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An Analysis on the Adequate Level of Capacity Price from a Long-Term Generation Expansion Planning Perspective: the Case of Korea

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Abstract – Capacity payment mechanism has been adopted as the incentive scheme to achieve resource adequacy in Korean electricity market, however, the level of capacity price has been controversial due to its insufficient extent to incur financial loss for certain generators. Therefore, a new method is proposed to estimate the proper level of capacity price incorporating profitability of market participants and resource adequacy in this paper. The proposed method is successfully applied to test system based on Korean power system.

Keywords: Capacity payment, Capacity price, Profitability, Resource adequacy

1. Introduction

The long-term generation expansion planning(GEP) has to be carried out to supply forecasted electricity demand in the future and also to satisfy predefined system reliability criterion at minimum cost or maximum social welfare [1]. In Korea, centralized cost minimization GEP has been adopted due to structure of power industry [2], and it focuses on constructing investment plan for minimizing total supply cost under system constraints, which are necessary in perspective of independent system operator (ISO) to ensure the power system reliable. Therefore, the profitability of market participants is not considered in long term planning process generally. As a result, market participants who invest new generators based upon investment plan led by ISO cannot achieve theirs financial target or recover investment cost, which is so-called the missing money problem [3].

Recently various types of capacity remuneration mechanisms have been adopted in electricity markets worldwide to resolve the missing money problem. The mechanisms can be categorized into two types: volume approach vs. price approach [4].

Typical volume approaches implemented globally are strategic reserve implemented in Sweden, Finland and Germany [5, 6], capacity auction implemented in PJM, NYISO and ISO-NE [7, 8], capacity payment implemented in Spain and Chile [9, 10]. In the same manner, the price approach, also called as 'capacity payment', is adopted in various countries such as Korea, Spain and Portugal, etc [11]. Even though the price approach is the simplest form of capacity remuneration mechanism and easy to implement in the electricity market, it has a fundamental weakness that the payment of capacity price does not guarantee the investment in new capacity and needs to be adjusted in ad hoc manner to secure the necessary generation capacity for reliable operation of the electricity market [12].

The main motivation of this paper is to analyze what is the proper level of capacity price in order for the long-term generation expansion planning to satisfy the given reliability condition or the minimum reserve margin constraint in capacity payment mechanism. In centralized scheme of the electricity sector, the capacity price might be determined fundamentally to guarantee fixed cost recovery for generators which contribute to resource adequacy. However, the capacity price may be required to be at higher level in deregulation scheme of the electricity sector which has been introduced in many countries [13]. Deregulation has triggered a massive influx of independent power producers (IPP) into the electricity sector. Consequently, the profitability of a market participant has become more important for securing resource adequacy since the profitability is one of the primary factors for investment decision making of the corresponding market participant.

The profitability can be evaluated mostly with the revenues from the energy market and capacity payment. Theoretically, the former can cover variable cost and the latter can cover fixed cost. Nevertheless financial loss due to market settlement process, fuel price fluctuation, etc., can be observed in peak-load generator especially which has relatively low infra-marginal rent. In real situation, the revenue from the capacity payment plays an important role to compensate financial loss of peak-load generator from the energy market[14]. Therefore, it can be claimed that the study to investigate the proper level of capacity price for the profitability and resource adequacy is needed.

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This paper proposes a systematical method to analyze the adequate level of capacity price incorporating the profitability and resource adequacy in marginal cost based electricity market. The proposed method is successfully applied for estimating the adequate level of capacity price of the actual Korean electricity market with various scenarios.

The major contributions of this paper are summarized as follows: First, a new method to estimate capacity price is proposed. Estimating the adequate level of capacity price can contribute to improve the profitability of market participants, which can reduce supply uncertainties caused by construction delay or cancelation. Second, it is expected that the capacity price from the proposed method can be fundamental to determine the amount of reserve capacity procurement and price when capacity market mechanism is introduced.

The rest of the paper is organized as follows. In section 2, mathematical formulation and methodology of the proposed method are described. In section 3, simulation scenarios and results are described. Finally, conclusions are outlined in section 4.

2. Description of the proposed method

2.1 Mathematical formulation

Aimed at minimizing the total power purchase cost that should be paid by the system operator or the power purchasing entities [15], the objective function is defined as the sum of the energy payment and capacity payment which can be described as follows:

Objective function

$$Min \sum_{y}^{Y}\sum_{q}^{Q}\sum_{g}^{G} A_y\{\omega_{g,q,y}MWh_{g,q,y} \\ +Hour_q(1\text{-}q_g)(1\text{-}MOR_{g,q,y})C_g CP\} \quad (1)$$

In Eq. (1), the first term denotes the energy payment where ω_g is the weighted average of the settlement price for the generator g in \$/MWh and $MWh_{g,q,y}$ is the expected generation amount of the generator g during the qth quarter in year y in MWh. The method how to calculate the weighted average of the settlement price ω_g will be explained in detail afterward. The second term denotes the total capacity payment where $Hour_q$ is the number of hours in qth quarter, q_g is the forced outage rate, $MOR_{g,q,y}$ is the maintenance outage rate in qth quarter in year y, C_g is the rated capacity of the generator g in MW and CP is the unit capacity price per hour in \$/MWh. Y, Q and G represent the set of year, quarter and generator respectively.

Profitability constraints

One unique constraint incorporated in the mathematical model in this paper is the profitability constraint for the newly built generators described as the following equation:

$$\sum_{y}^{Y} HR_{g,y}\{\sum_{q}^{Q}(\pi_{g,q,y}+R_{g,q,y})\text{-}O_{g,y}+S_{g,y}\text{-}I_{g,y}\} \\ \geq 0, \forall g \in M \quad (2)$$

where $HR_{g,y}$ represents discount factor and M is a set of all the newly built generators. $\pi_{g,q,y}$ and $R_{g,q,y}$ are the profits from infra-marginal rent and capacity payment of the generator g during the corresponding periods, respectively and $R_{g,q,y}$ is equal to the second term of the objective function. $O_{g,y}$, $S_{g,y}$ and $I_{g,y}$ are the O&M (operation and maintenance) cost, salvage value and investment cost of the generator g in year y, respectively. Hence, the net present value for the newly built generator is guaranteed to be positive by the above constraint.

Another constraint is the profit constraint for generation companies, which is an extended version of Eq. (2) described as follows:

$$\sum_{y}^{Y}\sum_{g}^{K_j} HR_{g,y}\{\sum_{q}^{Q}(\pi_{g,q,y}+R_{g,q,y})\text{-}O_{g,y}+S_{g,y}\text{-}I_{g,y}\} \\ \geq 0, \forall j \in J \quad (3)$$

where j and J are indices of generation company and set of all generation companies which have to achieve their financial targets, respectively, and K_j is the set of all generators owned by a specific generation company.

Profit calculation of a newly built generator

The profit of a generator generally consists of the infra-marginal rent and capacity payment. For simplicity it is assumed that the scarcity rent is not allowed in this paper.

In order to calculate the infra-marginal rent of a generator, it is necessary that the values of two market elements should be derived: the generation (production) amount and the market settlement price.

The expected generation amount of a generator can usually be calculated using the probabilistic simulation technique based on mathematical convolution technique [16-18]. The mathematical convolution of the equivalent load duration curve (ELDC) is defined as follows:

$$ELDC_n(x) = (1\text{-}q_n)ELDC_{n\text{-}1}(x) + q_n ELDC_{n\text{-}1}(x\text{-}C_n), \\ n = 1, 2, \cdots, N \quad (4)$$

where n represents the index for the nth generator in the merit order stacking dispatch algorithm (the cheapest generator has the index one) and the q_n and C_n represent forced outage rate and rated capacity of the nth generator, respectively. Hence, the expected production of the nth generator can be calculated by the following equation [19, 20]:

$$MWh_n = (1\text{-}q_n)\int_{\underline{P}_n}^{\overline{P}_n} ELDC_{n\text{-}1}(x)dx, n = 1,2,\cdots,N \quad (5)$$

where $\underline{P}_n$ represents the sum of capacity of all the generators whose positions in the merit order are lower than the generator n, and $\overline{P}_n$ represents the sum of $\underline{P}_n$ and the capacity of the generator n.

Meanwhile, the market settlement price can be calculated as the cost of the most expensive generating unit included in the dispatch schedule of each hour, or the marginal cost of the marginal generator [12]. However, since calculating the marginal cost every each hour for long-term simulation is a time-consuming task, it is necessary to simplify the calculation procedure. Therefore, instead of calculating individual hourly market prices, we calculate the probability of how long a generator becomes the marginal generator. The probability that a generator becomes the marginal generator is equal to the probability that demand occurs within output range of the generator in the merit order stacking. The probability can be calculated with the following equation.

$$\begin{aligned} f(\underline{P}_n \le D \le \overline{P}_n) &= \tau_n \\ &= (1\text{-}q_n)\{ELDC_{n\text{-}1}(\underline{P}_n)\text{-}ELDC_{n\text{-}1}(\overline{P}_n)\}, \\ & n = 1,2,\cdots,N \end{aligned} \quad (6)$$

The function $f(D)$ denotes the probability that demand D occurs. It should be noted that a generator can become the marginal generator only if the generator can operate. Therefore, the probability calculated as the difference of two ELDC values should be multiplied by $(1-q_n)$. The proof of eq. (6) is summarized in Appendix I.

Next, settlement process for generators has to be formulated. As merit order stacking dispatch algorithm is applied to calculate production of generators, a generator operates when supply marginal cost is equal to or greater than its marginal cost. Hence, the weighted average settlement price of each generator can be derived as follows:

$$\omega_g = \frac{\sum_i \lambda_i \tau_i}{\sum_i \tau_i}, \{\forall i \in G \mid \lambda_g \le \lambda_i\}, \forall g \in G \quad (7)$$

where i is generator index and $\lambda_g(\lambda_i)$ represents the marginal cost of a generator in \$/MWh. τ_i represents the probability where a generator becomes the marginal generator as written in eq. (6). Consequently, the profit π_g from infra-marginal rent of the generator g can be calculated as follows:

$$\pi_g = (\omega_g \text{-} \lambda_g) MWh_g, \forall g \in G \quad (8)$$

Reliability Constraints

Most of the generation expansion planning methods generally incorporate the reliability constraints in the mathematical models. But the reliability constraint and profitability constraint have a tendency to be conflict to each other and both of the constraints cannot be satisfied simultaneously most of the cases. Hence, the reliability constraint is not included in the mathematical model in this paper. Instead, the reliability condition is separately checked afterward.

2.2 Capacity price calculation

The following procedure explains how to calculate the proper level of capacity price:

Step-1) Set initial value of capacity price arbitrarily and define the system configuration for each year. System configuration for each year can be derived by enumerating all possible combinations constructed with the maximum number of prospective generators which are allowed to be built in the corresponding year as shown in fig. 1.

Step-2) For system configuration of each year, the power purchase cost being paid by the system operator (or the power purchasing entities) and the profit of generation companies for the corresponding year($\bar{y}$) are calculated with eq. (4) through Eq. (8) and the following equations (9) and (10). Eq. (9) and eq. (10) represent power purchase cost and the profit of a generation company, respectively.

$$\sum_q^Q \sum_g^G A_y \{\omega_{g,q,\bar{y}} MWh_{g,q,\bar{y}} + Hour_q (1\text{-}q_g)(1\text{-}MOR_{g,q,\bar{y}}) C_g CP\} \quad (9)$$

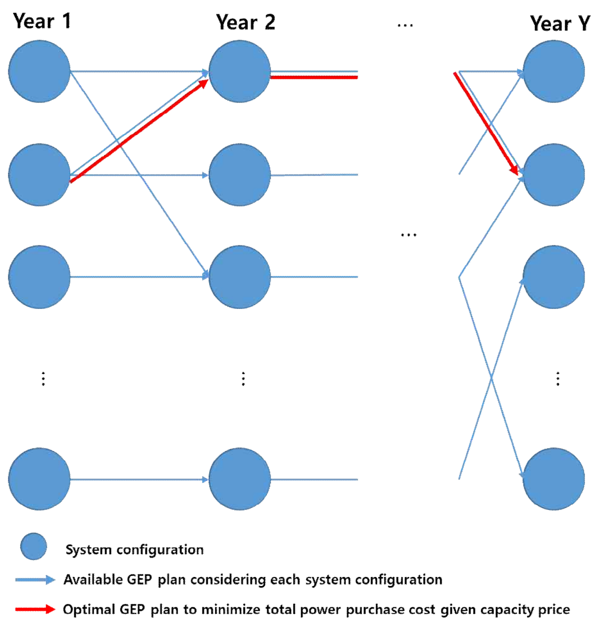

Fig. 1. Illustrative example how to fine the optimal plan

$$\sum_{g}^{K_j} HR_{g,\bar{y}}\{\sum_{q}^{Q}(\pi_{g,q,\bar{y}}+R_{g,q,\bar{y}})\text{-}O_{g,\bar{y}}+S_{g,\bar{y}}\text{-}I_{g,\bar{y}}\}, \forall j \in J \quad (10)$$

Step-3) With the numerical results calculated in Step-2, find the optimal GEP plan to minimize total power purchase cost formulated as eq. (1) while satisfying the profit constraint, Eq. (3), for the planning horizon, which is marked by the red arrows in fig. 1, with a proper simulation technique such as dynamic programming [21]. If there is no feasible GEP plan satisfying the profit constraint, increase capacity price and go to Step-2. Otherwise, go to Step-4.

Step-4) Once the optimal GEP plan is found, reliability condition has to be checked. If there is no single year violating minimum reserve rate criterion for the planning horizon, then the corresponding capacity price is stored and decrease capacity price. Go to Step-2. Otherwise, the corresponding capacity price is required to be higher to encourage investment. Increase capacity price and go to Step-2.

Step-5) Stop the procedure when the minimum capacity price which allows existing the optimal GEP plan satisfying reliability condition is determined. The minimum capacity price is defined as the adequate capacity price.

The flowchart of the proposed method is presented in fig. 2. Hence, the adequate capacity price guarantees that the GEP plan where reliability condition and the profit constraint are satisfied simultaneously can be found.

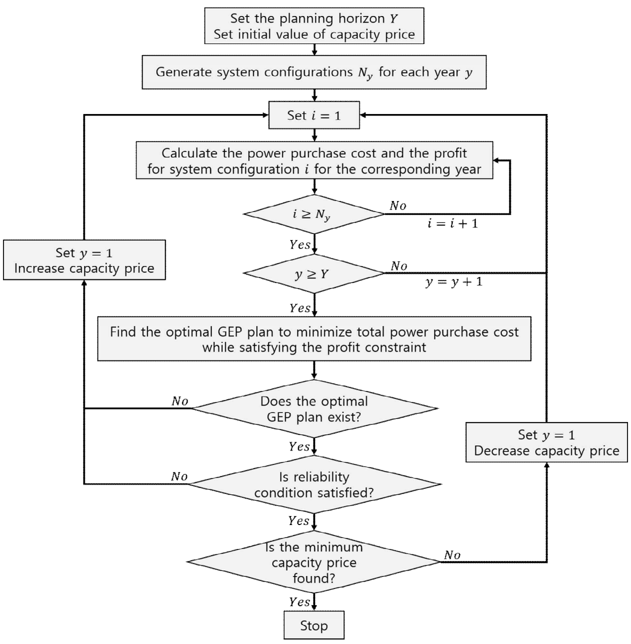

Fig. 2. Flowchart of the proposed method

3. Description of the Simulation Scenarios and Results

3.1 Simulation scenarios

The proposed method is applied to an electricity market hypothetically constructed based on the 7th Basic Plan of Long-Term Electricity Supply and Demand(BPE) in Korea [22]. The minimum reserve rate criterion is chosen at 15% which is equivalent to the loss of load expectation (LOLE) 0.3 days per year as described in 7th BPE. Annual peak demand is shown in Table 1 and the system configuration in base year is briefly outlined in Table 2. Other detailed information needed for the case study can be found in [23]. Discount rate is arbitrarily chosen at 5.5%.

Simulation scenarios are described in table 3. In COAL scenario, it is assumed that coal generator can be built only and all newly built coal generators are owned by one

Table 2. Overview of system configuration in base year

Fuel type	Capacity [MW]	Average operation cost [$/MWh]	Average fixed O&M cost[$/kW]
Nuclear	20,716	5.66	174.07
Coal	24,535	76.95	68.47
LNG	21,363	139.15	58.07
Oil	4,736	207.47	120.54
CES*	2,150	118.2	5.65
REN (P/S)	6,200 (4,700)	0	27(P/S only)

*CES : Community Energy System

Table 3. Classification of simulation scenarios

Scenario	COAL scenario	LNG scenario	MIX scenario
Fuel type of candidate	Coal	LNG	Coal, LNG

Table 1. Annual peak demand

Year	‘14	‘15	‘16	‘17	‘18	‘19	‘20	‘21
Peak (MW)	80,154	82,478	84,612	88,206	91,795	94,840	97,261	99,792
Year	‘22	‘23	‘24	‘25	‘26	‘27	‘26	‘29
Peak (MW)	101,849	103,694	105,200	106,644	107,974	109,284	110,605	111,929

Table 4. Technical and economical parameter of generators

Fuel type	COAL	LNG
Rated capacity(MW)	1,000	900
Operation cost($/MWh)	68.3	100.4
Construction cost($/kW)	1,500	920
Fixed O&M cost($/kW)	54.8	47
Force outage rate(%)	4.7	5.8
Maintenance days(day)	31	27
Lifetime(year)	30	30

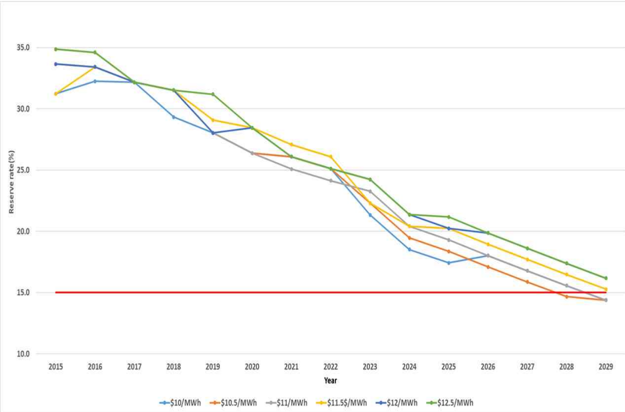

Fig. 3. Reserve rate comparison

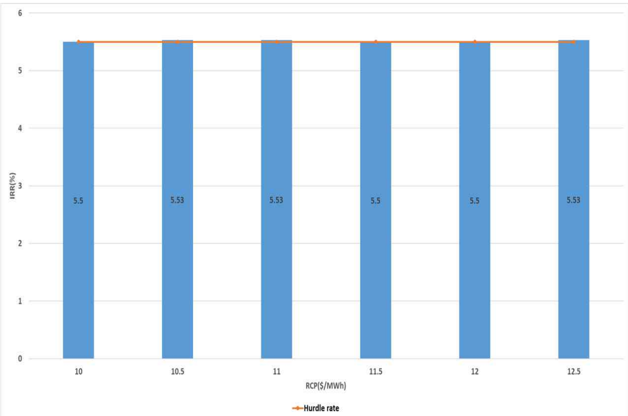

Fig. 4. Internal rate of return

hypothetical generation company. Likewise, LNG generator is the only option being considered in LNG scenario and all newly built LNG generators are owned by a hypothetical generation company. In MIX scenario, coal and LNG generators are allowed to be constructed. To simplify the analysis, only two types of generators are considered in this study as shown in table 4.

3.2 COAL scenario

Fig. 3 shows reserve rate calculation results of the

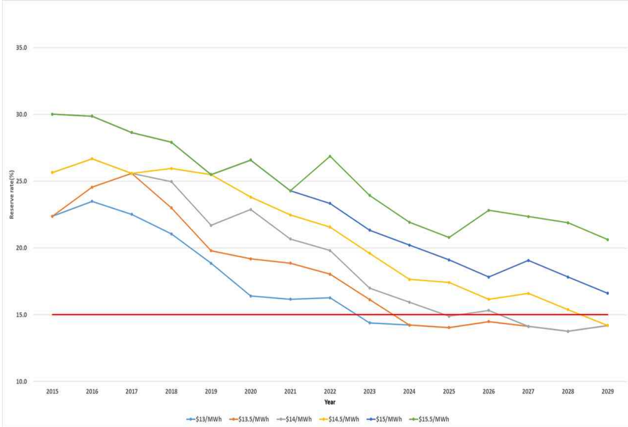

Fig. 5. Reserve rate comparison

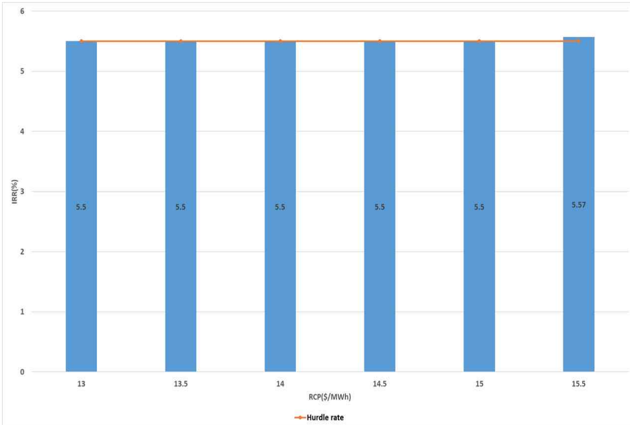

Fig. 6. Internal rate of return

optimal GEP plans with different capacity prices in COAL scenario. The red solid line represents the minimum reserve rate criterion. As shown in fig. 3, the minimum reserve rate criterion is violated until the capacity price increases to $11.5/MWh. Therefore, $11.5/MWh is the minimum capacity price where the optimal GEP plan satisfies reliability condition, and it also guarantees the profitability of the generation company as shown in fig. 4. In other words, the minimum capacity price $11.5/MWh is the adequate capacity price in COAL scenario.

3.3 LNG scenario

Fig. 5 shows reserve rate calculation results for the LNG scenario. The minimum reserve rate criterion is violated in certain years until the capacity price is as high as $15/MWh as shown in fig. 5. Therefore, $15/MWh is the adequate capacity price in LNG scenario since it is the minimum level of capacity price to satisfy reliability condition and guarantees the profitability of the generation company as shown in fig. 6. The adequate capacity price in

Table 6. Adequate capacity price in MIX scenario

# of Coal	2	4	6	8	10
$/MWh	15	15	15	15	15
# of Coal	12	14	16	18	20
$/MWh	15	15	15.5	15.5	15.5

LNG scenario is $3.5/MWh higher than the COAL scenario mainly due to the low infra-marginal rent of the LNG generator.

The simulation result shows that the level of capacity price is required to increase significantly to secure resource adequacy for reliable operation of power system where the peak-load generator ratio of the generation mix has become higher due to environmental concerns, etc.

3.4 MIX scenario

In this section, the simulation result with the scenario when both coal and LNG generators are allowed to be built is described. However, it is obvious that the simulation result of MIX scenario will be exactly same to the simulation result of COAL scenario due to the significant gap of fuel price between coal and LNG in Korea. Therefore, the scenario is slightly modified such that the added number of coal generators in base year is fixed, and table 6 shows the adequate capacity price from the simulation scenario.

Generally, the more coal generators added, the lower energy price and the worse profitability of LNG generators are expected. Consequently, the capacity price should be raised for the profitability of newly built LNG generators as shown in table 6.

In practice, base-load generator and peak-load generator are both considered as prospective generators for the diversified generation mix in long-term GEP scheme. Therefore, the capacity price may have to be much raised in real situation where the types of candidates are much diversified based on that the adequate capacity price in MIX scenario is equal to or higher than the adequate capacity price in the LNG scenario.

4. Conclusion

In this paper, a new method was proposed to estimate the proper level of capacity price incorporating the profitability of generation companies and resource adequacy, and it was successfully applied to the actual Korean electricity market with three different scenarios. In summary, the adequate capacity price was estimated to slightly higher than $15/MWh to satisfy the reliability criterion and the profitability of peak-load generator simultaneously.

In particular, analyzing LNG scenario may enlighten us about the impact of energy policies of Korea related with environmental accord and energy transition on power system. In Korea, LNG generators has become important more than before to reduce carbon emission and to back-up intermittency of renewable energy as renewable energy has been growing rapidly. It implies that a number of LNG generators have to be built in the near future in spite of that electricity demand growth has been decreased gradually. In this case, the revenue from infra-marginal rent of peak-load generator may be further decreased, and market participants who consider peak-load generator investment may cancel financing or investment. Therefore, the capacity price has to be determined practically to encourage peak-load generator investment especially.

For further study, it is necessary to analyze the cost structure of the newly built generators in more detail to make the results more realistic. For example, this paper does not consider any extra costs such as interest during construction, transmission connection capacity cost, no load and startup cost and so on. In addition, the proposed method does not consider abruptly changing dynamics of demand or the intermittency of renewable energy, which is one of the most important issues in recent electricity market. Consequently, the revenue from ancillary service cannot be included properly, and the capacity price calculated from the proposed method may not be enough for financial recovery of the flexible capacity such as ESS, gas turbine or variable speed pumped storage which is required to provide flexibility to cope with increased penetration of renewable energy. Therefore, further research has to be followed to improve described limitations. Also it should be noted that the simulation results can be varied depending on system data, market rules and policy scenarios being tested, therefore, further analysis has to be followed to investigate impact of these factors on the adequate capacity price.

However, the proposed method can be utilized to design the proper capacity payment mechanism without significant modification.

Appendix

A.1 Probability calculation being a marginal generator

In this paper, the probability that each generator becomes the marginal generator is calculated by eq. (6). It is proved by eq. (A) through eq. (F) as follows. First, we can define loss of load probability as the probability that demand exceeds supply capacity, and it can be derived from final equivalent load duration curve traditionally. Second, it is assumed that loss of load probability derived from final equivalent load duration curve is equal to difference between total probability, which is 1, and summation of the probabilities that each generator becomes the marginal generator. It is formulated as eq. (A). In eq. (A), $LOLP(K)$ represents loss of load probability and $TCAP$ represents the total system capacity. Eq. (B) represents an enumerated mathematical formulation of final equivalent load duration curve. Next, eq. (A) is reformulated by applying eq. (6) and eq. (B) as shown in eq. (C). Eq. (D) can be derived by removing same terms on the both side of eq. (C). In order to move on the next step, we need a general formulation of each load duration curve as described in eq. (E). Then, eq. (F) can be derived by substituting each term in eq. (D) with eq. (E). In eq. (F), $ELDC_0$ represents an initial inverted load duration curve and $ELDC_0(0)$ is the probability that 0MW demand occurs, which is 1. Therefore, the probability that each generator becomes the marginal generator can be calculated by eq. (6).

$$LOLP(K) = ELDC_N(TCAP) = 1\text{-}\sum_{i=1}^{N} f_i \tag{A}$$
$$, where \quad f_i = \{(1\text{-}q_i)ELDC_{i\text{-}1}(C_1+C_2+\cdots+C_{i\text{-}1}) \\ \text{-}(1\text{-}q_i)ELDC_{i\text{-}1}(C_1+C_2+\cdots+C_i)\}$$

$$\begin{aligned} &ELDC_N(TCAP) \\ &= (1\text{-}q_N)ELDC_{N\text{-}1}(TCAP) + q_N ELDC_{N\text{-}1}(TCAP\text{-}C_N) \end{aligned} \tag{B}$$

$$\begin{aligned} 1\text{-}\sum_{i=1}^{N} f_i &= 1-\ \{(1-q_N)ELDC_{N\text{-}1}(C_1+C_2+\cdots+C_{N\text{-}1}) \\ &-(1-q_N)ELDC_{N\text{-}1}(C_1+C_2+\cdots+C_N) \\ &+(1-q_{N\text{-}1})ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}2}) \\ &-(1-q_{N\text{-}1})ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}1}) \\ &\vdots \\ &+(1-q_2)ELDC_1(C_1)-(1-q_2)ELDC_1(C_1+C_2) \\ &+(1-q_1)ELDC_0(0)-(1-q_1)ELDC_1(C_1)\} \\ &= (1-q_N)ELDC_{N\text{-}1}(TCAP)+q_N ELDC_{N\text{-}1}(TCAP-C_N) \end{aligned} \tag{C}$$
$$, where \quad TCAP = \sum_{i=1}^{N} C_i$$

$$\begin{aligned} 1-\{&ELDC_{N\text{-}1}(C_1+C_2+\cdots+C_{N\text{-}1}) \\ &+(1-q_{N\text{-}1})ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}2}) \\ &-(1-q_{N\text{-}1})ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}1}) \\ &\vdots \\ &+(1\text{-}q_2)ELDC_1(C_1)-(1-q_2)ELDC_1(C_1+C_2) \\ &+(1-q_1)ELDC_0(0)-(1-q_1)ELDC_1(C_1)\} \\ &= 0 \end{aligned} \tag{D}$$

$$\begin{aligned} &ELDC_{N\text{-}1}(C_1+C_2+\cdots+C_{N\text{-}1}) \\ &= (1-q_{N\text{-}1})ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}1}) \\ &\quad + q_{N\text{-}1}ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}2}) \\ &ELDC_{N\text{-}2}(C_1+C_2+\cdots+C_{N\text{-}2}) \\ &= (1-q_{N\text{-}2})ELDC_{N\text{-}3}(C_1+C_2+\cdots+C_{N\text{-}2}) \\ &\quad + q_{N\text{-}2}ELDC_{N\text{-}3}(C_1+C_2+\cdots+C_{N\text{-}3}) \\ &\vdots \\ &ELDC_1(C_1) = (1-q_1)ELDC_0(C_1)+(q_1)ELDC_0(0) \end{aligned} \tag{E}$$

$$1\ \text{-}ELDC_0(0) = 0 \tag{F}$$

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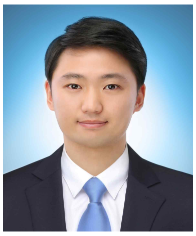

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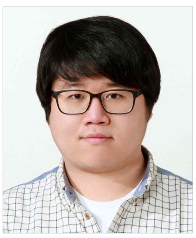

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