Paper

Coordinative Generation Expansion Planning in Consideration of IPPs' Participation in Partially Deregulated Market

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In recent years, by promotion of the deregulation of electricity markets, competition has been introduced in generation field. When planning for generation expansion, utilities must take into account independent power producers (IPPs). Utilities prefer introducing IPPs to building new generators if the participation of IPPs can maximize their profits. At the same time, IPPs want to maximize their own profits and therefore bid against each other to participate in the generation market. In the partially deregulated market where only generation sector has been liberalized, the relationship between utilities and IPPs is competitive, and also is cooperative, because they all want to maximize their own profits to obtain the share of generation in the same market. This paper discusses the bidding conditions for IPPs based on their scenario analyses, and proposes a solution for the utility to obtain the coordinative generation expansion planning from the viewpoint of a utility at the same time considering the profits of IPPs. Supply reliability and the environmental problem of emissions, such as of CO_2 emissions, are considered. Based on the extended Dynamic Programming (DP) approach, the feasibility of the proposed approach is demonstrated in a test power system, and the coordinative generation expansion plan for the utility, while the impact of IPPs is taken into account, is obtained.

Keywords: generation expansion planning, IPP, CO_2 emission, supply reliability, extended DP

1. Introduction

Generation expansion planning is an important activity for electric utilities. Because of the long-term feature for development of power resources from planning to operation, it is necessary for the company to develop the best overall scheme for well-balanced generation planning. In recent years, accompanying the deregulation of the electric power industry, competition has been introduced in power generation, power transmission, and power distribution. Japan has passed legislation to introduce competition in power generation, with the result that more and more independent power producers (IPPs) will join the power generation market to compete with utilities. In the meantime, utility companies will have the choice of constructing new generating plants by themselves or introducing some IPPs, whichever they believe to be most profitable. On the other hand, IPPs will also try to maximize their profits. If the utility proposes an optimal scheme regardless of IPPs' profits, the IPPs will not accept it. Only if the IPPs' profits are taken into account will the transaction be concluded. Therefore, the relationship between utilities and IPPs is competitive and cooperative, and the coordinative generation expansion planning in consideration of IPPs' participation in the partially deregulated market is a keen issue[(1)-(5)].

The Kyoto Protocol has mandated limits on emissions of greenhouse gases such as CO_2. Therefore, we consider the environmental problem, especially the CO_2 emission problem, in generation expansion planning. To ensure the stable power supply, Loss of Load Probability (LOLP) and Expected Energy Not Served (EENS) are used in this paper as two valuation indices.

The purpose of the paper is to present a method for obtaining a coordinative generation expansion plan from the viewpoint of a utility, within the constraints of limits on CO_2 emissions and the need for IPPs to be profitable. In Section 2, the general concept of generation mix including IPPs is discussed, and the optimization models for the utility and IPPs are proposed. Regarding the discrete nature of generating units and transparency of the method of solution as important, the extended Dynamic Programming approach is proposed in Section 3.This paper divides IPPs into three types based on their different generation characteristics: base-type, middle-type, and peak-type, and the different bidding conditions for the different IPPs are clarified in Section 4 based on the scenario analyses of the IPPs. In Section 5 an algorithm is proposed for the utility to solve the problem of coordinative generation expansion plan with different CO_2 limits at the same time considering IPPs. In Section 6, by using a test power system to demonstrate the proposed approach and to obtain the coordinative generation expansion plan.

2. Problem of the generation mix including IPPs

2.1 IPPs in the generation mix Various generation technologies can be used to fill the load duration curve so as to decrease the cost of the overall supply. The optimal method is to have the generation technology with the lowest variable cost occupy the lowest horizontal slice of the load duration curve and so on, in rising variable cost order[(6)(7)]. According to this, the merit order for generation technologies from bottom to top under the load curve, as shown in Fig. 1, is nuclear (N), coal (C), LNG (L), oil (O), gas (G).

The problem of how to deal with IPPs when they are introduced by the utility is taken into account as follows:

Table 1. Characteristics of IPPs

IPP type	Operation time (One day)	Duration time (One year)
Base-type	24h (0-24)	8760h
Middle-type	17h (7-24)	6250h
Peak-type	8h (9-17)	2920h

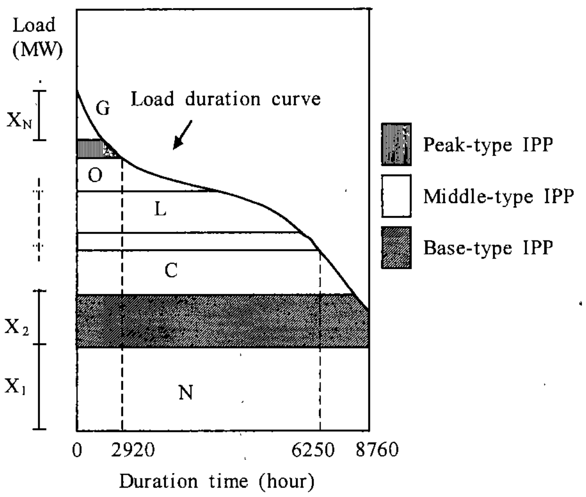

Fig.1 Optimal order of utility and IPPs

IPPs can be divided into three types by power generation characteristic as shown in Table 1: base type, middle type and peak type[(8)~(10)]. The difference in duration of generation determines the difference in their location under the load curve. When IPPs are introduced by the utility, they replace generating plants that are with similar characteristics. Therefore IPPs are regarded as individual generation technologies and their locations under the load curve can be treated the same as other generation that belongs to the utility.

Based on questionnaires on potential capacity of IPP's in the electric power wholesale market in Japan[(10)], this paper considers IPPs of three fuel types as follows:

Base-type: residual oil, coal
Middle-type: LNG, crude petroleum
Peak-type: LP gas

Considering that variable costs for IPPs are lower than for those of comparable utility generation, the merit order for generating plants, as shown in Fig.1, is nuclear (N), base-type IPP, coal, middle-type IPP, LNG (L), oil (O), peak-type IPP, gas turbine (G). In addition, to secure the reliable supply of peak load, peak-type IPP is below gas turbine, which fills the peak load of the load duration curve.

2.2 Formulation Before formulating the problem of optimal generation mix including IPPs, several hypotheses are set up as follows:

1) Annual load demand, load factor, and peak load at the target year are known;
2) The utility has nuclear, coal, LNG, oil and gas generation;
3) IPPs are classified into three types: Basic, middle and peak type;
4) These three types of IPPs bid against each other on generation expansion planning of utility.

The optimization model of the utility and IPPs can be described by the following equations, taking into consideration the interaction of the utility and the IPPs:

i . For the utility

Objective function:

Total profit of the utility should be maximized and can be expressed by equation (1).

$$Max\quad \lambda_d\sum_{i=1}^{3}Q_{di}+\sum_{j=1}^{3}(W_{Cj}x_j+W_{Ej}Q_j)-\sum_{i=1}^{M}(a_ix_i+b_iQ_i)-\sum_{j=1}^{3}\lambda_jQ_j \tag{1}$$

If the sales prices of base-type, middle-type and peak-type generation on customers are set separatly, $\lambda_d\sum_{i=1}^{3}Q_{di}$ in equation (1) can be expressed by $\sum^{3}\lambda_{di}Q_{di}$

ii . For IPPs

Objective function:

Maximum profit for the IPP can be expressed by:

$$Max\ \lambda_{Rj}x_{Rj}+\lambda_jQ_j-C_j \qquad (j=1,2,3) \tag{2}$$

Subject to:

$$x_{i,j\,\min}\le x_{i,j}\le x_{i,j\,\max} \tag{3}$$

$$\sum_{i=1}^{M}x_i+\sum_{j=1}^{3}x_j\ge P_D+P_R \tag{4}$$

$$X_0=0,\ X_i=\sum_{k=1}^{i}x_k \qquad (i=1,2,\cdots,N) \tag{5}$$

$$Q_i=\int_{X_{i-1}}^{X_{i-1}+x_i}L_T(u)\,du \qquad (i=1,2,\cdots,N) \tag{6}$$

$$Q_{i\min}\le Q_i\le Q_{i\max} \qquad (i=1,2,\cdots,N) \tag{7}$$

$$\sum_{i=1}^{N}\beta_iQ_i\le L_{CO_2} \tag{8}$$

$$LOLP\le LOLP_T \tag{9}$$

$$EENS\le EENS_T \tag{10}$$

Where

λ_d : Utility's sales price to customers (Yen/kWh).
λ_{di} : Tariff for i-type power generation (Yen/kWh). i=1,2,3 represent respectively base-type, middle-type and peak-type utility generation.
Q_{di} : i-type generation (kWh)
W_{Cj} : Wheeling charge of capacity of j[th] IPP (Yen/kW)
W_{Ej} : Wheeling charge of energy of j[th] IPP (Yen/kWh)
x_j : Installed capacity of j[th] IPP (kW)
Q_j : Introduced energy of IPP by utility(kWh)
a_i : Fixed cost of i[th] generating plant (Yen/kW)
b_i : Variable cost of i[th] generating plant (Yen/kWh)
x_i : Introduced capacity of i[th] utility generation (kW)
Q_i : Annual generated power energy of i[th] utility generation at target year (kWh)
λ_j : Purchase price of power energy of j[th] IPP (Yen/kWh)
M : Total number of generating plants of utility
N : Total number of generating plants and IPPs ($N=M+3$)
P_D : Peak load at target year (kW)
P_R : Supply reservation at target year (kW)
X_i : Cumulative introduced capacity from 1[st] to i[th] generating plant (kW)
$L_T(u)$: Inverse function of load duration curve supplied by utility in target year

β_i : Coefficient of CO_2 emission for variable cost of generating unit (Ton/kWh)
λ_{Rj} : Purchase price of capacity as reserved (Yen/kW)
x_{Rj} : Reserved capacity (kW)
C_j : Cost of j[th] IPP (Yen)
L_{CO_2} : Limits of CO_2 emission
$LOLP_T$: Level of loss of load probability
$EENS_T$: Level of expected energy not supplied

iii. Extended optimization model for utility and IPPs

1) For utility

The utility's profit can be obtained from its revenue from power sold, consisting of base, middle and peak load. To highlight the relationship between the IPPs and the utility, we assume that the utility's price to customers is fixed so that its revenue is constant.

IPPs must use the utility grid and therefore must pay wheeling charges to the utility. Here, we adopt the Postage Stamp method, in which the wheeling charge is expressed by introduced capacity in kW [11][12], therefore, in equation (1), $W_{Ej}=0$.

For bidding, the energy (kWh) method is generally used. This means that the utility only purchases energy (kWh) from the IPPs when the IPPs bid competitively. Therefore, the cost to the utility for introducing IPPs is expressed as shown in equation (1).

Based on the above analyses, the maximization problem can be expressed by the minimization problem in which the objective function is the sum of the utility's generation cost, the cost of introducing IPPs and the wheeling charge (negative value).

2) For IPP

$\lambda_{RJ}\chi_{RJ}$ is the reservation capacity purchased by the utility. Because this paper assumes that the peak load of the utility is filled by gas turbines belonging to the utility, it is considered to be zero.

In case that the reservation capacities are provided by IPPs in the electric market, not only the gas turbines of utilities, but also the supply of reservation from IPPs should be considered in the formulation.

2.3 Consideration of supply reliability In Fig.2, $f_0(x)$ is the original load duration curve. The convolution for generating unit i is generally expressed by:

$$f_i(x) = p_i f_{(i-1)}(x) + q_i f_{(i-1)}(x - C_i) \tag{11}$$

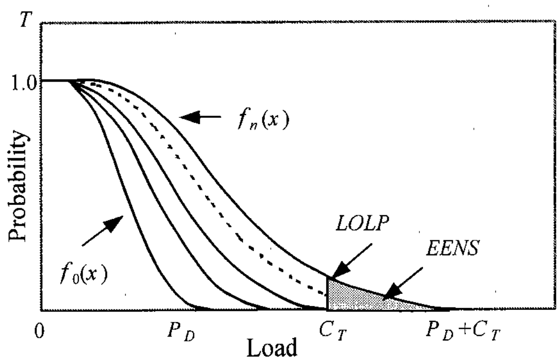

Fig.2 Equivalent load curve and reliability indices

Where C_i and q_i are respectively the capacity and the forced outage rate of generating unit i, and $p_i=1-q_i$.

Suppose there are n generating units with a total capacity of C_T, the equivalent load duration curve is $f_0(x)$ when the convolution process is completed for all the generating units. The maximum equivalent load is $P_D + C_T$. At this point the system's LOLP and EENS are respectively[13]:

$$LOLP = f_n(C_T) \tag{12}$$

$$EENS = T\int_{C_T}^{P_D+C_T} f_n(x)dx \tag{13}$$

3. Explanation of extended DP approach

Taking account of the discrete characteristics of the generation expansion planning problem, and emphasizing transparency of the method of solution, the Dynamic Programming (DP) algorithm is generally used in the generation planning problem[8][14].

When using the DP algorithm, the fundamental idea is that each generation technology is regarded as one stage in a cost accumulation process, while the total capacity of various generation technologies is expressed by the state of the process. The problem can be characterized as a dynamic program, whose stages are generation technologies and whose states are cumulative capacities. In conventional DP, the amount of calculation increases exponentially with the increase in the number of types of generation, therefore it is not feasible for the large-scale problem.

This paper introduces the extended DP algorithm, which is adopted aiming at reducing the state set of the normal solution in multiple-dimensional DP[15]~[18]. In the computation, eliminate the state values that are judged not get the optimal solution based on criterion at each stage, the number of states are obviously cut down. Because the state set of every stage have to be calculated and the number of states at later stage is influenced by the one at former stage, the states are reduced geometrically by this way and the combinatorial explosion can be avoided.

The criterion for judging in extended DP is as follows:

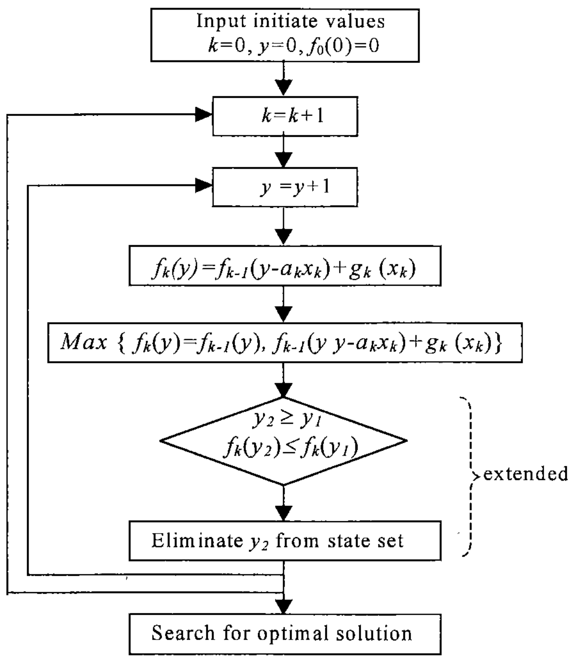

Fig.3 The principle of extended DP

Objective function:

$$Max\ Z = \sum_{i=1}^{n} g_i(x_i) \tag{14}$$

Subject to:

$$\sum_{i=1}^{n} a_i x_i \le b \quad (i = 1 \sim n) \tag{15}$$

Suppose $k = 1 \sim n$, $y = 0 \sim b$, then based on DP approach, the following equation can be obtained:

$$f_k(y) = f_{k-1}(y - a_k x_k) + g_k(x_k) \tag{16}$$

At stage $k\,(<n)$, when the two states $(y_1, f_k(y_1))$, $(y_2, f_k(y_2))$ exist, If $y_2 \ge y_1$ and $f_k(y_2) \le f_k(y_1)$, then the following conclusion can be drawn, which is that $(y_2, f_k(y_2))$ will not obtain the optimal solution.

The necessary for the formulation of the extended DP approach is the above basic calculating formulae that are used for determining this criterion and state set of stage. All the state set can be got by repeating the basic calculation and above judging treatment from the first stage to the last stage; the optimal solution can be obtained by searching the objective value that becomes biggest from the state set in the last stage. The principle of the extended DP can be expressed by Fig. 3.

4. Scenario analyses of IPPs

In a competitive generation market, to maximize profit, IPPs want to sell electricity to the utility at the highest possible price while the utility wants to purchase electricity from IPPs at the lowest possible prices. Therefore, it is important to specify the transaction prices at the time that the IPPs are brought into the market by the utility. The following discusses the bidding strategies of IPPs based on analyses of their scenarios[(19)~(21)].

4.1 Case of one IPP The IPP's cost can be formulated by a linear relation as follows:

Total cost = Fixed cost + Variable cost coefficient × Power generated by IPP (17)

In Fig.4, suppose that λ is the utility's purchase price from an IPP. If IPP sells power Q_O to the utility, because cost equals revenue, IPP makes no profit. But if IPP sells power Q_A ($Q_A > Q_O$) to the utility, then revenue is over cost, the IPP will make profit and the profit is $P_A - C_O$.

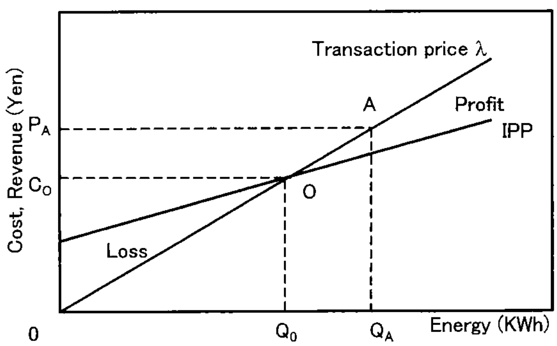

Fig.4 Scenario with one IPP

4.2 Two IPP case In Fig.5, IPP1 and IPP2 represent different types of IPPs, whose fixed costs and variable costs satisfy the following conditions:

Fixed cost of IPP1 < Fixed cost of IPP2

Variable cost of IPP1 > Variable cost of IPP2

When IPPs sell power over Q_O (such as Q_A) to the utility with

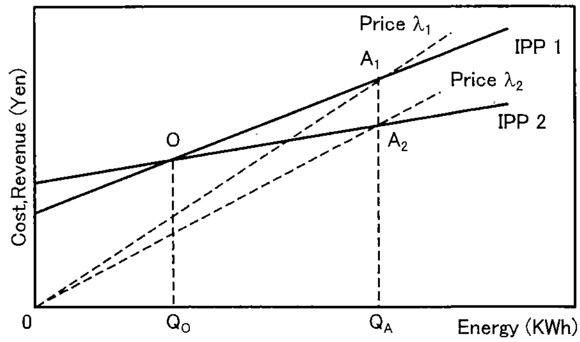

Fig.5 Scenarios with two types of IPPs

some prices, for IPP1, it can make profit only if the transaction price is over λ_1. Similarly, for IPP2, it can only make a profit if the transaction price is greater than λ_2. Because price $\lambda_2 < \lambda_1$, when the utility wants to purchase power at a cost above Q_O, it will choose IPP2 rather that IPP1. If the utility wants to purchase power that at a cost below than Q_O, it will choose IPP1 rather than IPP2. The energy Q_O can be regarded as an energy limit for the two types of IPPs at the time they bid together.

4.3 Three IPP cases In Fig.6, there are three types of IPP: peak-type IPP, middle-type IPP and base-type IPP. Suppose Q is the amount of energy that the utility wants to purchase from IPPs. Based on the above analyses, the following conclusions can be drawn:

1) If $Q < Q_A$, the utility will select the peak-type IPP, and λ_A will be the minimum purchase price for the peak-type IPP;
2) If $Q > Q_A$ and $Q < Q_B$, the utility will select the middle-type IPP. λ_A will be the maximum purchase price and λ_B will be the minimum purchase price for the middle-type IPP;
3) If $Q > Q_B$, the utility will select the base-type IPP, and λ_B will be the maximum purchase price for the base-type IPP.

The above conclusions can be generalized to the general case of optimization of the IPPs, in which the IPPs all try to maximize their own profits and balance is reached in the end.

Taking changes in price into account, we assume two transaction prices for each type of IPP with different energy limits. The maximum price or minimum price for each IPP is one case. The values in the range between the maximum and minimum prices are the other cases. Considering all possible combinations of the cases, there are in total 8 cases. To illustrate the procedure of the proposed method, only three types of IPPs and two cases of prices are assumed. However, even if more types of IPPs and more prices were supposed, the generality of the problem formulation would not be changed.

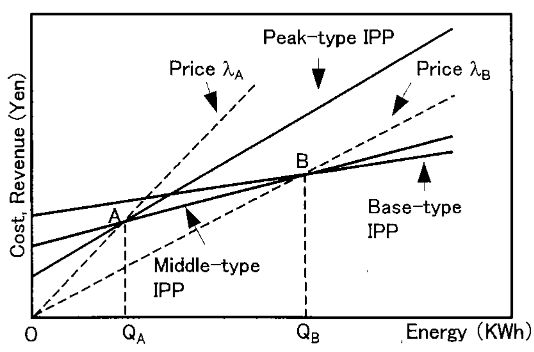

Fig.6 Scenarios with three types of IPPs

5. Solution for coordinative generation expansion planning including IPPs

As shown in Fig.7, the flow of the solution may be abstracted as follows:

Step1: Estimate annual load duration curve for the target year;

Step2: Set up limits for CO_2 emissions at 16.0 GTon and 18.0 GTon respectively;

Step3: Set up cases for three types of IPPs competitively bidding against one another. We assume 2 purchase prices for each type of IPP, for a total of 8 combinations;

Step4: Determine the corresponding bidding conditions (energy limits) of the IPPs based on the optimization model for competing IPPs;

Step5: Obtain the optimal generation plan of utility while considering IPPs;

Step6: Calculate LOLP and EENS. If it is not possible to satisfy $LOLP_T$ and $EENS_T$ at the same time, add one gas turbine;

Step7: Repeat Step 5 until the conditions are satisfied;

Step8: Calculate minimum costs and record the optimal combination. Return to Step 3, change the conditions and repeat the calculation;

Step9: Return to Step 2, change the limit of CO_2 emission and repeat the same calculation;

Step10: Compare the results and select the lowest cost. This is the coordinative generation expansion plan for the utility that guarantees profits to the IPPs under different CO_2 emission limits.

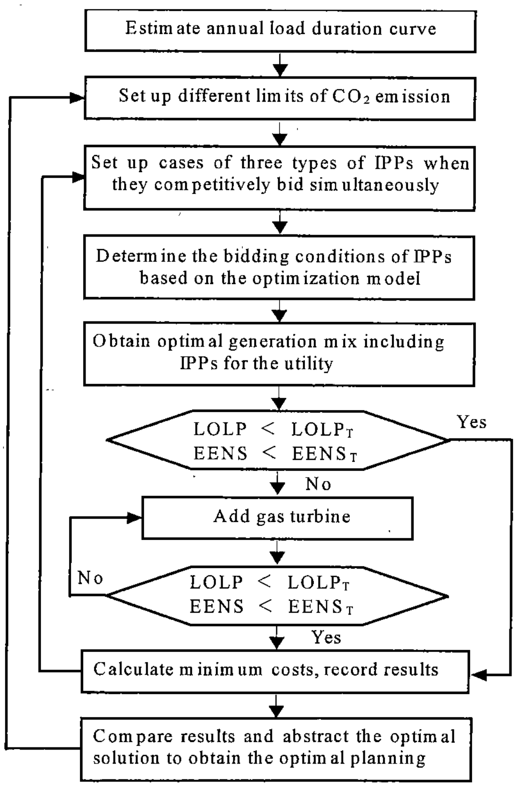

Fig.7 Flow of decision method

The optimization model at Step 4 is used to determine the bidding prices of IPPs to obtain equilibrium solutions for utility and IPPs. As shown in Fig. 8 the process of optimization is expressed by following steps:

1) Input the initiate value of sales price of IPP λ_{j0};

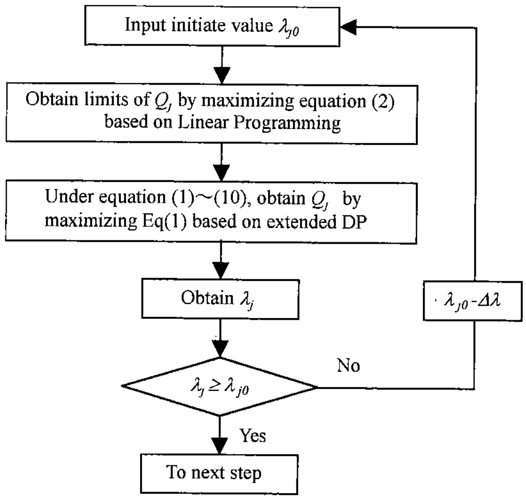

Fig. 8 Determining process of IPPs' bidding prices

2) By maximizing equation (2), obtain the limits of Q_j of IPPs based on Linear Programming method;

3) Under equation (1) ~ (10), obtain Q_j by maximizing equation (1) based on extended DP;

4) Obtain the value of λ_j;

5) Compare the magnitude of λ_{j0} and λ_j, if $\lambda_j < \lambda_{j0}$, $\lambda_{j0} - \Delta\lambda$ then return to step 1);

6) If $\lambda_j \geq \lambda_{j0}$, finish the calculation and keep the value of λ_{j0}.

6. Application to a test power system

This paper assumes a peak load of 15600MW, demand of 88.8 TWh and a load factor of 65% in the target year, and uses an analytical function to simulate the annual load duration curve*. Table 2 shows the parameters for utility generation. Table 3 shows the parameters for the IPPs. From Table 3, the transaction prices and respective energy limits for the IPPs when they are bidding into the generation market can be obtained based on the their optimization models. This paper assumes 2 purchase prices for each IPP with their respective energy limits. The 8 cases are shown in Table 4.

Table 2. Parameters for various utility generation technologies

Unit type	Unit capacity (MW)	Fixed cost (KYen/kW)	Variable cost (Yen/kWh)	CO_2 coefficient (Ton/MWh)	Outage rate (%)
Nuclear	1000	36.0	1.0	0	4.0
Coal	500	25.0	2.4	0.33	3.5
LNG	300	19.0	4.1	0.23	3.0
Oil	200	15.5	4.7	0.28	2.5
Gas	150	12.0	6.2	0.21	2.0

Table 3. Parameters for IPPs

IPP type	Unit capacity (MW)	Fixed cost (10^9 Yen)	Variable cost (Yen/kWh)	CO_2 coefficient (Ton/MWh)	Outage rate (%)
Base	500	16.5	2.0	0.35	4.0
Middle	300	11.0	3.8	0.25	3.5
Peak	150	8.0	5.8	0.21	3.0

(*)Load duration curve $L(t) = 0.01p{\cdot}r + (a - 0.01p{\cdot}r)/tg(-1.25) \cdot tg(2.5t - 1.25)$
t: Duration time; p: peak load; r: Load factor.

Table 4. Cases of IPPs bidding into the generation market

IPP / Case	Base-type		Middle-type		Peak-type	
	λ_j	Q_j	λ_j	Q_j	λ_j	Q_j
Case 1	4.9	3.8-	7.2	1.5-3.8	13.0	0.3-1.5
Case 2	4.9	3.8-	7.2	1.5-3.8	11.0	0.4-1.5
Case 3	4.9	3.8-	6.0	2.2-3.8	13.0	0.3-2.2
Case 4	4.9	3.8-	6.0	2.2-3.8	11.0	0.4-2.2
Case 5	4.5	4.3-	7.2	1.5-4.3	13.0	0.3-1.5
Case 6	4.5	4.3-	7.2	1.5-4.3	11.0	0.4-1.5
Case 7	4.5	4.3-	6.0	2.2-4.3	13.0	0.3-2.2
Case 8	4.5	4.3-	6.0	2.2-4.3	11.0	0.4-2.2

(Unit: Price λ_j (Yen/kWh), Energy Q_j (GWh))

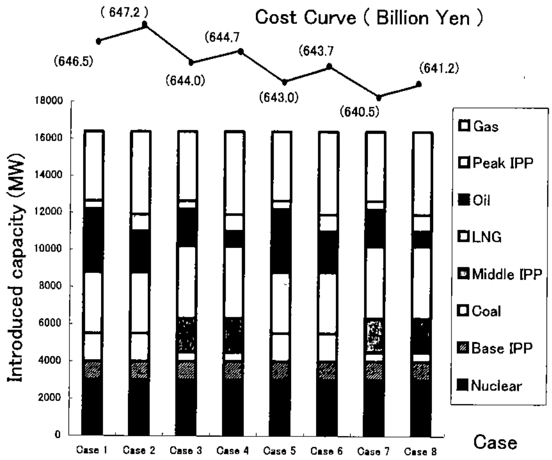

Fig.9 Simulation results within emission limits of 16.0 GTon CO_2

Fig.9 shows the simulation results of the generation mix for the utility that includes IPPs with emission limits of 16.0 GTon CO_2. In all cases, the IPPs are introduced. It shows that the introduction of IPPs can make utility costs down. The purchase prices for base-type IPPs in Case 5 - Case 8 are lower than that in Case 1 - Case 4, and the costs of the utility in Case 5 - Case 8 are lower than that in Case 1 - Case 4. This demonstrates that the utility can reduce its costs (raise its profits) while base-type IPPs bidding with lower sales prices.

Similarly, when the base-type IPPs bid with same sales prices, the utility can reduce its costs if the middle-type IPPs bid with lower sales prices. Such as the cost in Cases 3, 4 is lower than that in Cases 1, 2 respectively, and the costs in Case 7, 8 are lower than the corresponding costs in 5 and 6. Therefore, the cost of the utility can be reduced when the base-type IPP and middle-type IPPs bid with lower sales prices.

However, the rule is not applicable to the peak-type IPP. In the cases that the base-type IPP and the middle-type IPP bidding with identical sales prices respectively, costs in Cases 1, 3, 5 and 7 are lower than the corresponding costs for Cases 2, 4, 6 and 8. This shows that the costs of utility can be reduced while the peak-type IPPs bidding with a higher sales prices. When peak-type IPPs bidding with cheaper prices, they are largely introduced by the utility such as shown in Cases 2, 4, 6 and 8. However, to ensure the reservation capacities, the gas turbines are added by the utility and make the costs increase, which are more than that in Cases 1, 3, 5 and 7.

From the above analyses, it was shown that the cost of utility can be reduced in case of the base-type IPPs and middle-type IPPs bidding with lower prices and the peak-type IPPs bidding

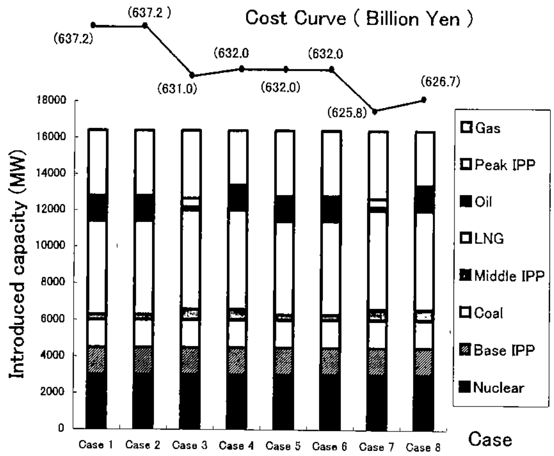

Fig.10 Simulation results within emission limits of 18.0 GTon CO_2

with higher prices.

Therefore, the lowest cost to the utility exists at the point that the sales prices of the base-type and middle-type IPPs are lowest and the one of the peak-type IPP is highest. The optimal plan is at Case 7, and three types of IPPs all get their profits at Case 7.

Fig.10 shows the simulation results for the generation mix of the utility that includes IPPs with emission limits of 18.0 GTon CO_2. The increase of base-type IPPs, LNGs and oil generators which have relatively higher CO_2 emission coefficients can be observed. When small quantity of peak-type IPPs is introduced by utility, the peak-type IPPs can not make profits. Therefore, even the bidding price of peak-type IPP is cheaper in Case 4, the peak-type IPP is not introduced by utility as compared with Case 3. Furthermore, because of that the increase of Oil generation makes the costs up, the costs in Case 4 is higher than the one in Case 3.The optimal plan is at Case 7, and three types of IPPs all get their profits. It can also be concluded that the total costs of utility can be reduced while the base-type IPPs and middle-type IPPs bidding with lower sales prices and the peak-type IPPs with higher sales prices.

Comparing the simulation results in Fig.9 and Fig.10 for identical cases, it is clear that the cost under the lower CO_2 limit is higher than the cost under the higher CO_2 limit. Therefore, the total cost will be reduced if the limit on CO_2 emissions is raised. Regarding to the cost variation for CO_2 values, the trade-off between the two situations in Case 7 is (640.5-625.8)/(18-16)=7.35 Yen/ton.

In addition, the simulation results depend on the supposed conditions (such as supply of reservation capacities, initiate parameters, etc), and if the conditions change, the results will change. Also in the simulations, as the assumed parameters and conditions are used to demonstrate the feasibility of the proposed method, real data would be necessary for actual applications

7. Conclusions

There is a trend toward competition in power generation in the present-day electric market, and Japan is placing increased emphasis on environmental issues. To obtain a well-balanced generation expansion plan taking these various factors into account, this paper proposed a method to determine the coordinative generation expansion planning from the viewpoint of a utility company while considering IPPs. The feasibility of the proposed approach was demonstrated by using a test system. The scenario analyses of IPPs clarified that different types of IPP have different bidding conditions. From the simulation results for different CO_2 emission limits, we can draw the conclusions as follows: The introduction of IPPs would reduce the cost of the utility; and when the base-type IPPs and middle-type IPPs bidding with lower sales prices and the peak-type IPPs bidding with higher sales prices, the utility can obtain an optimal generation expansion plan with lower costs; If CO_2 emission limits are raised, the utility can obtain further cost savings.

The proposed approach can offer utility companies as reference for determining the coordinative generation expansion problem in the new, present-day environment.

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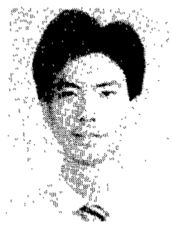

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