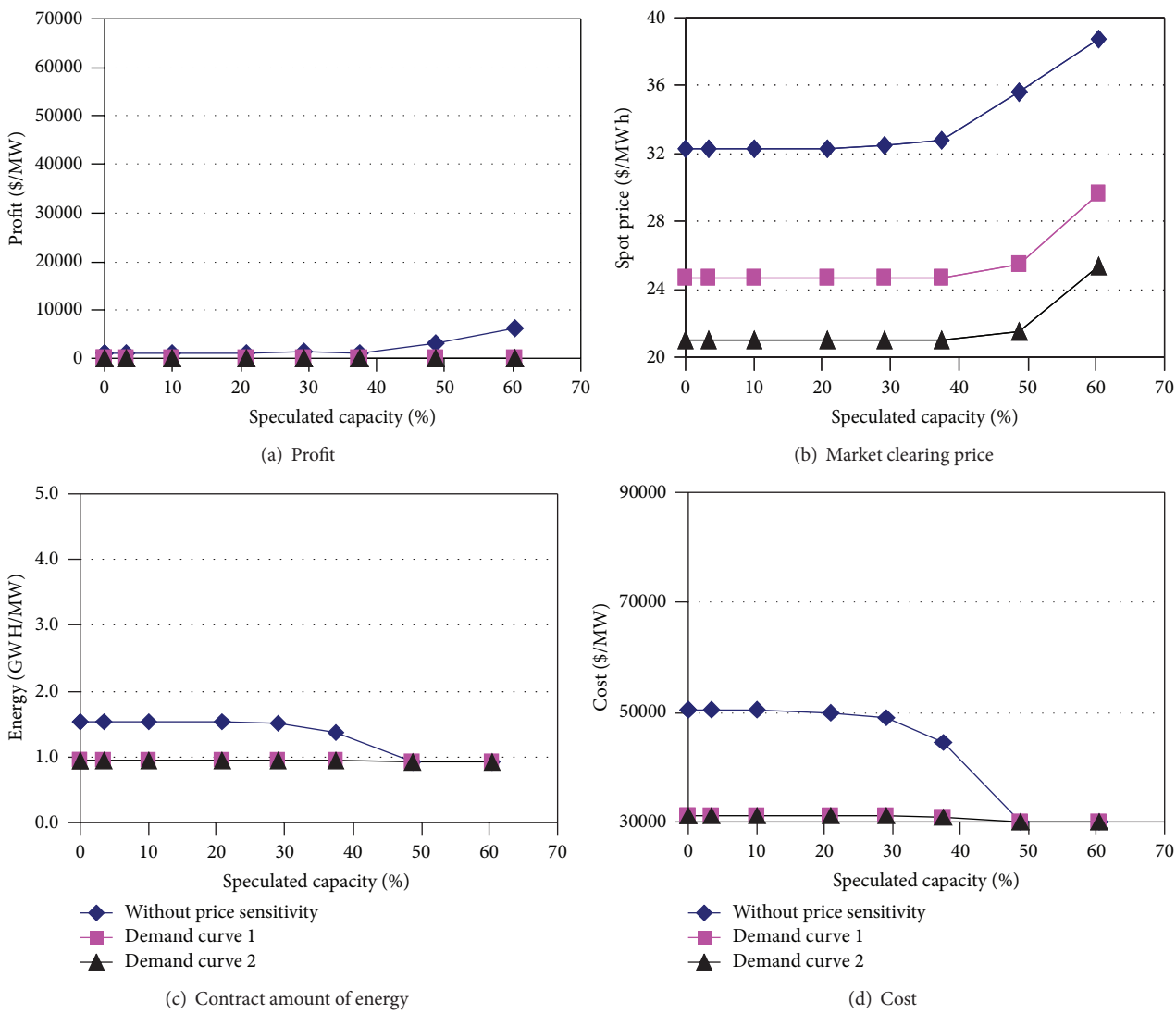


Figure 9: Effect of speculation by GT and COAL2.

the speculated capacity percentage is smaller for the case where the demand has price sensitivity, and this is one reason why the profit does not decrease.

Next, the load dispatching of generation and the market clearing price for the speculated capacity percentages of 0% (cost-based), 29%, 49%, and 60% are compared for demand curve 1 and demand curve without price sensitivity. Figures 7 and 8 show diagrams of load dispatching of generators and market clearing prices for sample demands 1 and 2, respectively. For example, from the diagram of Figure 7 showing the cost-based example, it can be seen that GT of Company A is contracted when there is no demand price sensitivity as mentioned above, but that the same GT is not contracted, together with the contract amount of COAL2 also being decreased, when there is price sensitivity. Moreover, in the case where the percentage of speculated capacity is 49% or 60%, the market clearing price is contracted to be the strategic price when there is no price sensitivity, but the market clearing price significantly decreases when there is price sensitivity. These phenomena are apparent from the comparison with Figure 5. Similarly, it can also be recognized from Figure 8 that, in the case where the percentage of speculated capacity is 49% or 60%, the contract amount of Company A does not change at all regardless of whether price sensitivity exists or not.

Figure 9 shows the profit and so forth of Company A to be gained only from GT and COAL2, which are obtained by subtracting profits, costs, and contract amounts due to HYDRO and COAL1 from each graph in Figure 3. By doing so, the generation market share of Company A drops from 33% to 18%, which is slightly larger than the reserve margin of 15% during the maximum demand period, and, accordingly, the residual demand becomes 3% when the demand does not have price sensitivity.

In the case of demand with no price sensitivity, if the percentage of speculated capacity is 49% or 60%, small profit is produced, but its value has decreased significantly compared to Figure 3. When GT and COAL2 are both at

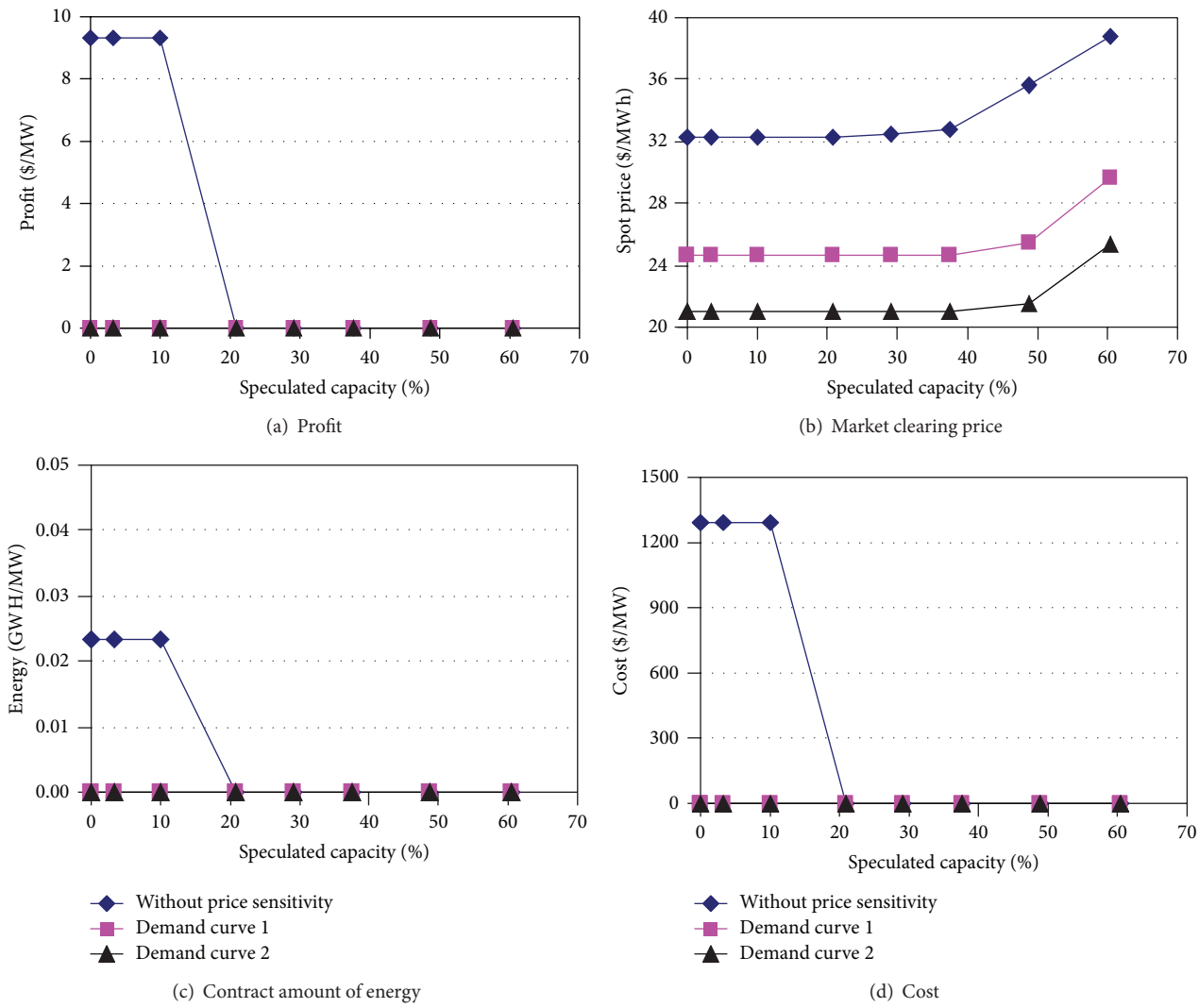


Figure 10: Effect of speculation only by GT.

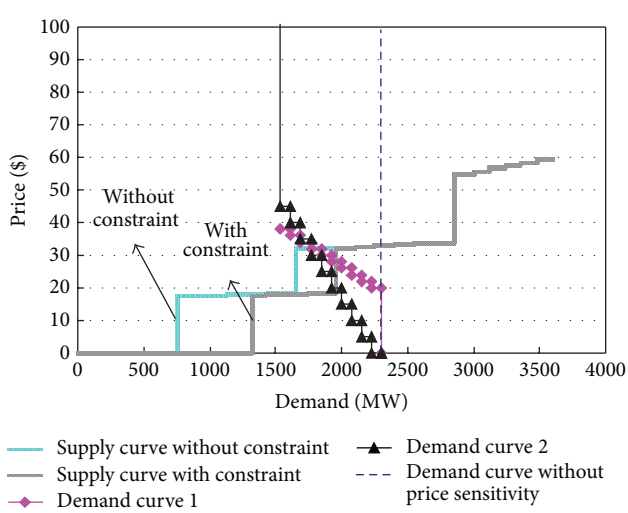
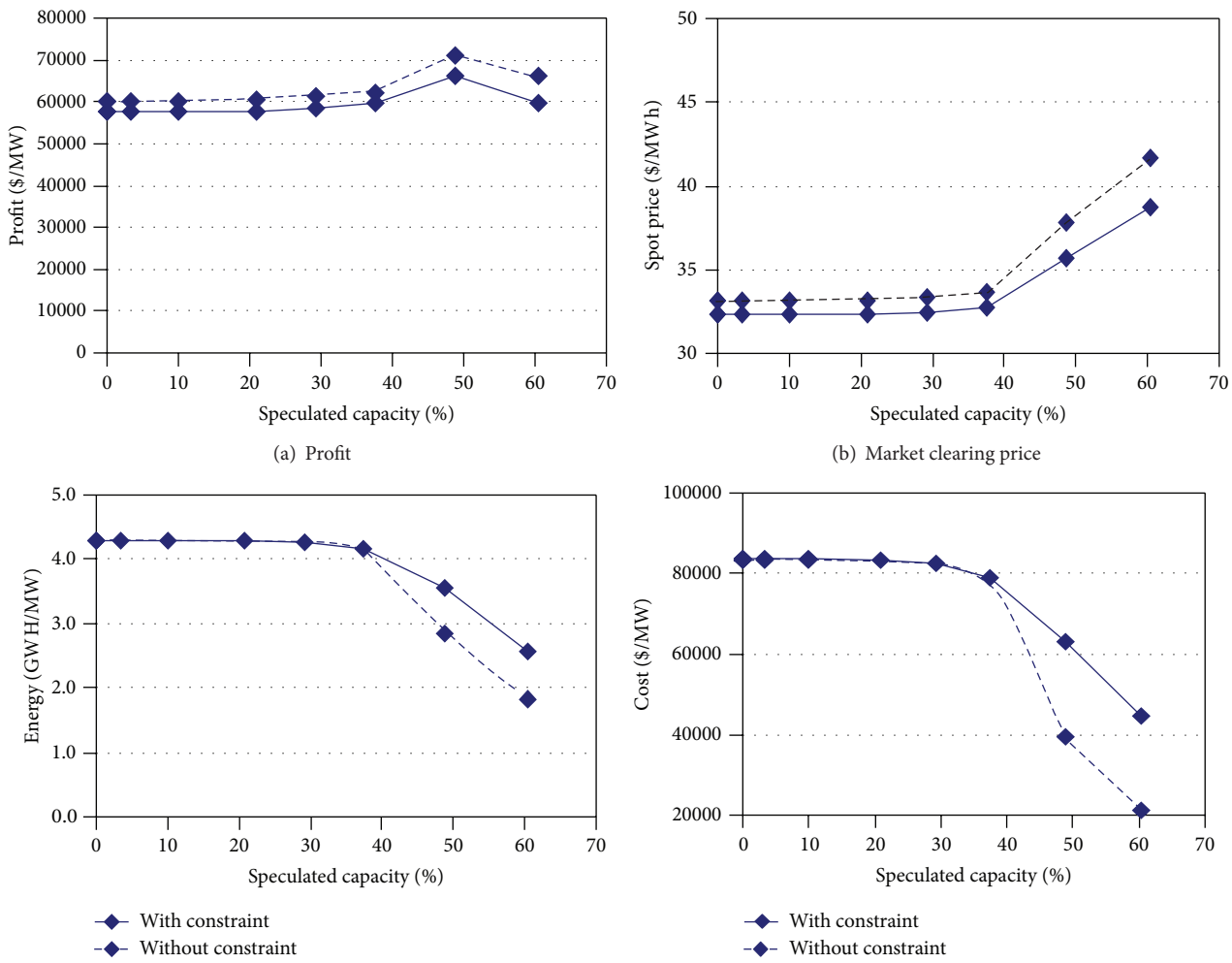


Figure 11: Change of supply curve by operating constraint.

the strategic prices, the percentage of speculated capacity is 49% or more. As the sum of the rated outputs of GT and COAL2 is 18% of the total capacity of all generators and the reserve margin is 15%, it can be seen that the market clearing price becomes a strategic price, boosting the profit slightly when there is no demand price sensitivity, provided that the load is heavy. On the other hand, when there is price sensitivity, the time zone when COAL2 is operating at the minimum output becomes extensive. In this case, the market clearing price becomes the bidding price of COAL1 whose price is cheaper than the operating cost of COAL2 (this is because the bidding price of the generator in question would be considered to be zero when the output decreases to the lower limit for the output), and the cost may exceed the revenue. Hence, regardless of the percentage of speculated capacity, the profit becomes negative, and an increase in profit such as the increase observed in the case of no price sensitivity is not observed.



(a) Profit (b) Market clearing price

(c) Contract amount of energy (d) Cost

Figure 12: Effect of operating constraint. (Demand without price sensitivity.)

Next, Figure 10 shows the profit and so forth of Company A to be gained only from GT, which are obtained by subtracting profits, costs, and contract amounts due to COAL1 from the graphs of Figure 9. (Since the values are small, the vertical axis is rescaled.) By doing so, the generation market share of Company A becomes 7%, which is smaller than the reserve margin of 15% during the maximum demand period, and, accordingly, the residual demand becomes zero even when the demand does not have price sensitivity. It can be seen from the figure that, in the case of demand with no price sensitivity, when the percentage of speculated capacity is small, the profit takes a very small value but has no extreme, and that, for the speculated capacity percentage of 21% or more, no contract is closed at all, pushing the profit down to zero. Therefore, it would be difficult for a company having GT only to secure profit by the strategic bidding of this generator even in the case of demand with no price sensitivity. Furthermore, the tendency that the profit decreases as the speculated capacity percentage increases suggests that, if there exists a company with skewed price characteristics such as the one with GT only, the principle of competition works in the day-ahead market.

3.2. Effect of Operational Constraint on Generators on Strategic Bidding. Because of the constraints associated with the minimum output, the minimum downtime and the minimum run-time for each generator, there may be a time period when the generator is operating at the minimum output although it is considered to be economically preferable to shut it down. During such a time period, the bidding prices of generators operating at the minimum operating output are treated as zero. Without these constraints, the market clearing price may become higher, as shown in Figure 11. Here, for the sake of argument, the peak demand of the day between seasons mentioned before will be used. By lifting the minimum output constraint, the supply curve shifts to the left, raising the market clearing price. The decrease of load also grows.

First, in order to compare cases with and without a constraint when the demand has no price sensitivity, the profit

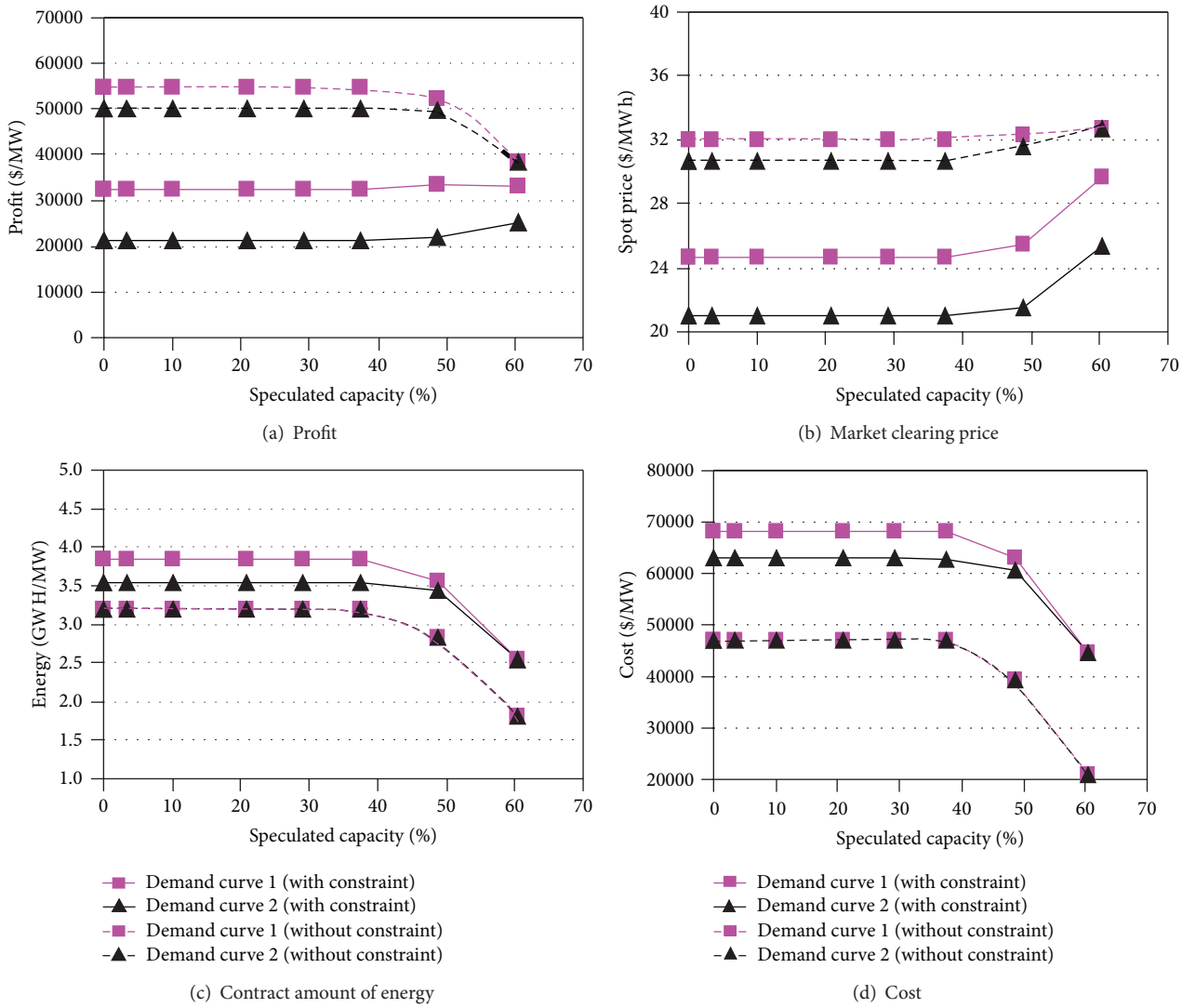


Figure 13: Effect of operating constraint. (Demand with sensitivity.)

and so forth of Company A are shown in Figure 12. Since constraints are lifted, the contract amount tends to decrease, but the profit is on the rise. This is because the supply curve in Figure 11 shifts to the left, and, especially, the market clearing price increases in the low demand zone.

Moreover, the reason for the sudden decrease in the contract amount at the speculated capacity percentage of 49% and beyond is because the minimum output of COAL2 adopts the strategic price. This is because the market clearing price, which was set at the price of COAL1 when the minimum output of COAL2 was contracted under operating constraint, is now set at the strategic price in the low output zone since the constraint has been lifted, and contracts are then awarded to Companies B and C, thereby decreasing the contract amount of Company A. On the other hand, the extent of increase in the contract price is so large that the profit is extreme due to the strategic bidding.

From the above discussion, it was confirmed that, in the case where the demand has no price sensitivity, the profit is extreme due to the strategic bidding regardless of whether there are operating constraints on the generators or not.

Next, cases with and without constraint are compared when the demand has price sensitivity. Graphs for demand curves 1 and 2, each including one with constraint and one without constraint, as shown in Figure 13. For both demand curves 1 and 2, the profit increases when there is no constraint. This is because the market clearing price increases by lifting the constraint as in the case of no demand price sensitivity. Moreover, when the speculated capacity percentage is raised, the extent of increase in the market clearing price is larger for the case with constraint than for the case without constraint. Accordingly, the difference in the market clearing price between the two becomes small, but the difference in the contract amount hardly changes, decreasing together. Therefore, the effect of speculated capacity vanishes by lifting the constraint, and the profit decreases almost monotonically as the speculated capacity increases.

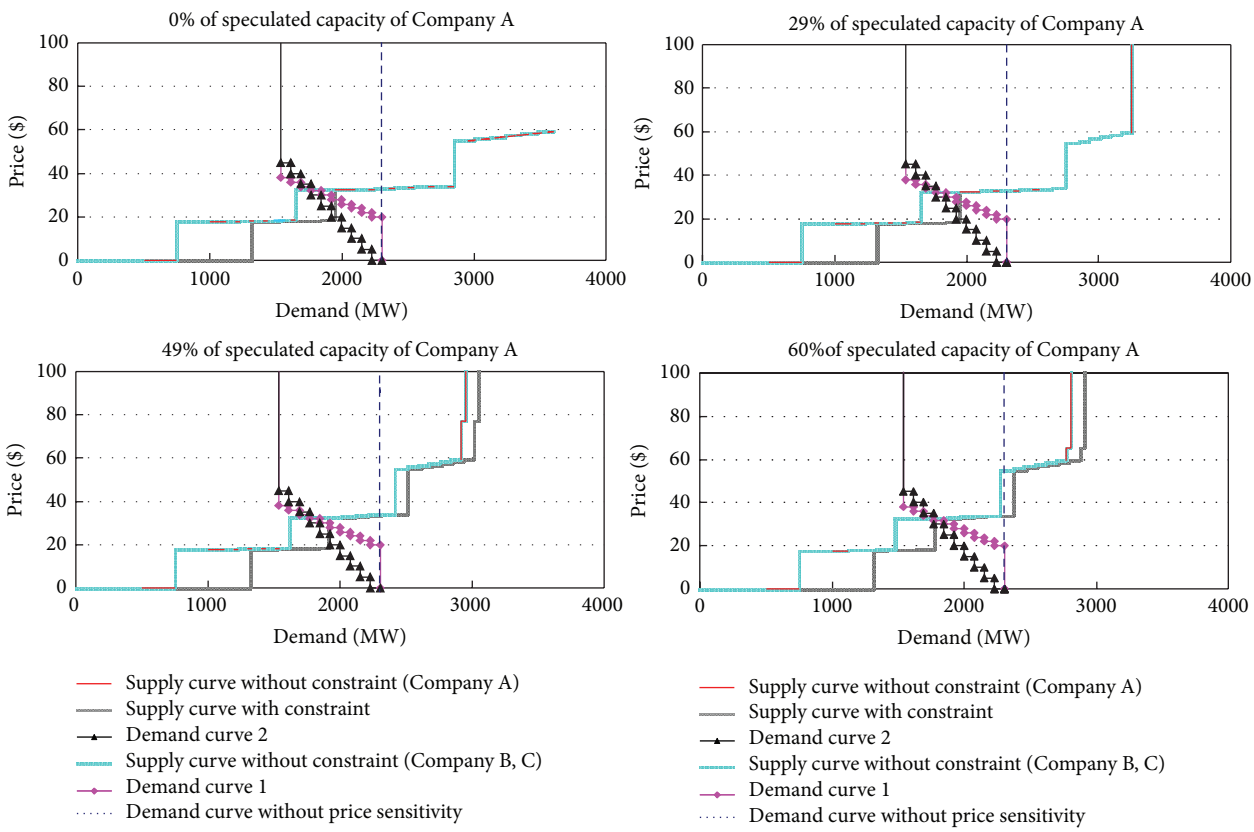


Figure 14: Supply and demand curve without constraint. (Sample demand 2: peak demand of the day between seasons.)

In order to verify this phenomenon, the supply and demand curve (for sample demand 2 explicitly showing its characteristics when viewed throughout a year) when there is no constraint are used in Figure 14. As the speculated capacity percentage is raised, the difference in the market clearing price between cases with and without constraint becomes small. However, as to the contract amount of Company A, almost the same decreasing tendency can be verified for both cases with constraint (Figure 6) and without constraint. Therefore, from Figure 13, it can be explained that, as the speculated capacity percentage is raised, the difference in the market clearing prices due to the presence or absence of constraint becomes small, while the difference in the contract amounts remains almost the same.

As discussed above, the following was verified for the case where the demand has price sensitivity: if there is an operational constraint on the generator, the profit is extreme due to the speculated capacity, but if there is no operational constraint on the generator, the profit decreases almost monotonically as the percentage of the speculated capacity increases. Hence, it can be seen that an operational constraint serves to discourage competition. Unlike hydropower generation, thermal power generation, especially steam-power generation, that is associated with the minimum down-time constraint or the minimum operating run-time constraint. Therefore, it is envisaged that, in a market where thermal power generation plays a main role, the principle of competition may not work.

4. Conclusion

The results of the analysis on the effect of strategic bidding when the demand has price sensitivity are as follows.

In the case where a generating company possesses a diverse power generation mix including HYDRO, COAL, and GT, if the demand does not have price sensitivity, then the profit can be increased by strategic bidding. Furthermore, in the case where the same condition remains but there is price sensitivity, if a certain amount of low-cost power source exists, then the same tendency is still present for the profit to increase by strategic bidding. It was then explicitly shown that one of the factors explaining this phenomenon was the operational constraint on the generator. Furthermore, if the low-cost power source of the generating company diminishes, then the profit of that generating company ends up decreasing almost monotonically as strategic bidding increases.

However, in order to ensure that the profit decreases as the speculated capacity increases (to make the principle of competition work), unrealistic price sensitivity of demand needs to be created, and, in addition, as to the generating companies, small companies with skewed price

characteristics need to exist in large numbers. On the other hand, in order to ensure the sustainable operation of power generating business, both the diversity of power generation mix and a certain level of scale of operation are indispensable. Therefore, it was found that it would be difficult for the principle of competition to work only with the wholesale power transactions in the day-ahead market.

These discussions revealed that, in an electric power market (except for those having a large reservoir capability), the wholesale power transactions only through the day-ahead market would create a sellers' market where prices could easily be manipulated. (The only exception would be Nord Pool. A time-shift capability due to large reservoirs makes it possible to discover the optimum volume in the day-ahead market, exercising the same effect as the large price sensitivity of demand. Furthermore, a variety of players exist in large numbers in Nord Pool.)

Conflict of Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

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