Unit Commitment for an Uncertain Daily Load Profile

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Abstract - In this study, a new Unit Commitment (UC) algorithm is proposed to consider the uncertainty of a daily load profile. The proposed algorithm calculates the UC results with a lower load level than that generated by the conventional load forecast method and the greater hourly reserve allocation. In case of the worst load forecast, the deviation of the conventional UC solution can be overcome with the proposed method. The proposed method is tested with sample systems, which indicates that the new UC algorithm yields a completely feasible solution even when the worst load forecast is applied. Also, the effects of the uncertain hourly load demand are statistically analyzed, particularly by the consideration of the average over generation and the average under generation. Finally, it is shown that independent power producers participating in electricity spot-markets can establish bidding strategies by means of the statistical analysis. Therefore, it is expected that the proposed method can be used as the basic guideline for establishing bidding strategies under the deregulation power pool.

Keywords: load profile, uncertainty, unit commitment

1. Introduction

The electric power industries have been vertically integrated and their regional monopolies were generally secured by regulations of governments before deregulation changed the industries in the 1980's. These conventional characteristics of the electrical power industries were slowly demolished with the introduction of deregulation and the opening of the transmission networks [1]. According to the tendency of the worldwide electric power industries, Korea began to deregulate its electrical power industry and six generating companies (Gencos) were split from the Korea Electric Power Corporation (KEPCO). The distribution part of KEPCO will be soon deregulated as well.

Almost all the theories and methods employed to operate the electricity market are now rapidly shifting to embrace the changes initiated by deregulation. There are two major tasks considered in the economical operation of the conventional power systems. One is the Unit Commitment (UC), which determines the on/off schedules of units in order to minimize overall system operation cost over the scheduling time period. The other is the Economic Dispatch (ED), which determines the assignment of generation power for the committed generating units to minimize the total fuel cost. However, under the competitive market place, the transaction between independent power producers (IPPs) and the end consumers becomes the focus of the economic operation of a power system. Therefore, electricity markets are formed and power exchanges are established to ensure proper operation of those markets. As a result, new approaches are required to reflect the continuously changing electricity market conditions.

The Korea Power Exchange (KPX) is now managing Korean electricity with the cost based pool (CBP) method. The market management method will be based on the two way bidding pool (TWPB) to establish a fully deregulated electricity market. When an electricity market is fully deregulated, typical behavior of the IPPs would be like this: Genco will compose its daily generation plan based on the previous day's load forecasting data. The company will participate in market bidding using this generation plan. When a discrepancy happens between the load forecast and the actual demand or in the event there is any unsatisfied demand in a market, Genco can participate in a spot bidding to meet that demand. If KPX moves into the TWBP, the IPPs in Korea would also follow this behavior.

Genco should have the optimal bidding strategy to make more profit and this optimal bidding strategy requires the optimal fuel cost calculation based upon the assumption that the hourly load demand is identical to the load pattern of the future. However, it is impossible for the IPPs to pre-estimate the exact assignment of generation power of the trading day due to the intrinsic characteristics of the market such as uncertainty. Little research has been done for the

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UC under this uncertain daily load profile, even though the solution for this problem is one of the crucial points where Genco can make greater profit. Therefore, a new way to solve the UC under the market uncertainty is presented in this paper.

2. Unit Commitment Considering Uncertainty

In recent years, there have been many studies performed on the UC considering the competitive electricity market. However, there have been very few investigations done that tried to reflect the actual bidding process or the market uncertainty.

2.1 Uncertain Daily Load Profile

A typical UC algorithm assumes that the hourly load forecast would perfectly match the actual demand to minimize the complexity of solutions. However, the load forecast cannot match the real demand because of metrological, social, environmental and cultural reasons. Furthermore, the uncertainty becomes more complicated when the bidding process in an electricity market does not guarantee that the total demand would be identical to the total amount of generation bidden by the Gencos. Hence, a proper UC algorithm should assume that there is always a certain level of uncertainty in the market. When a UC algorithm does not reflect the market uncertainty, the following problems might be observed:

- The feasibility problem of the UC solution when unexpected load demands occur
- The over generation problem due to abnormal weather conditions or too optimistic a load forecast
- The under generation problem due to abnormal weather conditions or too pessimistic a load forecast
- The possibility of running units involving high fuel costs
- The deviation from its optimal operation point due to the change of the generation plan
- The safety issues of the generation facilities

In fact that the accuracy of the load forecast is closely related with the optimality of a UC solution, a proper UC solution should be made under the consideration of the above problems. However, solving the UC problem with the market uncertainty is not easy because there are already many constraints in the problem. Thus, conventional studies focus their approaches on the solution refinement method of the pre-calculated UC results.

2.2 Coping with the Uncertain Load Profile

To present the way to treat uncertainty in the load profile, Fig. 1 is given as a starting point.

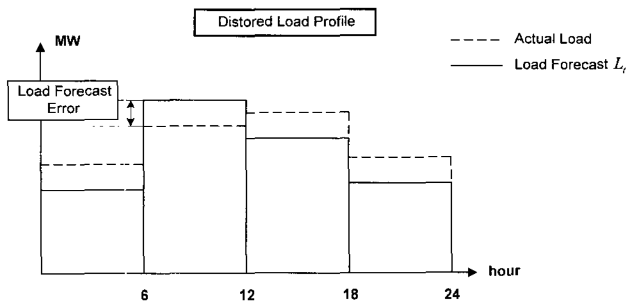

Fig. 1 The distorted load profile

The difference between the solid lines and the dotted lines in Fig. 1 arises from the uncertainty in the load forecast and the bidding in the market. If a UC schedule is made with the solid lines in Fig. 1, the total generation would exceed the demand between hour 6 to hour 12 and the demand would exceed the generation during the remainder of the time.

On the contrary, if a UC plan is composed with the value made by deducting the maximum error from the solid lines, the surplus generation would be eliminated, but the demand would still exceed the generation during the rest of the time. If a UC solution is composed with the value made by adding the maximum error to the solid lines, the surplus generation would be reintroduced.

The comparison between the load forecast curve and the real load curve is presented in Fig. 2. Assuming that the real load demand can be within +/- 2.5% of the forecast, the upper and the lower dotted lines show this range.

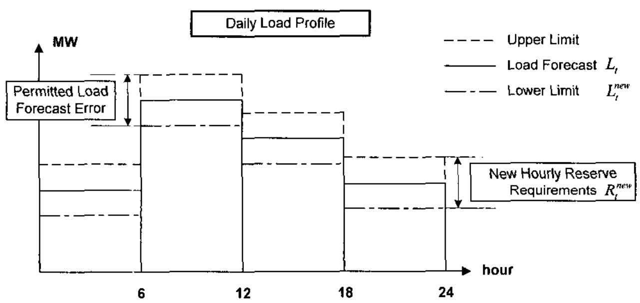

Fig. 2 The normal load forecast vs. the actual uncertain load demand

Generally, the range of the maximum permitted load forecast error can be determined. For that reason, the under generation and the over generation problems can be resolved by performing a UC algorithm covering the range from the lower dotted lines to the upper dotted lines in Fig. 2. By examining Fig. 2, one can intuitively discover that the two problems can be solved by adopting the following schemes into a UC algorithm.

- Using L_t^{new} instead of the original load forecast
- L_t^{new} : the value made by deducting the maximum error from the solid lines
- Changing the hourly reserve requirement into R_t^{new}.
- $R_t^{new} = \frac{UpperLimit - LowerLimit}{LowerLimit} \times 100$ [%]

2.3 Unit Commitment for an Uncertain Load Profile

As stated before, the UC can be performed for an uncertain daily load profile by using a lower load level than the one generated by the conventional load forecast and the sufficient generating reserve to cover the maximum load forecast error. Therefore, the following unit commitment algorithm is suggested in this section.

2.3.1 Objective Function

$$F = \sum_{t=1}^{M} \sum_{i=1}^{N} \left[St_i^t F_i(P_i^t) + St_i^t (1 - St_i^{t-1}) Su_i(H_i^{t-1}) \right] \quad (1)$$

where,

F : total operation cost of the entire system

P_i^t : power generation of unit i at hour t (MW)

$F_i(P_i^t)$: fuel cost of unit i when generating power is equal to P_i^t

N : total number of units

M : total study time span in hours

St_i^t : commitment state of unit i at hour t (1 or 0)

H_i^t : time duration for which unit i has been on/off at hour t

$H_i^t > 0$ if $St_i^t = 1$

$H_i^t < 0$ if $St_i^t = 0$

$Su_i(H_i^{t-1})$: start up cost of unit i after H_i^{t-1} hours off

$Su_i(H_i^{t-1})$ is calculated by Eq. (2) when TC_i, CH_i, BC_i and SMC_i are known.

$$Su_i(H_i^t) = TC_i + (1 - e^{-t/CH_i}) \times BC_i + SMC_i \quad (2)$$

TC_i : turbine start up cost of unit I

CH_i : boiler cooling time of unit i (hour)

BC_i : boiler start up cost of unit i

SMC_i : start up management cost of unit i

Otherwise,

$$Su_i(H_i^t) = \begin{cases} CSC_i & if \ -H_i^t \ge CH_i \\ HSC_i & if \ -H_i^t < CH_i \end{cases} \quad (3)$$

2.3.2 New Constraint Variables L_t^{new}, R_t^{new}

The lower limit of system load demand at hour t is yielded by the following Eq. (4).

$$L_t^{new} = L_t \times (1 - E_{LF} \times 0.01) \ \text{(MW)} \quad (4)$$

where, E_{LF} is the maximum permitted load forecast error due to the uncertainty of bidding or the inaccuracy of the load forecast.

The new generating reserve requirement considering the permitted load forecast error is as follows:

$$\begin{aligned} R_t^{new} &= L_t \times (1 + E_{LF} \times 0.01) - L_t^{new} \ \text{(MW)} \quad (5) \\ &= \frac{L_t \times (1 + E_{LF} \times 0.01) - L_t^{new}}{L_t^{new}} \times 100 \ (\%) \end{aligned}$$

2.3.3 Constraints

(C.1) System load demand

$$\sum_{i=1}^{N} P_i^t = L_t^{new} \qquad t = 1, \ldots, M \quad (6)$$

(C.2) Hourly reserve requirements

$$\sum_{i=1}^{N} St_i^t Rp_i \ge R_t^{new} \qquad t = 1, \ldots, M \quad (7)$$

where,

Rp_i : ramp rate limit of unit i (MW/h)

(C.3) Unit generation limits

$$\underline{P_i} \le P_i^t \le \overline{P_i} \qquad i = 1, \ldots, N \quad t = 1, \ldots, M \quad (8)$$

where,

$\underline{P_i}$: rated lower generation limit of unit i

$\overline{P_i}$: rated upper generation limit of unit i

(C.4) Minimum up/down times

$$\left[H_i^{t-1} - Mu_i \right] \times \left[St_i^{t-1} - St_i^t \right] \ge 0 \quad (9)$$

$$\left[-H_i^{t-1} - Md_i \right] \times \left[St_i^t - St_i^{t-1} \right] \ge 0 \quad (10)$$

where,

Mu_i : minimum up time of unit i

Md_i : minimum down time of unit i

(C.5) Ramp rate limits

$$\left|P_i^t - P_i^{t-1}\right| \le UR_i \text{, for } P_i^t > P_i^{t-1} \quad (11)$$

$$\left|P_i^t - P_i^{t-1}\right| \le DR_i \text{, for } P_i^t < P_i^{t-1}$$

where,

UR_i : up ramp rate of unit i (MW/h)

DR_i : down ramp of unit i (MW/h)

(C.6) Start up constraint

$$P_i^t = \underline{P}_i, \quad \forall i \text{ st. } St_i^{t-1} = 0, \quad St_i^t = 1 \quad (12)$$

3. Case Study

The proposed algorithm has been tested with sample systems. The generator data are the same as used in reference [2]. The load demand and system reserve requirement in the test cases are given in Tables 1 ~ 2.

Table 1 Load demand in test cases

Hr	Load (MW)	Hr	Load (MW)	Hr	Load (MW)
1	2070	9	2420	17	2520
2	1880	10	2540	18	2340
3	1820	11	2600	19	2380
4	1770	12	2630	20	2260
5	1890	13	2780	21	2320
6	2020	14	2840	22	2110
7	2160	15	2810	23	2030
8	2310	16	2740	24	2090

Table 2 System reserve requirement

Hr	Reserve %	Hr	Reserve %	Hr	Reserve %
1	5	9	6	17	6
2	5	10	6	18	6
3	4	11	7	19	6
4	4	12	7	20	6
5	5	13	7	21	6
6	5	14	7	22	5
7	6	15	7	23	5
8	6	16	7	24	5

In this paper, the conventional DP-STC (Dynamic Programming Sequential & Truncated Combination) algorithm [3-6] is employed for the UC calculation. The UC is performed under the consideration of the constrains such as system load demand, hourly reserve requirements, unit generation limits, minimum up/down times, up/down ramp rate limits and the startup limit. During the iterative DP-STC optimization process, the generating power P_i^t is calculated by means of the conventional ED algorithm with the quadratic generation cost function $F_i(P_i) = a_iP_i^2 + b_iP_i + c_i$. The start up cost of each unit is calculated using Eq. (3), and $FLAC_i$ (Full Load Average Cost of unit i) is selected for the priority list index of the DP-STC method.

This paper deals with 6 test cases, and Table 3 presents the simulation condition for each case.

Table 3 Test cases

Case	E_{LF} (%)
1	0 % - Original L_t is used
2	1 %
3	2 %
4	3 %
5	4 %
6	5 %

In order to analyze the suggested method, 1) the UC results for each test case are calculated with the proposed method, 2) 60,000 random load profiles are yielded that have the maximum 2.5% load forecast error, and 3) the average over generation (AOG) and the average under generation (AUG) are calculated by averaging the difference between 1) and 2). The results of each case are shown in Tables 4 ~ 5.

Table 4 Average over generation (MW) at each stage

Case \ E_{LF}	1 %	2 %	3 %	4 %	5 %
1	2.88	5.77	8.67	11.53	14.38
2	0.0	0.16	2.88	5.75	8.61
3	0.0	0.0	0.0	0.15	2.92
4	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0

Table 5 Average under generation (MW) at each stage

Case \ E_{LF}	1 %	2 %	3 %	4 %	5 %
1	2.87	5.76	8.63	11.55	14.39
2	11.53	11.59	14.43	17.36	20.16
3	22.99	22.99	22.99	23.12	25.91
4	34.53	34.53	34.54	34.59	34.59
5	46.07	46.07	46.08	46.13	46.13
6	57.73	57.73	57.74	57.80	57.80

As shown in Table 4, the over generation problem appears only in the upper right triangular region. And one can find that the amount of AOG also increases according to E_{LF} increase. This means that if the electricity market offers the maximum load forecast uncertainty then Gencos are able to restrain the occurrence of AOG with the proposed method.

In the competitive market, the upper right triangular region of Table 4 corresponds to: 1) the amount of a successful bid in the daily market is less than that of an expectation, and 2) the amount of the practical load demand is less than that of the total transaction occurred in the daily market. In this case, AOG increases according to the increase of uncertainty E_{LF}. Hence, Gencos sell the redundant electric power in the spot market instead of generating the surplus.

Therefore, restraining AOG is preferable to Gencos having a tendency to pay an important role on the safety issues of the generation facilities. It is advantageous for such companies that the UC schedule is calculated under the assumption of the large E_{LF}. In contrast, there are Gencos having the UC schedule calculated under the assumption of the small E_{LF}. Following the strategy may be preferable to such Gencos having small electric power facility capacitance. But such companies should have an alternate bidding strategy to re-sell the redundant electric power in case that the actual E_{LF} is large during that trading day.

For the reasons stated above, Gencos might have the following bidding strategies.

S1) For the safe operation of the generation facilities, it is preferable for Gencos to participate in the daily electricity market with the UC solution calculated under the assumption of $\frac{E_{LF}}{2} \le x \le E_{LF}$.

S2) If the electricity spot market exists, it is advantageous for Gencos to participate in the daily electricity market with the UC schedule yielded under the assumption of $0 \le x \le \frac{E_{LF}}{2}$.

S3) If Gencos participate in the daily electricity market with the strategy S1, but the actual E_{LF} in the trading day is greater than the expected maximum value $\frac{E_{LF}}{2}$, then the companies participate in the daily electricity market with the strategy S2 instead of S1.

S4) If Gencos participate in the daily electricity market with the strategy S2, but the actual E_{LF} in the trading day is less than the expected minimum value $\frac{E_{LF}}{2}$, then it is preferable for the companies not to participate in the electricity spot market.

Comparing Table 5 with Table 4, AUG is distributed more normally than AOG, except in Case 1. This means that the proposed method does not influence AUG heavily and that E_{LF} does not influence on AUG yielded by the proposed method. Also, the AUGs of Case 2 to Case 6 are already considered by Eq. (7) so that units in the practical area are sufficient to cope with the lower left triangular region of Table 5.

4. Conclusion

In this paper, a new UC algorithm is proposed to consider the uncertainty of a daily load profile. The proposed algorithm calculates the UC results with the lower load level than the one generated by the conventional load forecast method and the greater hourly reserve allocation. In case of the worst load forecast, the deviation of the conventional UC solution can be overcome with the proposed method. Also, the effects of the uncertain hourly load demand are statistically analyzed, particularly by the consideration of the average over generation and the average under generation. Finally, it is shown that independent power producers participating in electricity spot-markets can establish bidding strategies by means of the statistical analysis.

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