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Assessing demand response and smart metering impacts on long-term electricity market prices and system reliability

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HIGHLIGHTS

- ▶ A framework to assess the impact of demand response and smart metering is developed.
- ▶ Uncertainties of demand and the supply are analyzed in a probabilistic manner.
- ▶ Interactions among generators under the price responsive demand are explored.
- ▶ Changes in market prices and system reliability are analyzed in IEEE RTS and Korean markets.

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ABSTRACT

This paper proposes a long-term electricity market analysis framework to assess the impacts of the demand response and smart metering infrastructure implementation on market price fluctuations and system reliability. Based on the probabilistic production cost simulation method that has been widely used in conventional power system planning, the suggested framework considers the uncertainties of the demand and the generator availability in a probabilistic manner. Furthermore, the framework considers the strategic interactions between generators (or, equivalently generation companies) and incorporates price responsive demand enabled with smart metering. To demonstrate how market equilibrium price changes and the system reliability enhances as the demand response with smart metering increases, the framework is applied to an experimental system based on the IEEE 1996 Reliability Test System (RTS) data, followed by a case study of 2010 Korean electricity markets.

1. Introduction

The global electric utility industry and its customers are faced with a set of challenges with the scope and scale which are unprecedented since the advent of widespread electrification. These challenges include increased likelihood of a carbon constrained future to mitigate the effects of traditional fossil fuel energy resources, significant new infrastructure investment to both replace a rapidly aging electricity infrastructure and meet new demand, and the great interests in more reliable and affordable electricity supply with lower prices. The smart grid infrastructure has been taken as promising solutions that resolve the challenges mentioned above effectively and fit the evolution in the energy value chain created by energy industry drivers such as more reliable power with higher quality, sustainable green energy procurement, and increased consumer awareness of price and bi-directional consumer engagement in the price-setting process. Therefore, the functional capabilities of demand response and smart metering, which enable informed consumers' active participation in electricity markets and timely use of electrical energy, have been greatly highlighted in the penetration of the smart grid technologies [1].

Smart and/or advanced metering infrastructure, a metering and communication system that records consumer consumption hourly or more frequently and transmits the measurement over two-way communication network, is often at the heart of the discussion of a smart grid, since the smart meter with a demand response functionality is an important enabler that encompasses major capabilities of smart grid technologies and is visible to the casual observer. Most smart grid technology developments around the world, as a result, have been primarily focused on the regional issues related to utility deployment of smart meters with demand response and other basic functional capabilities. This platform can enable consumers to use consumption and price data to optimize their own consumption patterns. In particular, the platform en-

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ables demand response programs in which the consumers benefit financially from energy use reduction during peak demand, direct load control, and outage management [1,2].

Up until now, the benefits of smart meter implementation, which can only be realized through consumer demand response to price signal, have been mainly assessed or measured in the context of near-term effects such as hourly market price decreases and daily peak load reduction [3]. The impacts of demand response resource (equivalently, impact of implementation of smart meter) in terms of long-term market prices and/or system reliability, however, have not been tackled much in analytical ways. Only conceptual and qualitative approaches have been made in assessing benefits of smart meter implementations. However, as the applications of these new technologies to the deregulated electricity markets will have long-term impacts on market competitiveness and system reliability, a proper analytical framework for long-term market equilibrium and system reliability considering demand response resources is essential to assess the sustainable long-term impacts of smart meter implementation.

One of the traditionally popular methods for long-term power system analysis is the probabilistic production cost simulation method [4,5]. The probabilistic production cost simulation method evaluates each generator's expected production as well as system reliability considering the uncertainties of the demand and generation availability. Following successful applications of the method in the centralized electricity industry context, many studies applied the probabilistic production cost simulation method to deregulated electricity market analysis [6–10]. Oren utilized the probabilistic production cost simulation method for analyzing the capacity market approach to ensure generation adequacy [7]. Choi et al. proposed a method for incorporating transmission system unavailability into the probabilistic production cost simulation in the electricity market context [8]. Yu et al. applied the probabilistic production cost simulation method to modeling and evaluating an interruptible power supply contract for flexible independent power producers [9] and interruptible electricity contracts [10].

Based on the conventional probabilistic production cost simulation method [11–13], an analytical framework to assess long-term benefits of the demand response and smart metering in electricity markets is proposed in this paper. Concept of strategic interactions between generators, or equivalently, generation companies, and the price responsive demands enabled with smart metering has been modeled, and the uncertainty of the demand and the generator availability has been explored in a probabilistic manner.

The rest of the paper is organized as follows: We propose a mathematical modeling for long-term electricity market price and system reliability evaluation in Section 2. In Section 3, we extend the framework proposed in Section 2 to capture the impact of demand response with smart metering. Section 4 presents case study results and the conclusion is given in Section 5.

2. Long-term electricity market price and system reliability evaluation

In a long-term electricity market analysis, two most fundamental quantities to be assessed are the system reliability and the electricity price. The system reliability has been the most crucial element in the power system planning analysis and this still holds in deregulated electricity markets. The electricity price has been a key parameter in the analysis of competitive electricity markets because it directly affects the revenues of generation companies and the costs of the customer, thereby influencing production and consumption patterns. Furthermore, it influences the policies of regulators who make modifications to market rules and trading mechanisms.

In this section, we present a framework for analyzing long-term electricity markets. The proposed framework is based on the probabilistic production cost simulation method [11,12] and provides a methodology to evaluate the system reliability and the electricity price.

2.1. Offer price model

In the deregulated electricity market, the conventional probabilistic production cost simulation method cannot be applied directly because the merit order in which the generators are dispatched is not based on production costs but on offer prices. Furthermore, a simple replacement of the production cost with the offer price in the conventional probabilistic production cost simulation framework is not enough since, in the deregulated electricity market environment, the strategic behavior of the generators, (or equivalently, generation companies) for formulating their offers should be considered.

In the deregulated electricity market where the generation companies compete with each other and make offers for serving demand, the generation companies will formulate the offers of their generators strategically to maximize their profits. If the market is properly designed, it can be assumed, in particular for the long-term analysis, that a reasonable level of competitiveness is achieved. Furthermore, it can also be reasonably assumed that the offers will be formulated based on the generators' true operating costs. In this study, we assume that the generation companies use a markup approach to formulate the offer prices of their generators. This relatively simple strategy formulation is reasonable enough for the long-term analysis and makes the conventional probabilistic production cost simulation method applicable to deregulated electricity markets without major modification.

In general, the cost of electricity supply consists of three components: capacity costs, energy costs (that is, fuel cost), and customer-related costs. When formulating prices on energy offers, generation companies are only interested in the energy costs of their generators because energy costs determine the generators' marginal costs for energy production. For simplicity, assume that the marginal energy costs of generators are constant, and that marginal costs of the ith generator, where $i = 1, 2, \ldots, N$ and N is the total number of generators, are denoted by mc_i, where the generators are ordered in cost-based merit order. Then, the offer price pr_i of the ith generator formulated by markup pricing is represented as:

$$pr_i = (1 + mu_i) \cdot mc_i \quad (\$/\text{MW h}) \tag{1}$$

where mu_i is the markup of the ith generator.

Furthermore, assume that the offer price-based merit order of the generators is the same as the cost-based merit order. That is, in the long-term market equilibrium, the generator with lower marginal costs will formulate its offer price lower than a generator with higher marginal costs. This assumption is highly plausible considering the previous assumption regarding the competitiveness of the long-term electricity markets. The assumption is formally written as (2):

$$pr_i \leqslant pr_j, \quad \text{if} \quad i < j \tag{2}$$

Note that, with the assumption in (2), the conventional probabilistic production simulation method can be now directly utilized to obtain the expected production of each generator and the system reliability indices such as loss of load probability (LOLP) and expected energy not served (EENS) in the proposed long-term electricity market model.

2.2. Expected profits

Let the total costs of the ith generator be denoted by tc_i which is represented as:

$$tc_i = mc_i \cdot E_i + fc_i \quad (\$) \tag{3}$$

where E_i is the expected production of the ith generator which can be determined by the conventional probabilistic production cost simulation and fc_i represents the fixed costs of the ith generator. Then, the expected profit EPR_i of the ith generator is expressed by (4):

$$\begin{aligned} EPR_i &= pr_i \cdot E_i - tc_i = pr_i \cdot E_i - mc_i \cdot E_i - fc_i \\ &= mu_i \cdot mc_i \cdot E_i - fc_i. \quad (\$) \end{aligned} \tag{4}$$

2.3. Strategic offer price formulation and market equilibrium

Now consider the strategic offer price pr_i of the ith generator. In this paper, the strategic behavior of the ith generator is modeled so that the ith generator will formulate its offer price and determine its markup mu_i for maximizing expected profit EPR_i in (4).

Suppose that $i < N$. As in (4), the expected profit of the ith generator is determined by three components: the markup mu_i, the expected energy production E_i, and the fixed costs fc_i. The fixed costs fc_i is a constant and a non-strategic factor. Moreover, under the assumption in (2), the expected energy production E_i is determined by the conventional probabilistic production cost simulation which is also non-strategic. Therefore, the only strategic determinant for the ith generator to maximize its expected profit EPR_i is its markup mu_i, and the profit maximization can be done by setting the markup mu_i as high as possible.

However, there is the underlying assumption in (2) regarding the competitiveness of the long-term market equilibrium that the offer price-based merit order should be the same as the cost-based merit order, in particular as:

$$pr_i^{eq} \leqslant pr_{i+1}^{eq} \tag{5}$$

In order for the assumption to be satisfied, the equilibrium expected profit EPR_i^{eq} of the ith generator should be greater than or equal to any expected profit from changing the merit order. In particular, the equilibrium expected profit EPR_i^{eq} of the ith generator should be greater than or equal to any expected profit $\overline{EPR}_i$ that is yielded if the ith generator offers a lower price than the $(i-1)$th generator and the ith generator is dispatched in $(i-1)$th order. Imposing this condition for the $(i+1)$th generator covers the case of the ith generator's changing the merit order in the opposite direction by submitting a higher offer price than the $(i+1)$th generator and being dispatched in $(i+1)$th order. Therefore, this condition takes care of merit order deviations in both directions.

In order to formalize this condition, consider the expected profit $\overline{EPR}_i$. In this case, since the dispatch order of the ith generator has been exchanged with that of the $(i-1)$th generator, the equivalent load that the ith generator is facing becomes the equivalent load for the $(i-1)$th generator without dispatch order change. Let us denote by C_j, r_j, and $\widetilde{F}_{j-1}$ the capacity, forced outage rate (FOR) of the jth generator, and the equivalent load duration curve for the jth generator, $j = 1,2,\ldots,N$, to be convoluted with, respectively. FOR is the probability measure that a generator will be unavailable for service when required. Let us also define by $C(j)$ the cumulative capacity of the generators from the 1st to the jth generators such that $C(j) = \sum_{k=1}^{j} C_k$. Then, the equivalent load duration curve for the ith generator's convolution with the dispatch order change becomes $\widetilde{F}_{i-2}$ which is the equivalent load duration curve for the $(i-1)$th generator without the dispatch order change. Therefore, the expected energy production $\overline{E}_i$ of the ith generator with dispatch order change is calculated by:

$$\overline{E}_i = (1 - r_i) \cdot \int_{C(i-2)}^{C(i-2)+C_i} \widetilde{F}_{i-2}(x)dx \quad (\text{MW h}) \tag{6}$$

Let $\overline{pr}_i$, $\overline{tc}_i$, and $\overline{mu}_i$ denote the offer price, the total cost, and the markup of the ith generator, respectively, with the dispatch order change. Then, the expected profit $\overline{EPR}_i$ of the ith generator with dispatch order change is obtained by:

$$\begin{aligned} \overline{EPR}_i &= \overline{pr}_i \cdot \overline{E}_i - \overline{tc}_i = \overline{pr}_i \cdot \overline{E}_i - mc_i \cdot \overline{E}_i - fc_i \\ &= \overline{mu}_i \cdot mc_i \cdot \overline{E}_i - fc_i \quad (\$) \end{aligned} \tag{7}$$

Now, the condition preventing any incentive for the ith generator to deviate the cost-based merit order can be re-stated as the equilibrium expected profit EPR_i^{eq} of the ith generator should be greater than or equal to any expected profit $\overline{EPR}_i$; that is, EPR_i^{eq} should be greater than or equal to the maximum of $\overline{EPR}_i$. Since the expected energy production $\overline{E}_i$ and the total costs $\overline{tc}_i$ are independent from the strategic formulation of the offer price $\overline{pr}_i$, the maximum value of $\overline{EPR}_i$ is obtained when $\overline{pr}_i$ is equal to the equilibrium offer price pr_{i-1}^{eq} of the $(i-1)$th generator:

$$\max \overline{EPR}_i = pr_{i-1}^{eq} \cdot \overline{E}_i - \overline{tc}_i \tag{8}$$

Therefore, the equilibrium condition is written as (9):

$$\begin{aligned} EPR_i^{eq} &= pr_i^{eq} \cdot E_i - mc_i \cdot E_i - fc_i \geqslant \max \overline{EPR}_i \\ &= pr_{i-1}^{eq} \cdot \overline{E}_i - mc_i \cdot \overline{E}_i - fc_i \end{aligned} \tag{9}$$

By rearranging (9) with respect to pr_{i-1}^{eq}, the equilibrium condition can be rewritten as:

$$pr_{i-1}^{eq} \leqslant \frac{pr_i^{eq} \cdot E_i + mc_i(\overline{E}_i - E_i)}{\overline{E}_i} \tag{10}$$

Now, it is easily seen that the right hand side of (10) is less than pr_i^{eq}, which shows that the cost-based merit order still holds. Therefore, given the equilibrium offer price pr_{i+1}^{eq} of the $(i+1)$th generator, the expected profit maximizing equilibrium offer price pr_i^{eq} of the ith generator is determined as:

$$pr_i^{eq} = \frac{pr_{i+1}^{eq} \cdot E_{i+1} + mc_{i+1} \cdot (\overline{E}_{i+1} - E_{i+1})}{\overline{E}_{i+1}} \quad (\$/\text{MW h}) \tag{11}$$

Now consider the Nth generator, which is the last dispatched generator. It knows that it is the last generator left for serving the expected energy E_N, and will try to submit the highest offer price possible. Since it is the last generator, there is no condition from strategic interactions between generators which will limit the maximum offer price. One of the common solutions for this situation in the electricity market is the price cap, whereby the highest offer price for the generator is given externally as a market rule. Let the price cap be denoted by pr^{cap}. Then, the equilibrium offer price pr_N^{eq} of the Nth generator is determined as the price cap:

$$pr_N^{eq} = pr^{cap} \quad (\$/\text{MW h}) \tag{12}$$

Once the equilibrium offer price pr_N^{eq} of the Nth generator is obtained, the equilibrium offer prices of the other generators can be determined in a backward manner by applying (11).

After the equilibrium offer prices of the generators are determined, we can also determine the probability distribution of the market equilibrium price by using the equivalent load duration curve (LDC) concept. A load duration curve (LDC) approach analyzes the cumulative frequency of historic load (demand) data over a specified period, typically 1 year in power system. The duration curve indicates the percent of time that load values have been reached or exceeded specific value for a given period. An equivalent LDC, converted from a load duration curve to fit it into probability measure, is frequently used in power system planning and operation because it can represent the cumulative probability distribution for loads exceeding specific values [14–16]. Based on the equivalent LDC concept, the probability of the ith generator's being the marginal generator and setting the market equilibrium price pr^{eq} as its equilibrium offer price pr_i^{eq}, denoted by PR, is determined as:

$$\mathrm{PR}(pr^{eq} = pr_i^{eq}) = \widetilde{F}_{i-1}(C(i-1)) - \widetilde{F}_i(C(i)), \quad \forall\, i = 1, 2, \ldots, N \tag{13}$$

The generators serving the base load cannot be marginal generators and the probability for their offer price to set the market equilibrium price is zero as can be easily seen from (13). Now, let v denote the order index of the first generator becoming the marginal generator. Then, $\forall\, i = 1, 2, \ldots, N$, (14) holds:

$$\begin{aligned} &\mathrm{PR}(pr^{eq} = pr_i^{eq}) = 0, \quad \text{if } i < v, \\ &\mathrm{PR}(pr^{eq} = pr_i^{eq}) > 0, \quad \text{if } i \geqslant v \end{aligned} \tag{14}$$

LOLP and EENS are calculated in exactly the same way as the conventional method using the equivalent LDC $\widetilde{F}_N$:

$$\mathrm{LOLP} = \widetilde{F}_N(C(N)) \tag{15}$$

$$\mathrm{EENS} = \int_{C(N)}^{\infty} \widetilde{F}_N(x)dx \quad (\mathrm{MW\,h}) \tag{16}$$

EENS is valued by the value of lost load (VoLL) which represents the value consumers put on the unsupplied energy.

3. Framework extension for smart metering

We extend the framework presented in Section 2 for incorporating the demand with smart metering. In order to assess the impact of the smart metering technology on the system reliability and the electricity price, we develop the extended framework in such a way that the comparative study between with and without the smart metering technology can be performed. Fig. 1 shows a schematic diagram of the framework proposed.

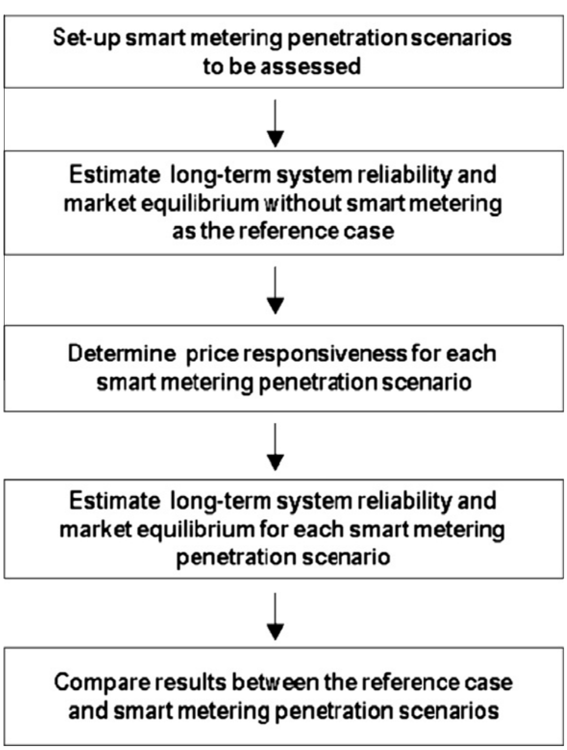

Fig. 1. A schematic diagram for the framework proposed.

3.1. Demand model with smart metering

With smart metering, the demand can respond to the electricity price following its willingness to pay. This paper models the demand with smart metering as the price-responsive demand, in particular, whose price-responsiveness is represented by linear demand curve.

Suppose there are M customers in the market who have installed smart metering. Following the proposed model, the demand curve D_j of the customer j ($\forall_j = 1, 2, \ldots, M$) with smart metering is represented as:

$$D_j(pr) = d_j - \alpha_j \cdot pr \quad (\mathrm{MW}) \tag{17}$$

where pr represents the market price, d_j is the maximum demand, and α_j represents the slope of the demand curve. For simplicity of the analysis, assume that the maximum price at which any customer with smart metering is willing to buy energy is the same for all the customers with smart metering. That is:

$$\frac{d_j}{\alpha_j} = \frac{d_k}{\alpha_k}, \quad \forall_{j,k} = 1, 2, \ldots, M \tag{18}$$

Then, the demand curves for the customers with smart metering can be aggregated into one equivalent demand curve D as:

$$D(pr) = d - \alpha \cdot pr \tag{19}$$

where $d = \sum_{j=1}^{M} d_j$ and $\alpha = \sum_{j=1}^{M} \alpha_j$.

3.2. Long-term market equilibrium model with smart metering

In order to properly assess the effects of the demand with smart metering, the smart metering demand model in (19) needs to be incorporated into the long-term electricity market price evaluation model in such a way that the incorporated model is comparable to the model without smart metering. The notations in the incorporated model use the superscript $'$ to differentiate them from those in the model without the demand with smart metering. For example, $(pr_i^{eq})'$ denotes the equilibrium offer price of the ith generator with the demand with smart metering. For the incorporated model to be comparable to the model without smart metering, the following two boundary conditions apply:

- *BC1*: The expected energy production $(E_v)'$ of the vth generator with the offer price of pr_v^{eq} is the same as the generator's expected energy production E_v without the demand with smart metering; and
- *BC2*: The price-responsive demand curve in (19) will cross the zero demand at the price of VoLL, since no demand is willing to purchase any energy more expensive than VoLL.

In order to formally express the above two boundary conditions, we first consider an expression of the expected energy production $(E_i)'$ of the ith generator. Let us denote by X and $(X)'$ the random variables representing the total system demand without and with smart metering, respectively. In particular, the total system demand $(X)'$ with smart metering is composed of two different types of demand; one is the price-irresponsive demand represented by a random variable $(X^{pir})'$ and the other is the price-responsive demand due to smart metering represented by a random variable $(X^{pr})'$. Suppose that, with the introduction of the smart metering technology, a fixed amount of demand, x^{pr}, in X is considered to be smart metered. That is, the random variable $(X^{pir})'$ for the price-irresponsive load is represented by:

$$(X^{pir})' = X - x^{pr} \quad \text{(MW)} \tag{20}$$

Now consider the price-responsive demand $(X^{pr})'$. Using the proposed demand curve model and a given a market price pr, $(X^{pr})'$ is determined as:

$$(X^{pr})' = D(pr) \quad \text{(MW)} \tag{21}$$

Therefore, given a market price pr, the total system load is represented by a random variable $(X)'$ as:

$$\begin{aligned}(X)' &= (X^{pir})' + (X^{pr})' \\ &= X - x^{pr} + D(pr). \quad \text{(MW)}\end{aligned} \tag{22}$$

The LDC $(\widetilde{F})'$ in the model with smart metering can be represented using the LDC $\widetilde{F}$ in the model without smart metering as:

$$(\widetilde{F})'(x;pr) = \widetilde{F}(x + x^{pr} - D(pr)) \tag{23}$$

Based on the LDC concept, the expected energy production of each generator considering the price-responsive demand with smart metering can be calculated. Consider the ith generator. Using (23), the equivalent LDC $(\widetilde{F}_i)'$ of the ith generator for a given price pr can be obtained by:

$$(\widetilde{F}_i)'(x;pr) = \widetilde{F}_i(x + x^{pr} - D(pr)) \tag{24}$$

Suppose that $i < v$. In this case, the ith generator always serve for the base demand and any market equilibrium price for the equivalent LDC for the ith generator will result in the same expected energy production result. In particular, we can use the vth generator's offer price pr_v, which is the lowest possible market equilibrium price. Then, the expected energy production $(E_i)'$ of the ith generator when $i < v$ is obtained by:

$$\begin{aligned}(E_i)' &= (1 - r_i) \cdot \int_{C(i-1)}^{C(i)} (\widetilde{F}_{i-1})'(x;pr_v)dx \\ &= (1 - r_i) \cdot \int_{C(i-1)}^{C(i)} \widetilde{F}_{i-1}(x + x^{pr} - D(pr_v))dx \quad \text{(MW h)}\end{aligned} \tag{25}$$

Now, suppose that $i \geqslant v$. In this case, when the ith generator considers the equivalent load, the relevant market price for the equivalent load is its offer price pr_i since the equivalent LDC integration region represents the region for the ith generator to become the marginal generator and pr_i becomes the market equilibrium price. Therefore, the expected energy production $(E_i)'$ of the ith generator when $i \geqslant v$ is obtained by:

$$\begin{aligned}(E_i)' &= (1 - r_i) \cdot \int_{C(i-1)}^{C(i)} (\widetilde{F}_{i-1})'(x;pr_i)dx \\ &= (1 - r_i) \cdot \int_{C(i-1)}^{C(i)} \widetilde{F}_{i-1}(x + x^{pr} - D(pr_i))dx\end{aligned} \tag{26}$$

In particular, $(E_v)'$ for the vth generator is determined as:

$$(E_v)' = (1 - r_v) \cdot \int_{C(v-1)}^{C(v)} \widetilde{F}_{v-1}(x + x^{pr} - D(pr_v))dx \tag{27}$$

Recall the first boundary condition $BC1$. From (27), it can be easily seen that if $D(pr_v^{eq})$ is the same as x^{pr}, then $(\widetilde{F}_{v-1})'(x;pr_v^{eq}) = \widetilde{F}_{v-1}(x)$ and $BC1$ will hold. That is, $BC1$ can be represented by the following equation:

$$D(pr_v^{eq}) = d - \alpha \cdot pr_v^{eq} = x^{pr} \tag{28}$$

The second boundary $BC2$ is represented by:

$$D(\text{VoLL}) = d - \alpha \cdot \text{VoLL} = 0 \tag{29}$$

By solving (28) and (29) simultaneously, the demand curve D in (19) is determined as:

$$D(pr) = \frac{x^{pr}}{\text{VoLL} - pr_v^{eq}} \cdot (\text{VoLL} - pr) \tag{30}$$

Now, where $i \geqslant v$, consider the expected profit $(EPR_i)'$ of the ith generator whose offer price pr_i determines the market price. Expected profit $(EPR_i)'$ is expressed by (31):

$$(EPR_i)' = pr_i \cdot (E_i)' - tc_i = pr_i \cdot (E_i)' - mc_i \cdot (E_i)' - fc_i \quad (\$) \tag{31}$$

To obtain the equilibrium price $(pr_i^{eq})'$, two conditions of profit maximization and strategic interactions between generators need to be considered as in Section 2. The profit maximization condition can be obtained by applying the first-order necessary optimality condition with respect to the offer price pr_i to (31). The following equation should hold for the profit maximizing price $(pr_i^{pm})'$:

$$\frac{d}{dpr_i}(EPR_i)' = (E_i)' + pr_i \frac{d}{dpr_i}(E_i)' - mc_i \frac{d}{dpr_i}(E_i)' = 0 \tag{32}$$

Using (25), (30), and (32) is rewritten as:

$$\begin{aligned}&\int_{C(i-1)}^{C(i)} \widetilde{F}_{i-1}\left(x + \frac{(pr_i^{pm})' - pr_v^{eq}}{\text{VoLL} - pr_v^{eq}} \cdot x^{pr}\right)dx - \frac{(pr_i^{pm})' - mc_i}{\text{VoLL} - pr_v^{eq}} \cdot x^{pr} \\ &\cdot \left[\widetilde{F}_{i-1}\left(C(i-1) + \frac{(pr_i^{pm})' - pr_v^{eq}}{\text{VoLL} - pr_v^{eq}} \cdot x^{pr}\right)\right. \\ &\left. - \widetilde{F}_{i-1}\left(C(i) + \frac{(pr_i^{pm})' - pr_v^{eq}}{\text{VoLL} - pr_v^{eq}} \cdot x^{pr}\right)\right] = 0\end{aligned} \tag{33}$$

Now, the profit maximizing price $(pr_i^{pm})'$ can be obtained by solving (33). It is challenging to solve (33) analytically without any further assumption about the equivalent LDC $\widetilde{F}_{i-1}$, but many numerical methods including Newton's method can be applied in a straightforward manner.

Now consider the strategic interactions. Following the same argument for (11) in Section 2, the strategic price $(pr_i^{st})'$ can be obtained by:

$$(pr_i^{st})' = \frac{(pr_{i+1}^{st})' \cdot (E_{i+1})' + mc_{i+1} \cdot ((\overline{E}_{i+1})' - (E_{i+1})')}{(\overline{E}_{i+1})'} \tag{34}$$

where

$$\begin{aligned}(\overline{E}_i)' &= (1 - r_i) \cdot \int_{C(i-2)}^{C(i-2)+C_i} (\widetilde{F}_{i-2})'(x;pr_i^{st})dx \\ &= (1 - r_i) \cdot \int_{C(i-2)}^{C(i-2)+C_i} \widetilde{F}_{i-2}\left(x + \frac{(pr_i^{st})' - pr_v^{eq}}{\text{VoLL} - pr_v^{eq}} \cdot x^{pr}\right)dx\end{aligned}$$

The strategic offer price $(pr_N^{st})'$ of the Nth generator is determined as the price cap as in Section 2:

$$(pr_N^{st})' = pr^{cap} \tag{35}$$

Then, the strategic offer prices of the other generators can be determined by applying (34) in a backward manner.

Finally, the equilibrium price $(pr_i^{eq})'$ is determined by:

$$(pr_i^{eq})' = \min((pr_i^{pm})', (pr_i^{st})') \tag{36}$$

LOLP and EENS are calculated using the equivalent LDC $(\widetilde{F}_N)'$ as:

$$\text{LOLP} = (\widetilde{F}_N)'(C(N)) \tag{37}$$

$$\text{EENS} = \int_{C(N)}^{\infty} \left(\widetilde{F}_N\right)'(x)dx \tag{38}$$

4. Case studies

In this paper, two case studies have been demonstrated to show the applicability of the framework proposed. First case study data is established based on the IEEE 1996 Reliability Test System (RTS) and second case is done with 2010 through 2017 Korean electricity market data. To implement the model suggested in this paper, we developed our own simulation tools using Java technology. In particular, we used J2EE framework based on Java Sever Faces 2.0.

4.1. Case study I: IEEE 1996 RTS

Based on the IEEE 1996 RTS data [17], 9 generator sample system has been developed, and the generator data of the sample system is listed in Table 1. The daily peak demand data has been established for 52 weeks based on the RTS data, and the annual peak demand is assumed to be 1088 MW so that the installed capacity reserve margin is equivalent to 25%. The daily peak demand profile is shown in Fig. 2.

The VoLL is assumed to be 2250 \$/MW h and the long-term price cap is set by 285.56 \$/MW h. In order to evaluate the market impacts with the price-responsive demand resources, 11 cases with different x^{pr} values from 0 to 500 MW increasing by 50 MW for each case were studied. Table 2 shows the resulting LOLP, EENS, and load weighted average market price for each case, and the profile change of these values with respect to different x^{pr} values are depicted in Figs. 3 and 4.

As shown in Fig. 4, the market equilibrium price becomes lower as the amount of the price responsive demand resources increases as the market becomes more competitive. Moreover, the more interesting results are shown in the other figures, in Fig. 3, which show that the system becomes more reliable as the amount of the price responsive demand resources increases. This is because the price responsiveness of the demand resources reduces the total amount of demand when the market price is high. The periods of high market prices are those with low reliability, and, therefore, reducing the demands at such period results in the increase of the amount of the capacity reserve, which eventually enhances the system reliability.

4.2. Case study II: Korea 2010–2020 electricity markets

The analyzing framework proposed in this paper has been applied to Korea electricity markets. Based on the long-term national supply and demand outlook 2010 through 2020 of Korea [18], a large-scale application test system is established. Installed generation capacity projections through 2020 and annual peak demand forecast in Korea electricity market are given in Table 3, and generators data by fuel-type with new capacity addition through 2020 is provided in Table 4.

It can be seen that peak demand in Korea increases each year by 2.0% on average, while generation capacity expands annually 3.3% on average. We have assessed a project opportunity of national installing smart meters in the year of 2010 in Korea, and six different scenarios where smart meters installation increases by 1% of

Table 1
Generator data for the sample system.

	Type	Capacity (MW)	Marginal cost (\$/MW h)	FOR
G1	Hydro	50	0.00	0.01
G2	Nuclear steam	400	15.00	0.12
G3	Fossil steam	350	21.73	0.08
G4	Fossil steam	155	22.74	0.04
G5	Fossil steam	76	30.04	0.02
G6	Fossil steam	197	96.32	0.05
G7	Fossil steam	100	105.85	0.04
G8	Fossil steam	12	126.72	0.02
G9	Combustion turbine	20	142.78	0.10

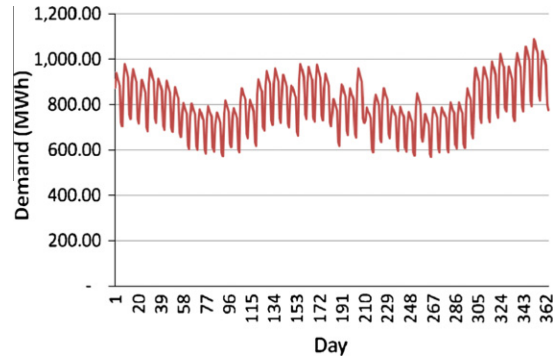

Fig. 2. Daily peak demand profile of the sample system.

Table 2
Case study results for the IEEE 1996 RTS.

x^{pr} (MW)	LOLP	EENS (MW h)	Load weighted average price (\$/MW h)
0	0.0337	92.29	53.85
50	0.0310	87.60	52.27
100	0.0291	83.98	51.78
150	0.0277	79.87	51.53
200	0.0264	76.62	51.13
250	0.0248	72.91	50.75
300	0.0236	69.99	50.28
350	0.0226	66.65	50.11
400	0.0219	63.98	49.99
450	0.0211	61.39	49.70
500	0.0202	58.41	49.59

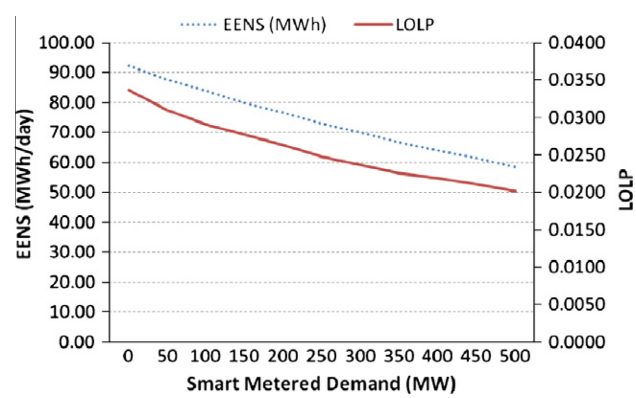

Fig. 3. EENS/LOLP change profiles as demand response increases.

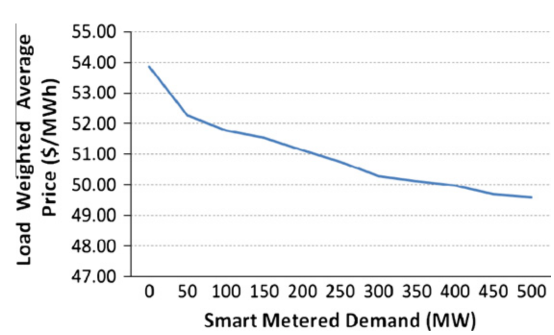

Fig. 4. Market price change profile as demand response increases.

Table 3
Korea electricity market supply and demand projection.

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Installed capacity (MW)	72,490	75,561	84,861	87,111	89,381	91,651	93,051	94,451	94,451	95,851	100,051
Peak demand (MW)	66,822	68,559	70,078	71,570	72,986	74,362	75,774	77,061	78,453	79,876	81,300

Table 4
Generator data by fuel-type with new capacity additions.

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nuclear (MW)		1000	2000	1000	1400	1400	1400	1400		1400	4200
Coal (MW)					870	870					
Gas (MW)		2071	6500	1250							
Etc (MW)			800								
Installed capacity (MW)	72,490	75,561	84,861	87,111	89,381	91,651	93,051	94,451	94,451	95,851	100,051

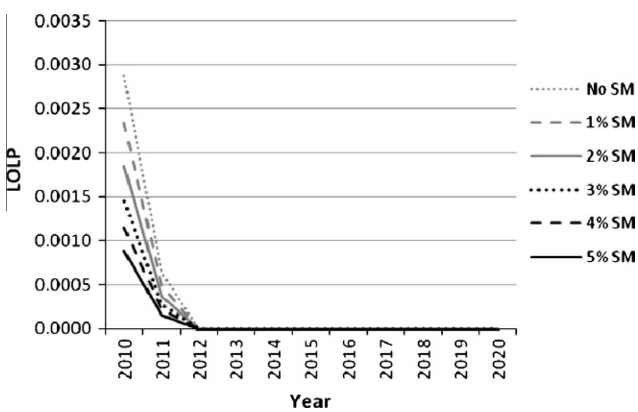

Fig. 5. LOLP change profile over years as demand response increases.

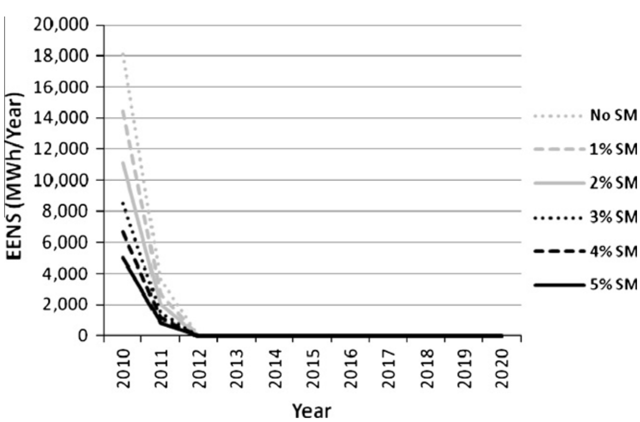

Fig. 6. EENS change profile over years as demand response increases.

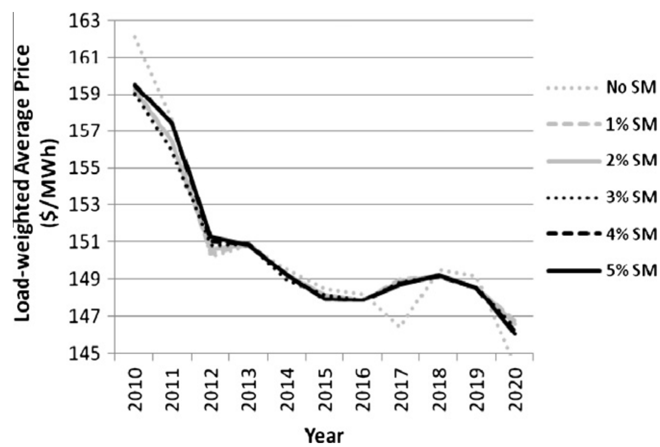

Fig. 7. Market price change profile over years as demand response increases.

peak demand up to 5% of peak demand, which is taken as the maximum potential of peak reduction with demand response [19], are demonstrated and analyzed in this study.

In Figs. 5 and 6, it can be seen that power system reliability over the year, which is measured by LOLP and EENS, becomes higher as the amount of smart meter installation increases. In Fig. 7, however, we can see that the drop of load-weighted average market price over the year is not proportional to the amount of smart meters installed. That is, no significant market price difference has been observed between 1% and 2% smart meter installation as well as 4% and 5% case.

The case study results show that power system reliability is improved as smart meter implementation increases. This can be easily understood since price-responsive demand with smart meters will reduce the peak load by responding to the high market price at the peak load, and, thereby, increase system reserve margin. On the other hand, the load-weighted equilibrium market price is not always decreasing with the increase of smart metering installation. That is, the lower market price may not be always secured with the more smart meters implementation. This is due to strategic interactions between generators, or equivalently, generation companies, in the market. It can provide an important policy implication in smart metering implementation and we will investigate it in the future study.

5. Conclusion

In this paper, a new framework to analyze the impact of smart metering technology implementation on the long-term electricity market prices and system reliability is developed. The framework is based on the conventional probabilistic production cost simulation method and considers the generators' strategic interactions. Following the proposed framework, a test market based on the IEEE RTS system was numerically studied. The case study was performed in a comparative manner with different amounts of smart meter installation, and the study results show that the more price responsive demand side resources are present in the market, the more competitive the long-term electricity market becomes and the more reliable the system becomes. However, when we extended the case study to Korea electricity market, the equilibrium market price did not decrease monotonically as the amount of smart meter installation increased. This is because actual power system data yielded more complicated strategic interactions between generators than the IEEE RTS data.

Acknowledgements

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