A Comparative Study of Pricing Mechanisms to Reduce Side-Payments in the Electricity Market: A Case Study for South Korea

Hansol Shin¹, Tae Hyun Kim¹, Kyuhyeong Kwag¹ and Wook Kim²,∗

¹ Department of Electrical and Electronics Engineering, Pusan National University, Busan 46241, Korea; fushigidane@pusan.ac.kr (H.S.); thk1519@pusan.ac.kr (T.H.K.); kkhg1007@pusan.ac.kr (K.K.)
² Department of Electrical Engineering, Pusan National University, Busan 46241, Korea
* Correspondence: kimwook@pusan.ac.kr; Tel.: +82-51-510-2369

Abstract: Under marginal-cost pricing, some generators cannot recover their production costs at the market price due to non-convexities in the electricity market. For this reason, most electricity markets pay side-payments to generators whose costs are not sufficiently recovered, but side-payments present the problem of deteriorating transparency in the market. Recently, convex hull pricing and extended locational marginal pricing have been reviewed or gradually introduced to reduce side-payments. Another method is to include non-convex costs in the market price, which is applied in the Korean electricity market. Although it is not generally considered in the electricity market, the Vickrey auction method is also one of the pricing mechanisms that can reduce side-payments. The main purpose of this study is to analyze the financial impact of these alternative pricing mechanisms on market participants through rigorous simulation. We applied the alternative pricing schemes to the Korean electricity market, and the impacts are analyzed by comparing the cost aspect of an electricity sales company and the profit aspect of generation companies. As a result of the simulation study, each pricing mechanism not only differed in the degree to which side-payments are reduced but also has different effects on the type of generators.

Keywords: marginal-cost pricing; system marginal price (SMP); convex hull pricing; extended locational marginal price (ELMP); Vickrey auction; side-payment

1. Introduction

From a general economic point of view, one general view is that total social welfare is maximized when prices in a perfectly competitive market are determined to be the marginal cost [1]. According to this view, most electricity markets are designed so that the market price is as close to the marginal price as possible [2]. However, unlike other markets, one of the factors that complicate the electricity market is that thermal generators have a fairly large portion of the quasi-fixed costs, such as no-load costs and start-up costs, which do not change in proportion to generation output [3]. In some cases, marginal and near-marginal generators may not fully recover the variable costs from the energy market when the market price is based only on marginal cost [4].

In addition, some fast-start resources (FSRs), such as block-loaded units, are committed and dispatched by an independent system operator (ISO) for the purposes of securing system flexibility, even though their generation costs are high, but they are generally excluded from price-setting due to their technical characteristics. Since the operational costs of such generators are normally higher than the market price, financial loss may occur unless separate compensation is provided. The most representative reason for this phenomenon is a pricing mechanism based on marginal cost and the non-convexity of generation costs [5].

If judged solely from a financial point of view without considering other social responsibilities of generation companies, it is more beneficial for such companies to not follow...
the ISO’s dispatch decision in the absence of additional incentives or compensation. In order to solve this problem, most electricity markets implement their own compensation policies. One of the typical methods is to provide side-payments that are discriminately paid for certain generators that cannot recover their total production costs at market prices. Although this side-payment has the advantage of being easy and intuitive to implement, it makes it difficult for market participants to predict the profitability of entering the market, and it deteriorates transparency [6]. Some market participants argue that this side-payment system undermines market efficiency, because small-scale performance improvement and cost reduction efforts by near-marginal generators only decrease the amount of the side-payments, but do not lead to an increase in profits, thus removing any motivation for such improvements [7].

The US Federal Energy Regulatory Commission (FERC) states that appropriate pricing should be designed for (i) maximizing social welfare; (ii) incentivizing market participants to follow dispatch instructions and invest in efficient capacities; (iii) improving market transparency; and (iv) ensuring that all generation companies recover their costs in the market [4,8]. In other words, a new market pricing mechanism needs to be designed not only to improve the problems in the existing pricing system, but to provide proper incentives to generation companies at market prices while reducing side-payments [4].

Several alternative pricing schemes have been studied to replace existing marginal-cost pricing in order to reduce side-payments. For example, Gribik et al. [9] introduced a convex hull pricing mechanism that determines the market price from the marginal costs of the total cost function’s convex hull in order to eliminate non-convexities in production costs. Several US electricity markets are seeking new methods to reduce side-payments by employing different pricing mechanisms (such as New York ISO’s Hybrid Pricing and ISO-New England’s Fast-Start Pricing) that allow FSRs—the main cause of side-payments—to set prices [10]. In particular, Midcontinent ISO (MISO) examined the implementation of convex hull pricing in order to minimize side-payments but concluded that convex hull pricing was computationally too expensive to apply in the actual large-scale electricity market. Accordingly, MISO developed and implemented the Extended Locational Marginal Price (ELMP) that approximates convex hull pricing [2].

Meanwhile, pricing in the Korean electricity market, dubbed the Cost-Based Pool (CBP), is designed so that the marginal generator can recover most of the quasi-fixed costs with the market price alone, even without receiving separate side-payments. The name of the wholesale electricity market price is called System Marginal Price (SMP), but, in reality, the market price is determined at a price close to the average cost by adding the average value of start-up costs and no-load costs to incremental costs, rather than using only simple marginal costs [11].

This pricing mechanism greatly helps reduce the amount of the side-payments but has three serious flaws that hinder efficient market operations. First, a market price reflecting no-load and start-up costs is maintained at a level of 5–10% higher than the marginal price, which enables the base-load generators to enjoy significantly higher profits, leading to motivation for more investment in environmentally harmful coal and nuclear plants [7]. Second, an economically undesirable price regressivity problem arises due to these average terms in pricing mechanisms. In general, the market price tends to increase when demand increases, but the opposite sometimes occurs in the Korean electricity market due to those average cost terms; that is, the market price decreases when there is a small electricity-demand increase [11]. This price regressivity problem is likely to act as another market-distortion factor, especially for the demand-response market. Third, like marginal-cost pricing, there is little incentive to invest in FSRs which are ineligible to set prices because they are operated with a small, fixed capacity. This generator must rely on side-payments to make a profit, and there is no guarantee that a sufficient profit can be recovered from the market.

The Korea Power Exchange (KPX), which operates the Korean electricity market, is aware of these problems, and is considering a new pricing mechanism that can solve the
regressivity problem while simultaneously reducing side-payments. However, the most sensitive and major obstacle to applying a new pricing mechanism is the financial impact of the new pricing method on each market participant. No matter how theoretically perfect the new pricing mechanism might be, it is difficult to apply a new pricing method to the actual electricity market if the financial impact on the existing market participants and shareholders is too great, and it may cause social issues due to excessive stranded costs. Therefore, it is worthwhile to analyze how a new pricing mechanism affects the market, compared to the incumbent pricing mechanism.

The main purpose of this study is to rigorously analyze the financial impacts of candidates for new pricing mechanisms when applied to the Korean electricity market. The goal is to understand a new pricing mechanism that reduces side-payments (and to understand the financial impact on existing participants) while solving the regressivity problem of the incumbent SMP mechanism, or the average-based pricing currently applied to the Korean CBP market.

Pricing mechanisms analyzed in this study are summarized as follows.

1. Marginal-cost pricing: This is the pricing mechanism generally adopted in most of the existing electricity markets. The market price is determined only by marginal costs, and discriminate side-payments are paid to generators that suffer financial losses due to the quasi-fixed costs or for other reasons.

2. SMP in the Korean CBP market [12]: It is a method of calculating the market price by adding no-load and start-up costs to marginal costs.

3. Convex hull pricing [9]: This mechanism was originally formulated as the Lagrangian dual problem, which cannot guarantee the polynomial time convergence. So, we adopt the primal formulation, which is one of the most actively studied methods recently that can guarantee the polynomial time convergence.

4. The ELMP mechanism of the US MISO market [13]: This is a pricing mechanism that can be considered an approximation of convex hull pricing, which decomposes convex hull pricing into each hour by ignoring inter-temporal constraints. This method allows FSRs to set prices, and reduces side-payments, by adding their commitment costs (no-load and start-up costs) to the market price.

5. Uniform Vickrey pricing: This is a pricing mechanism based on the Vickrey auction concept [14]. This method determines the market price at an incremental cost of the runner-up generator (the generator that is one rank higher than the marginal generator in the merit-order). The market price increases slightly compared to marginal-cost pricing, which enables generators to recover some of the quasi-fixed costs, and reduces side-payments.

Among the pricing schemes mentioned above, (1)–(4) have already been dealt with in the existing literature and in various electricity markets, but Vickrey pricing is a mechanism additionally proposed in this study. The Vickrey auction (where the highest bidder wins, but the actual payment or price is determined not by the winner’s bid price but by the runner-up’s bid price) has the advantage of incentivizing participants to bid a true value. The drawback is that it is particularly vulnerable to market price manipulation, and bidders do not prefer truth-revealing strategies [15]. In addition, there is still some theoretical controversy about which method is superior for the electricity market: discriminatory pricing rules (such as the Vickrey auction) or a uniform pricing rule. In this study, a pricing mechanism similar to the Vickrey auction in the uniform-price market is adopted based on recent research on the Vickrey auction method [16]. In an electricity market where market manipulation is tightly monitored, the Vickrey pricing mechanism can be considered one of the promising candidates for reducing side-payments.

This paper is organized as follows. In Section 2, the basic concepts of the pricing mechanisms covered in this study are described. The pros and cons of each scheme are described, and side-payments that occur under the pricing rules are defined. Section 3 presents simulation results of alternative pricing schemes by using actual market data from the Korean CBP, and the market impact is analyzed by comparing not only the marginal
price but the SMP of the existing Korean power market. Finally, Section 4 concludes this study.

2. Pricing Mechanisms

This section briefly describes the general definition of side-payments in the electricity market, and describes how such side-payments are decided under the various pricing mechanisms.

2.1. Side-Payments in the Electricity Market

Mathematical models of the electricity market including the unit commitment and economic dispatch (UCED) problem have significant non-convexities, because the actual market includes discrete variables to represent operational characteristics of generators. Due to these non-convexities, under marginal-cost pricing, some generators prefer to not follow the ISO decisions without appropriate compensation [5].

Therefore, in many markets, separate discriminatory side-payments are paid to each generator for incentive compatibility. The side-payments are generally classified into two types: make-whole payment (MWP) and lost-opportunity cost (LOC) as follows [6]:

\[
MWP_g = \min \left[ 0, \sum_{t \in T} \{ \pi_t p_{g,t}^* - C_g \left( p_{g,t}^*, x_{g,t}^*, u_{g,t}^* \right) \} \right], \forall g \in G
\]

\[
LOC_g = \left\{ \max \sum_{t \in T} \pi_t p_{g,t} - C_g \left( p_{g,t}^*, x_{g,t}^*, u_{g,t}^* \right) \right\}_{\pi_t \in \chi_g^g}, \forall g \in G
\]

where \( g \in G \) is the generator index, \( t \in T \) is the time index, \( \pi_t \) is the given market price at time \( t \), \( P_{g,t}^* \) is the generation amount at time \( t \), \( x_{g,t}^* \) is the operating variable at time \( t \), \( u_{g,t}^* \) is the start-up variable at time \( t \), \( \chi_g^g \) is the feasible solution set of each generator in the UCED problem, and \( C_g \) is the cost function of generator \( g \). The superscript * indicates the optimal results of the UCED problem.

In MWPs calculated from Equation (1), it is guaranteed that each generator can recover at least the total variable production costs, and the amount that exactly matches the loss incurred on each operating day is paid. On the other hand, for LOCs calculated with Equation (2), the side-payment is to guarantee the potential maximum profit of each generator. LOCs are defined as the difference between the profit-maximizing solution of each generator and the actual profit earned by complying with the ISO’s instruction [5]. Moreover, note that the two types of side-payments are not mutually exclusive; MWPs can be considered special LOCs [6]. Because these side-payments are paid a different amount for each generator, related information tends to not be transparently disclosed, and it is difficult to predict in advance, which further deteriorates transparency in market operations. Therefore, the electricity market needs to be designed so that the amounts of the MWPs or LOCs are minimized.

The following subsections briefly describe the various pricing mechanisms that have been used or reviewed in various electricity markets to reduce side-payments.

2.2. SMP in the Korean CBP Market

The Korean wholesale electricity market is a regulated mandatory pool introduced in 2001. All available generators must bid the maximum capacity to the KPX in the day-ahead market; the KPX establishes the price-setting schedule based on the cost information evaluated monthly in advance by a government committee, and then determines the market price at the point where the supply curve and the forecasted demand curve meet [17].

Since the generator’s cost consists of not only fuel costs but also the quasi-fixed costs, the average cost of most generators tends to be higher than the marginal cost [18]. For this reason, marginal or near-marginal generators often fail to recover their total costs from marginal price alone. The Korean CBP market is designed so that the marginal generator
can recover the quasi-fixed costs only with the market price, SMP, which is conceptually expressed as follows [12]:

$$\text{SMP}_t = \max_{g \in G_{PSI}} \left\{ 2a_g p_{g,t} + b_g + \frac{\sum_{i=y}^{t} \left( c_g x_{g,t} - a_g p_{g,t}^2 + h_g u_{g,t} \right)}{\sum_{i=y}^{t} p_{g,t}} \right\}, \forall t \in T$$ (3)

where $a_g, b_g, c_g$ denote coefficients of the quadratic fuel cost function of the generator, $h_{g,t}$ is the start-up cost of the generator, $G_{PSI} \subset G$ is the subset of generators that can be eligible to set the market price, and $y, z \in T$ are the start and end times of a contiguous commitment period. Equation (3) consists of marginal costs, labeled (i), and the no-load intercept, labeled (ii).

The no-load intercept term in Equation (3) can be explained in more detail with the following equation:

$$\text{NoloadIntercept}_{g,t} = \frac{C_g(p_{g,t}, x_{g,t}, u_{g,t})}{p_{g,t}} - \frac{\partial C_g(p_{g,t}, x_{g,t}, u_{g,t})}{\partial p_{g,t}} = \frac{c_g x_{g,t} - a_g p_{g,t}^2 + h_g u_{g,t}}{p_{g,t}}$$ (4)

where $C_g(p_{g,t}, x_{g,t}, u_{g,t}) = a_g p_{g,t}^2 + b_g p_{g,t} + c_g x_{g,t} + h_g u_{g,t}$ denotes the generation cost.

The no-load intercept is defined as the non-recoverable cost, which is the difference between the average cost, marked (iii), and the marginal cost, marked (iv), and its value is averaged out during a contiguous commitment period (ii) to prevent market prices from fluctuating rapidly due to the no-load intercept. The Korean CBP market is distinguished from other markets in that side-payments such as MWPs are not paid for losses in operating costs, because the no-load intercept is already included in the market price.

This SMP mechanism has been applied without major problems for about 20 years, but the price regressivity problem began to emerge as demand-side programs started to enter the electricity market. Figure 1 shows the typical curves of average cost (blue line) and the marginal cost (red line) versus power output. Generally, the marginal cost of a generator increases monotonically with respect to power output, while the average cost decreases as power output increases toward the rated output. Additionally, the no-load intercept (yellow shaded area in the Figure 1) also tends to decrease as output increases.

As a result, the SMP, which includes the average cost factor, may cause the price regressivity problem, or the market price may fall when electricity demand increases slightly. Due to this price regressivity, the market price happens to rise occasionally when demand decreases because small-scale demand-response resources participate in the market. Therefore, the retail company may suffer the double burden of settlement for demand-response, and higher power-purchase costs caused by the increased market price [19].

If the demand-response market becomes more active in the near future, the market may operate irrationally under the current SMP mechanism, so this should be improved. Therefore, there is a strong desire in the Korean electricity market for new market pricing mechanisms that can simultaneously solve the price regressivity problem while reducing side-payments.
2.3. Convex Hull Pricing

Gribik et al. [9] proposed convex hull pricing as one of the alternative pricing mechanisms to minimize side-payments by replacing the traditional marginal-cost pricing. The concept of convex hull pricing is to yield the convex hull on the total cost function in order to eliminate non-convexities caused by the technical individuality of generators. The market price decided by convex hull pricing monotonically increases as the load increases, and it was proven to not eliminate side-payments completely, but it minimizes LOCs [6].

Early studies on convex hull pricing have been mainly based on dual formulation; i.e., the mathematical basis is that the optimal solution of convex hull pricing is equivalent to the Lagrangian dual of the UCED problem. However, research is deadlocked because the algorithm that guarantees the optimal solution to convex hull pricing within the polynomial convergence time has not yet been developed. Therefore, the recent research trend is to focus on the primal formulation of convex hull pricing, instead of dual formulation [6].

Hua and Baldick [5] proposed primal convex hull pricing formulation by replacing the cost function of the UCED problem with its convex envelope, and replacing the feasible set with its convex hull. The mathematical assumption of this method is that the optimal objective function value of the Lagrangian dual problem and the minimum solution to the proposed primal problem are the same, and that the optimal solution to the dual problem and the dual variable value of the primal problem are also the same. The convex hull pricing model with the piecewise linear cost function proposed by Hua and Baldick [5] can be formulated as follows:

\[
\min \sum_{t \in T} \sum_{g \in G_B} C^*_{g,x,t}(p_{g,t}, x_{g,t}, u_{g,t}) \\
\text{where } C^*_{g,x,t}(p_{g,t}, x_{g,t}, u_{g,t}) = \begin{cases} 
   a_g x + b_g + c_g x + h_g u_t & \text{if } \frac{p_{g,t}}{x_{g,t}} \in I_k \\
   0 & \text{if } x_{g,t} = 0 
\end{cases}, \\
\text{s.t. } \sum_{g \in G_B} p_{g,t} = d_t, \forall t \in T, \\
u_{g,t} \geq x_{g,t} - x_{g,t-1}, \forall t \in [2, T], \forall g \in G_B, 
\]
where $t, tt \in \{1 \ldots T\}$ are the time indices, and $G_B$ is the subset of generators ($G_B \subset G$) that participate in the bidding, while $k \in K$ and $I_k$ are the index and the interval partitioned for piecewise linearization, respectively. $C_{g,k}^{**}$ is the convex envelope of a generator’s piecewise linear cost function, $C_g^k$; $\chi_g^k$ is the convex hull set of $C_g^k$, while $a_{g,k}$ and $b_{g,k}$ are coefficients of the generator’s piecewise linear cost function for each interval; $d_t$ is the demand at time $t$, and $L_g, I_g, T_g, P_g$ denote the minimum up/down time and maximum/minimum output, respectively, for each generator.

Equation (5) represents the convex envelope of the piecewise linear cost function of each generator, consisting of the line between the original cost function in operation and an origin point. Equation (6) is the supply–demand balance condition, and Equation (7) is the state-transition constraint for the start-up. Equations (8) and (9) are constraints on the minimum up and down time, respectively, for each generator.

\[
\sum_{tt = t - L_g + 1}^{t} u_{g,tt} \leq x_{g,tt}, \forall t \in [L_g + 1, T], \forall g \in G_B,
\]

\[
\sum_{tt = t - L_g + 1}^{t} u_{g,tt} \leq 1 - x_{g,tt}, \forall t \in [L_g + 1, T], \forall g \in G_B,
\]

\[
x_{g,tt} P_g \leq p_{g,tt} \leq x_{g,tt} P_g^r, \forall t \in T, \forall g \in G_B,
\]

\[
u_{g,tt} \geq 0, \forall t \in [2, T], \forall g \in G_B,
\]

Equation (5) represents the convex envelope of a generator’s piecewise linear cost function, $C_g^k$; $\chi_g^k$ is the convex hull set of $C_g^k$, while $a_{g,k}$ and $b_{g,k}$ are coefficients of the generator’s piecewise linear cost function for each interval; $d_t$ is the demand at time $t$, and $L_g, I_g, T_g, P_g$ denote the minimum up/down time and maximum/minimum output, respectively, for each generator.

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2.4. ELMP in MISO Market

Recently, several US electricity markets, such as MISO, started to install FSRs to enhance flexibility in system operations. MISO determined that these FSRs would be justifiably entitled to determine the market price. MISO also acknowledged that it is a deficiency of the market mechanism that peak-load generators, including combustion turbines, cannot determine market prices due to the technical limits of the generators [20].

Accordingly, MISO developed the ELMP mechanism to derive market prices within a reasonable computation time while maintaining the main features of convex hull pricing. The multi-hour convex hull pricing problem is decomposed into single-hour ELMP problems by allocating commitment costs during the hours when qualified generators are on-line [2]. How to allocate the commitment cost plays a very important role in this method for stable market operations. In MISO, no-load and start-up costs are reflected slightly differently in the offer cost. With no-load costs, it is reflected in the offer cost during the hours when the generator is on-line, whereas with start-up costs, the value obtained by dividing start-up costs by the minimum run time (dubbed allocated-shared-start-up cost) is reflected in the offer cost only for hours corresponding to the minimum run time. In other words, start-up cost is reflected in the market price only when the FSRs are “most needed” [2,13].

MISO determines the market prices through the following processes. First, the commitment status of qualified generators (i.e., FSRs) and non-qualified generators is decided by a separate unit commitment process. Second, the binary variables for the operation status of committed FSRs determined by the preceding unit commitment process are relaxed to continuous variables (MISO calls this method partial commitment). Finally, the commitment costs of committed FSRs are reflected in the offer cost. By carrying out the economic dispatch problem based on these two methods, the prices can be obtained. This process can be formulated mathematically as follows [2]:

\[
\sum_{tt = t - L_g + 1}^{t} u_{g,tt} \leq x_{g,tt}, \forall t \in [L_g + 1, T], \forall g \in G_B,
\]

\[
\sum_{tt = t - L_g + 1}^{t} u_{g,tt} \leq 1 - x_{g,tt}, \forall t \in [L_g + 1, T], \forall g \in G_B,
\]

\[
x_{g,tt} P_g \leq p_{g,tt} \leq x_{g,tt} P_g^r, \forall t \in T, \forall g \in G_B,
\]

\[
u_{g,tt} \geq 0, \forall t \in [2, T], \forall g \in G_B,
\]

\[
\chi_g^k = \{p_{g,tt} \in \mathbb{R}, x_{g,tt} \in \mathbb{R}, u_{g,tt} \in \mathbb{R}|(6) - (11)\}, \forall t \in T, \forall g \in G_B
\]
where \( ASC_{g,t} = \begin{cases} \frac{h_g}{L_g}, & \forall t \in [y, y + L_y] \\ 0, & \text{otherwise} \end{cases} \)

\[
\min \sum_{t \in T} \left\{ \sum_{g \in G_O} C_g(p_{g,t}) + \sum_{g \in G \cap G_O} x_{g,t}(ASC_{g,t} + c_g) \right\} 
\]

\[\text{s.t.} \quad \sum_{g \in G_O} p_{g,t} = d_t, \forall t \in T \tag{14}\]

\[x_{g,t}^g p_{g,t} \leq p_{g,t} \leq x_{g,t}^g p_{g,t}, \forall t \in T, \forall g \in (G_O \cap G_Q) \tag{15}\]

\[x_{g,t}^g p_{g,t}^s \leq p_{g,t} \leq x_{g,t}^g p_{g,t}^s, \forall t \in T, \forall g \in G_B \cap (G_Q \cap G_O) \tag{16}\]

\[
\chi_g = \{ p_{g,t} \in \mathbb{R}, x_{g,t} \in [0, 1] \} \text{ for each generator, and } x_{g,t}^g \text{ is the parameter for operating status information for each generator at time } t \text{ as determined in the UC problem.}
\]

Equation (13) is the objective function consisting of the fuel costs of the generators, no-load costs, and the allocated-shared-start-up costs of the qualified generators. Equation (14) is the supply–demand balance condition, and Equations (15) and (16) are the power output constraints for qualified and non-qualified generators, where the backslash (\(\setminus\)) denotes the set difference operation. From partial commitment of the operating variables in Equation (17), qualified generators can be eligible to set prices even when the output is lower than the minimum generation. With the unit commitment results, non-qualified on-line generators are set to between minimum and maximum generation, and off-line generators are shut down.

### 2.5. Vickrey Pricing in a Uniform-Price Market

The Vickrey auction, also known as the second-price sealed-bid auction, is a single-unit auction mechanism proposed by William Vickrey [14]. In the Vickrey auction, the bidder with the highest price (or the lowest price in a reverse auction) is the winner, but the amount actually paid (or received) is determined not by the winner’s bid but by the runner-up’s bid [21]. The most significant advantage of the Vickrey auction is that the best strategy for the bidder is to bid a true value, which can prevent excessive competition from overwriting the bid (or underwriting the bid in a reserve auction) [22].

Although the Vickrey auction has hardly been applied to an actual electricity market, several studies have been conducted to investigate the feasibility of applying the method to electricity markets [23–25]. In particular, O’Mahoney and Denny [26] proposed using the Vickrey auction as a pricing mechanism for a mandatory pool established for the liberalization of the electricity market, which can ultimately induce market participants to bid at their true marginal costs in the long term.

The main reason the Vickrey auction has rarely been applied to an actual energy market is that the method is vulnerable to collusion between bidders, and market participants are reluctant to participate in a bidding process where the actual costs or bid prices are naturally disclosed [15]. However, the Korean electricity market is rather free from these problems because all cost information of the generators participating in the market was already revealed and evaluated by a separate government committee [27].

From the electricity market perspective, since the amount the winner (marginal generator) receives in a Vickrey auction is not the winner’s own bid (the marginal cost) but the runner-up’s bid, winners can secure an additional inframarginal rent on top of their own marginal cost. This gives winners an opportunity to recover some of the quasi-fixed costs, which may reduce the amount of side-payments.
In order to apply the Vickrey auction as a pricing mechanism (Vickrey pricing) in the uniform-price electricity market, this research uses the simplest form of the Vickrey auction concept. Figure 2 illustrates an example of how a Vickrey pricing would determine the market price. For simplicity, it is assumed that power generation is produced at the marginal cost of each generator. In Figure 2, G4 is the marginal generator, but the market price is determined by the marginal cost of the runner-up generator, or G5 (Vickrey price in Figure 2).

![Figure 2. A conceptual diagram for Vickery pricing.](image)

As described above, the Vickrey price is determined by the runner-up’s bid, which is equivalent to the lowest value among the marginal costs of generators that are not dispatched due to economic reasons. Vickrey pricing with piecewise linear function can be formulated mathematically as follows:

\[
Vickrey\text{Price} = \min_{g \in G_B \setminus (G_G \cup G_T)} \left\{ \frac{\partial C_g(p_g)}{\partial p_g} \left| \frac{\partial C_g(p_g)}{\partial p_g} > \lambda_t, \ p_{g,t} = p_{m,t}^* \right\}, \ m \in M_t, \ \forall t \in T \right\},
\]

where \( M_t := \left\{ g \left| \frac{\partial C_g(p_g)}{\partial p_g} = \lambda_t, \ p_{g,t} < p_{g,t}^* < p_{g,t} \right\}, \forall t \in T \),

where \( \lambda_t \) is the dual variable of the supply–demand balance condition in the UCED problem (that is, the marginal price at time \( t \)). \( M_t \subset G \) is the subset of marginal generators at each time on the operating day, and \( m \in M_t \) represents the marginal generator at time \( t \). \( G_T \subset G_B \) is the subset of generators that cannot supply the generation amount of the marginal generator in the corresponding time due to technical constraints, such as minimum run time.

Unlike the SMP mechanism, where the quasi-fixed costs are reflected in the market, a Vickrey price is decided only by the runner-up’s marginal cost. Hence, price regressivity does not occur. In addition, Vickrey pricing means MWPs are partially reduced, compared to marginal-cost pricing, because the actual marginal generator has a small amount of extra inframarginal rents between its marginal cost and the market price.

3. Case Study

3.1. Description of the Simulation Study

In this study, the various alternative pricing mechanisms described in the previous section are applied to the Korean electricity market, and the simulation results are compared and analyzed. To this end, a simulation database is constructed based on the actual Korean power system from 2015 to 2017. Tables 1 and 2 summarize the information on the system simulated [28–31].
Table 1. Summary of the test system.

|                      | 2015     | 2016     | 2017     |
|----------------------|----------|----------|----------|
| Peak demand (MW)     | 73,550   | 79,940   | 82,090   |
| Annual consumption (GWh) | 493,310 | 509,122  | 518,443  |
| Installed capacity (MW) | 97,688   | 104,238  | 110,937  |

Table 2. Summary of the major power sources.

| Power Source                             | 2015     | 2016     | 2017     |
|------------------------------------------|----------|----------|----------|
| Installed capacity (MW)                   |          |          |          |
| Nuclear                                  | 22,205   | 23,582   | 23,687   |
| Coal                                     | 27,094   | 30,450   | 33,997   |
| Combined cycle gas turbine               | 38,745   | 40,707   | 45,056   |
| Oil                                      | 2908     | 2761     | 2720     |
| Combined heat and power plant            | 401      | 403      | 403      |
| Installed capacity (MW)                   |          |          |          |
| Nuclear                                  | 2176     | 2304     | 2387     |
| Coal                                     | 18,557   | 17,155   | 24,272   |
| Combined cycle gas turbine               | 81,830   | 54,450   | 56,882   |
| Oil                                      | 73,581   | 37,734   | 46,713   |
| Combined heat and power plant            | 78,364   | 57,279   | 53,253   |
| Installed capacity (MW)                   |          |          |          |
| Nuclear                                  | 60       | 50       | 42       |
| Coal                                     | 41       | 32       | 31       |
| Combined cycle gas turbine               | 34       | 30       | 27       |
| Oil                                      | 38       | 42       | 25       |
| Combined heat and power plant            | 38       | 29       | 34       |

3.2. Assumptions

In this study, the UCED problem and pricing processes are implemented using the CPLEX solver, which is one of the typical mixed-integer linear programming (MIP) and linear programming (LP) solvers available with the General Algebraic Modeling System (GAMS) [32]. The MIP gap is set to 0%. It should be noted that transmission congestion and loss are not considered in this study in order to eliminate the influence of transmission operations on the simulation results because they are irrelevant to the pricing mechanisms considered.

3.2.1. Pricing Schemes

As described above, mathematical models of the following pricing mechanisms were implemented, and simulation studies were conducted using actual market data of the Korean electricity market.

1. Marginal-cost price: the marginal price is calculated from the value of the dual multiplier of the supply-and-demand balance equation of the UCED problem;
2. System Marginal Price: SMP is calculated with Equation (3) using the results of the UCED problem;
3. Convex hull price: Convex hull price is derived from the dual multiplier in Equation (6). In order to derive a convex hull price, it is necessary to construct the convex hull of the feasible set. The primal formulation in Section 2.3 derives convex hull prices in the absence of ramping constraints, which can be seen as the lower bound of exact convex hull prices considering ramping constraints. Considering the current status of research on convex hull pricing, it is realistic to not consider ramping constraints, as suggested by Hua and Baldick [5]. Therefore, ramping constraints are not considered in this study. However, in practice, ignoring the ramping constraints does not cause a significant error because most of the peak generators that determine the market prices can ramp their outputs up or down between the minimum and the maximum limits within an hour;
4. Extended Locational Marginal Price: ELMP is derived from the dual multiplier in Equation (14). Before determining ELMP, however, it is needed to specify qualified generators. ELMP Phase I, introduced in 2015, designated generators with a minimum run time of less than one hour and a start-up notification time of less than 10 min as FSRs. This tight control resulted in a very limited number of generators being included in the FSRs. In order to broaden the benefits of the ELMP mechanism, MISO initiated ELMP Phase II in 2017, which eases FSR eligibility to on-line generators with both the minimum run time and a start-up time of less than one hour [33]. In general, as the number of qualified generators increases, the market price tends to rise. It was judged that the eligibility of an FSR should not be defined based on a specific theoretical background, but arbitrarily determined to maintain the market price at an appropriate level. Hence, in order to properly introduce the ELMP method in a specific electricity market, it should be decided which generators will be qualified considering the specific market conditions and policies. In this study, the following two cases were considered as qualifications for generators in the Korean electricity market.

1. ELMP(a): all generators for which MWPs are to be paid when marginal-cost pricing is qualified.
2. ELMP(b): if the marginal generator for each hour of the UCED problem is CCGT, this generator is qualified.

For both cases, only CCGTs committed each hour are entitled to decide on the market and, in general, a relationship \( n \left( G^{\text{ELMPa}}_Q \right) \geq n \left( G^{\text{ELMPb}}_Q \right) \) of holds where \( G^{\text{ELMPa}}_Q \) and \( G^{\text{ELMPb}}_Q \) are a subset of qualified generators for ELMP(a) and ELMP(b), respectively.

5. Vickery price: the Vickrey price is calculated using Equation (18).

This study analyzes the day-ahead market, adopts a single-node pricing system that does not consider transmission congestion and energy losses. However, since the actual electricity market operates with physical line capacity limitations, more rational and ecological prices can be derived with the zonal or nodal pricing methods that reflect transmission congestion and losses, such as locational marginal pricing scheme [34,35].

By adding a simple linear transmission constraint and DC power flow equation to the alternative pricing model, the zonal or nodal prices can be calculated [2,5]. Marginal price, convex hull price, and ELMP are determined by the dual multiplier of the zonal or nodal balance equation as the zonal or nodal prices. In the case of zonal or nodal SMP, the market price can be calculated using Equation (3) for generators in a zone or node. However, Vickery pricing makes it difficult to determine which generator is the marginal generator within a zone or node due to transmission constraints. Zonal or nodal Vickery prices can be determined by setting the generator with the highest incremental cost among generators with the generation amount between the minimum and maximum output as the marginal generator of a zone or node and applying the proposed Vickrey pricing methodology.

Figure 3 summarizes the pricing methods and describes an overview of the simulation process.
3.2.2. Financial Analysis

After calculating the market prices under each pricing mechanism, the settlement amount of each generator should be calculated to compare and analyze the financial impact on generators. The settlement amount is calculated as the product of the generation amount of each generator and the market price, which can be calculated using the results of separate UCED processes and the pricing methods described in the previous subsection and which can be described as follows:

\[
PowerPurchaseCost = \sum_{v \in T} \sum_{g \in GB} \pi_t p_{g,t}^s
\]

\[
TotalSettlementCost = PowerPurchaseCost + \sum_{g \in GB} MWP_g
\]

\[
Profit_g = \sum_{v \in T} \left\{ \pi_t p_{g,t}^s - C_g \left( p_{g,t}, x_{g,t}^s, u_{g,t}^s \right) \right\} + MWP_g, \; \forall g \in GB
\]

where \( v \in T \) is a time index corresponding to 24 h of the operating day.

Equation (19) describes the power purchase cost, or the settlement cost that an electricity sales company should pay to the generators for the purchased energy at the market-clearing price. Since the electricity sales company has to provide additional side-payments, the final total payment can be expressed with Equation (20), which is the sum of the power-purchase cost and the MWPs. As described in Equation (21), the profit of each generation company is calculated by subtracting total production costs from revenue. If the generators receive MWPs, the profit from those generators on the operating day is zero.

3.3. Simulation Results

Figures 4–6 show the simulation results under each pricing mechanism for the periods 2015, 2016, and 2017, respectively, in the form of hourly price duration curves. In addition, Table 3 shows the weighted-average values of the market prices for the six pricing mechanisms.

Figure 4. Price duration curves by market price for 2015.
Figure 5. Price duration curves by market price for 2016.

Figure 6. Price duration curves by market price for 2017.
### Table 3. Comparison of annual demand-weighted average market price (KRW/kWh).

| Pricing Scheme       | 2015 Rate of Change | 2016 Rate of Change | 2017 Rate of Change | Average | Average Change |
|----------------------|---------------------|---------------------|---------------------|---------|----------------|
| SMP (base)           | 97.07               | 70.44               | 74.02               | 80.51   | −5.9%          |
| Marginal price       | 92.50               | 66.30               | 74.02               | 75.74   | −5.9%          |
| Convex hull price    | 95.20               | 68.55               | 70.93               | 78.23   | −2.8%          |
| ELMP(a)              | 98.27               | 72.04               | 76.02               | 82.11   | 2.0%           |
| ELMP(b)              | 96.72               | 69.53               | 72.40               | 79.55   | −1.2%          |
| Vickrey price        | 101.17              | 74.84               | 79.05               | 85.02   | 5.6%           |

1 when documenting this paper, USD1.0 was equal to approximately KRW 1125.0.

Judging simply by the average market price, the pricing mechanism that shows the most similarity to the current SMP mechanism is ELMP(b), whereas the mechanism that causes the most difference is convex hull pricing, excluding marginal pricing. On the other hand, ELMP(a) and Vickrey pricing have higher prices than SMP, with Vickrey showing the highest trend. These phenomena appeared consistently in all three of the yearly simulations.

Table 4 represents the summarized results of financial analysis for an electricity sales company according to the pricing mechanisms for three years.

### Table 4. Comparison of the settlement results by market price (hundred million KRW).

| Year | Pricing Scheme | Power Purchase Cost | Side-Payment | Total Settlement Cost |
|------|----------------|---------------------|--------------|-----------------------|
|      |                | MWP                 | LOC          |                       |
| 2015 | SMP            | 458,560             | 12           | 458,571               |
|      | Marginal price | 437,774 (−4.53%)    | 563          | 438,337 (−4.41%)      |
|      | Convex hull price | 449,771 (−1.92%) | 18           | 449,791 (−1.91%)      |
|      | ELMP(a)        | 464,304 (1.25%)     | 13           | 464,316 (1.25%)       |
|      | ELMP(b)        | 456,977 (−0.35%)    | 44           | 457,021 (−0.34%)      |
|      | Vickrey price  | 477,570 (4.15%)     | 137          | 477,707 (4.17%)       |
| 2016 | SMP            | 341,883             | 7            | 341,890               |
|      | Marginal price | 322,550 (−5.65%)    | 503          | 323,054 (−5.51%)      |
|      | Convex hull price | 332,762 (−2.67%) | 15           | 332,777 (−2.67%)      |
|      | ELMP(a)        | 349,748 (2.30%)     | 9            | 349,757 (2.30%)       |
|      | ELMP(b)        | 337,553 (−1.27%)    | 31           | 337,584 (−1.26%)      |
|      | Vickrey price  | 362,841 (6.13%)     | 79           | 362,920 (6.15%)       |
| 2017 | SMP            | 363,805             | 14           | 363,819               |
|      | Marginal price | 337,956 (−7.11%)    | 693          | 338,649 (−6.92%)      |
|      | Convex hull price | 348,664 (−4.16%) | 20           | 348,684 (−4.16%)      |
|      | ELMP(a)        | 373,805 (2.75%)     | 15           | 373,820 (2.75%)       |
|      | ELMP(b)        | 355,930 (−2.16%)    | 68           | 355,998 (−2.15%)      |
|      | Vickrey price  | 388,108 (6.68%)     | 98           | 388,206 (6.70%)       |

Note: Numbers in parentheses are the percentage change with respect to the SMP mechanism.

Table 5 describes the profit for electricity generation companies according to the type of generator, as calculated using Equation (21). The total profit for generation companies also shows the same trend as settlement costs. However, unlike market price and total settlement cost, the profit of each generator varies widely, depending on whether it is a

Obviously, the SMP mechanism, which includes non-recoverable costs in the market price in advance, has the lowest MWPs compared to other pricing mechanisms, but has the fatal disadvantage of price regressivity, as explained earlier. Meanwhile, we can see that the LOC of the convex hull pricing mechanism is the lowest, which is consistent with the results of Hua and Baldick [5]. ELMP(b), where total settlement costs are 0.34%~2.15% lower than the SMP mechanism each year, is most similar to the current SMP mechanism from among the alternative pricing schemes. In terms of total settlement costs, the ELMP(a) and Vickrey mechanisms have 1.25%~2.75% and 4.17%~6.70% higher costs, respectively, compared to the SMP mechanism.

Table 5 describes the profit for electricity generation companies according to the type of generator, as calculated using Equation (21). The total profit for generation companies also shows the same trend as settlement costs. However, unlike market price and total settlement cost, the profit of each generator varies widely, depending on whether it is a
base-load generator or a peak-load generator. In both ELMP(a) and Vickrey mechanisms, the profit for base-load generators is higher compared to the SMP mechanism. The profit of base-load generators from Vickrey pricing is higher than the ELMP(a) mechanism. On the other hand, under ELMP(a), the profit for CCGT generators (typical peak-load generators) is significantly higher than under the SMP mechanism for all years. However, the average profit for CCGT generators from the Vickrey price mechanism is lower than under the SMP mechanism.

Table 5. Comparison of profits by market price (hundred million KRW).

| Year  | Pricing Scheme | Total Plant Profit | Base-Load Plant Profit | CCGT Plant Profit |
|-------|----------------|--------------------|------------------------|------------------|
|       |                |                    | Hospital               | Hospital          |
|       |                |                     | Nuclear                | Nuclear           |
|       |                |                     | Coal                   | Coal              |
| 2015  | SMP            | 284,712             | 152,896                | 122,829           | 8070             |
|       | Marginal price | 264,413 (−7.1%)     | 145,285 (−5.0%)        | 113,344 (−7.7%)   | 5067 (−37.2%)    |
|       | Convex hull price | 275,935 (−3.1%)  | 149,591 (−2.2%)        | 118,743 (−3.3%)   | 6779 (−16.0%)    |
|       | ELMP(a)        | 290,456 (2.0%)      | 154,409 (1.0%)         | 124,871 (1.7%)    | 10,225 (26.7%)   |
|       | ELMP(b)        | 283,157 (−0.5%)     | 152,037 (−0.6%)        | 121,873 (−0.8%)   | 8345 (3.4%)      |
|       | Vickrey price  | 303,844 (6.7%)      | 162,178 (6.1%)         | 133,244 (8.5%)    | 7477 (−7.3%)     |
| 2016  | SMP            | 198,694             | 116,546                | 76,761            | 4079             |
|       | Marginal price | 179,806 (−9.5%)     | 109,088 (−6.4%)        | 67,589 (−11.9%)   | 2140 (−47.5%)    |
|       | Convex hull price | 189,583 (−4.6%) | 112,864 (−3.2%)        | 72,329 (−5.8%)    | 3227 (−20.9%)    |
|       | ELMP(a)        | 206,562 (4.0%)      | 118,794 (1.9%)         | 79,788 (3.9%)     | 6475 (58.7%)     |
|       | ELMP(b)        | 194,386 (−2.2%)     | 114,558 (−1.7%)        | 74,490 (−3.0%)    | 4064 (−0.4%)     |
|       | Vickrey price  | 219,723 (10.6%)     | 126,514 (8.6%)         | 88,145 (14.8%)    | 3753 (−8.0%)     |
| 2017  | SMP            | 193,783             | 124,177                | 63,489            | 6108             |
|       | Marginal price | 168,496 (−13.0%)    | 114,319 (−7.9%)        | 50,488 (−20.5%)   | 3685 (−39.7%)    |
|       | Convex hull price | 178,650 (−7.8%) | 118,121 (−4.9%)        | 55,733 (−12.2%)   | 4792 (−21.5%)    |
|       | ELMP(a)        | 203,784 (5.2%)      | 126,698 (2.0%)         | 67,867 (6.9%)     | 9206 (50.7%)     |
|       | ELMP(b)        | 185,959 (−4.0%)     | 120,603 (−2.9%)        | 59,314 (−6.6%)    | 6036 (−1.1%)     |
|       | Vickrey price  | 218,170 (12.6%)     | 135,574 (9.2%)         | 76,582 (20.6%)    | 6009 (−1.6%)     |

Note: Numbers in parentheses are the percentage change with respect to the SMP mechanism.

Although the market price and settlement cost of the ELMP(b) mechanism are slightly lower than under the SMP mechanism, the results are the most similar to the SMP mechanism from among all the alternative pricing schemes. With ELMP(b), the profit for base-load generators is lower, whereas the profit for peak-load generators does not show a constant trend, and there are cases that are higher or lower than the SMP mechanism each year. In conclusion, in most cases, the level of profit based on generator type under the EMLP(b) mechanism is the most similar to the SMP mechanism, which is the pricing mechanism currently applied in the Korean electricity market.

3.4. Discussions

Figure 7 summarizes the profits for generation companies, the total settlement costs (black line), the MWPs (green line), and the LOCs (yellow line) under each pricing mechanism. Table 6 also shows the results of market price changes based on demand levels in 2017. For convenience, only 2017 results are shown, but the results for other years have similar trends.
As shown in Figure 7, compared to the SMP mechanism currently applied in the Korean electricity market, the pricing mechanism that provides the profit most similar to CCGTs is ELMP(b), and the total settlement costs and the profits for all generation companies also show a similar pattern. This is because, as shown in Table 6, market prices under the ELMP(b) mechanism are similar to the SMP mechanism in high-demand scenarios, but are lower when demand is low. This has the effect of reducing the profit for base generators, such as coal and nuclear generators, while the profit for peak generators, which mainly operate during high demand, remains unchanged. Therefore, the introduction of an ELMP mechanism may be useful for the purpose of increasing profits for CCGTs that can provide flexibility for the intermittency of renewable energy, while not increasing profits for coal-fired and nuclear generators in accordance with recent energy policies, such as greenhouse gas reduction or post-nuclear generation.

On the other hand, under the convex hull pricing mechanism, the market price tends to decrease, compared to the current SMP mechanism in both low- and high-demand periods. For this reason, the convex hull pricing mechanism resulted in the lowest profits for both baseload and peak generators from among the alternative pricing mechanisms. Therefore, convex hull pricing can be effectively used when the market operator wants to minimize LOCs and reduce the overall profits of generation companies, and increase the profit for retail companies instead. Vickrey pricing shows a very different trend from the other mechanisms. While most of the other pricing mechanisms show a larger increase in market price in high-demand periods than in low-demand periods, Vickrey pricing instead increases in low-demand periods. As a result, most of the base-load generators...
showed significantly higher profits than under the current SMP mechanism, but the peak generators’ profits decreased slightly.

Table 7 summarizes the pros and cons of each pricing mechanism covered in this study.

| Pricing Scheme | Pros | Cons |
|----------------|------|------|
| Marginal price | theoretically safe (marginal-cost pricing) | higher side-payments |
| | lowest total settlement costs | lowest profits |
| SMP | lowest MWP | excessive profits for base-load generators |
| | stable margin for peak generators | price regressivity problem |
| Convex hull price | lowest LOCs | lower profits |
| | lower total settlement costs | ramping constraints are ignored |
| | increase with demand | |
| ELMP | lower side-payments | additional research is required to decide appropriate qualified generator groups |
| | higher profit for peak generators | |
| Vickrey price | a straightforward methodology | highest LOCs |
| | extra inframarginal rents for peak generators | affected by the distribution of fuel cost levels |

4. Conclusions

From a traditional economic point of view, it may be desirable to determine the market price based on marginal cost, but in the electricity market, side-payments increase due to the quasi-fixed costs, such as no-load and start-up costs, which in turn hinder the transparency of market operations. The main purpose of this study is to review the various alternative pricing mechanisms that can reduce side-payments in the electricity market, and to examine how each method financially affects the shareholders in the electricity market.

The alternative pricing mechanisms reviewed in this study are marginal pricing, convex hull pricing, two variants of ELMP, and Vickrey pricing. For these various alternative pricing mechanisms, mathematical formulations are derived using the most recent related research results, and simulations were performed for a three-year period using actual data from the Korean electricity market.

As a result of a rigorous simulation study over a three-year period, each pricing mechanism has the following advantages and disadvantages.

1. The SMP mechanism currently applied to the Korean electricity market has the smallest side-payments amounts, but the price regressivity problem prevents new modern market elements (such as demand-response) from entering the electricity market. The SMP mechanism can be a good option when the market price is too low, and it is necessary to improve the profits of generation companies.

2. The convex hull pricing mechanism minimizes LOCs, and the settlement costs of an electricity sales company seem to be the lowest from among the alternative pricing models. Although the pricing mechanism needs to be modified to reduce side-payments, it is a good option if you do not want to significantly increase the profits of power generation companies.

3. The ELMP mechanism variants show slightly different results according to the qualification requirements of the fast-start resources that are subject to partial commitment in the pricing process. The most distinctive feature is that market prices tend to rise relatively higher during high-demand periods than during low-demand periods. Hence, it is a good option if you want to selectively increase the profits of peak generators rather than baseload generators.

4. The Vickrey pricing mechanism tends to be the opposite of the ELMP mechanism. Market prices under Vickrey pricing tend to rise relatively higher during low-demand periods than during high-demand periods. Hence, it is a good option if you want to selectively increase the profits of baseload generators rather than peak generators.
Of course, the results from the application of certain pricing mechanisms vary greatly depending on the generation mix, fuel costs, demand profiles, and other energy policies, so the simulations from this study cannot be absolute. Therefore, it is obvious that each electricity market needs to perform its own rigorous simulation study to find a suitable pricing mechanism for its own market.

The main contribution of this study is to present a guideline for market designers who want to introduce a new custom pricing mechanism to achieve a market-driven energy policy. Additionally, it should be noted that the alternative pricing mechanisms analyzed in this study are markedly different in their features, strengths, and weaknesses, and in order to apply these to an actual market, a substantial social agreement between the stakeholders is necessary.

The pricing mechanisms proposed in this paper cannot be seen as a final form that can be directly applied to the electricity market. Further work to increase the efficiency of the electricity market should be carried out through combination with a pricing mechanism such as nodal or zonal pricing that can take into account network congestion or loss, and other important issues in the electricity market such as environmental concerns. Furthermore, it is necessary to enhance the study on the pricing mechanism that can maximize the efficiency of distributed generation and demand responses, which have been gradually increasing recently.

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