Ph. D. Dissertation in Engineering

Analysis of power system flexibility and economic impact due to expansion of renewable energy based on power market simulation

전력시장 시뮬레이션 기법을 활용한 재생에너지 확대가
전력시스템 유연성 및 경제성에 미치는 영향 분석

February 2021

Graduate School of Seoul National University

Technology Management, Economics, and Policy Program

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이 논문을 공학박사학위 논문으로 제출함

2021 년 2 월

서울대학교 대학원

협동과정 기술경영경제정책 전공

김형근

김형근의 공학박사학위 논문을 인준함

2020 년 12 월

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Abstract

Analysis of power system flexibility and economic impact due to expansion of renewable energy based on power market simulation

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To achieve the reduction target of greenhouse gas emissions, energy transition policy is being implemented to expand the share of renewable energy worldwide. However, the expansion of renewable energy not only causes the flexibility problem of the power system due to volatility and uncertainty of renewable energy output, but also affects the merit order of traditional power generation sources due to low operating costs of renewables or national policy objectives. These effects give rise to a huge transformation in power systems with a high share of renewable energy. In this context, this study evaluates the flexibility of the power system and analyzes the economic impact on the power market in 2031, when the share of renewable energy exceeds 20% due to Korea's energy transition policy. First, a mixed-integer linear programming approach was used to formulate the power system day-ahead unit commitment and economic dispatch model, and a power market simulation was

conducted to compare the performance of the electricity market in 2031 based on 2018 figures, when the share of renewable energy is relatively low at 6.2%.

To assess the flexibility of the power system in 2031, the number of periods of flexibility deficit for 8,760 hours was calculated by comparing the supply of flexibility according to the scenario of available flexibility resources with the flexibility requirement, which is the fluctuation in net load over an hour. The results show that if only the operational reserve is considered as a flexibility supply resource, about 94% of the renewable energy volatility can be dealt with in terms of upward flexibility, but the role of the quick-start generation resources is found to be important for 6% of the ramping event greater than the reserve capacity. On the other hand, the number of times flexibility deficit occurs in terms of downward flexibility is expected to be about 18, showing a very low probability of occurrence.

The analysis of the distribution of renewable energy volatility reveals that, unlike the standard for operational reserve, which was traditionally fixed, the resource for responding to flexibility problem in renewable energy needs to operate the flexible securing standard. In addition, it is necessary to review the improvement of the current upper limit method of power output level and the separate operation of the reserve auxiliary service market from the energy service market to ensure that power generation sources suitable for supplying flexibility with physical characteristics for response to flexibility are included in the operational reserve. At this time, the minimum market size of the reserve auxiliary service that could be considered was estimated to be about KRW 162 billion.

The expansion of renewable energy will lower the system marginal price by 13.7 KRW/kWh on average in 2031. As the share of renewable energy generation increases, the capacity of net load to be met by traditional power generation decreases, and the drop in the system marginal price may be even worse. Such a decrease in electricity market prices seems to lead to the accompanied decline in the power vendors' wholesale electricity price. However, when looking at the result of power purchase cost analysis considering the renewable portfolio standard (RPS) and the emissions trading scheme (ETS) to expand renewable energy, it was predicted that the capacity settlement amount, the emission trading cost, and the RPS obligation fulfillment cost, excluding the electricity settlement amount, would increase. According to the analysis of power market simulation by RPS obligatory rate, paid allocation ratio for emissions trading, and emissions price per unit scenarios, the average power purchase cost may increase up to about 13% from 93.87 KRW/kWh in 2018 to 106.03 KRW/kWh in 2031. This suggests that it could act as a pressure factor to raise electricity rates in the future.

The results of this study have the following policy implications. First, to secure the flexibility of the power system to an appropriate level in 2031, it is necessary to consider the alternative method of securing the operating reserve via competitive bidding for flexibility resources that meet the power system requirement instead of the upper limit constraint on generation output. In addition, for the purpose of responding to variability of renewable energy, quick-start generators operated separately from the operational reserve should be implemented as planned. It is also necessary to refine the system for predicting the amount of renewable energy generation in consideration of the mechanism for responding to the variability of each flexibility resource to realize the flexible regulation of flexibility supply amount.

Second, if policy makers consider revising or establishing a new policy related to the expansion of renewable energy, it is necessary to examine not only the expected direct effect of the policy but also the indirect ripple effect, such as the pressure to increase electricity rates due to the hike in power purchase costs of vendors. Third, since the amount of renewable energy generation and electricity market price are expected to change in an increasingly inconsistent pattern, it is also important to reconsider the design for the settlement rules of the cost-based pool market or method of deciding the market price.

Finally, in the future power market, the pattern difference between the demand peak and the market price peak may increase. Therefore, various policies that consider demand patterns, such as demand management, economical demand response, and electricity fee system, should be reviewed in the direction of considering the net load pattern in the future.

Keywords: Renewable Energy, Unit Commitment and Economic Dispatch Modeling, Mixed-Integer Linear Programming, Evaluation of the Power System Flexibility, Power Market Simulation, Economic Impact Analysis

Student Number: 2017-36365

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Chapter 1.　Introduction

1.1 Research Background

Since the Paris Agreement in 2015, all countries around the world have defined their nationally determined contribution (NDC) according to the circumstances of each country and have promoted various energy policies to achieve this greenhouse gas reduction goal. The energy transition policy, which has recently been implemented by leading countries to reduce greenhouse gases (GHGs) by replacing existing fossil fuel power sources (e.g., coal, LNG) with renewable energy, is also one of national energy policies along with energy efficiency improvement and demand management.

According to the International Energy Agency's (IEA) World Energy Outlook 2018, the share of renewable energy in global power generation facilities will increase from 25% in 2017 to 40% in 2040. China is expected to contribute 40% to this expansion of renewable energy supply, followed by Europe with 25%, and the US and India with 13% (IEA, 2018). In the 8^{th} Electricity Supply and Demand Basic Plan (hereafter ESDP) and the 3rd National Energy Master Plan, South Korea (hereafter Korea) has also published a plan to expand the share of renewable energy generation to 20% by 2030 and 30–35% by 2040, and is promoting the energy transition policy (Ministry of Trade, Industry, and Energy, 2019, 2017).

Globally, the share of solar and wind power generation has been increasing remarkably within the renewable energy power generation sector owing to the effect of the energy transition policy in each country. In particular, with the improved competitiveness of solar power generation, the capacity of such generation facilities is expected to exceed that of wind power generation facilities by 2025, hydropower generation by 2030, and coal power generation by 2040 (IEA, 2018). Furthermore, to examine the prospect for the composition of power generation sources based on Korea's rated capacity in 2031 (Figure 1), the share of solar and wind power generation facilities in the new and renewable power generation facilities of 58.6GW is the highest at 87.6% (51.3GW).

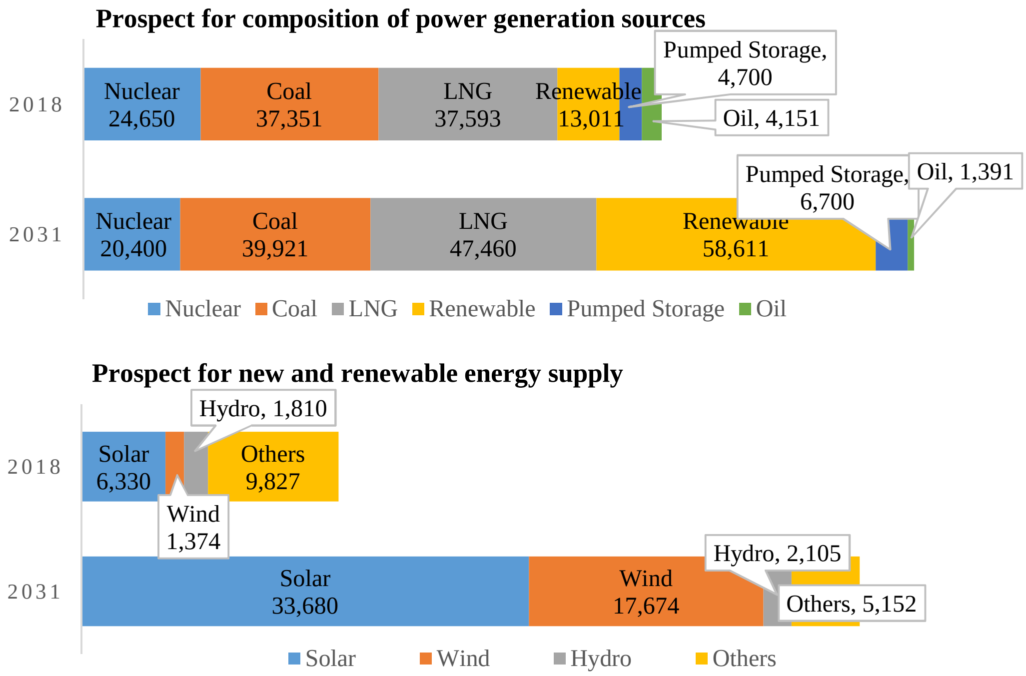

Figure 1. Prospects for composition of power generation in 2031 (unit: MW)

1) Others: marine energy, bio energy, waste-to-energy plant, byproduct gas, fuel cell, IGCC

Source: 8th ESDP, reconstructed by the author

Among the renewable energy generation technologies, solar and wind power are determined by weather conditions, the power generation output cannot be adjusted unlike traditional power sources (e.g., nuclear, coal, LNG), and uncertainty and volatility in power generation output appear as inherent features (Edenhofer et al., 2013; Hirth, 2013; IRENA, 2018; Ueckerdt et al., 2013). Volatility and uncertainty in power system operations is not a new issue. Traditionally, power systems have secured flexibility in supply to cope with demand prediction errors and failures of power plants and transmission lines to maintain balance between demand and power generation, and have secured reliability through demand reduction and transfer (Babatunde et al., 2020; Lannoye et al., 2012; Nosair & Bouffard, 2015). Due to the recent increase in the share of variable renewable energy generation, the ramping event of net load (demand–variable renewable energy generation) is a factor that can deteriorate the reliability of the power system; the concept of flexibility has been extended not only in the operation of power systems, but also in the establishment of power generation plans. Power system flexibility is defined as an ability to manage the uncertainty and volatility of power demand and supply on all relevant time scales in cost-effective and reliable levels (IEA, 2018). Korea is also strongly promoting an increase in the share of renewable energy as a national policy. In particular, due to the characteristics of the power system that has high shares of solar and wind power generation with high volatility and is independent or isolated from the power grids of other countries, power system flexibility will become a more important issue with the increase in renewable energy generation. Accordingly, many research have been conducted on methods to strengthen power system flexibility (Ahn, 2017; Jang and Cho, 2018; Cho and Cho, 2018).

The expansion of renewable energy can cause not only the problem of power system flexibility due to volatility and uncertainty, but also many changes in the power wholesale market (Ela et al., 2014). Ela et al. (2014) suggested the following effects of renewable energy expansion on the US power market. First, such expansion can lower the average locational marginal price (LMP). Since the merit order of renewable energy is higher than the existing power generation sources due to national policy or low operation cost, the profits and operation schedules of the traditional power sources depend on the renewable energy generation. Second, although the LMP is determined in the day-ahead market (hereafter DAM) according to the prediction of renewable energy generation, the gap with the real-time market price may widen due to the volatility of renewable energy generation, and this can also increase the uncertainty of power generation companies' participation in pricing. Third, the volatility can increase the flexibility capacity required in the power system. If there is no incentive in terms of the acquisition of flexibility capacity, the reliability of the power system can be degraded or power generation sources that require a high operating cost can be introduced. Lastly, the expansion of renewable energy in the reserve auxiliary service market requires an increase in the scale of reserves, regulation changes such as the dynamic operation of reserves, or improvement in the accuracy of the renewable energy output prediction. These characteristics are general facts that may occur not only in the wholesale market of the US, but also in the power market where the share of renewable energy generation is increasing.

However, unlike the price-bidding-pool (PBP) of the US and Europe, the wholesale power market of Korea is a cost-based-pool (hereafter CBP) where the energy and auxiliary service markets are not separated and the real-time market is also not introduced. As shown in Figure 2, in the domestic power market, KEPCO's 6 power generation subsidiaries, independent power producers, private generation companies and community energy systems produce electric power, and KEPCO transports the electric power it purchased from KPX through the transmission and distribution network, and sell it to general customers.

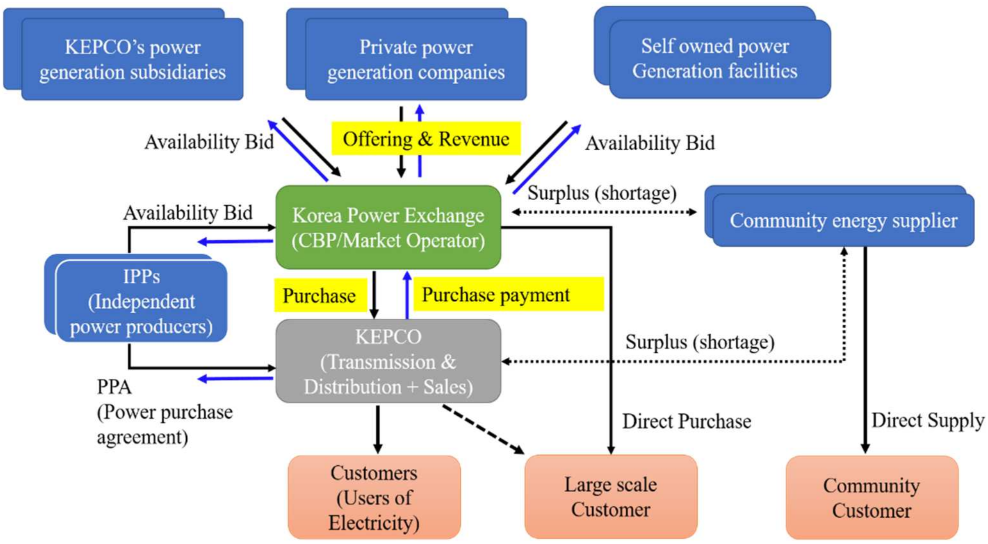

Figure 2. Structure of Korea's power wholesale market

Thus, the power market design may be different in each country. In other words, the evaluation of power system flexibility and economic effect analysis according to the expansion of renewable energy can derive different results depending on the power market situation of each country. Therefore, to accurately evaluate the impact of the increased proportion of renewable energy on the wholesale power market of Korea, it is necessary to construct a simulation model reflecting the domestic power system protocol and operating regulation and conduct a quantitative analysis using this model.

1.2 Research Objectives

To analyze the impact of the increased proportion of variable renewable energy on the power market in terms of flexibility and economics, this study constructs a power market simulation model using mixed-integer linear programming (MILP). The day-ahead generation scheduling program, which is a major part of power market simulation, optimizes the unit commitment (UC) and economic dispatch (ED) simultaneously, and is used to establish the price-setting and operational power generation plans. The Resource Scheduling and Commitment (RSC) system also applies the MILP methodology. This system is used by the Korea Power Exchange (hereafter KPX), the power system operator in Korea, to establish the day-ahead unit commitment and economic dispatch schedule. This is a method of adding energy policy changes as new constraint equations, and has the advantage of easily analyzing the power market impact. Commercial unit commitment and economic dispatch programs for practical purposes should reflect complicated market conditions such as heat, fuel, and transmission constraints. However, this study developed a simplified power market simulation model to evaluate power system flexibility and analyze economic impacts. Problems such as the release of the proprietary information of power generation companies including generation cost and physical constraints and the increased complexity of programs were taken into consideration. Despite the simplified structure, the proposed model can still perform simulation analysis according to various energy policies (e.g., restriction of coal-fired power generation for reduction of particulate matters and adjustment of taxes and public charges on power generation fuels). The proposed model also has the advantage that it is easy to change the reserve amount and various constraints in accordance with the research objectives.

The main objective of this study is to evaluate the power system flexibility of Korea in 2031 using the proposed power market simulation model. Power system flexibility is drawing significant attention due to an increase in the generation of variable renewable energy (hereafter VRE). To evaluate power system flexibility based on forecast data for the composition of power generation sources in 2031 reflecting the plan on the new construction and demolition of power generation facilities in the 8^{th} ESDP, the flexibility supply amount is analyzed separately for the spare generation capacity in the unit commitment and economic dispatch schedule and for the generation capacity that can be supplied after a dispatch order in off state. Through this process, the complementary relationship between current policies on operational reserves and regulation on the management of quick-start generators are examined, as well as the degree of contribution to flexibility supply. Power generation sources (including quick-start generators) in on and off states have different physical properties (e.g., start-up time and ramp-up/down rates) and operation costs in terms of the flexibility supply amount. Thus, the degree of contribution to flexibility supply of each power generation source needs to be analyzed. Furthermore, quick-start generators are regarded as reserves like the current oil power generation. As these resources are used in backup facilities for controlling the power output variability of renewable energy and handling emergency situations, rather than in generation facilities for creating profits unlike traditional energy sources, incentives or appropriate compensations should be provided to support these flexibility resources so that they can enter the power market.

Therefore, this study derives implications on the conditions required for quick-start generators to enter the power market as flexibility resources and the required technological development considering the characteristics of such resources.

According to the power market operating regulation, the operational reserves that can be acquired by setting the upper limit (95–100%) for the power generation output in the CBP market must be included the reserve resources in the order of the variable cost of each generator, which is the criterion for minimizing the generation cost in the energy market, unless the constraints for power generation sources constituting the reserves are given. The restrictions on the power generation sources constituting the reserves and on the physical properties (e.g., ramp-up/down rates) of the reserves originating from the power generation sources may lead to shortages for intra-hour although the flexibility supply amount is sufficient for inter-hour. To analyze this problem, the second objective is to evaluate the volatility response ability according to the composition of reserve resources considered as flexibility supply amount. In addition, the appropriate size of the reserve auxiliary service market is estimated in terms of the separation of energy market and this market, which is under review to respond to renewable energy volatility, and market system improvement directions are derived.

As the share of the renewable energy generation with a high merit order increases, not only are the generation schedules of the traditional power generation sources (e.g., nuclear, coal, LNG) changed and reduced, but also the power market price. That is, the system marginal price (hereafter SMP) will show a different pattern from the existing power market that has a low proportion of renewable energy generation. Furthermore, the expansion of renewable energy can be an important trigger that finally determines whether to raise electricity rates because it not only changes the profit structure of the power generation companies, but also affects the power purchase cost of the Korea Electric Power Corporation (hereafter KEPCO), the only seller in the power market in Korea. Therefore, the third objective is to analyze the economic effects of the renewable energy expansion on the power market such as the wholesale price and the power purchase cost changes of the power vendors.

1.3 Research Outline

To analyze the effects of the energy transition policy for renewable energy expansion on the domestic power market operation in 2031 in terms of flexibility and economics and to derive policy implications, this rest of this study is organized as follows. Chapter 2 examines the existing studies on power system flexibility to respond to renewable energy volatility, unit commitment and economic dispatch scheduling models, and the energy transition policy of Korea. It also presents the limitations of previous studies and the motivation of this study. Chapter 3 proposes a research methodology to evaluate power system flexibility and analyze economic effects using a power market simulation model. It also presents the objective functions and constraint equations applied to the MILP to build a day-ahead unit commitment and economic dispatch scheduling model based on the CBP market of Korea. The fitness of the proposed power market simulation model was verified using the mean absolute percentage errors (MAPE) of the SMP estimates, which are the result of the optimal unit commitment and economic dispatch scheduling simulation, and the SMP results published by the power market. Chapter 4, Empirical Studies, are composed of three parts: evaluation of the power system flexibility, analysis of the composition of flexibility resources and volatility response ability, and economic impact analysis. Section 4.1 outlines the flexibility evaluation including the data required for power system flexibility evaluation and the collection and processing methods. The flexibility capacity required in the power system is calculated by estimating the volatility of net load in 2031. The proposed model is used to calculate the flexibility supply amount corresponding to the flexibility requirement. The flexibility of the power system in 2031 is evaluated by comparing the flexibility requirement with the flexibility supply amount by operation state (in-market, out-of-market). Section 4.2 analyzes the incentive effect for the participation of power generation sources included in the flexibility capacity in reserve services and examines the relationship between the composition of operational reserve resources and the volatility response ability. The differences in the volatility response mechanisms of operational reserves and quick-start generators are also analyzed. In addition, the analysis results for the reserve market size estimation, which can be considered when the energy and reserve auxiliary service markets are separately operated based on the generation cost simulation, are described. Section 4.3 analyzes economic impact and compares the effects on power market participants through SMP and power purchase cost forecasts. Chapter 5 summarizes the analysis results of the effects of renewable energy expansion on the power market and policy implications. In addition, the limitations of this study are presented, and future research topics are suggested.

Chapter 2. Literature Review

This study evaluates the flexibility of the domestic power system in 2031 and analyzes the economic impacts such as power market price, total generation cost, and power purchase cost. The focus is on the volatility problem due to renewable energy expansion and the high merit order of renewable energy due to lower operation cost than conventional power generation sources. To analyze the impact on the power market such as flexibility evaluation, the power market operation results for 2018 and 2031 are compared using a day-ahead unit commitment and economic dispatch scheduling model. Considering these research objectives, the literature review is organized as follows. Section 2.1 examines existing works on the flexibility concept of power system, the types and characteristics of flexibility resources, and flexibility evaluation. Section 2.2 examines the UC and ED planning model and the unit commitment and economic dispatch optimization technique. Section 2.3 reviews studies on the flexibility of the power system for the domestic energy transition policy and the optimal mix of the conventional power generation sources for remaining demand excluding the share of renewable energy generation. Finally, the limitations of previous studies and the motivation of the current study are presented in section 2.4.

2.1 Power System Flexibility

To respond to climate change, the basic trend of expanding zero-carbon power generations that increase the share of renewable energy generation to reduce CO_2 emissions in the power industry requires a change of the power system. Most types of renewable energy generation have the intrinsic characteristics of volatility, unpredictability, locational constraints, asynchronous power generation, and low operation cost (IEA, 2014). Thus, the net demand changes dynamically even within the unit of power system operating time. These characteristics are emerging as new risk factors in satisfying the energy demand in real time and maintaining the voltage and frequency regulations, thus increasing the uncertainty of power system operation (Babatunde et al., 2020). Since the ability to respond to the volatility and uncertainty of renewable energy was defined as flexibility, numerous studies have investigated the flexibility evaluation of power systems, flexibility supply resources, establishment of long-term plans to secure flexibility and the improvement of predictive power for renewable energy volatility. After the flexibility of power system was officially mentioned by the IEA (2011) and the North American Electric Reliability Corporation (NERC, 2009, 2010), researchers and institutions have defined flexibility in various ways according to their research objectives (Table 1).

Table 1. Definitions of power system flexibility by previous studies

Previous studies	Definition
Lannoye et al. (2012)	"The ability of a system to deploy its resources to respond to changes in net load, where net load is defined as the remaining system load not served by variable generation."
IEA (2011)	"Flexibility expresses the extent to which a power system can modify

	its electricity production and consumption in response to variability, expected or otherwise.”
Bouffard and OrtegaVazquez (2011)	“The potential for capacity to be deployed within a certain timeframe.”
Makarov et al. (2009), Dvorkin et al. (2014)	“In terms of power capacity (MW), ramp rate (MW/min).”
Silva et al. (2015)	“The ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons.”
Zheng et al. (2012)	“The system’s capability to respond to a set of deviations that are identified by risk management criteria through deploying available control actions within predefined timeframe and cost thresholds.”

As can be seen from Table 1, power system flexibility can be defined as an ability to respond to the net demand variations due to the volatility and uncertainty of renewable energy stably and cost-effectively using the flexibility supply resources participating in the power market. Each country has a different power market operating on different time intervals. For example, in the Korean power market, the generation scheduling for price-setting or operation is established on an hourly units, but this flexibility must be secured at all times, between 1-hour units and within 1 hour.

As renewable energy expansion is promoted as a major policy in the power generation sector, existing studies on the power system flexibility can be largely classified into the calculation of flexibility requirement, flexibility supply resources, power system flexibility evaluation, the issues and barriers of the power market, short- to long-term supply and demand, and operation planning. These distinctions are not mutually exclusive, but closely correlated. Thus, studies are considering the above issues separately or in combination according to the research objective. In the current study, for calculation of the flexibility requirement in a power system, the net demand difference between unit commitment and economic dispatch scheduling time units suggested by Lannoye et al. (2012) is applied and used as hourly flexibility demand. Since this flexibility requirement also contains uncertainty such as the renewable energy output, when the flexibility demand is predicted, economic, technical, and institutional measures such as power generation facility planning in terms of flexibility supply, change of the operation method, and improvement of the power market system should be used as response measures for this uncertainty. In this context, rather than studies on predicting renewable energy variability, existing studies on flexibility supply resources and flexibility evaluation that power market participants may consider are examined.

2.1.1 Sources of Flexibility

The flexibility supply sources considered to integrate variable renewable energy efficiently in a power system can be largely distinguished by power supply and demand aspects and by methods of connecting with other industrial sectors (IRENA, 2018). Traditionally, when the share of renewable energy was low, flexibility was supplied by sources that allow dispatch control (e.g., coal, LNG, pumped storage, hydropower). However, with the rising proportion of renewable energy, the requirements for generation ramp-up/down (MW) and ramp-up/down rates (MW/min) are also increasing. Thus, while efforts are being made to improve the physical properties of existing generators, LNG gas turbine (hereafter GT), variable-speed pumped storage power generation, and large-capacity battery energy storage device technologies are being investigated as new flexibility supply resources (IEA, 2018). In other words, methods to improve the technical properties of the existing power generation sources or to introduce sources that have such properties in such a way so as to increase the ramp-up/down rates per minute of the those supplying flexibility, lower the minimum operation level, and reduce the start-up and shut-down times have been suggested on the supply side (Balling L, 2011; Cochran et al., 2014; Eser et al., 2016; Kubik et al., 2015). The physical properties of power generation sources for each fuel are important factors to consider when day-ahead unit commitment and economic dispatch scheduling and real-time market are operated (Table 2). Among them, start-up time, minimum generation capacity, and output increase/decrease rate are closely related to power system flexibility.

Table 2. Physical constraints of generators

Classification	Description
Start-up time	Duration from the time when a dispatch order is received until the generator is started and connected to the power system.
Maximum generating capacity	Maximum generation capacity based on the high-voltage side of the main transformer.
Minimum generation	Stable output level based on the high-voltage side of the main transformer.

Minimum up-time	Minimum up-time that must be maintained until the generator can be disconnected after it is connected to the power system.
Minimum down-time	Minimum time interval during which the generator can be reconnected after it is disconnected from the power system.
Ramp up/down rate	Output change amount that the generator can increase or decrease per minute at the maximum.
Auxiliary service characteristic data	Frequency following operation, Automatic generation control operation range, etc.

Source: Power Market Operation Regulation (2019.12.14), compiled by the author

Energy storage systems (hereafter ESS) can solve the problem of supply and demand imbalance within a short time of several seconds to several minutes when it is not connected to the power system (Eser et al., 2016). Among ESSs, pumped hydro energy storages (PHES) are large ESSs that are being widely installed and used worldwide (IRENA, 2019; Lund et al., 2015). However, with recent renewable energy expansion, small ESSs (e.g., batteries, superconductors, flywheels) are also being extensively researched. In particular, battery energy storage system (BESS) is a technology that has reached commercialization level to some degree for the purpose of direct integration in a distribution network and renewable energy power generation sources with large volatility. However, BESS still requires continuous technical development efforts in terms of capacity, investment cost, and restrictions on charge and discharge cycles (N. Li et al., 2016; Sinsel et al., 2020).

Unlike the prediction of renewable energy output, power demand can be predicted within a certain error range based on power system operation experience for several tens of years and the reserve supplied from the conventional power generation sources can be used to respond to uncertainty (IRENA, 2018). Demand management policies have been implemented worldwide since the 1970s for power system operation with cost minimization through strategic customer demand management. Furthermore, with the expansion of renewable energy, various demand response programs are being researched for new purposes such as volatility response and resolution of constraints (e.g., curtailment of renewable generation) to renewable energy output (Akrami et al., 2019; Bayer, 2015; Shariatzadeh et al., 2015). However, to use a demand response program as a flexibility resource, various practical difficulties should be addressed, such as the installation of smart meters (e.g., advanced metering infrastructure), collection and management of reliable load resources, and proper compensation measures for load reduction and transfer (Babatunde et al., 2019; W. T. Li et al., 2015; Mohandes et al., 2019).

Furthermore, power grid connections with neighboring countries or regions as resources to supply power system flexibility provide the advantages of electricity trading between power systems and using solar power generation in different time zones as interconnection reserves (Bell et al., 2012; Guo et al., 2018; Huber et al., 2014). Each country has various power generation operating constraints such as the congestion of the existing power grid, the maintenance of the minimum power output of base power generations such as coal and nuclear energies, and overload and imbalance due to the concentration of renewable energy generation between regions. Recently, various studies have been conducted to minimize the curtailment of renewable energy generation (IRENA, 2018; Kondziella & Bruckner, 2016). This problem is closely related to the evaluation of how much renewable energy can be accommodated by the power grid. Research is also being conducted on how to connect with related energy industries to convert the renewable energy output exceeding the power grid acceptance limit to thermal energy or use it for electric vehicle charging and power-to-gas (P2G) conversion (Colmenar-Santos et al., 2019; Mazza et al., 2018; Quarton & Samsatli, 2018; Vandermeulen et al., 2018). However, according to Gross et al. (2018), it takes several decades to commercialize and propagate new technologies in the energy industry. For example, it took 18–21 years to introduce and commercialize power generation technologies in the power market. In other words, commercialization must be verified through a sufficient test period to introduce new technologies in the power system operation where stability and reliability are critical, and only the technologies whose performance has been verified can be actually applied to the power system. Therefore, Korea has established plans to introduce flexibility supply resources in the long term such as variable-speed pumped storage power generation, power plants that can operate LNG GT in a single mode, and ESS technologies (Ministry of Trade, Industry, and Energy, 2017).

2.1.2 Studies on Flexibility Evaluation

Studies on power system flexibility evaluation can be classified by purpose into long-term plan and short-term facility operation feasibility evaluation. Power generation facility planning on a long-term basis is periodically performed in most countries to achieve the reliability and stability of the power system by comprehensively considering technical, social, and environmental problems. Every two years, Korean government establishes the

ESDP to prepare for domestic power demand over the next 15 years (Ministry of Trade, Industry, and Energy, 2017). Regarding research on optimal modeling techniques for long-term power generation facility plans according to the increasing proportion of renewable energy, improvement of power generation portfolio, integration strategy of renewable energy, probabilistic modeling that reflects uncertainty, and resilient power system design considering real options have been proposed (Caunhye & Cardin, 2017; Oree et al., 2017; Sadeghi et al., 2017).

Lannoye et al. (2012) suggested insufficient ramping resource expectation (IRRE) for the number of cases where the net demand volatility is not responded to through a comparison of hourly flexibility requirement and supply amount in terms of long-term power generation facility planning. The feasibility of establishing such a plan can be determined by the technical characteristics of each power generation source that contribute to the flexibility supply amount. Oree and Sayed Hassen (2016) developed a complex index considering the importance and correlations between indices through the analytic hierarchy process (AHP) using physical constraints such as the output range, ramp-up/down ability, start-up time, and shutdown time of each power generation source as individual indices. There have been efforts to extend the developed flexibility evaluation indices to the national power system assessment level. Abdin and Zio (2018) proposed a model that combined power generation facility planning and quantitative flexibility evaluation to reflect the result of power system flexibility evaluation considering short-term technical constraints from the long-term facility planning stage. What is important about flexibility evaluation is the method of calculating flexibility requirements and supply amount.

The uncertainty and variability of VRE can be shown very differently over various time scales (Qin et al., 2017). Several studies have analyzed how much the variability of renewable energy can occur within multiple time resolutions using the stochastic methodology (Dvorkin et al., 2014; Erik Ela & O’Malley, 2012; Heggarty et al., 2019; Nazir & Bouffard, 2012; Qin et al., 2017). In particular, the intra-hour volatility will become an increasingly important issue as it expands the share of renewable energy. However, since VRE output is highly dependent on weather conditions, there is a problem that it is difficult to predict, so the question still remains as to whether the renewable energy output pattern predicted using statistical techniques in existing studies will actually be realized in reality (Ssekulima et al., 2016). Therefore, in this study, for the purpose of evaluating the flexibility of the power system, it does not analyze the variability by predicting the renewable energy output pattern, but assuming that the past renewable energy output pattern will be maintained in the future, the required amount of flexibility is calculated. In other words, rather than developing a methodology for analyzing the required amount of flexibility, when the required amount of flexibility is given, it focuses on analyzing whether or not the amount of flexibility supplied to meet the required amount is sufficient.

There are two streams of research on the calculation of the power system flexibility supply amount: using the simplified generation scheduling established based on the merit order stack of each generator according to Lannoye et al.’s (2015) load duration curve, and using the day-ahead unit commitment and economic dispatch schedule established through UC simulation. Between these two methods, the flexibility evaluation that realistically reflects the power market condition, institution, and policies is the second method based on power market simulation. However, there can be limitations in acquiring vast amounts of data such as national power generation information, transmission network operation information, heat and fuel constraints, and it should also be noted that information corresponding to power generation companies' trade secrets may be included.

The power system flexibility evaluation in this study is aimed at improving Lannoye et al.'s (2015) methodology based on the composition outlook of energy sources in 2031, determining the flexibility supply amount for each scenario for flexibility supply resources through day-ahead unit commitment and economic dispatch scheduling simulation, and analyzing the number of periods of ramp-up/down flexibility deficits by comparing the flexibility supply amount with the flexibility requirement. In other words, an unit commitment and economic dispatch model that determines the merit order in the power market is firstly programmed, and then the power market is simulated and analyzed by reflecting the operating regulations for reserves and quick-start generators. This methodology can more accurately evaluate the power system flexibility than using rough merit order and can analyze the validity of long-term facility plans and short-term operation aspects simultaneously.

2.2 Generation Scheduling

Unregulated power markets can be generally classified into one in which the UC and ED plans are determined by independent system operators (ISO) based on power generation companies' bidding information and a market that is determined based on market participants' profit maximization strategy. As the share of renewable energy is rising in these two markets, the traditional UC optimization problem is becoming more complex and the need for establishing the unit commitment and economic dispatch schedule to have increasingly higher flexibility is increasing. Consequently, the improvement of unit commitment and economic dispatch scheduling methodology is being researched to respond to the renewable energy volatility (Abujarad et al., 2017).

2.2.1 Unit Commitment and Economic Dispatch Model

Generation scheduling in the power market in the short term (hourly, daily, or weekly) is composed of the UC problem, which determines the generator to start considering the physical constraints, environmental, and economic conditions of each generator while satisfying the demand of the power system for a short period, and the ED problem, which determines the optimal power generation of the generator to minimize the total generation cost. Ultimately, the unit commitment and economic dispatch problem can be modeled as a mixed-integer combinatorial optimization problem that combines the non-convexity characteristics due to the use of an on/off binary variable of the UC problem and the characteristics of the non-linearity cost function for ED decision (T. O. Ting et al., 2006; Tiew On Ting et al., 2003).

The UC plan optimization is performed by setting the objective function for problems that each country and region considers important such as minimization of generation cost, minimization of GHG emissions from coal-fired power plants, and the maximization of security constraints, and by adding the generator's physical constraints or the power system's operational constraints as conditional expressions (Chandrasekaran et al., 2012; Dieu & Ongsakul, 2008; Gjorgiev et al., 2015; Saber et al., 2007). In the case of the security-constraint optimal power flow (SCOPF) model, which is applied by the power system operator when establishing a short-term power generation operation plan of the DAM or real-time market, the ISOs, who are regional power system operators of the US, have largely used three methodologies (FERC, 2011): linear programming (LP), Lagrangian relaxation (LR), and mixed-integer programming (MIP). Korea also used the priority list method until 1980, the LR method during the 1990s, and has used the MIP methodology since the 2000s (Eom et al., 2009). Table 3 indicates that the MIP methodology is mainly used when the ISOs in the US and Korea establish a short-term power generation operation plan in the DAM.

Table 3. Generation scheduling methodologies for DAM of ISOs in the US and Korea

	Methodology	Plan

	LR	MIP	LP	
CAISO		○		Maintains MIP
ISO-NE		○		-
MISO		○		-
NYISO		○		Applied MIP to day-ahead market since 2014 (changed from LR to MIP)
PJM		○		Maintains MIP
SPP		○	○	Uses MIP in the day-ahead market Uses LP for dispatch planning and pricing
KPX (Korea)		○		-

Source: FERC (2011), Liu et al. (2019), compiled by the author

2.2.2 Optimization techniques for solving UC problem with High Renewable Energy Sources Penetration

Most studies on the expansion of variable renewable energy have added the renewable energy volatility as a constraint to the conventional UC and ED problems or reflected the required flexibility supply amount in the reserve quota. Since such volatility is a probabilistic rather than a deterministic factor, new methodologies for unit commitment and economic dispatch scheduling have been suggested to improve the conventional UC planning problem based on a probabilistic renewable energy generation scenario such as deterministic unit commitment (DUC), stochastic unit commitment (SUC), interval unit commitment (IUC), hybrid deterministic-stochastic unit commitment (HUC), and probabilistic unit commitment (PUC) (Bruninx, 2016; Bruninx et al., 2016; Conejo et al., 2010; Pandzic et al., 2016). Abujarad et al. (2017) provide detailed comparison of the newly suggested methodologies regarding the objective function, uncertainty reflection method, and the considered constraints.

What is important is that to increase the power system flexibility to respond to renewable energy volatility, the output and reserves of generators participating in the market need to be changed, and that a change of the power generation operation plan for this purpose is not only able to increase the total generation cost, but also change the profit structure of the existing power generation companies. The generation cost increase to respond to renewable energy volatility is called balancing cost, which is a new cost in the power market. When establishing a UC plan, a method of securing the flexibility supply amount that minimizes this new cost should be established (Hirth & Ziegenhagen, 2015). Meanwhile, according to Koltsaklis et al. (2017), the flexibility requirement can be affected not only by the composition of renewable energy sources, but also by the locations of renewable energy power plants. The authors analyzed the flexibility requirement and compensation level according to the renewable energy supply rate of Greece, whose power system is connected to the power systems of five countries, and emphasized that the ramp-up/down rates of secured resources are more important factors as well as whether or not the flexibility supply amount has been acquired. This means that the physical characteristics of the source of flexibility should be considered in order to enhance the flexibility of the power system. Moreover, the flexibility for response to renewable energy volatility may have a different response mechanism from that of the existing reserve resources for responding to the demand prediction errors or unexpected failures of power plants and transmission lines. Although the current operational reserve has an operational mechanism for immediate response after a major accident, responding to variability of new and renewable energy may require proactive measures if it exceeds the scope of the operational reserve. For these reasons, the California ISO (CAISO) has introduced ramping product service in the power market separately from the existing reserve auxiliary service to secure the flexibility supply amount, and uses it as a resource for responding to renewable energy volatility (CAISO, 2015).

A short-term power system flexibility enhancement plan can be created by establishing a day-ahead or several-hours-ahead unit commitment and economic dispatch schedule that is economical, consistent with national energy policy, and satisfies various constraints. This short-term generation scheduling means the establishment of a day-ahead unit commitment and economic dispatch schedule in the domestic power market. With the rising proportion of renewable energy, it is necessary to analyze whether the reserve securing regulation operated by each power system during UC and ED planning is appropriate for the situation and characteristics that require flexibility and to derive improvement measures. In this context, the simulation of the short-term power market based on the proposed generation scheduling model can be used to analyze not only the flexibility evaluation of the future power system by utilizing the information of the 8^{th} ESDP, but also the improvement direction of the power market operation according to the renewable energy expansion.

2.3 Research of the Energy policy in Korea

In 2017, Korea announced the "Renewable 3020" plan to achieve a 20% share of renewable energy in total power generation by 2030 and is promoting the energy transition policy to replace nuclear and coal power generation with renewable energy and LNG power generation (Ministry of Trade, Industry, and Energy, 2017). The facility capacity changes in Table 4 show that the facility capacities of coal, LNG, and new and renewable power generation excluding nuclear and oil power are increasing. In particular, 95% of the increase in the new and renewable energy generation originates from the increase in solar and wind power facilities. A sharp increase in the variable renewable energy of solar and wind power generation can cause an intermittence problem in the power system. To respond to such output uncertainty, methods of evaluating and strengthening domestic power system flexibility are being researched (Ahn, 2017; Chang & Cho, 2018; Cho & Cho, 2018).

Table 4. Prospect of power generation mix according to the energy transition policy of Korea

Year	Classification	Nuclear	Coal	LNG	renewables	Other (oil, pumped storage)	Total
2017	Share (%)	30.3	45.4	16.9	6.2	1.3	100
	Facility capacity (GW)	22.5	36.9	37.4	11.3	8.9	117.0
2030	Share (%)	23.9	36.1	18.8	20.0	1.1	100
	Facility capacity (GW)	20.4	39.9	47.5	58.5	7.5	173.8

	Difference (%p)	-6.4	-9.3	1.9	13.8	-0.2	0.0

Source: 8th ESDP, compiled by the author

Ahn (2017) formulated a 2030 power supply scenario for evaluation of domestic power system flexibility and established a short-term unit commitment and economic dispatch schedule using long-term model in M-Core, a commercial power market simulation program. Following Lannoye et al. (2015), the author determined the number of periods of flexibility deficits in an hourly unit by calculating the available ramp-up/down flexibility supply amounts. According to the result, the upward flexibility deficits occur five times in total when the share of the power generation in capital region is 20%, but it was estimated that hourly volatility could be managed by adjustment of the merit order, independent operation of GT, and new pumped storage. However, since long-term model in M-Core estimates the approximate merit order of centrally-dispatched generation units for fast performance, there is a limitation to analyzing up/downward flexibility supply. In other words, to analyze the power market impact according to the research purpose requires modifications to constraints or conditions on generation scheduling model, but the embedded constraints and function in commercial program M-Core cannot be modified or added. Therefore, generation scheduling model in this study is directly implemented, which reflected the fact that the domestic power market operates dual unit commitment and economic dispatch schedules for DAM: price setting scheduling with no constraints and operation setting scheduling that reflects operational reserves and constraints. As a result, the current dispatch operation method could be analyzed in detail.

According to the 8th ESDP, the domestic flexibility facilities that are newly constructed to respond to the renewable energy volatility are composed of 3.2 GW LNG generators that allow the independent operation of GT and 2 GW variable-speed pumped storage generators that can control the output during both generating and pumping mode (Ministry of Trade, Industry, and Energy, 2017). These resources are considered as flexibility supply sources when evaluating the domestic power system flexibility. According to the estimation result of flexibility deficits of domestic power system in 2030 in time units of 10, 30, 60, and 120 min, approximately 1.8 GW of flexibility capacity is insufficient in the 120 min unit only. Even this deficit was predicted to be resolved by using demand-responding resources and ESS or adjusting the upper limit of the LNG power generation. However, the available flexibility capacity was analyzed assuming the merit order as nuclear, LNG (for resolving thermal constraint of the capital area), coal, and LNG (others) without using the power market simulation program. Therefore, this method has the limitation that the flexibility supply amount, which is the sum of the power generation remaining after satisfying the net demand and the reserve, can be different from the actual power market operation.

Meanwhile, with respect to the power market simulation model, Cho and Cho (2018) analyzed the hourly reserve requirements to respond to the renewable energy generation volatility of 24 hours on the representative days of four seasons using the multi-period security-constraint optimal power flow (MPSOPF) model, which can analyze the power system continuously for 24 hours. The model was developed by researchers at Cornell University with the support of the US Federal Energy Regulatory Commission (FERC). They also estimated the reserve requirements in units of 10 minutes using change rate analysis separately from the model. As a result, the fluctuation of renewable energy in 2030 was estimated to be approximately 3.2 GW. It was expected that additional reserves would need to be secured because the current standard for securing spinning reserve was 1.5 GW excluding non-spinning reserve. Furthermore, it was also claimed that a plan to dynamically operate the reserve securing regulation should be examined, considering the different reserve requirements by season. The MPSOPF has advantages such that it can be applied to day-ahead generation scheduling because it can analyze the power system continuously for 24 hours unlike the conventional SCOPF method, and it is easy to analyze probabilistic data such as the volatility of renewable energy output and demand. However, the purpose of power flow calculation is to establish a power system operation plan in real time or every few minutes considering the capacity restriction of the transmission line, the loss of the transmission line, and the voltage size of each bus. As a function included in the Energy Management System (EMS), the MPSOPF is appropriate for real-time dispatch operation. In other words, the power system operator determines the power market price by establishing the next-day generation scheduling the day before, establishes the operational generation plan for actual system operation considering the various constraints affecting the power system, and notifies related power generation companies of dispatch information on start-up/shut-down the generator the next day. The same day power system operation is performed by real-time dispatch to maintain stability and fairness of the power system considering the generator start-up, stop, output adjustment, and load reduction instruction of demand-responding resources, and occurrence of transmission restrictions according the variations of power demand and renewable energy output based on the operational generation scheduling established the day before (Korea Power Exchange, 2020a). Furthermore, the MPSOPF corresponds to SUC among the UC techniques. Since the domestic power market is still using the DUC, the MPSOPF has a limitation as a tool for power system flexibility evaluation and economic impact analysis, although it can be an appropriate alternative for flexibility management.

Among the studies on energy transition policy, Song et al. (2018) analyzed the effects of the complete or partial abolition of nuclear and coal power generation scenarios on the domestic power market on the premise of expanding renewable energy generation over the period of 2018–31. They comprehensively evaluated the SMP, total generation cost, GHG reduction, and power generation fuel variability factors and suggested that replacing coal power with nuclear power can not only reduce generation cost and GHGs, but also draw social consensus. Although they established a day-ahead unit commitment and economic dispatch scheduling program by MILP and analyzed its effects on the power market from various perspectives, it has the limitation that the flexibility supply side considering renewable energy volatility was not included in the evaluation of the power mix to configure the remaining 80% when the 20% share goal for renewable energy generation is achieved.

2.4 Limitations of previous research and Research Motivation

In the energy transition policy for renewable energy expansion, the propagation and expansion of renewable energy is a crucial issue. However, we should also not neglect to improve the power market system and prepare the risk response strategies by evaluating measures to improve renewable energy volatility or their impact on the power market in advance. Many studies have been conducted in terms of the evaluation of power system flexibility and the establishment of short- to long-term unit commitment and economic dispatch schedules to improve the renewable energy volatility. However, most selectively focus on individual issues rather than comprehensively dealing with new issues in the power market that may result from renewable energy expansion such as flexibility evaluation, flexibility resources, and improvement of the unit commitment and economic dispatch scheduling program. Since various stakeholders such as power generation companies, ISO, power grid companies, sales companies, and electricity consumers are organically interconnected in the power market, all the individual issues also interact with one another. Therefore, this study aims to comprehensively analyze the effects of the renewable energy transition policy on the domestic power market in terms of flexibility and economics. For the simulation of the power market, a day-ahead unit commitment and economic dispatch scheduling program is implemented as an MILP problem using the General Algebraic Modeling System (GAMS) taking into account the domestic power market. Until now, new methodologies for UC optimization (e.g., SUC, IUC, HUC, and PUC) or MPSOPF have been developed, but they are not yet applied practically at the academic research level.

Studies on the flexibility evaluation and flexibility improvement methods for the domestic power system have been conducted around the Korea Energy Economics Institute. Most established day-ahead unit commitment and economic dispatch schedules by using the commercial program M-Core or by assuming a rough merit order, and compared the resulting reserve and spare generation as flexibility supply amount with the flexibility requirement. However, the merit order decision methods are different from the method currently used in the domestic market and do not examine the differential physical properties of the flexibility supply sources in detail. Moreover, the method of assuming merit order is likely to cause significant error in calculating capacity of flexibility available. Song et al. (2018) analyzed the effects of the renewable energy policy on the domestic power market. They defined and analyzed the several factors for deciding the power mix of the traditional power generation sources excluding renewable energy generation, but did not consider the flexibility aspect to respond to the renewable energy volatility.

In this study, different from previous studies, it is possible to find out the online/offline flexibility contribution of the flexibility supply cause operational reserve through the results of the flexibility evaluation of the future electric power system, and to estimate the number of ready-to-operation times of fast-response resources. In addition, by analyzing the contribution to the flexibility supply of operational reserves and fast-response resources, it is possible to propose a standard for operating in a fixed or flexible manner. In terms of methodology, unlike commercial programs, it has the advantage to analyze the economic impact by directly reflecting the constraint formula according to the research purpose. Finally, it is expected that expansion to various research topics will be possible through the next-day development plan establishment model presented in this study in the future.

Renewable energy expansion can have a significant influence on the power wholesale market depending on the merit order in the establishment of day-ahead commitment and economic dispatch schedules, as well as on the power system flexibility problem due to volatility and uncertainty. However, the influence of the renewable energy policy on the domestic power market has not yet been analyzed comprehensively. Therefore, this study aims to analyze the three objectives described below using a simplified power market simulation model reflecting the domestic power market operating regulation. This study derives the improvement points of the power market system with high penetration of renewable energy through evaluating the power system flexibility and analyzing economic impacts such as the variations of power market price, the profits of power generation companies, and the power purchase cost of power vendors such as KEPCO.

Chapter 3. Methodology

3.1 Methodological Framework

To analyze the impact of the energy transition policy on the domestic power market in terms of the flexibility and economic aspects of the power system, this study used the data of the 8th ESDP for the power supply and demand situation of 2031. To evaluate the flexibility of the domestic power system, this study was conducted in four steps as follows (Figure 3).

[Step 1] Analysis of volatility of renewable energy

[Step 2] Modeling the power market based on generation scheduling

[Step 3] Evaluation of power system flexibility

[Step 4] Examination of the configuration of reserve resources and flexibility

In Step 1, to analyze the volatility of renewable energy, the demand patterns for the past three years (2016–18) were analyzed, and demand data for 8,760 h in 2031 were generated using the forecast increase rates of power consumption presented in the 8th ESDP. For the variable renewable energy (VRE), a representative power generation curve was generated by weight-averaging the power generation data for the past three years based on each facility capacity for solar and wind power generations, and the forecast increase rates of

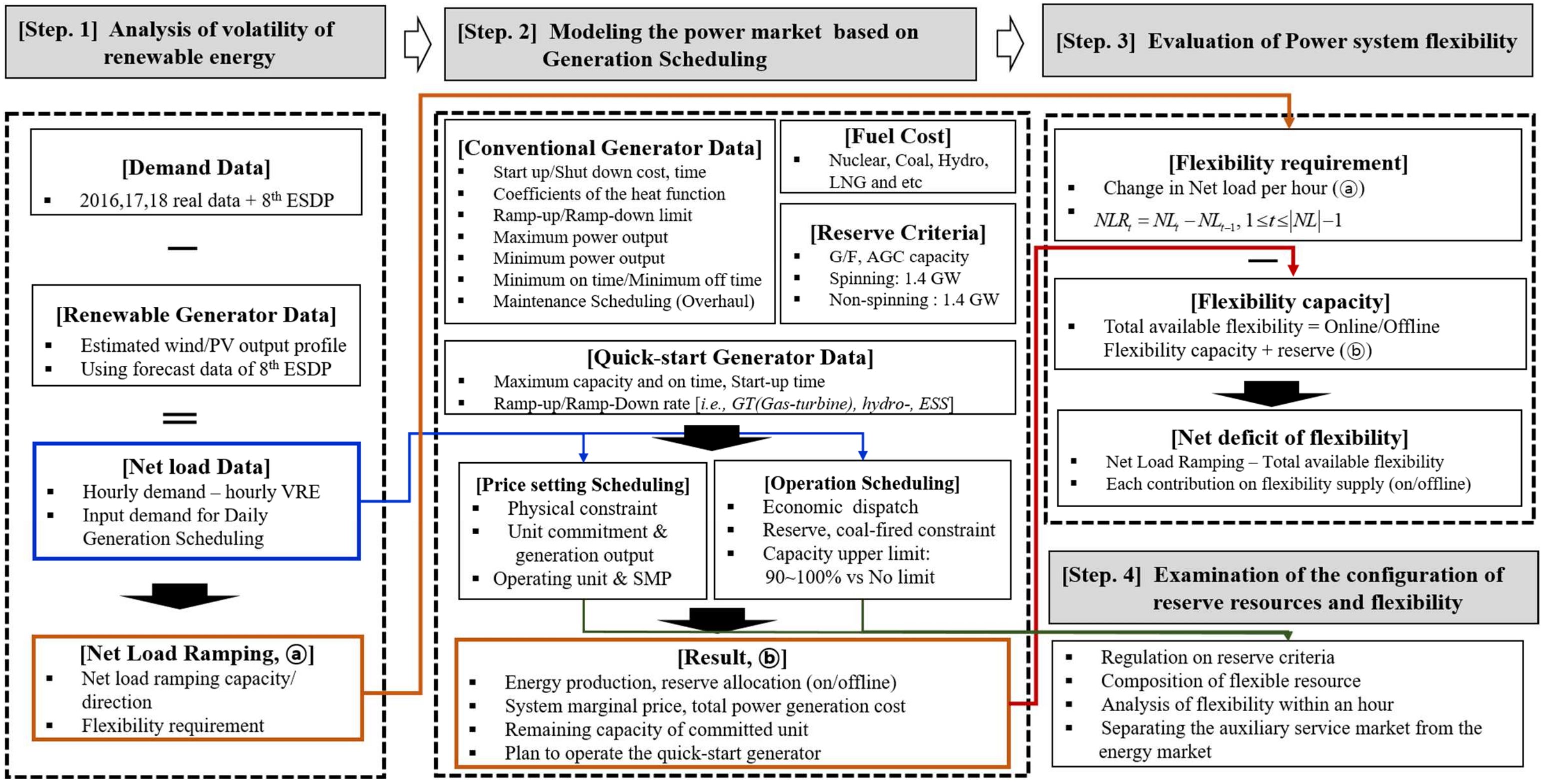

Figure 3. Power system flexibility evaluation methodology

renewable energy generation were used for the generation patterns for 2031. The net load and net load ramping were derived using the estimated demand and renewable energy generation data. Net load ramping (NLR) was used as an hourly flexibility requirement in the power system.

In Step 2, the day-ahead unit commitment and economic dispatch, which is a critical part of the power market simulation, was directly implemented using the MILP method. The specific objective functions and constraints are described in section 3.2. The proposed unit commitment and economic dispatch model is divided into price setting and operation setting scheduling modules considering the power generation facility data, fuel cost, reserve regulations, and quick-start generators. The model can calculate the annual SMP, generator start-up and shut-down plan, and power generation output. Furthermore, additional data such as the total power generation cost, the remaining capacity of the committed unit, and power generation sources for reserves can be acquired. Such data can be used as basic data for detailed analysis of the operation of flexibility resources such as upward and downward flexibility supply amounts and power market impact analysis.

In Step 3, the flexibility of the domestic power system in 2031 is evaluated by comparing the flexibility requirement and supply amounts derived from Steps 1 and 2. In Step 4, the variations of variability response capacity according to the composition of operational reserve resources in responding to the renewable energy volatility through the current operational reserve system, the roles of quick-start generators, and the limitations due to the integrated operation of the energy market and the auxiliary service markets are analyzed.

Regarding the analysis of economic impact of the expansion of renewable energy on the power market, not only the direct impacts due to the high merit order of renewable energy such as the change in power purchase cost of vendors, the change in the profit structure of vendors, and the change in the total power generation cost, which can be a factor in increasing electricity rates, to which consumers are sensitive, but also indirect impacts due to the Renewable Portfolio Standard (hereafter RPS), and emissions trading system related to the expansion of renewable energy were considered (Figure 4).

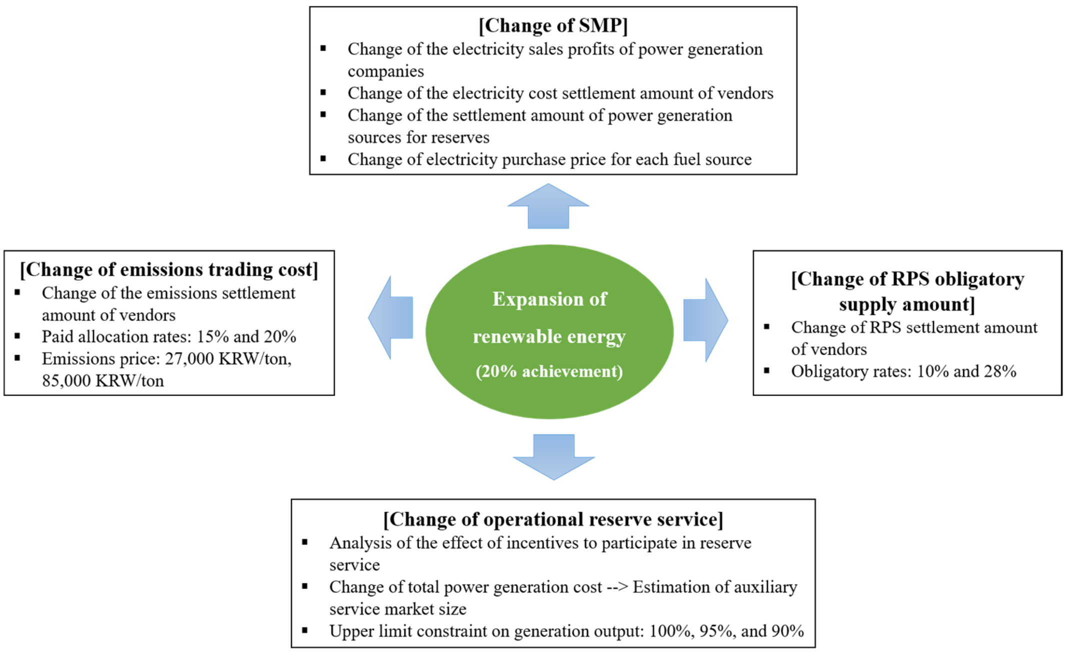

Figure 4. Analysis of economic impacts of the expansion of renewable energy on the power market

The change of power purchase cost of vendors is analyzed based on the criteria for calculating the power market settlement amount by using the SMP and the power generation and cost of each generation source estimated through power market simulation. Since the real-time dispatch operation results of the future cannot be accurately predicted, the generation schedule established one day ahead is assumed as the result to simulate the changes of electricity settlement amount, RPS obligation fulfillment cost, and emissions trading cost in 2031 relative to 2018. Furthermore, the effects of incentives to participate in reserve service were compared based on the criteria for calculating the reserve settlement amount. Finally, when operating separately from the energy market, the market size of reserve ancillary service was estimated using the change of the total power generation cost when securing reserves through the upper limit constraint for each power generation source.

3.2 Unit Commitment and Economic Dispatch Modeling

The domestic power market is a CBP market where the merit order is determined based on the marginal cost of power generation for each generator type such as coal, nuclear, and LNG. The electricity trading process is as follows (Figure 5). When power generation companies bid one day ahead on the amount of electricity that they can supply at each hour the next day, the KPX determines the power market price at each hour and the generation amount of each generator by reflecting the electricity demand at each hour on the day of power supply and orders the power generation companies to supply power. After paying the price according to the actual amount of power generation, they charge the amount to the vendor, KEPCO.

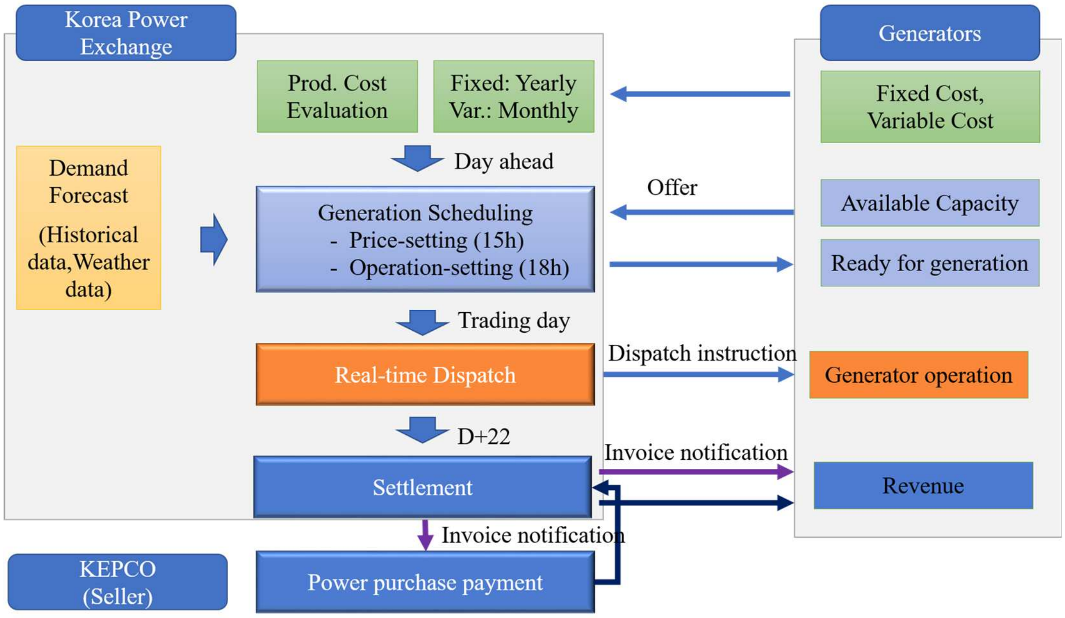

Figure 5. Electricity market business process in Korea

Source: KPX, reconstructed by the author

The optimal unit commitment and economic dispatch model developed herein was implemented using the MILP method for price setting scheduling and operation scheduling, which are performed one day ahead by the KPX. To minimize the total power generation cost, the physical characteristics of the generators and the requirements for power system operation were reflected as constraints according to the domestic power market operating regulation.

3.2.1 Generation scheduling using MILP

Generation scheduling is a mixed-integer problem that combines the start-up/shut-down plan of the generators participating in the power market and the ED that determines the generation amount of power plants scheduled for start-up for economic operation. The algorithms proposed to find the solution of the generation scheduling problem include numerical methods such as priority technique (Senjyu et al., 2003), Lagrangian relaxation (Ongsakul & Petcharaks, 2004), and MILP (Guan et al., 2003). Recently, metaheuristic approaches for optimization search such as genetic algorithm, simulated annealing, and Tabu search have also been applied to generation scheduling (Abujarad et al., 2017). Among these methods, the MILP methods are mainly used for next-day generation scheduling in the power market from the 2000s owing to advanced computer performance and algorithm evolution (e.g., CPLEX, LINDO, OSL, and XPRESS-MP). Since generation scheduling is basically modeled as a mixed-integer problem, the optimal solution can easily be found by modeling new constraints or reflecting the changes of the power market. Therefore, this study modeled the generation scheduling problem using the GAMS through the MILP and applied a methodology for optimizing generation scheduling using the CPLEX, which is an MILP solver.

When establishing the next-day generation schedule, the objective function is generally set as the minimization of the power generation operating cost. However, it can be set in various ways depending on the research objective such as minimization of GHG emissions, maximization of security constraints, and minimization of reserve securing cost. In this study, the minimization of power generation operating cost, which is used when establishing the day-ahead generation schedule in the domestic power market, was set as the objective function. Simulation was then performed by configuring the constraints in accordance with the object of generation scheduling (price setting or operation).

Objective function

The objective function for generation scheduling aims at minimizing the total operation cost (TOC) during the target period of scheduling.

$$\min TOC = \sum_{h=1}^{H}\sum_{i=1}^{I}(U_i^h \cdot F_i^h(P_i^h) + U_i^h \cdot S_i^h) \qquad \text{Eq. (1)}$$

where I is the centrally dispatched generation units, H is time (24 h), U_i^h is the condition of generator i at time h (0, 1), F_i^h is the generation cost of generator i at time h, P_i^h is power generation of generator i at time h (MW), and S_i^h is the start-up cost of generator i at time h.

The generation cost of generator i at time h is calculated using the price coefficient a_i, b_i and c_i, and the power generation of the corresponding time as expressed by Eq. (2):

$$F_i^h(P_i^h) = a_i(P_i^h)^2 + b_i P_i^h + c_i \qquad \text{Eq. (2)}$$

Power plant start-ups can be classified by the operation condition and the elapsed time after shut-down into re-start and hot, warm, and cold starts. However, in the case of the CBP market, the start-up cost (S_i^h) is calculated based on the hot-start[1] operation result. Thus, the start-up cost applied herein means the hot-start cost and the shut-down cost is not considered according to power market operating rules.

Constraints

To find the optimal solution of the objective function, the physical constraints of the generator and the operational constraints of the power system must be considered. The generally considered constraints are as follows.

For the constraints on generator power output, the upper and lower limits are set, and the generator power is adjusted in this range, as follows:

$$P_i \min < P_i^h < P_i \max \qquad \text{Eq. (3)}$$

where $P_i \min$ is the minimum power output of generator *i*, $P_i \max$ is the maximum power output of generator *i*.

The sum of the power demand and the power of the online committed generator at each

[1] The start-up cost varies by the temperature of the generator. The hot start means start-up when the generator temperature is sufficiently high. In the domestic power market, it is defined as 6 h or shorter down time until re-start after the generator is disconnected from the power system.

hour must be identical as follows:

$$\sum_{i=1}^{I} P_i(h) \cdot U_i\ (h) = D_h \qquad \text{Eq. (4)}$$

where D_h is the total power demand at time *h*.

At this time, the pumping mode operation of the pumped-storage generator can be added to the corresponding hourly demand, and the power generation of demand-responding resources and renewable energy can be subtracted from the demand.

The minimum up-time constraint that the online committed generator must maintain before shut down after being connected to the power system and the minimum down-time constraint that is required before the generator can be reconnected after shut down are set as follows:

$$H_i^{on} > MUT_i, H_i^{off} > MDT_i \qquad \text{Eq. (5)}$$

where H_i^{on} is the total on time of generator *i*, H_i^{off} is the total off time of generator *i*, MUT_i is the minimum up-time of generator *i*, and MDT_i is the minimum down-time of generator *i*.

The adjustment of the generator power output is constrained by ramp-up/down rate constraints in the increase or decrease direction as follows:

$$P_{i,h} - P_{i,h-1} \le UR_{i,} \; P_{i,h-1} - P_{i,h} \le DR_i \qquad \text{Eq. (6)}$$

where UR_i is the ramp-up rate of generator *i* and DR_i is the ramp-down rate of generator *i*.

The constraints for the generator on and off states are set with the on or off condition of the generator at time *h*, U_i^h, and a binary decision variable indicating start-up SU_i^h or shut-down SD_i^h as follows:

$$U_i^h - U_i^{h-1} = SU_i^h - SD_i^h, \; SU_i^h + SD_i^h \le 1 \qquad \text{Eq. (7)}$$

where U_i^h takes the value of 1 when generator *i* is on (committed), and 0 when it is off (uncommitted), SU_i^h takes the value of 1 when generator *i* switched from off to on, and 0 otherwise. SD_i^h takes the value of 1 when generator *i* switched from on to off, and 0 otherwise.

The pumped-storage generator operates in two modes: pumping and generating. The water level of the reservoir is converted to the electric power. The constraints related to the operation of the generator consist of maximum and minimum storage powers, the relationship between pumping and generating modes, and the maximum and minimum power generations and pumped storages.

First, the reservoir water level at the first and last hours of the day can be input in the model. However, the starting initial value was assumed to be full water level and from the second day, it was assumed that the reservoir water level of the last 24 h of the previous day was used as the initial value, as follows:

$$\begin{aligned} &VOL_i^{h=1} = VOLINIT_i, i \in PHES \\ &VOL_i^{h=24} = VOLLAST_i \end{aligned} \quad \text{Eq. (8)}$$

where VOL_i^h is the water level at time *h* of pumped-storage generator *i* (MWh), $VOLINIT_i$ is the initial water level of pumped-storage generator *i* (MWh), and $VOLLAST_i$ is the final water level of pumped-storage generator *i* (MWh).

Here, the final water level at time *h* is determined by subtracting the power generation at time *h* from the water level at time *h*-1, or by multiplying the energy stored by pumping by the efficiency of the pumped-storage generator as follows:

$$VOL_i^h - VOL_i^{h-1} = -Pgen_i^h + Ppump_i^h \times Effic_i \quad \text{Eq. (9)}$$

where $Pgen_i^h$ is the power generation of pumped-storage generator *i* at time *h* (MWh), $Ppump_i^h$ is the pumped storage of pumped-storage generator *i* at time *h* (MWh), and $Effic_i$ is the total efficiency of pumped-storage generator *i* (%).

Here, the reservoir water level of the pumped-storage generator and the upper and lower limit constraints of pumping and generating modes can be set as follows:

$$
\begin{aligned}
&VOL\min_i \le VOL \le VOL\max_i, \\
&Pump\min_i \le Ppump \le Pump\max_i, \\
&Pgen\min_i \le Pgen \le Pgen\max_i
\end{aligned}
\qquad \text{Eq. (10)}
$$

where $VOL\min,\max_i$ is the minimum and maximum pumped storages of the reservoir of pumped-storage generator *i* (MWh), $Pump\min,\max_i$ is the minimum and maximum pumped storages of pumped-storage generator *i* (MWh), and $Pgen\min,\max_i$ is the minimum and maximum power generations of pumped-storage generator *i* (MWh).

The pumped-storage generator cannot be operated simultaneously in pumping and generating modes. Thus, the binary decision variables of the pumping and generating mode operations have the following relationship:

$$
Pumping_i^h + Generating_i^h \le 1 \qquad \text{Eq. (11)}
$$

where $Pumping_i^h$ takes the value of 1 in the pumping mode operation of pumped-storage generator *i*, and 0 otherwise. $Generating_i^h$ takes the value of 1 in the generating mode operation of pumped-storage generator *i*, and 0 otherwise.

Although there is a constraint related to congestion in the transmission network, the constraint on power generation capacity due to insufficient capacity of the transmission line was not reflected in this study to simplify the model. However, the long-term transmission and substation facility plan of KEPCO, the transmission network operator, indicates that the high-voltage direct current (HVDC) back-to-back (BTB) and flexible AC transmission system (FACTS[2]) are continuously expanding. Thus, there is sufficient room for improvement in transmission restrictions in the future.

3.2.2 An empirical model for day-ahead unit commitment and economic dispatch

The proposed optimal generation scheduling model aims at establishing the UC and ED plans of centrally dispatched generation units for 8,760 h for one year each in 2018 and 2031. The optimization is performed daily in 24 h units. The unit commitment and economic dispatch simulation is sequentially performed for the total period of 365 days, using the result of the UC and ED planning of the previous day as the initial values of the next day planning, including the constraints of generators (e.g., minimum up/down time). Tables 5–7 below report the definitions and descriptions of the sets, parameters, and decision variables used in the proposed optimal unit commitment and economic dispatch model.

Table 5. Definitions and descriptions of sets and elements

Sets	Description

[2] The flexible AC transmission systems refer to thyristor controlled series capacitor (TCSC) and static synchronous compensator (STATCOM), which can increase the transmission capacity by actively controlling the electricity flow and reduce the restriction cost of a large-scale power generation complex due to the loss reduction effect.

Technology, t	Generator set (Nuclear, Coal, LNG, Oil, Pump, Renewable, Hydro)
Dispatch_tech, dt	Set of centrally dispatched generators (Nuclear, Coal, LNG, Oil, Pump)
Nuclear_Gen	Nuclear generator set (Nuclear_Gen ⊂ t, dt)
Coal_Gen	Coal generator set (Coal_Gen ⊂ t, dt)
LNG_Gen	LNG generator set (LNG_Gen ⊂ t, dt)
Oil_Gen	Oil generator set (Oil_Gen ⊂ t, dt)
Pump_Gen, pump	Pumped-storage generator set (Pump_Gen ⊂ t, dt)
Renewable_Gen	Renewable generator set (Renewable_Gen ⊂ t)
FRE_Gen, FRE	Fixed-renewable energy (excluding solar, wind) (FRE ⊂ t),
VRE_Gen, VRE	Variable renewable energy (solar, wind) (VRE ⊂ t)
Whole, w	8,760 h a year, $w \in \{1, 2, 3, \dots, 8{,}760\}$
Day, d	365 days a year, $d \in \{1, 2, 3, \dots 365\}$
hour, h, hh	24 h a day, $h \in \{1, 2, 3, \dots 24\}$
Mode, m	Upper and lower limit powers of generator, Mode ∈ {low, high}
Cost_factor	Heat rate coefficient, Cost_factor ∈ {QHC, LHC, NLHC, Mincost}
SMP_cost_factor	price coefficient, SMP_cost_factor ∈ {QPC, LPC, NLPC}
Cost_set	Fuel cost and start-up cost, Cost_set ∈ {FCOST, SCOST}
Cost Segments, k	Cost segments for piece-wise linear function, k ∈ {sg1, sg2, sg3, … sg20}
TLF	Transmission loss factor, TLF ∈ {TLF1, TLF2, … TLF12}
Specification, spec	Technical specifications set of each generator, spec ∈ {minimum up-time, minimum down-time, start-up time, minimum output, ramp-up/down rate}
Pump_specification	Technical specifications set of pumped-storage generator, Pump_specification ∈ {efficiency, maximum power generation time, charging time, maximum output, minimum output, maximum power storage, minimum power storage, maximum charge amount, minimum charge amount}

Table 6. Definitions and descriptions of parameters

Parameters	Description
Demand (w)	Power demand for 8,760 h (MWh)
PO (t, h)	Presence or absence of preventive maintenance of generator *t* at time *h* (0 / 1)
FRE_Gen_year (w, FRE)	Power generation of fixed renewable energy for 8,760 h (MWh)
VRE_Gen_year (w, VRE)	Power generation of variable renewable energy for 8,760 h (MWh)
Capacity (t)	Rated capacity of generator *t* (MW)
Mode_cap (dt, m)	Output upper and lower limits of centrally dispatched generator *dt* (MW)
Consumption (dt)	Internal power consumption rate of centrally dispatched generator *dt* (%)
Cost_table (dt,cost_set)	Fuel cost and start-up cost of centrally dispatched generators dt (1,000 KRW)
Cost_data (k, dt, *)	Heat consumption per segment of centrally dispatched generation units *dt* (Gcal/h)
Tech_spec (dt, spec)	Technical specifications table for each centrally dispatched generator
Pump_spec (Pump_gen, Pump_specificatin)	Technical specifications table for each pumped-storage generator
Pump_consumption(Pump_gen)	Internal power consumption rate of pumped-storage generator (%)
pVolmax (pump)	Maximum power storage of pumped-storage generator *pump* (MWh)
pVolmin (pump)	Minimum power storage of pumped-storage generator *pump* (MWh)
pVollast (pump)	Power storage of pumped-storage generator *pump* at previous midnight (twenty four hundred hours) (MWh)
pPumplast (pump)	Charge amount of pumped-storage generator *pump* at previous midnight (twenty four hundred hours) (MWh)
pGenlast (pump)	Generation amount of pumped-storage generator *pump* at previous midnight (twenty four hundred hours) (MWh)
pEffic (pump)	Total efficiency of pumped-storage generator *pump* (%)

Margin_cost (dt, h)	Incremental cost of centrally dispatched generator *dt* at time *h* (KRW/kWh)
Nload_cost (dt, h)	No-load cost of centrally dispatched generator *dt* at time *h* (KRW/kWh)
S_cost (dt, h)	start-up cost of centrally dispatched generator *dt* at time *h* (KRW/kWh)
SMP (h)	SMP at time *h* (KRW/kWh)
IGP (dt, h)	Interim generating unit price of centrally dispatched generator *dt* at time *h* (KRW/kWh)
GP (dt, h)	Adjusted generating unit price of centrally dispatched generator *dt* at time *h* (KRW/kWh)
SP (dt, h)	Stack price of centrally dispatched generator *dt* at time *h* (KRW/kWh)
COD (dt)	Continuous operation time of centrally dispatched generator *dt* (h)
T_PSE (dt)	Total daily power generation of centrally dispatched generator *dt* (MWh)
pIniUC (dt)	Generation of centrally dispatched generator *dt* at previous midnight (twenty four hundred hours) (0/1)
pIniout (dt)	Generation amount of centrally dispatched generator *dt* at previous midnight (twenty four hundred hours) (MWh)
Oper_hour_remained (dt)	Next-day operation time remained of centrally dispatched generation units *dt* (h)
Stop_hour_remained (dt)	Next-day stop time remained of centrally dispatched generation units *dt* (h)

Table 7. Definitions and descriptions of decision variables

Decision variables	Description
vTotalVCost	Total power generation cost for 24 h a day (KRW)
vCommit (t, h)	Start-up/shut-down state of generator *t* at time *h* (0/1)
vStartup (dt, h)	Start-up or not of centrally dispatched generator *dt* at time *h* (0/1)
vShutdown (dt, h)	Shut-down or not of centrally dispatched generator *dt* at time *h* (0/1)

vHpumping (pump, h)	Pumping mode or not of pumped-storage generator *pump* at time *h* (0/1)
vHgenerating (pump, h)	Generating mode or not of pumped-storage generator *pump* at time *h* (0/1)
vProduct (dt, h)	Output of centrally dispatched generation units *dt* at time *h* (MWh)
vProduct1 (dt, h, k)	k-th segment output of centrally dispatched generator *dt* at time *h* (MWh)
vProdut2 (dt, h)	Sum of *vProduct1* of centrally dispatched generator *dt* at time *h* (MWh)
vTotaloutput (h)	Total power generation output at time *h* (MWh)
vPVol (pump, h)	Power storage of pumped-storage generator *pump* at time *h* (MWh)
vPump (pump, h)	Pumped storage of pumped-storage generator *pump* at time *h* (MWh)
vPgen (pump,h)	Power generation of pumped-storage generator *pump* at time *h* (MWh)

The objective function of day-ahead unit commitment and economic dispatch schedule in the domestic power market is the minimization of the total power generation cost. The generator operation combination for each time slot is determined in terms of minimization of the fuel cost and start-up cost according to the power generation, and the economic output is allocated after UC planning.

Therefore, the objective function implemented with the mixed-integer model was set as Eq. (12a). The heat rate function to calculate the fuel consumption for each generator is a quadratic curve equation, which cannot be directly applied to the LP (linear programming). Thus, the power generation output range was divided into 20 segments using the piecewise linear function and the fuel consumption of all intervals were summed up (Carrión & Arroyo, 2006). When the actual quadratic cost curve for unit commitment, Eq. (12b), is replaced with the approximated piecewise linear functions, the objective function can be set as Eq. (12a), where $Mincost_{dt}$ is the heat rate at minimum output, and $SegmentCost_{k}$ is the marginal heat rate per unit capacity of k-th segment.

$$\min.v\mathrm{TotalVCost} = \sum_{dt}\sum_{h=1}^{24}\left[\begin{array}{l}(vCommit_{dt,h}\mathrm{Mincost}_{dt}+\sum_{k=1}^{20}SegmentCost_{k}vProduct1_{dt,h,k})\\ \times\mathrm{FCOST}_{dt}\,/\,\mathrm{TLF}_{dt}+\mathrm{SCOST}_{dt}\times\mathrm{vStartup}_{\mathrm{dt,h}}\end{array}\right] \quad \text{Eq. (12a)}$$

$$H_{i} = \mathrm{QHC_{i}\,vProduct_{i,h}^{2}} + \mathrm{LHC_{i}\,vProduct_{i,h}} + \mathrm{NLHC}_{i} \quad \text{Eq. (12b)}$$

where H is total heat rate (Gcal/h), QHC is the quadratic heat rate coefficient (Gcal/MW^{2}h), LHC is the linear heat rate coefficient (Gcal/MWh), and $NLHC$ is the no load heat rate coefficient (Gcal/h).

When the generation cost is divided by the transmission loss factor (hereafter TLF), which represents the degree of power loss of each generator, the closer the power generation source is to the demand site, the lower the power generation cost. Consequently, the merit order may be raised, or conversely, may be lowered as the distance between the power generation source and demand site increases. Thus, it can be interpreted as reflecting a policy that encourages power generation sources to be located near demand sites. The TLF will be explained in more detail in section 3.2.3. The physical constraints and power system operation constraints of the generator considered to obtain the minimum value of the objective function are as follows.

(1) Maximum and minimum output constraints of generator

$$Mode\_cap(dt,'low') \le vProudct(dt,h) \le Mode\_cap(dt,'high') \qquad \text{Eq. (13)}$$

(2) Power supply and demand balance constraint

$$vTotaloutput(h) = demand\_hour(h) - renewable\_generation(h) + \sum_{pump} vPump(h) \qquad \text{Eq. (14a)}$$

$$vTotaloutput(h) = \sum_{dt} \mathrm{vProduct(h)} \times \mathrm{(1\text{-}consumption(dt))} + \sum_{pump} vPgen(h) \times (1 - pump\_consumption(pump)) \qquad \text{Eq. (14b)}$$

Eq. (14a) represents the net load determined by subtracting the renewable energy generation from the hourly demand and then adding the pumping mode charge of the pumped-storage generator. Eq. (14b) represents the net generation excluding the internal power consumption rates of the centrally dispatched and pumped-storage generators. In other words, the demand and supply balance means that Eqs. (14a) and (14b) must be identical at each hour.

(3) Ramp-up/down constraints of centrally dispatched generation units

$$vProduct2(dt,h) - vProduct2(dt,h-1) \le tech\_spec(dt,'Ramp\_up') \quad \text{Eq. (15a)}$$

$$vProduct2(dt,h) - vProduct2(dt,h-1) \ge -tech\_spec(dt,'Ramp\_down') \quad \text{Eq. (15b)}$$

(4) Minimum up/down time constraints of centrally dispatched generation units

$$\sum_{hh=h+1-Minoper(dt)}^{h} vStartup(dt,hh) \le vCommit(dt,h) \quad \text{Eq. (16a)}$$

$$\sum_{hh=h+1-Minstop(dt)+Startuptime(dt)}^{h} vShutdown(dt,hh) \le 1 - vCommit(dt,h) \quad \text{Eq. (16b)}$$

Only if, $h = \{h \mid h \ge oper(stop)\_hour\_remained(dt)\}$

Eqs. (16a) and (16b) are cases where the minimum up- and down-time constraints of one day-ahead do not affect the next day. Considering the case where they affect the next day, a condition was added to apply the above equations only at times when they are greater than the respective remaining constraint time.

(5) start-up and shut-down constraints of centrally dispatched generation units

$$vCommit(dt,h) - vCommit(dt,h-1) = vStartup(dt,h) - vShutdown(dt,h) \quad \text{Eq. (17a)}$$

$$vStartup(dt,h) + vShutdown(dt,h) \le 1 \quad \text{Eq. (17b)}$$

On the day of preventive maintenance of the generator, the corresponding generator is set as in a shut-down condition for 24-h of the maintenance day. The generators' commitment state and generation output information in the last hour of the previous day (*d*, h=24) are input as the initial values (*d*+1, h=0) for the next-day generation scheduling.

(6) Maximum and minimum storage power constraints of pumped-storage generator

$$pVolmin(pump) \leq vPVol(pump,h) \leq pVolmax(pump) \qquad \text{Eq. (18)}$$

(7) Pumping and generating mode constraints of pumped-storage generator

$$vHpumping(pump,h) + vHgenerating(pump,h) \leq 1 \qquad \text{Eq. (19)}$$

(8) Pumping and generating mode relationship constraint of pumped-storage generator

$$\begin{aligned} &vPVol(pump,h) - vPVol(pump,h-1) = \\ &-vPgen(pump,h) + vPump(pump,h) \times pEffic(pump) \end{aligned} \qquad \text{Eq. (20)}$$

(9) Maximum and minimum pumped-storage generation constraints of pumped-storage generator

$$\begin{aligned} &pumpMin \times vHpumping \leq vPump \leq pumpMax \times vHpumping, \\ &Pmin \times vHgenerating \leq vPgen \leq Pmax \times vHgenerating \end{aligned} \qquad \text{Eq. (21)}$$

The types of bidding for a pumped-storage generator is divided into a pumping plan and a power-generation plan, and initial and modified bids are available the day before the trading day. At this time, when submitting a bid for a pumped-storage generator, the power generation business operator is required to submit the power generation amount and the pumping amount in connection with each other, and the deviation rate between the annual generation bid amount and the pumping bid amount is maintained within 10% of the allowable deviation rate. In addition, KPX is required to allocate power generating and pumping to each transaction time so that generation costs are minimized within the total amount of possible power generation per day and the total planned amount of pumping when establishing a price setting scheduling for pumped storage generators.

In this study, since the bidding process and redistribution process cannot be implemented, a simple power generation plan was established with 24-hour daily optimization, the allowable deviation between the amount of power generation and the amount of pumped water was set to be 0%, and simulation was carried out. The results of power generation scheduling of pumped storage power plants in 2031 were reported in Appendix 1.

3.2.3 Model Input data

The data required to build an optimal unit commitment and economic dispatch model largely consist of forecasts for demand and renewable energy generation, the status and plans of generation facilities, and data related to generation cost evaluation (Table 8).

Table 8. Summary of model input data

Classification	Year	Description	Source

Demand	2018	· Demand forecast data for price setting (8,760 h)	KPX
	2031	· Actual demand data for 2018 (8,760 h) · Power consumption forecast for 2031	· KPX · 8th ESDP
Renewable energy (Non-dispatchable)	2016-18	· Hourly solar and wind power generations · Capacities of solar and wind power generation facilities	KPX
	2031	· Solar and wind power generation forecasts for 2031	8th ESDP
Power generation facilities (Dispatchable)	2018	· Status of generators by fuel source (number of units, capacity, etc.)	KPX
	2031	· Generator construction and demolition plans by year	8th ESDP
Generation cost	2018	· Unit price of heat · Input/output characteristic curve coefficient · Start-up cost · Technical characteristics data (physical characteristics such as start-up, shut-down, ramp-up/down rates, etc.) · Internal power consumption rate · Preventive maintenance plan · TLF · Other renewable energy generations · Technical characteristics data for pumped-storage generator	KPX
	2031	Similar generation cost information is applied considering the scale and fuel for new power plants based on the generation cost data for 2018.	-

Power demand data are divided into demand forecast data used for the price setting schedule and actual demand performance data for predicting future demand. The power demand data for 2031 were generated by reflecting the year-by-year power consumption increase rates considering the hourly actual demand results data of 526,149 GWh/year for 2018 and the power consumption forecasts of the 8th ESDP (Table 9).

Table 9. Forecasts for power consumption and solar and wind power generations (2019–2031)

	Power consumption		Solar power		Wind power	
Year	GWh	increase rate (%)	GWh	increase rate (%)	GWh	increase rate (%)
2018	519,069	-	7,534	-	2,397	-
2019	530,358	2.17	9,453	25.47	3,921	63.58
2020	540,054	1.82	11,371	20.29	5,576	42.21
2021	548,898	1.63	13,673	20.24	7,333	31.51
2022	556,088	1.30	15,975	16.84	9,615	31.12
2023	561,700	1.00	18,277	14.41	12,422	29.19
2024	566,228	0.80	21,347	16.80	15,756	26.84
2025	569,824	0.63	24,416	14.38	19,614	24.49
2026	572,800	0.52	27,486	12.57	23,473	19.67
2027	575,229	0.42	31,067	13.03	27,433	16.87
2028	577,029	0.31	34,648	11.53	32,443	18.26
2029	578,515	0.25	38,229	10.34	37,454	15.45
2030	579,547	0.17	42,322	10.71	42,566	13.65
2031	580,443	0.15	42,514	0.45	42,566	0.00

Source: 8th ESDP, reconstructed by the author

The power demand data used in price setting scheduling are forecast on an hourly basis based on the hourly power generation (demand results) of one day ahead, the highest and lowest temperatures of eight major cities nationwide, and operate rate status (Korea Power Exchange, 2020a). Therefore, the forecast demand data for price setting scheduling used to verify the model consistency of unit commitment and economic dispatch simulation in this study is different from the actual demand result data. For the VRE data for 2031, a representative power generation pattern for 2018 was generated by weighted averaging the hourly power generation of solar and wind power generation in 2016–18 by the yearly facility capacity ratio. Then, the power generation increase rate in Table 9 was applied. The power generations of hydro, marine, bio, waste-to-energy, by-product gas, fuel cells, and IGCC, excluding solar and wind power, were calculated by multiplying the facility capacity forecast by the average hourly utilization rates for 2015–2017.

The operation data for power generation facilities in the power market were input based on the operation results of the power market. The power mix forecast data for 2031 were set up by reflecting the new construction and demolition plans in the 8th ESDP (Table 10). The combined cycle (CC) power plant is a generator composed of gas turbine (GT) and steam turbine (ST), and generates power firstly by starting the GT and secondly by starting the ST with the exhaust gas heat generated from the GT. However, GT single mode operation was not considered herein, and the LNG power plant was assumed to operate in combined mode. The GT single mode operation has the characteristics of low merit order due to higher generation cost than combined mode operation and high ramp-up/down rates.

Thus, it is mainly used as a resource to respond to rapid output variations in real-time dispatch operation. Thus, it has little effect on the merit order decision in the establishment of the day-ahead unit commitment and economic dispatch.

Table 10. Inputs to power generation facilities in 2018 and 2031

Classification	2018 (Model)		2018 (Market)	2031 (Model)		2031 (Forecast)
	Generators (units)	Capacity (GW)	Capacity (GW)	Generators (units)	Capacity (GW)	Capacity (GW)
Nuclear	23	21.85	21.85	18	20.40	20.40
Coal	61	35.32	35.4	58	38.07	39.92
LNG	86	37.8	37.8	100	47.94	47.46
Oil	23	4.1	4.1	9	0.80	1.39
Pump	16	4.7	4.7	22	6.7	6.7
Renewable	9	13.5	13.5	9	58.61	58.61
Total	218	117.27	117.35[1)]	212	172.52 [2)]	174.48

Source: Reconstructed by referring to Electric Power Statistics Information System (EPSIS) and the 8th ESDP

1) To total power generation of facilities in the power market in 2018 was 119 GW. 105.5 GW of centrally dispatched generation units was reflected in the model, but some non-centrally dispatched generators (coal, oil) that do not affect the merit order were not reflected.

2) Some differences were generated because the 1.85 GW of non-centrally dispatched coal power plant and the fuel of steam power plants in Jeju and Namjeju will be converted to bio-oil in 2031 and the collective energy construction was not reflected after the announcement of the 8th ESDP.

Generation cost data include the unit cost of heat per generator required to calculate the market price of the electricity produced by the generator and determine the merit order, coefficients related to input/output characteristic curve equations, the operation cost of each power generation facility such as start-up cost, and technical characteristics data. It is directly applied to the operations of the power market and power system such as the establishment of price setting scheduling, market price decision, real-time dispatch orders, and calculation of settlement amount for each generator. Such generation cost data are created directly by power generation companies operating the generators according to the detailed operating regulations for cost evaluation and confirmed through the deliberation and decision of the Cost Evaluation Committee (Korea Power Exchange, 2020b).

The heat unit price means the fuel cost (KRW/Gcal) required to generate unit heat for each generator. Table 11 lists the monthly heat unit prices for each fuel of centrally dispatched generators in 2018 applied in this study. Since the generation efficiency of generators varies by the output phase, the fuel consumption heat (H) according to the generator output appears as a quadratic curve equation. The three values (linear, quadratic heat rate coefficients and no load heat rate constant) required to define this generating units' quadratic cost curve for the UC problems are known as input/output characteristic curve equation coefficients.

The input/output characteristic curve equation is used to calculate the generation cost required for each output phase of the generator. The generator cost is calculated by multiplying the input/output characteristic curve equation by the heat unit price as follows:

$$\begin{aligned}\text{Generation cost} &= (QHC \times P^2 + LHC \times P + NLHC) \times Heat\ unit\ price \\ &= QPC \times P^2 + LPC \times P + NLPC\end{aligned} \qquad \text{Eq. (22)}$$

where QPC is the quadratic incremental price coefficient (KRW/MW2h), LPC is the linear incremental price coefficient (KRW/MWh), and $NLPC$ is the price coefficient (KRW/h).

The start-up cost is related to generator start-up and consists of start-up fuel, internal power consumption, and water costs. It is calculated using the results data of generators. In addition, the generation cost data include the start-up time, maximum and minimum generation capacities, and output increase and decrease rates, which are physical constraints of each generator presented in Table 2. In the model, the cost data were input individually for each generator, but they are trade secrets of power generation companies. Hence, the input data are briefly outlined as average values for each fuel in Table 12.

Since the merit order decision is affected by the schedule of preventive maintenance conducted to maintain the performance of generators, the accurate maintenance plan was reflected by using the weekly preventive maintenance schedules announced by the KPX, and daily preventive maintenance schedules were applied for each generator. When setting the preventive maintenance level for 2031, some shut down plans were reflected for coal-fired power generators (winter: 8–15 coal-fired generators, spring: 21–28 coal-fired generators) in spring and winter as part of particulate matter reduction measures. The preventive maintenance schedules of other generators were adjusted in accordance with the power generation proportions in 2031 in consideration of the level of 2018, and the same preventive maintenance schedules were then applied continuously for analysis. Through the model proposed in this study, if the policy to abolish coal-fired power plants and limit the total amount of power generation of coal-fired power plants is applied to the market, it is possible to easily modify and upload a new maintenance plan schedule due to the policy.

TLF is an indicator of the degree of power loss generated in the process of transmitting the power generated by the generators to the demand sites. It was introduced to provide geographic price signals for operation and investment of power generation facilities and is used to decide the generation cost of generators applied to price setting scheduling and operation scheduling.

TLF is calculated as the ratio of output change of the reference generator[3] to the unit output increase of a random generator. The TLF of reference generators is 1, and the generator closer to the demand site has a value larger than 1 and those farther from the demand site have a value less than 1 (Korea Power Exchange, 2012). The monthly TLF values of each generator for 2018 were obtained from the KPX. For power plants that are newly constructed until 2031, the TLF data of the power plants in operation in nearby areas were applied.

[3] Reference generators are generators No.3 to 6 of the Boryeong Thermal Power Plant on the mainland and the generators of Jeju Thermal Power Plant on Jeju Island. According to Article 2.5.1 of the Power Market Operation Regulation, TLF is the power generation of the standard bus required for unit load supply of a random bus (unit line to which various power facilities such as generators are connected). It is calculated as the ratio of the power generation reduced from the reference generator including grid loss when the load increases by 1 MW per bus.

Table 11. Monthly average heat unit prices of centrally dispatched generation units by fuels in 2018 (unit: KRW/Gcal)

Classification	Jan	Dec	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bituminous	22,523	22,390	23,426	23,253	24,162	24,104	24,719	24,542	24,428	25,593	25,961	25,876
Domestic coal	25,240	24,666	24,674	24,908	24,648	25,612	25,345	24,042	23,932	26,126	24,405	27,496
Oil	51,256	54,756	59,043	60,637	60,639	60,228	60,791	61,132	66,413	70,384	72,274	73,126
LNG	53,941	53,807	59,493	52,760	51,097	52,843	52,771	53,747	57,228	59,419	61,303	64,528
Nuclear	2,339.6	2,341.2	2,353.2	2,357.1	2,356.5	2,355.6	2,351.6	2,354.0	2,353.8	2,352.5	2,356.9	2,358.1

Source: KPX, reconstructed by the author

Table 12. Average data for generation cost characteristics input for centrally dispatched generation units in 2018

Classification	QHC(Gcal/ MW^2h)	LHC(Gcal/ MWh)	NLHC (Gcal/h)	Start-up time (h)	Minimum up-time (h)	Minimum down-time (h)	Output ramp-up/down rates(MW/h)	Start-up cost(1000 KRW)	Internal consumption rate
Bituminous	0.000408	1.763827	177.012042	3.3	7.6	12.9	503	46,885.3	0.0505
Domestic coal	0.00087	2.123138	62.304671	5.3	9.3	12	60	12,423.7	0.0872
Oil	0.001899	1.543843	126.275744	2.5	7.3	9.2	235	16,188.2	0.0575
LNG	0.000839	1.445838	79.614824	2	4	3.3	570	3,654.9	0.0174
Nuclear	0.000241	1.868985	369.131725	93.9	10.5	10.3	68	0	0.0383

Source: KPX, reconstructed by the author

For the technical characteristics data of pumped-storage generators, the physical characteristics data for 16 such generators in 2018 were input using the total efficiency, start-up time for generating and pumping modes, generation and pumping available times, and maximum power storage in the report of the Korea Power Exchange (2013) (Table 13). For Yeongdong, Pocheon, and Hongcheon pumped-storage power plants to be newly constructed by 2031, 85.8% was applied for the total efficiency by estimating it using the exponential smoothing method. For other characteristics, the data of Yecheon, Cheongsong, and Yangyang power plants, which were most recently constructed, were used.

Table 13. Technical characteristics data of pumped-storage generators

Classification	Cheong pyeong	Sam-nangjin	Muju	San-cheong	Yang-yang	Cheong-song	Yecheon
Completion year	1980	1985	1995	2001	2006	2006	2011
No. of generators	2	2	2	2	4	2	2
Rated capacity (MW)	400	600	600	700	1,000	600	800
Total efficiency (%)	72.3	76.3	76.5	78.7	80.0	81.6	82.6
Start-up time (generating, min)	5	2	5	4	3	3	3
Start-up time (Pumping, min)	6	10	15	7	7	7	7
Generation available time(h)	6.5	6.0	6.9	7.0	8.3	9.5	8.3
Pumping available time(h)	8.8	7.0	9.4	10.1	10.3	10.9	9.0
Maximum power storage(GWh)	2.6	3.6	4.1	4.9	8.3	5.7	6.6

Source: Study on the operation methods for pumped-storage generators considering system reliability (Korea Power Exchange, 2013)

3.2.4 Evaluation of the power system flexibility

The flexibility of the domestic power system is evaluated by the number of periods of flexibility deficit by comparing the flexibility requirement and supply for 8,760 h in a year. The flexibility requirement is applied by the hourly fluctuation of net load (NL), flexibility supply is divided into on/offline, and is separately calculated for downward flexibility supply according to the increase of VRE output, and conversely for upward flexibility supply according to the decrease of VRE output.

Flexibility requirement is calculated using hourly net load ramping (NLR) and is expressed as Eq. (23). The monthly statistics of NLR are outlined in Table 14.

$$NLR_h = NL_h - NL_{h-1}, 1 \leq h \leq |NL| - 1 \qquad \text{Eq. (23)}$$

Table 14. Monthly statistics for net load ramping in 2031

Classification	Jan	Feb	Mar	Apr	May	Jun
Maximum (MW)	9,905.1	9,596.5	8,627.8	7,038	6,135.6	6,017.1
Minimum (MW)	-7,485.4	-9,895	-6,980.6	-6,310.5	-5,365.6	-4,652
Average (MW)	17.9	-6.2	-9.5	-2.4	5.1	-6.5
Standard deviation	3,208.1	3,265.1	3,044.4	2,715.7	2,358.7	2,003.8
Average increase (MW)	2,742.6	2,637	2,429.2	2,400.1	2,122.1	2,003.8

Frequency of increase (times)	357	338	379	334	343	330
Average decrease (MW)	-2,502	-2,681.1	-2,541.8	-2,081.2	-1,805.6	-1,707.6
Frequency of decrease (times)	386	334	365	386	401	390
Classification	Jul	Aug	Sep	Oct	Nov	Dec
Maximum (MW)	6,188.8	6,607	7,709.6	9,701.8	9,837.2	9,473
Minimum (MW)	-5,798.5	-5,301.5	-6,197	-7,484.6	-8,383.3	-8,625.2
Average (MW)	20.3	-12.2	-12.6	7.7	0.9	6.2
Standard deviation	2,485.5	2,460.7	2,416.6	2,836.6	2,138	3,380.5
Average increase (MW)	2,075.2	2,131.1	2,202.1	2,441.5	2,703.5	2,914.7
Frequency of increase (times)	371	355	317	340	340	351
Average decrease (MW)	-2,023.6	-1968.1	-1,754.7	-2,040.5	-2,417.3	-2,591.4
Frequency of decrease (times)	373	389	403	404	380	393

Analyzing the variability of NL in 2031 according to Eq. (24) revealed the maximum and average total fluctuation rates were 36.3% and 4.12%, respectively. These values are slightly different from the solar and wind power fluctuation rates of 30% and 23%, respectively, in Park (2017), and of 32.8% and 18.6% in the 9th ESDP (provisional version). However, it has the effect of simultaneously considering the volatility of demand and renewable energy together when using the hourly fluctuation in NL. Hence, the NLR for 2031 is assumed as flexibility requirement.

$$\text{Net load variability (\%)} = \frac{NL_h - NL_{h-l}}{VRE_h} \times 100 = \frac{NLR_h}{VRE_h} \times 100 \qquad \text{Eq. (24)}$$

Flexibility supply can be divided into output margin of power plant in operation including operational reserves regulated in the power market, and the output of un-committed power plants (including quick-start generators) which are not included in the day-ahead unit commitment and economic dispatch schedule. In addition, flexibility supplies can be divided by direction into upward and downward flexibility. Here, '*RampUp*' and '*RampDown*' refer to the amount of power generation that can be increased or decreased over 60 minutes.

(1) Upward flexibility capacity from committed power plants

$$Flex_{h,+}^{Online} = \sum_{dt} \begin{bmatrix} vCommit(dt,h) \times \min(RampUp, \\ Mode\_cap(dt,'high') - vProduct(dt,h)) \end{bmatrix} \qquad \text{Eq. (25)}$$

(2) Upward flexibility capacity from un-committed power plants

$$Flex_{h,+}^{offline} = \sum_{dt} \begin{bmatrix} (1 - vCommit(dt,h)) \times \min(RampUp \times \\ (1 - Startuptime(dt)), Mode\_cap(dt,'high')) \end{bmatrix} \qquad \text{Eq. (26)}$$

(3) Downward flexibility capacity from committed power plants

$$Flex_{h,-}^{Online} = \sum_{dt} \begin{bmatrix} vCommit(dt,h) \times \min(RampDown, \\ vProduct(dt,h) - Mode\_cap(dt,'low')) \end{bmatrix} \quad \text{Eq. (27)}$$

The downward flexibility capacity from uncommitted power plants can be used to consider the case where a stationary pumped-storage generator operates in pumping mode. However, a power storage deficit is required for pumping mode operation. Since the usability of pumped-storage power plants is expected to increase as upward flexibility resources together with the expansion of renewable energy, an appropriate level of power storage will be maintained for emergency response. In this situation, the contribution of pumping mode operation to the downward flexibility can only be insignificant. Moreover, the downward flexibility capacity can be coped with by means of renewable energy output curtailment, P2G, and ESS charging schedule adjustment. Thus, this study only considers the downward flexibility capacity in operation state, and such capacity in off state is not considered.

(4) Total upward/downward flexibility capacities

$$TFlex_{h,+} = \sum_{dt} (Flex_{h,+}^{online} + Flex_{h,+}^{offline}) + reserve_{+} \quad \text{Eq. (28a)}$$

$$TFlex_{h,-} = \sum_{dt} Flex_{h,-}^{online} + reserve_{-} \quad \text{Eq. (28b)}$$

The operational reserve ($reserve_{\pm}$) can contribute to both upward and downward flexibility capacities. However, if the reserve resources of power generation sources in operation are used as flexibility resources in an actual power system, the operational reserve can be insufficient until a supplementary reserve resource is allocated. It should not be overlooked that if an emergency occurs in the power system in this state, the response ability can have a problem.

(5) Evaluation of power system flexibility

$$\begin{aligned} &D_{h,+} = TFlex_{h,+} - NLR_{h,+}, \quad D_{h,-} = TFlex_{h,-} - \left| NLR_{h,-} \right| \\ &PFD_{+} = \# D_{h,+} \quad \forall D_{h,+} < 0, \\ &PFD_{-} = \# D_{h,-} \quad \forall D_{h,-} < 0 \end{aligned} \qquad \text{Eq. (29)}$$

For evaluation of the power system flexibility, the number of periods of flexibility deficit (PFD) suggested by Lannoye et al. (2015) was calculated, and the numbers of upward/downward flexibility deficits were used as indicators.

3.2.5 Economic impact analysis

To analyze economic impact on power market participants, such as estimating the power generation sales of the power generation companies and the power purchase cost of vendors using the changed composition of power generation sources in 2031 due to the expansion of renewable energy, it is critical to identify the variations of power market prices. Thus, price setting scheduling was performed using the proposed day-ahead unit commitment and economic dispatch model, and the SMP was calculated, which provides the criterion for calculation of hourly power settlement amount of the trading day. The SMP is set to the highest price among the stack prices (SP) of each generator to which the unit commitment and economic dispatch amount is assigned according to the hourly price setting scheduling. It is calculated through the interim generating unit price (IGP) and the generating unit price (GP) as shown in Table 15 (Korea Power Exchange, 2020a).

Table 15. SMP calculation process

Sequence	Classification	Description
1	IGP	Incremental fuel cost + no-load cost + start-up cost of generator
2	GP	Price adjustment of the generated generator within one hour
3	SP	The GP of the generator in an abnormal operation state (generation at minimum generation capacity, output increase or decrease at maximum speed) is excluded
4	SMP	Determined as the maximum SP of each generator

Source: Power Market Operation Regulation, reconstructed by the author

To forecast the power market operation results of 2031 and to compare them with those of 2018, this study performs power market simulation using operation scheduling that reflects the reserve constraint in price setting scheduling. The KPX stably operates the power system in real time through operation scheduling, real-time dispatch scheduling, and dispatch instructions to power generation companies (Korea Power Exchange, 2020a). Among these, operation scheduling refers to generation schedule established for actual system operation on the trading day considering various constraints that influence the power system. It is established one day ahead of the trading day after considering additional constraints such as heat supply and fuel constraints for each generator, power transmission constraint, reserve level, and power system stability after price setting scheduling of the trading day. In contrast, real-time dispatch scheduling is performed through the process of state estimation (every 1 min), demand forecast (every 5 min), security constrained economic dispatch (SCED, every 5 min), and ED planning (every 1 min) to determine the effective output of the generator in real time by considering the generator cost, reserve, contingency, and transmission line constraints in real time through the EMS on the trading day. Based on the results of operation and real-time dispatch scheduling, the power system is operated through dispatch instructions to power generation companies regarding grid connection or disconnection of generator, active power and frequency adjustment, power generation output instruction, voltage adjustment, and automatic generation control operation (Korea Power Exchange, 2020a). However, simulation of the real-time dispatch scheduling of the power market in 2031 requires assumptions of numerous market conditions, is difficult to implement, and the reliability of the result is inevitably low. Therefore, operation scheduling was performed by simplifying the constraints influencing the power system only to the reserve level in line with the research objective, and it was assumed that dispatch instructions are made according to this schedule for the actual operation of the power generation facilities on the trading day.

The sets and parameters added for the analysis of economic impact on the operation scheduling and power market are listed in Table 16.

Table 16. Sets and parameters added for operation scheduling

Set	Description
RPS_Gen(dt)	Generators subject to RPS among the centrally dispatched generator *dt* RPS_Gen (dt) ∈ $\{dt \mid Capacity(dt) \geq 500\}$
Parameters	Description
oPerReserve(h)	Operational reserve in operation state required at time *h* (MWh)
Limit_capacity(dt)	Upper limit of generation of centrally dispatched generator *dt* (%)
DR_capacity	Average demand reduction per day (201 MW/1 time × 3 times/day)
○○***_purchase_cost(d,h)***	Power purchase cost of ○○power generation sources on day *d* at time *h* (KRW)
○○***_generation(d,h)***	Power generation on of ○○power generation sources on day *d* at time *h* (MWh)
	- ○○ ∈ {Nuclear, Coal, LNG, Oil, Renewable, Pump}
RPS_generation(d)	Power generation on day *d* of power plant subject to RPS (MWh)
SA_coeff	Settlement adjustment coefficient - Nuclear: 0.6083, Coal: 0.7037, others: 1 (as of 2017)

Among the operational reserves, the frequency-adjusted and standby/substitute reserves in on state are secured from the power generation sources included in the generation schedule. The hourly reserve regulation was added as a constraint as follows:

$$oPerReserve(h) = \sum_{dt}[vCommit(dt,h) \times Mode\_cap(dt,'high') - vProduct(dt,h)] \quad \text{Eq. (30)}$$

According to the Power Market Operation Regulation (Korea Power Exchange, 2020a), the operational reserve is secured by setting the bid supply capacity of coal, LNG, pumped storage, and hydro generators excluding nuclear to 95%, thus limiting the maximum output. As a proviso clause, coal-fired power can be distributed in 95–100% to ensure that adequate reserve power is first secured by generators other than battery storage devices and coal-fired power generators. In other words, the operational reserves are secured through 5% extra output that has not been dispatched due to upper limit constraint on generation output, and dispatch adjustment. The method of securing operational reserves in on state was reflected in the unit commitment and economic dispatch simulation as shown in Eqs. (30) and (31). For the operational reserves in off state was assumed to be secured every hour according to the regulation on the amount of secured reserve because it is specified separately by the KPX after generation scheduling based on operation experience and system condition analysis.

$$vProudct(dt,h) \leq Mode\_cap(dt,'high') \times Limit\_Capacity(dt) \qquad \text{Eq. (31)}$$

where $Limit\_Capacity(dt)$ is nuclear 100%, and coal, LNG, oil, and pumped storage 90-100%.

The settlement adjustment coefficient is used to adjust the power settlement amount of the generators owned by power generation subsidiaries of electricity vendor (KEPCO) subject to government regulations and centrally dispatched coal-fired generators. If KEPCO pays the power settlement amount to all power generation companies based on SMP as it is, those companies operating base generators using nuclear and coal-fired power plants will earn too much profit. Therefore, the settlement adjustment coefficient is used to adjust the power settlement amount paid for the recovery of base generators' excess profit and the maintenance of financial balance between KEPCO and power generation subsidiaries (Korea Power Exchange, 2020a, 2020b). Thus, the power purchase cost was reflected differently depending on whether the settlement adjustment coefficient is applied[4] as follows:

$$purchase\_cost(d,h) = \sum_{dt\in\{nuclear,coal\}} \begin{bmatrix} vProduct(dt,h)\times\{Margin\_cost(dt,h)+(SMP(h) \\ -Margin\_cost(dt,h))\times SA\_coeff)\} \end{bmatrix} + \sum_{dt\in\{LNG,oil,pump,renewable\}} [vProduct(dt,h)\times SMP(h)] \qquad \text{Eq. (32)}$$

To calculate the settlement amount for the RPS obligation fulfillment cost, the power generations of power plants with 500 MW or higher facility capacity, which are subject to the RPS, need to be estimated. The obligatory supply amount of the current year is calculated by multiplying the total power generation of the previous year (excluding renewable energy) by the RPS obligatory rate of the current year (Table 17). In this model, the total power generation of the previous year excluding renewable energy is calculated using Eq. (33).

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4 Power settlement amount = Variable cost by generator + (SMP- Variable cost by generator) x Settlement adjustment coefficient. A larger settlement adjustment coefficient increases the power settlement amount paid by KEPCO to power generation subsidiaries and the variable cost excess profits of subsidiaries.

$$RPS\_generation(d) = \sum_{RPS\_Gen(dt)} \sum_{h=1}^{24} vProduct(dt) \qquad \text{Eq. (33)}$$

Table 17. RPS obligatory rates

Year	12	13	14	15	16	17	18	19	20	21	22	23~
Ratio (%)	2.0	2.5	3.0	3.0	3.5	4.0	5.0	6.0	7.0	8.0[1)]	9.0[1)]	10.0[1)]

Source: Korea Energy Agency

1) The 1% increase from 2021, which was announced legislation by the Ministry of Trade, Industry, and Energy in May 2020, was not reflected.

The market operation result for demand response (hereafter DR) trading in 2018 is a total reduction of 221,264 MWh for 1,279 h according to the power market statistics of the KPX (Table 18). DR was not considered as flexibility supply resource, but to reflect the DR trading result in the demand variation of operation scheduling, it was assumed that demand reduction of approximately 201 MW for 3 h per day occurred in the daily peak hour. The DR market has a high potential as flexibility resource, but in Korea, since the market opening in November 2014, the economic DR and reliability DR (peak reduction) were operated at first. Since January 2020, economic, particulate matter, and peak demand DR have been operated. The system of using DR as a flexibility resource has not been introduced yet.

Table 18. Monthly DR trading results in 2018

Month	1	2	3	4	5	6	7	8	9	10	11	12
Reductions (GWh)	36	14.4	3	14.7	13.1	12.8	6.5	27.9	11.9	5.4	47.5	28
Implemented hours (h)	99	76	29	120	96	47	39	140	112	74	248	199

Source: Power Market Statistics 2018 by KPX (May 2019), reconstructed by the author

3.3 Model validation

3.3.1 Overview of model validation

To verify the reliability of the power market simulation model proposed herein, the SMP announced in the power market in 2018 is compared with the estimated SMP. To use the method of comparing the generation amounts and shares of power generation sources, it is necessary to forecast the results of power system operation in real time by reflecting various constraints. However, the proposed model did not reflect all constraints due to the research purpose. Thus, the model is verified using the SMP of price setting scheduling, which assumes an ideal condition with no constraints for price setting.

To calculate the forecast error rate of the SMP result and estimate for 8,760 h based on the mainland in 2018, the mean absolute percentage error (MAPE), which is often used to calculate error rates, is applied as Eq. (34). Song et al. (2018) also verified the proposed power market simulation model using SMP based on the MAPE and the MAPEs for 2016 and 2017 were 4.03% and 4.68%, respectively. Other methods to evaluate the accuracy of time series data forecasts include mean absolute error (MAE) and root mean square error (RMSE), but the MAPE has the advantage of showing the error intuitively in a situation where sufficient data can be acquired (de Myttenaere et al., 2016).

$$MAPE = \frac{100}{8,760} \sum_{w=1}^{8,760} \left| \frac{SMP_{market,w} - SMP_{model,w}}{SMP_{market,w}} \right| \qquad \text{Eq. (34)}$$

where SMP_{market} is the result announced in the power market and SMP_{model} is the model estimate.

As shown in Figure 6, the trend of yearly weighted average SMP of the domestic power market based on the mainland from 2001 to 2018 shows large variability. The main causes must be variations of fuel cost for power generation and changes in power mix. The monthly SMP variability level for one year is 109.34 KRW/kWh at the maximum and 86.58 KRW/kWh at the minimum as shown Figure 7, which shows the monthly weighted average SMPs of 2018. Note that the SMPs have been separately applied to the mainland and Jeju since 2010. The weighted average SMP is the hourly SMPs that were weighted averaged by the corresponding hourly power demand forecasts and is mainly used to analyze market trends. To examine the variation range of hourly SMPs in 2018, the maximum value is 140.73 KRW/kWh, the minimum value is 51.12 KRW/kWh, and the standard deviation is 10.4 KRW/kWh. SMPs have similar patterns by period such as day and season according to the net demand pattern excluding the renewable energy generation. Thus, the representative section for each quarter is set and the SMP result and estimate patterns will be compared and presented together with the model consistency evaluation result.

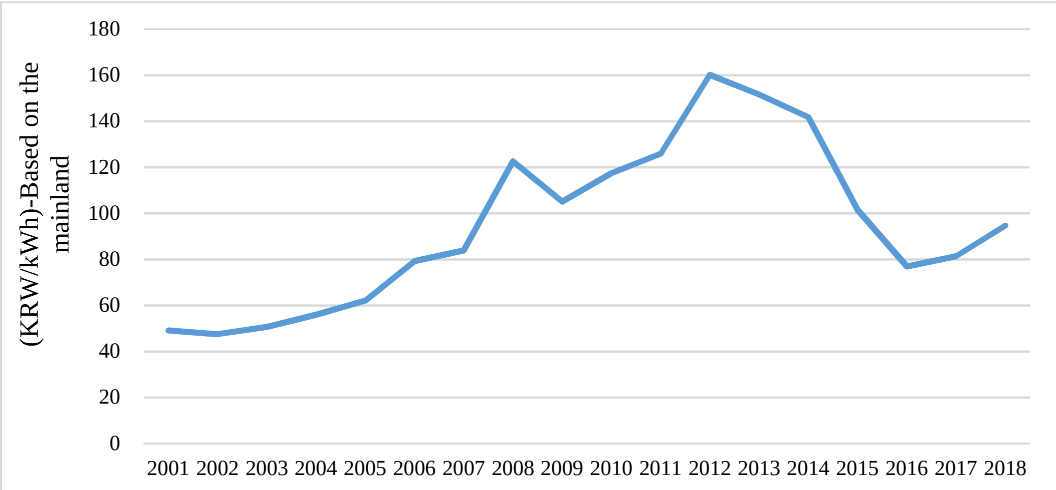


Figure 6. Yearly weighted average SMP in 2001-2018

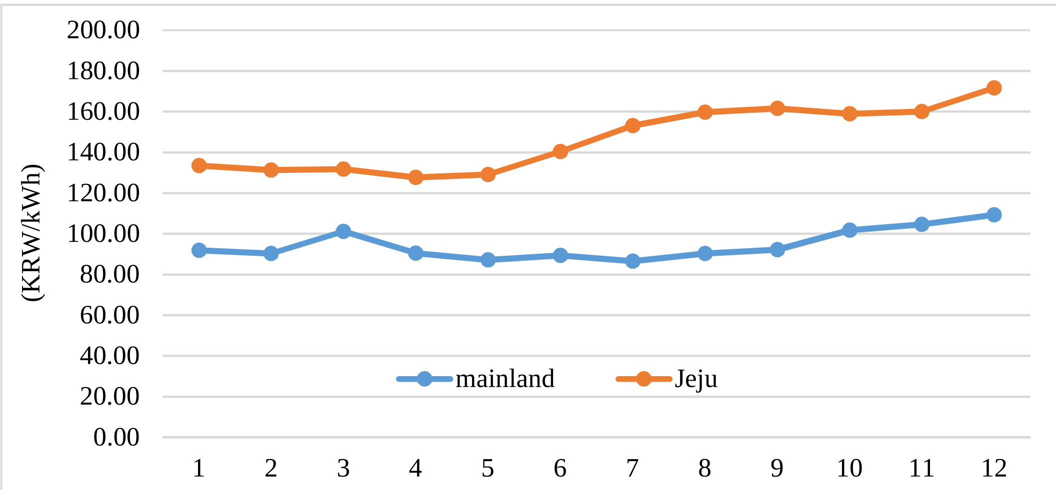


Figure 7. Monthly weighted average SMP in 2018

Source: Electric Power Statistics Information System (EPSIS), reconstructed by the author

3.3.2 Model validation result

Table 19 reports the results of evaluating the consistency of the power market simulation model. It can be seen that the MAPE value for the SMP estimates for 8,760 h in 2018 is 2.37%. According to Lewis (1982), a MAPE value of less than 10 can be considered highly accurate forecasting, 10–20 as good forecasting, and 20–50 as reasonable forecasting, and over 50 as inaccurate forecasting. Thus, this result suggests the day-ahead unit commitment and economic dispatch scheduling of the proposed model is highly accurate.

Table 19. Monthly MAPEs in 2018 (unit: %)

Month	1	2	3	4	5	6	7	8	9	10	11	12	Average
2018	1.62	2.36	1.87	1.63	2.54	2.66	3.78	3.20	3.47	1.51	1.59	2.20	2.37

The monthly MAPEs for 2018 show relatively large errors during the summer period from July to September. In particular, the largest forecast error appears in July. However, when comparing with the results of evaluating the credibility of the simulation proposed by Song et al. (2018) (maximum error: 7.47%, minimum error: 1.64%), it can be seen that the model proposed in this study estimates SMP with relatively more elaboration. The main cause of errors is the limitation that the renewable energy generation, preventive maintenance and failures of generators, performance changes by external temperature and the DR trading information cannot be reflected realistically. The KPX forecasts the renewable energy generation of the next day and applies this to the day-ahead unit commitment and economic dispatch scheduling. However, since these forecasts are not open to the public, the proposed model used the renewable energy generations created based on past results. Furthermore, the preventive maintenances and failures of generators are managed on an hourly basis in the power market; however, this study only considered daily preventive maintenances, taking account the complexity of the model. The differences in input information for renewable energy generations affect the hourly net demands and the generator maintenance and power plant failures cause differences in the one day-ahead bidding information for hourly available supply capacities of power plants. This can ultimately cause differences in the hourly marginal price setting generators. Lastly, among the DR resources, the economic DR can cause a change of the marginal price setting generators if demand reduction is more economical than power supply of the generators through price competition, but it can cause an error because the DR resource operating principle was not reflected in the model. However, what is important is that the above reasons can generate some forecasting errors, but this does not have a significant effect to lower model consistency.

For additional verification of the model estimates, the quarterly representative sections were set and the patterns of SMP results and estimates in each section were compared. The representative section was set as 240 h from the 1st to 10th of the first month of each quarter to include both weekdays and weekends. Through this comparison, whether the trend for SMP estimates of the model has been reflected can be checked visually. Figure 8 shows the result of comparing the quarterly SMP patterns. It can be seen that the model provides similar estimations of the trends of SMPs in summer, weekends, and holidays when the SMP changes the most during the day.

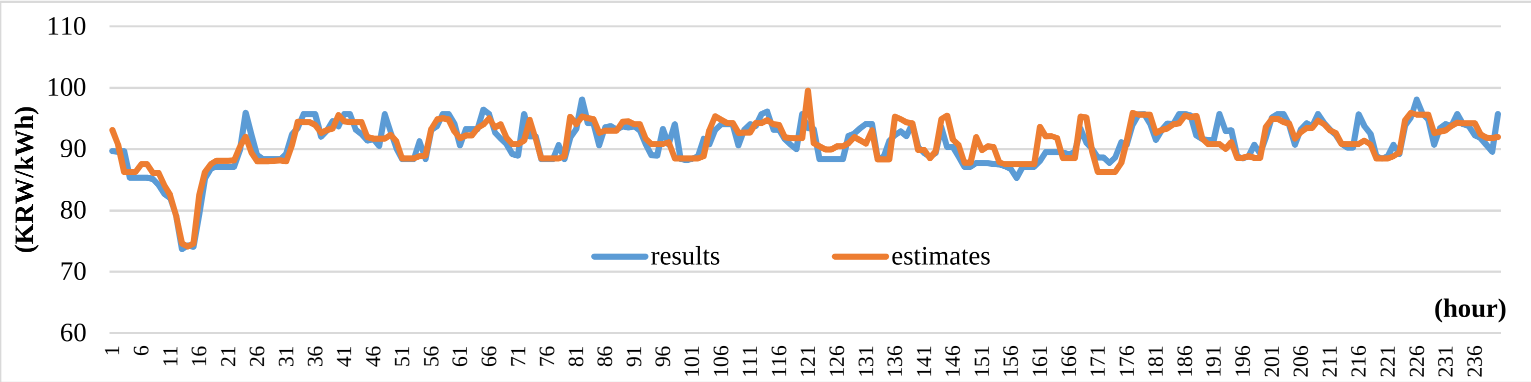


Figure 8 (a). Comparison of the trends of SMP results and estimates from Jan 1–10 (240 h) in 2018

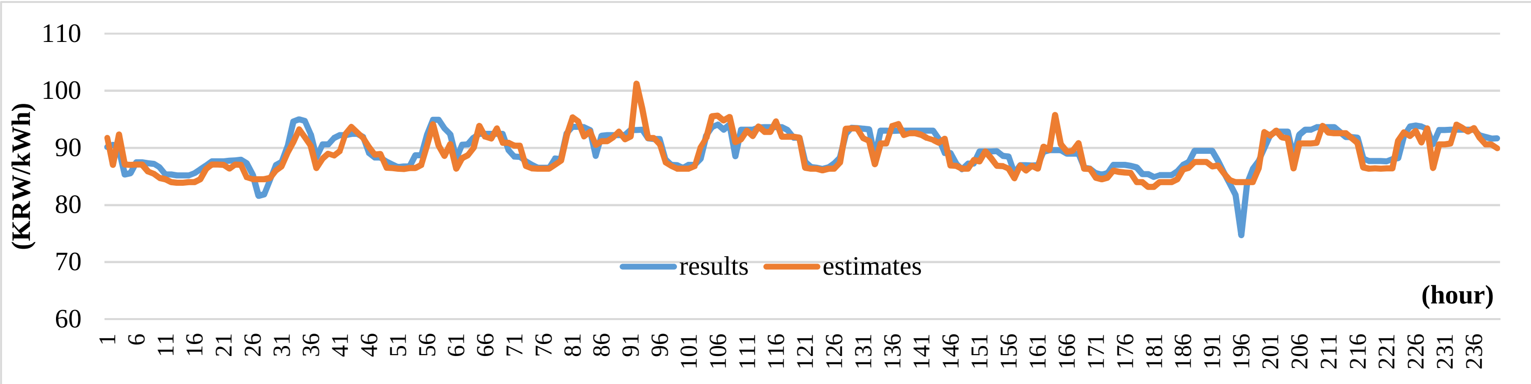


Figure 8 (b). Comparison of the trends of SMP results and estimates from Apr 1-10 (240h) in 2018

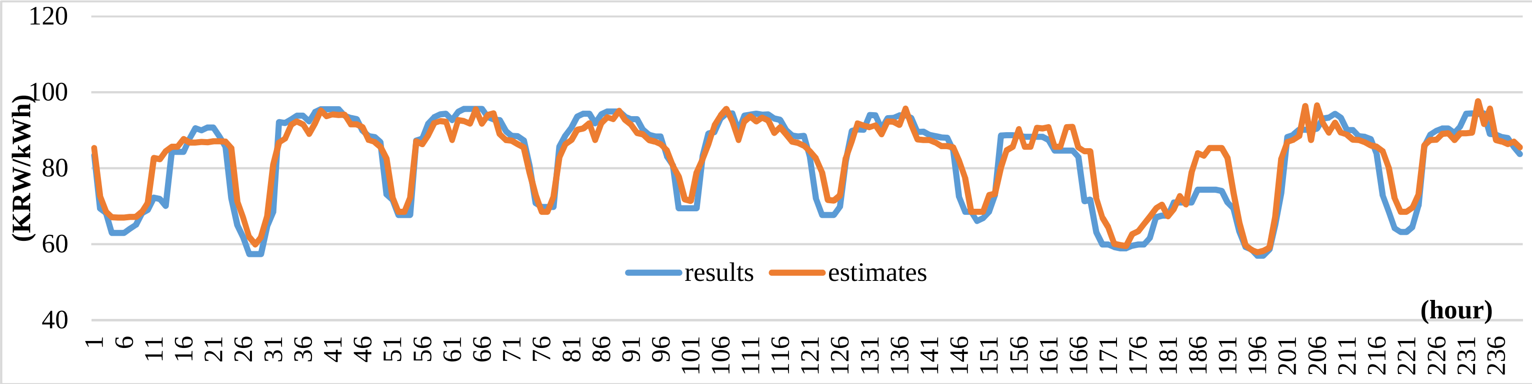


Figure 8 (c). Comparison of the trends of SMP results and estimates from July 1–10 (240 h) in 2018

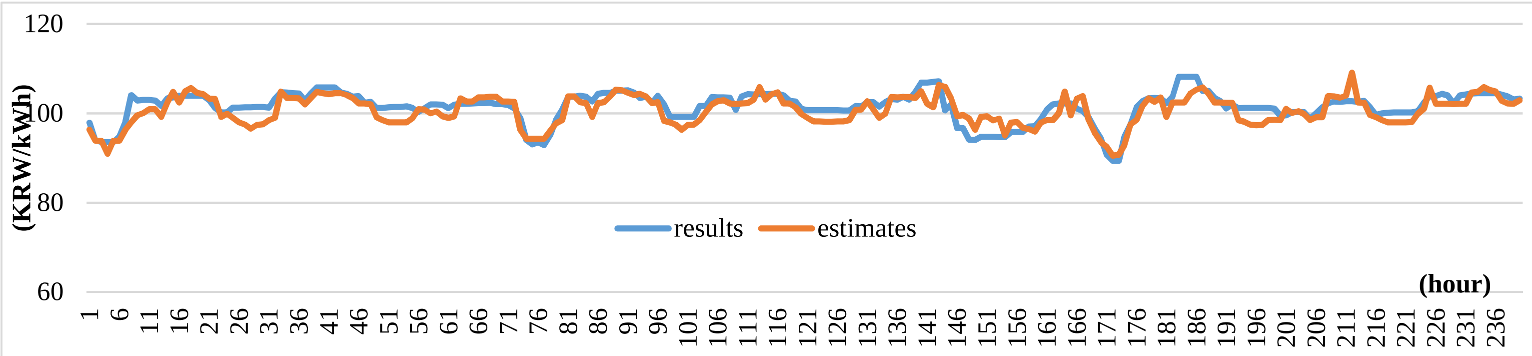


Figure 8 (d). Comparison of the trends of SMP results and estimates from Oct 1–10 (240 h) in 2018

Chapter 4. Empirical Studies

4.1 The study on evaluating the power system flexibility

This section evaluates the flexibility of the domestic power system in 2031 due to the expansion of VRE. First, this study presents an overview of flexibility evaluation. Second, the net load variability is predicted and hourly flexibility requirements are calculated. Third, the flexibility supply amounts of power generation sources in on/off states are calculated through the optimal unit commitment and economic dispatch scheduling simulation. Lastly, the periods of flexibility deficit of the power system in 2031 are compared and calculated, and the analysis results are presented.

4.1.1 Overview of flexibility evaluation and premises of analysis

To examine the composition of power generation sources in the domestic power market in 2031 in terms of flexibility, the optimal generation scheduling of flexible power generation sources (e.g., coal, LNG, pumped storage, hydro, ESS, and oil) should respond to the output variations of the variable power generation sources (solar and wind power). The flexibility supply amount is secured through the operation of operational reserves and quick-start generators. However, if the upper limit of the maximum generation capacity for each power generation source is regulated to secure the operational reserve, more spare generation capacity for each generator that can be secured unintentionally is generated in addition to the flexibility supply amount secured according to regulations as a result of unit commitment and economic dispatch scheduling.

In terms of flexibility responsiveness, only the ramp-up/down rate constraint may be considered for flexibility resources supplied from power generation sources in an on state. However, for operational reserves or quick-start generators in an off state, the compliance time, which is the time elapsed from the start-up until connection to the power system after a dispatch instruction, must be also considered. In other words, in terms of the speed of the response to flexibility, the operational reserve and spare generation capacity secured from power generation sources in an on state have much higher utility than those in an off state. Therefore, the flexibility capacity supplied from power generation sources in an on state is used first, and then flexibility supply from those in an off state will be considered additionally if there is a deficit of the flexibility supply amount.

To secure reliability of the power system, the operational reserves consist of frequency control reserve for maintaining stable frequency in ordinary times, and first, second, and third reserves for restoring the frequency in the event of a failure. Quick-start generators refer to centrally dispatched generators that can comply within 20 min and maintain output for over 4 h separately from the operational reserve to respond to renewable energy volatility, and mainly specify hydro, pumped storage, and gas turbine generators (Korea Power Exchange, 2020a). The secured energy and secured time criterion by reserve type are outlined in Table 20.

Table 20. Operation criteria for operational reserve and quick-start generators

Classification	Secured energy (MW)	Secured time criterion
Frequency control reserve	700 or higher	Comply within 5 min Output for more than 30 min
First reserve	1,000 or higher	Comply within 10 s Output for more than 5 min
Second reserve	1,400 or higher	Comply within 10 min Output for more than 30 min
Third reserve	1,400 or higher	Secure within 30 min
Quick-start generators	2,000 or higher	Comply within 20 min Output for more than 4 h

Source: Power Market Operation Regulation (2020) reconstructed by the author

If the reserve resources (general power generation sources excluding pumped storage, hydro, and ESS) are classified into on and off states based on the secured time criterion, the frequency control reserve and the first and second reserves must be secured in an on state, and the third reserve and quick-start generators must be secured in an off state considering the start-up time of each power generation source. To summarize, the online flexibility is the sum of operational reserves higher than 3.1GW secured in the on state (frequency control reserve + first reserve + second reserve) and spare generation capacity, whereas the offline flexibility is the sum of 3.4GW or higher (third reserve + quick-start generators) power secured by the Power Market Operation Regulation and the power generation that can be secured within 1 h from the power generation sources in an off state that have not been specified as reserves and quick-start generators.

The flexibility supply amount calculation scenarios for flexibility evaluation were set as shown in Table 21. When setting up the scenarios for analyzing the flexibility supply amount, important factors such as the size of the upper limit constraint, the supply capacity for each state of operational reserve, and whether or not a quick-start resource is applied should be considered.

To analyze the impact of each factor on the supply of flexibility, a total of five scenarios were set. For Scenario 1, it is assumed that there is no regulation on operational reserve and quick-start generators, and the online upward/downward flexibility capacities that can be secured automatically by unit commitment and economic dispatch scheduling according to the change of the upper limit of power generation (90–100%) are analyzed. For Scenario 2, the need for operational reserve regulation is analyzed assuming that there are only regulations on it without generator upper limit. For Scenario 3, the need for operating quick-start generators is examined considering the offline flexibility supply amount and quick-start generators. For Scenarios 4a and 4b, the secured amount of flexibility is calculated according to the size of the generator upper limit assuming the generator upper limit as 95% and 90% and compared with the flexibility requirement.

In Table 21, (On) and (Off) Reserve are the classification of the operational reserve and quick-start generators in Table 20 by operation state. The minimum value of the secured amount was applied to this analysis.

Table 21. Flexibility supply amount calculation scenario

Classification	Settings	Description
1	Limit_Capacity(h) = 90-100%, Reserve = 0	Upper limit of power generation 90-100%, No regulation on operational reserve and quick-start generators
2	Limit_Capacity(h) = 100%, (On) Reserve = 3.1 GW, (Off) Reserve = 1.4 GW	Upper limit of power generation 100%, Operational reserve in on state 3.1GW, Operational reserve in off state 1.4GW
3	Limit_Capacity(h) = 100%, (On) Reserve = 3.1 GW, (Off) Reserve = 3.4 GW	Upper limit of power generation 100%, Operational reserve in on state 3.1GW, Operational reserve+quick-start generators in off state 3.4GW
4a	Limit_Capacity(h) = 95%, (On) Reserve = 3.1 GW, (Off) Reserve = 3.4 GW	Upper limit of power generation 95%, Operational reserve in on state 3.1GW, Operational reserve+quick-start generators in off state 3.4GW
4b	Limit_Capacity(h) = 90%, (On) Reserve = 3.1 GW, (Off) Reserve = 3.4 GW	Upper limit of power generation 90%, Operational reserve in on state 3.1GW, Operational reserve+quick-start generators in off state 3.4GW

4.1.2 Net load variability and calculation of flexibility requirement

Net load is the hourly demand forecast data minus the forecast generation amount of VRE. The net load duration curves in 2018 and 2031 are compared in Figure 9. The power consumption in 2031 is approximately 11.8% higher than that in 2018, whereas the share of the variable renewable energy generation increases to 20%. As a result, the power generation that must be supplied every hour by general generators (excluding renewable generators) decreases in general.

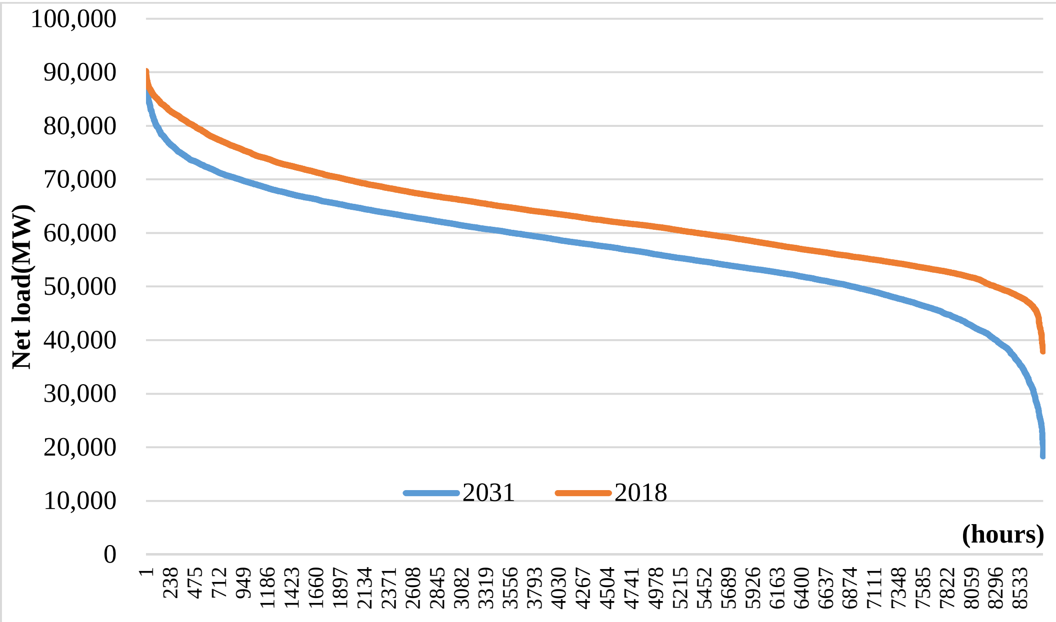


Figure 9. Net load duration curves in 2018 and 2031

The variability of net load is caused by the errors in the forecasts of demand and VRE generation. In flexibility research, calculating the flexibility requirement by the hourly fluctuations of net load means to reflect the variability of demand and that of renewable energy generation together as in Eq. (35).

$$\begin{aligned} NLR_h &= NL_h - NL_{h-1} \\ &= (Demand_h - VRE_h) - (Demand_{h-1} - VRE_{h-1}) \\ &= \Delta Demand - \Delta VRE \end{aligned} \qquad \text{Eq. (35)}$$

To compare the variations of hourly net load and VRE in 2018 and 2031, the size of the VRE variation relative to the net load variation based on the maximum in Table 22 is approximately 17.2% in 2018 and approximately 93.6% in 2031. Thus, it can be seen that most of the net load variability comes from the variation of VRE output.

Table 22. Comparison of the variations of net load and VRE in 2018 and 2031

Classification	Net load variation		VRE variation	
	2018	2031	2018	2031
Maximum (MW)	9,460.92	10,362.48	1,630.10	9,702.43
Minimum (MW)	-6,155.74	-9,766.44	-1,498.26	-8,555.48
Mean (MW)	0.95	1.04	-0.06	-0.98
Standard deviation	2,127.30	2,875.05	394.91	2,260.05
Mean increase (MW)	1,675.79	2,388.97	275.79	1,590.81
Increase frequency (times)	4275	4177	3915	4132
Mean decrease (MW)	-1,595.82	-2,175.82	-222.96	-1,422.17
Decrease frequency (times)	4484	4582	4845	4628

When the contribution of renewable energy volatility to the variation of the net load maximum change date and time is examined, in 2031, it is November 1, 15:00–16:00. This change is caused by an increase in the demand of 1,807 MW and a decrease in the VRE output of 8,555 MW. On the other hand, the net load maximum change date and time in

2018 is January 8, 07:00–08:00, when the demand increases by 9,519 MW, but the VRE output increases by 58 MW, thus giving a very small impact. In other words, if the net load ramping (NLR) is used as the flexibility requirement according to the expansion of renewable energy, the variations of demand and variable renewable energy generation can be considered together. However, if the share of VRE generation is low, characteristics that represent the volatility of demand may appear. Therefore, the contribution of demand and renewable energy generation should be checked first before applying the NLR.

The hourly variations of the VRE output profile applied herein are shown in Figure 10. If the volatility of demand is also considered, the net load variations in 2031 appear as shown in Figure 11. This value is assumed as the flexibility requirement and flexibility are evaluated by comparing this with the flexibility supply amount at the same time slot.

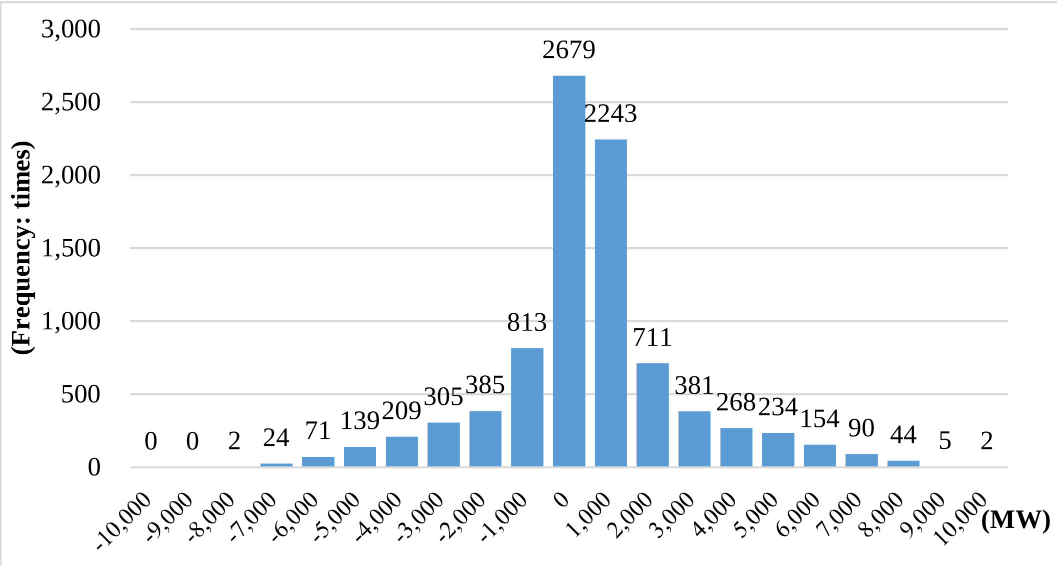


Figure 10. Histogram of hourly variations of VRE

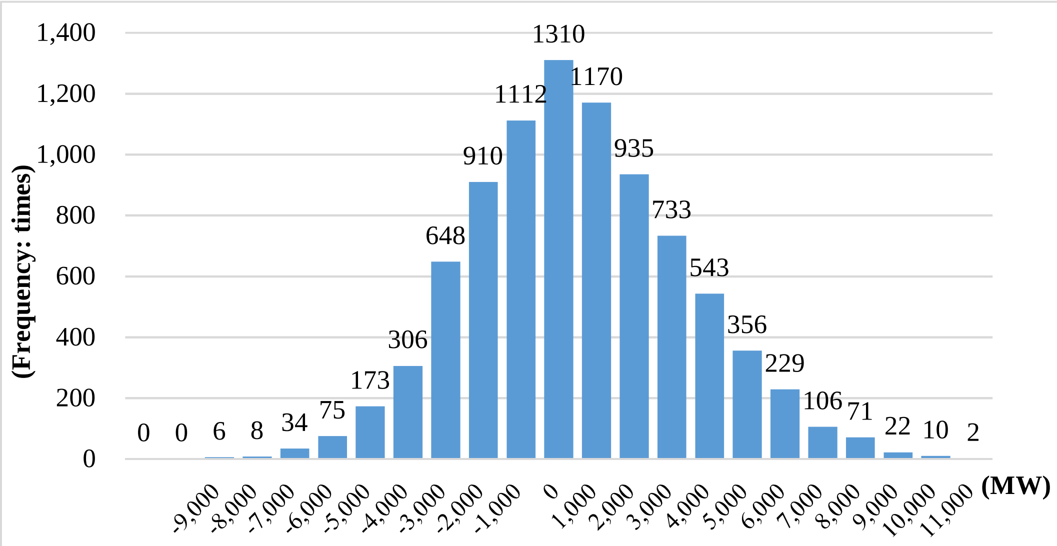


Figure 11. Histogram of net load variation

4.1.3 Unit commitment and economic dispatch simulation and calculation of flexibility supply amount

In this section, the flexibility supply amount is calculated by performing optimal unit commitment and economic dispatch simulation according to the flexibility supply amount calculation scenario (Table 21). In Scenario 1, the variations of spare generation capacity of the generators that were determined to committed centrally-dispatched generation units according to the result of unit commitment and economic dispatch scheduling were analyzed while decreasing the generation upper limit from 100% to 95% and 90%.

Figure 12 shows the variations of the secured amount of upward flexibility according to the size of the upper limit of power generation. It can be seen that the higher the upper limit, the larger the spare generation capacity becomes, and the greater the secured amount of upward flexibility also becomes. When the variations of the mean secured amount of upward flexibility are examined, it was found to be 599 MW at 100%, 2,487 MW at 95%, and 4,590 MW at 90%. Thus, the amount of upward flexibility that can be obtained by a 5% increase of the upper limit was approximately 2,000 MW. However, when the upper limit of power generation is increased, generators with high power generation costs are additionally started, leading to a higher total power generation cost.

Figure 13 shows the change in the secured amount of downward flexibility in Scenario 1. Unlike the upward flexibility, there is a power reduction margin of 17,320MW on average even without an upper limit. When the upper limit of 95% was applied, the secured energy decreases to 16,442MW, and it decreased to 15,442MW when the upper limit of 90% was applied. Thus, the secured energy decreased gradually as the upper limit was increased. To summarize, although restricting the upper limit of power generation contributes to the solution of the upward flexibility deficit problem, it does not contribute to the downward flexibility deficit. Hence, a different method for this problem should be considered.

In Scenario 2, the generation capacity secured by the operational reserve regulation is calculated in a condition where 100% rated output for each generator is possible without the upper limit of power generation. Specifically, the online operational reserve of 3.1GW and the generation capacity remaining after securing the operational reserve were analyzed through the unit commitment and economic dispatch simulation, and the offline operational reserve of 1.4GW was added to the result to determine the total upward flexibility. When calculating the downward flexibility supply amount, reserve_ is a concept of room for reduction as power adjustment becomes possible by temporarily releasing designated reserve resources, and is the similar as the concept of online downward flexibility. Thus, the total downward flexibility was determined through simulation assuming that the reserve_ was already reflected. The flexibility supply amount calculated in Scenario 2 is shown in Figure 14. The secured upward flexibility is in the range of 4.4–13.6 GW, and the secured downward flexibility is in the range of 0–31.3 GW.

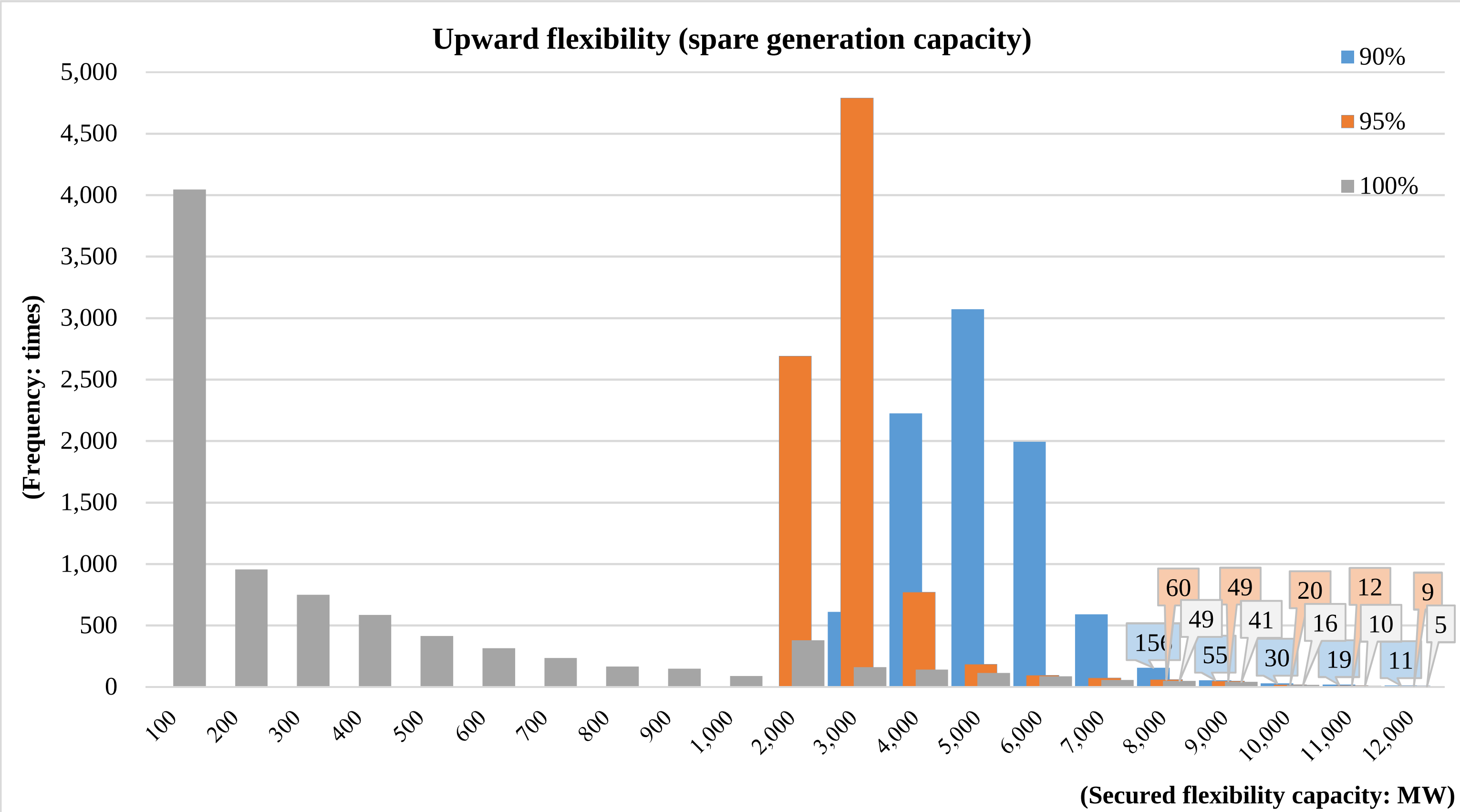


Figure 12. Change of upward flexibility capacity in Scenario 1

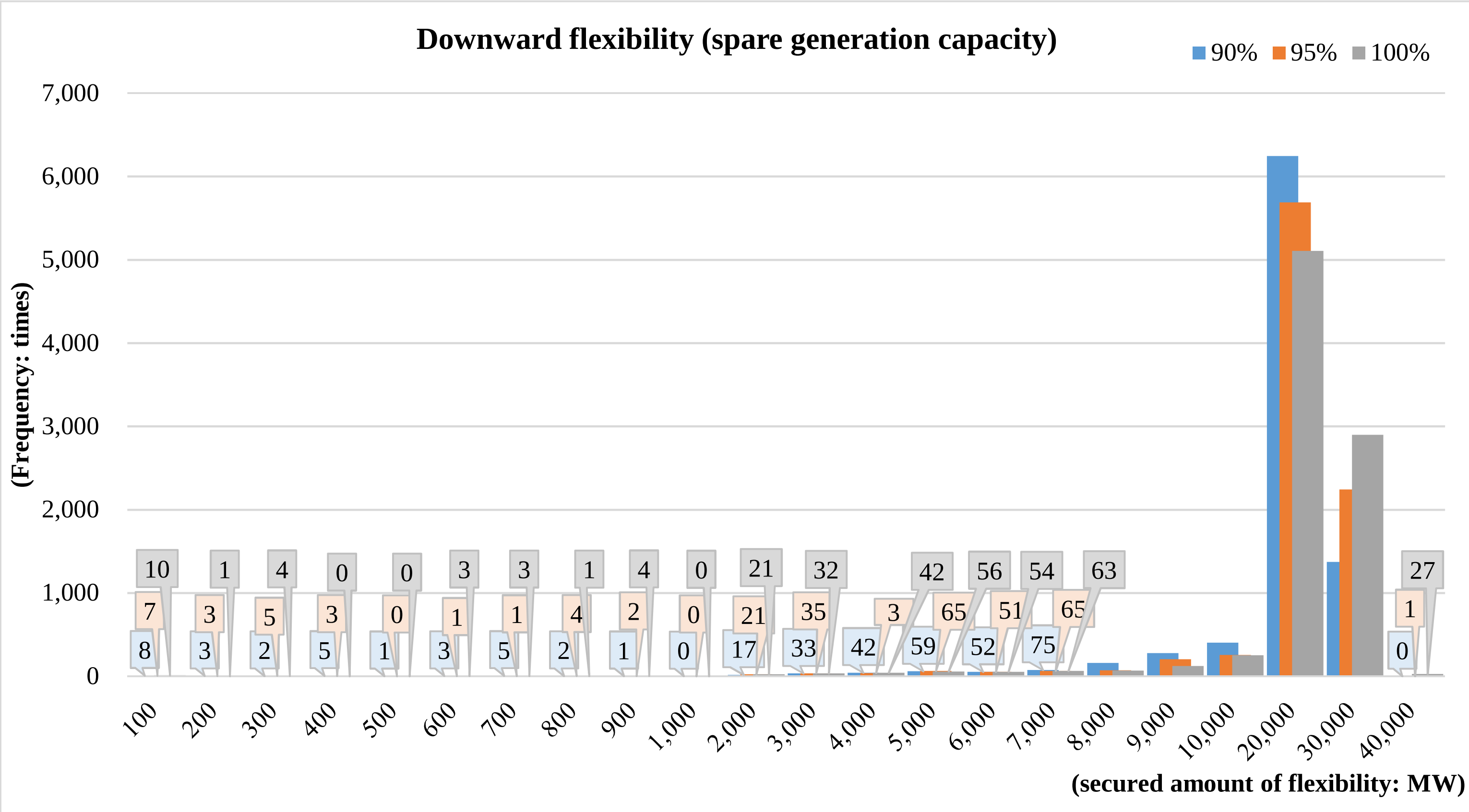


Figure 13. Change of downward flexibility capacity in Scenario 1

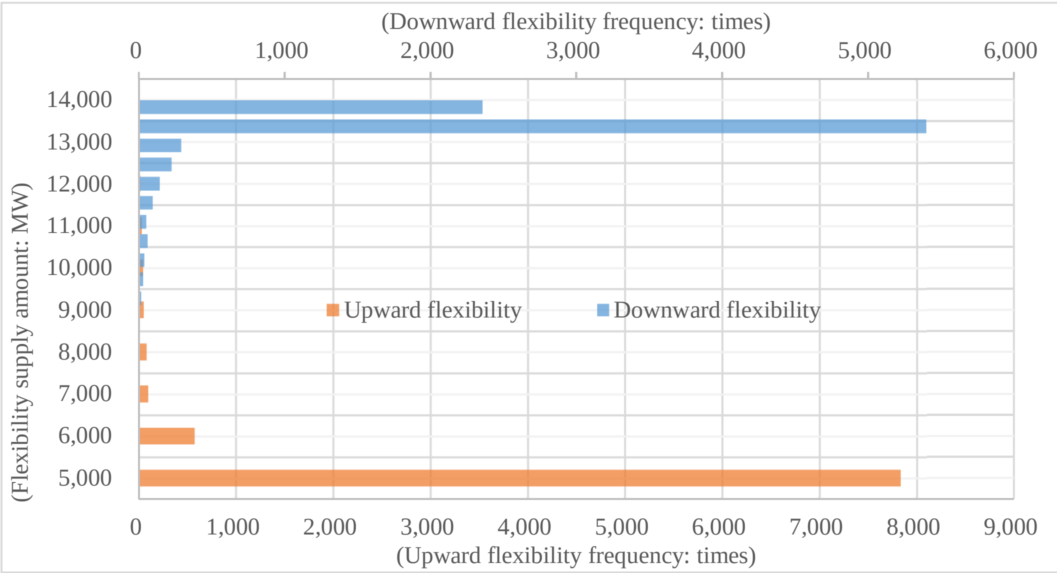


Figure 14. Secured amount of flexibility in Scenario 2

In Scenario 3, the 2 GW quick-start generators are additionally considered as flexibility supply resources in addition to those in Scenario 2. Because they are not affected by the day-ahead unit commitment and economic dispatch scheduling, the quick-start generators that supply flexibility capacity while waiting in an off state can be added to the upward flexibility capacity of 2 GW calculated in Scenario 2 to determine the total supply amount. In other words, since an upward flexibility of 4,773 MW and a downward flexibility of 16,387 MW can be secured averagely in Scenario 2, the upward flexibility in Scenario 3 increases to 6,773 MW, but the downward flexibility will be the same as the amount secured in Scenario 2. However, in Scenarios 4a and 4b where the power output upper limit is adjusted to 95% and 90%, respectively, the unit commitment and economic dispatch scheduling result is affected by the changed constraints. The analysis results for flexibility supply amount through simulation in Scenarios 4a and 4b are shown in Figures 15 and 16, respectively. With respect to the upward flexibility supply amount, it can be seen that the secured amount increases with the upper limit as in the analysis result of Scenario 1.

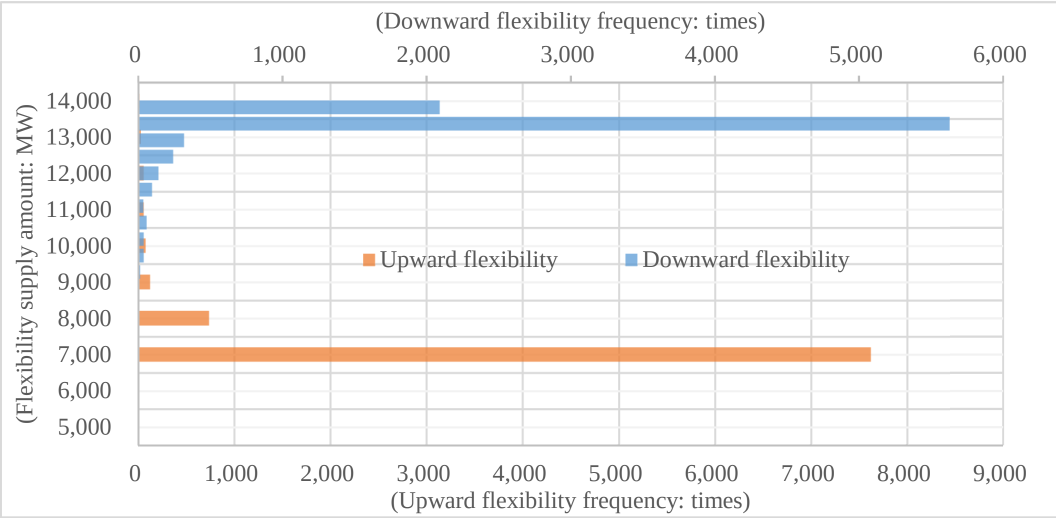


Figure 15. Secured amount of flexibility in Scenario 4a

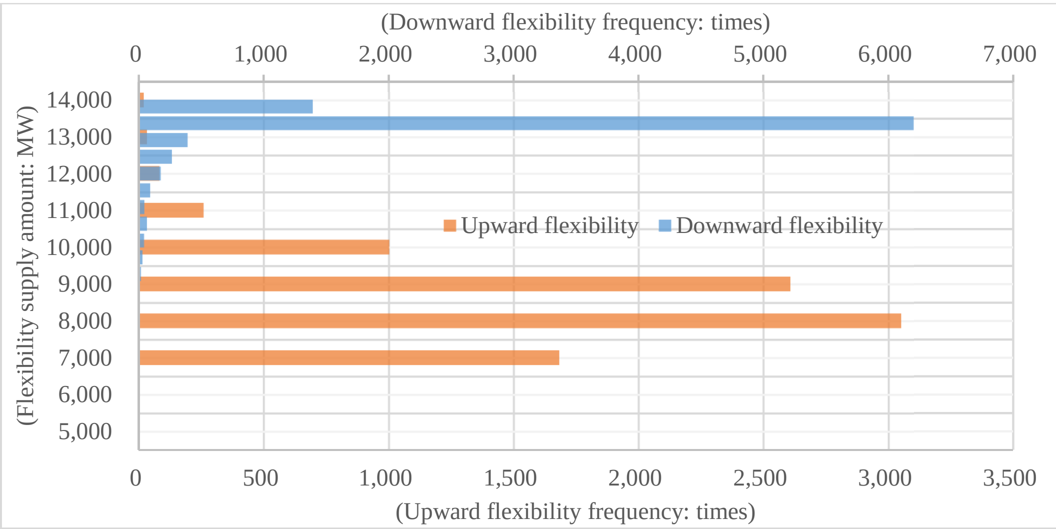


Figure 16. Secured amount of flexibility in Scenario 4b

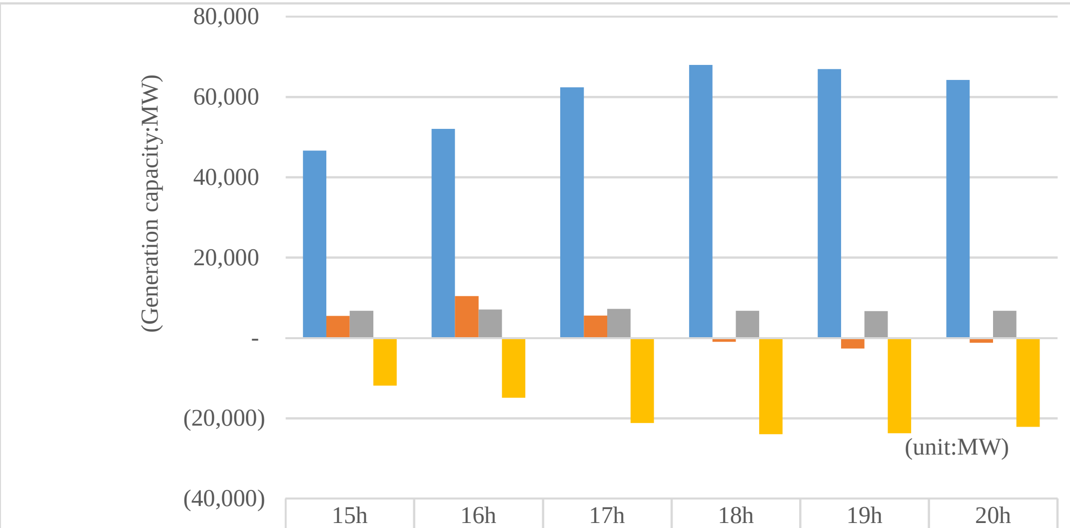
Table 23. Comparison of upward flexibility supply amount by scenario

(unit: GW)	5	6	7	8	9	10	11	12	13	14	15	16
Scenario 2	7,837	576	99	83	55	47	35	16	11	1	0	0
Scenario 3	0	0	7,837	576	99	83	55	47	35	16	11	1
Scenario 4a	0	0	7,621	740	129	82	62	61	32	18	13	2
Scenario 4b	0	0	1,683	3,051	2,609	1,003	260	83	33	21	14	3

In Table 23, Scenarios 3 and 4a secure similar flexibility supply amounts but show very different patterns in terms of total power generation cost or the composition of operational reserve resources. Unlike Scenario 4a, 4b, which applies the power output upper limit method reflecting the current operational reserve acquisition system, Scenario 3 is designed to secure the operational reserve by deciding the UC plan and the spare generation capacity of started generators inside the simulation without upper limit method. If this reserve optimization method is used, it is expected that the total power generation cost could be reduced by 300.3 billion KRW for one year in 2031 compared to Scenario 4a, and reserve resources could also be secured mainly from power generation sources with high variable costs such as LNG power plants. Thus, this can be a cost-effective alternative solution to improve the reserve securing method. The downward flexibility supply amount did not differ significantly by scenario and was similar to the result presented in Scenario 1. In addition, Scenario 3 was not separately presented the flexibility evaluation result in 4.1.4 section because it has a flexibility supply amount pattern similar to Scenario 4a for analyzing the change of amount according to the upper limit of power generation.

4.1.4 Empirical results of evaluating the power system flexibility

For the flexibility evaluation of the domestic power system in 2031, the number of flexibility deficits was determined by comparing the flexibility requirement for 8,760 h with the flexibility supply amount. For example, Figure 17 shows the flexibility requirement and supply amount for 15:00–20:00 on November 1, which is the date when the largest change was made to the net load in 2031. Since the upward flexibility supply amount of 7,051 MW is lower than the fluctuation in net load of 10,362 MW, which is the flexibility requirement at 16:00, a flexibility deficit of 3,311 MW can occur at this time.



	15h	16h	17h	18h	19h	20h
Net load	46,593	52,049	62,412	67,928	66,906	64,197
Flexibility requirement	5,457	10,362	5,517	-1,022	-2,709	-1,215
Upward flexibility	6,722	7,051	7,171	6,759	6,607	6,706
Downward flexibility	-11,896	-14,961	-21,227	-24,042	-23,786	-22,166

Figure 17. Comparison of calculation results for flexibility requirement and supply amount on November 1, 2031

The flexibility evaluation results of Scenarios 2, 4a, and 4b for calculation of flexibility supply amount are presented by the number of upward flexibility deficits (PFD+) and the number of downward flexibility deficits (PFD-). The flexibility evaluation result for Scenario 2 in Figure 18 shows that PFD+ occurred 537 times and PFD- occurred 18 times. For lack of upward flexibility, cases less than 2,000 MW is 404 times and can be solved when quick-starter generators are reflected. To cope with the remaining deficits of upward flexibility increasing the level of securing operational reserves should be considered

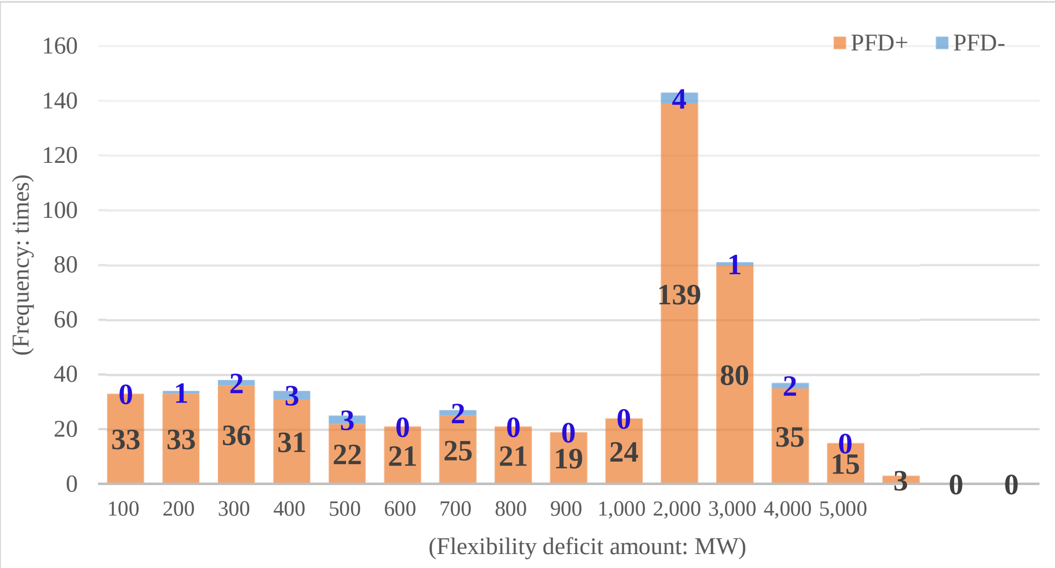


Figure 18. Flexibility evaluation result of Scenario 2

When the frequency and probability of occurrence at each hour were analyzed, the distributions of PFD+ and PFD- are as shown in Figure 19 and 20, respectively.

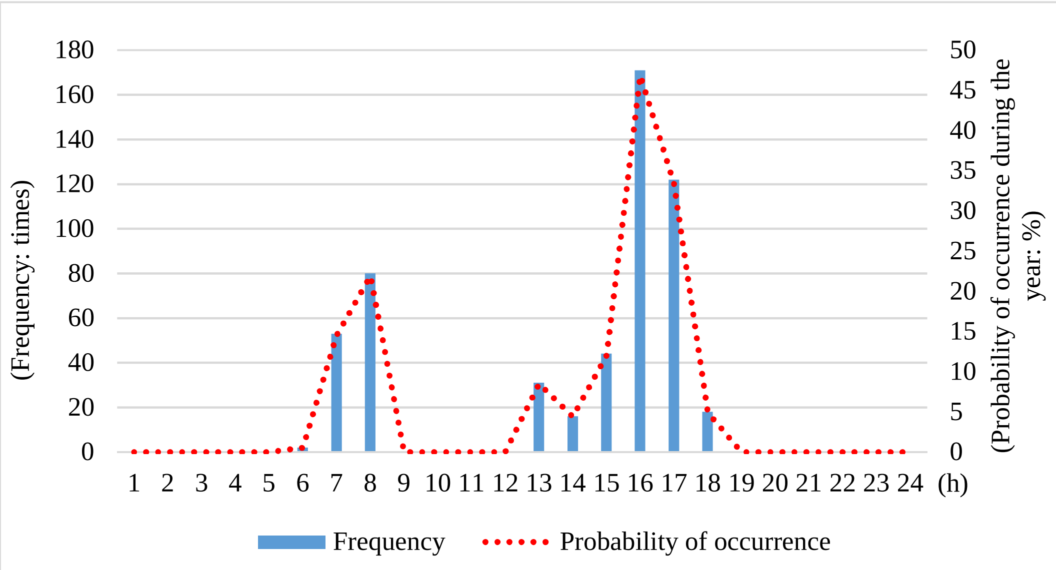


Figure 19. PFD+ distribution of Scenario 2

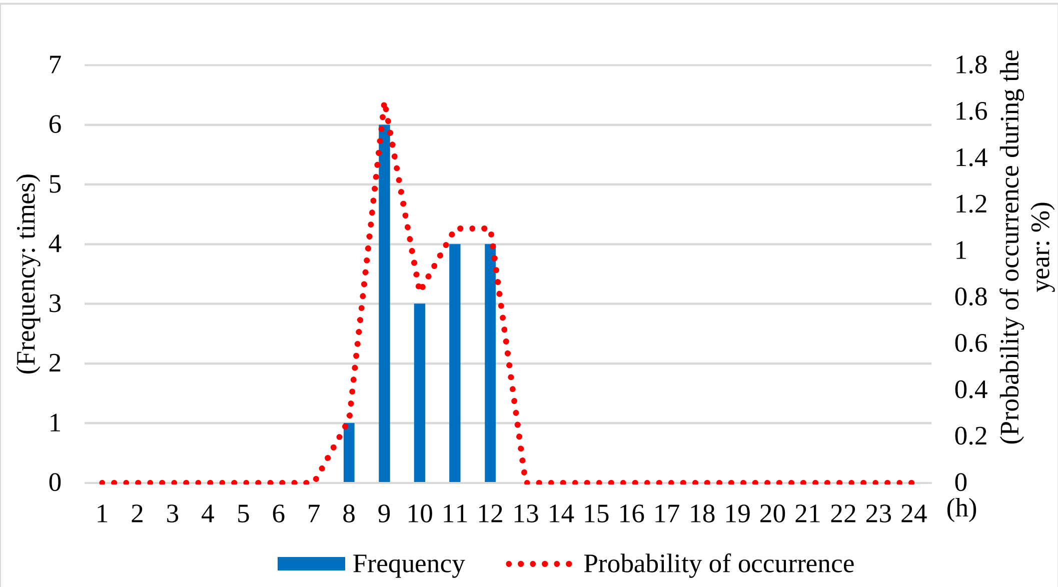


Figure 20. PFD- distribution of Scenario 2

The PFD+ distribution shows that many upward flexibility deficits occur between 7:00–8:00 and 13:00–18:00. The flexibility requirement at 7:00–8:00 is the ramping-up power generation capacity required due to a sharp increase in demand rather than renewable energy volatility, and could be responded to by real-time dispatch operation. By contrast, the flexibility requirement at 13:00–18:00 is caused by renewable energy volatility, and an increase of the flexibility supply amount should be considered. The PFD- distribution shows that due to a rapid increase of renewable energy generation, a downward flexibility deficit can occur at 8:00–12:00 when a reduction of the output of the existing power generation sources is required. Thus, it can be considered as a period in which it is appropriate to respond with a renewable energy output curtailment, P2G, ESS, and pumped-storage charging.

In Scenario 4a, for which quick-start generators were additionally reflected, PFD+ was found to occur 126 times and PFD- occurred 19 times in total (Figure 21). The cause of the decreased number of upward flexibility deficits by 411 times compared to Scenario 2 can be considered to be primarily the contribution of quick-start generators. The PFD+ distribution in Figure 22 shows that the largest number of deficits occurs at 16:00–17:00. It is estimated that the upward flexibility requirement increased due to a reduced output of solar power generation. Furthermore, in the case of PFD-, one deficit additionally occurred at 12:00 in the PFD- distribution of Scenario 2. What is important here is that although the flexibility deficits decreased significantly compared to prior to the introduction of quick-start generators by adding 2 GW quick-start generators as flexibility resources, the problem remains that a flexibility deficit phenomenon can still occur.

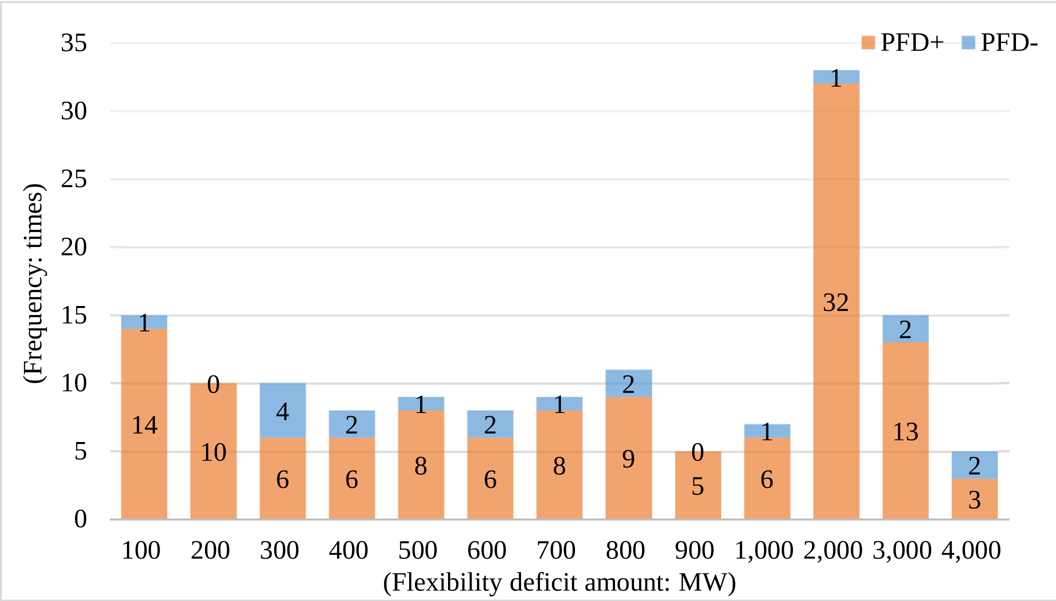


Figure 21. Flexibility evaluation result of Scenario 4a

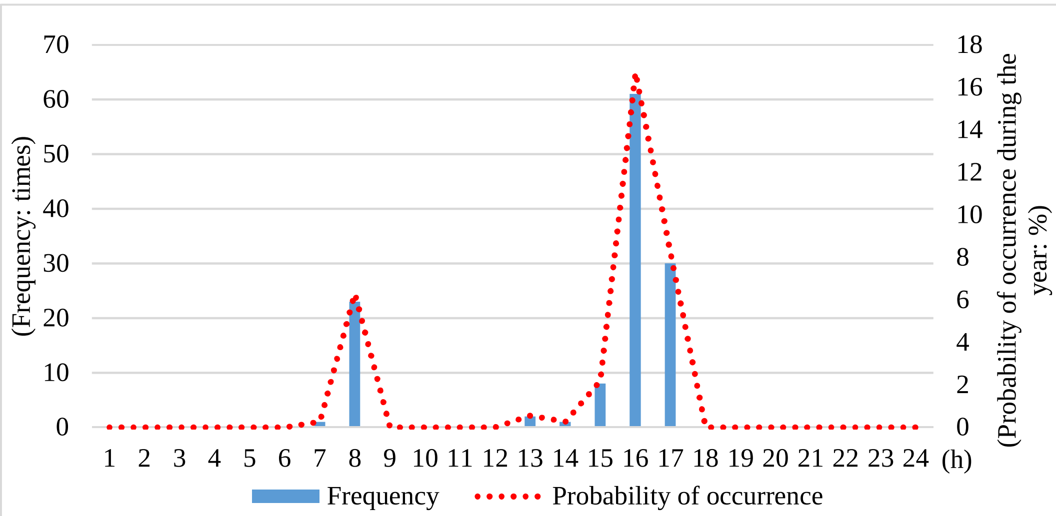


Figure 22. PFD+ distribution of Scenario 4a

In Scenario 4b, the upper limit of power generation of Scenario 4a was adjusted from 95% to 90%, PFD+ and PFD- occurred 59 and 18 times, respectively (Figure 23). Due to the effect of increasing the spare generation capacity of each generator when the upper limit amount is larger, the upward flexibility deficits decreased by over 50% compared to Scenario 4a. When the PFD+ distributions are compared between Scenarios 4a and 4b, the periods of upward flexibility deficit are similar, but the number of deficits decreased in Scenario 4b due to the increased output limit of 5% (Figure 22 and 24). It can be seen that compared to scenario 4a, the probability of lack of upward flexibility decreases from about 16.7% at 16:00 to about 8.7% for scenario 4b.

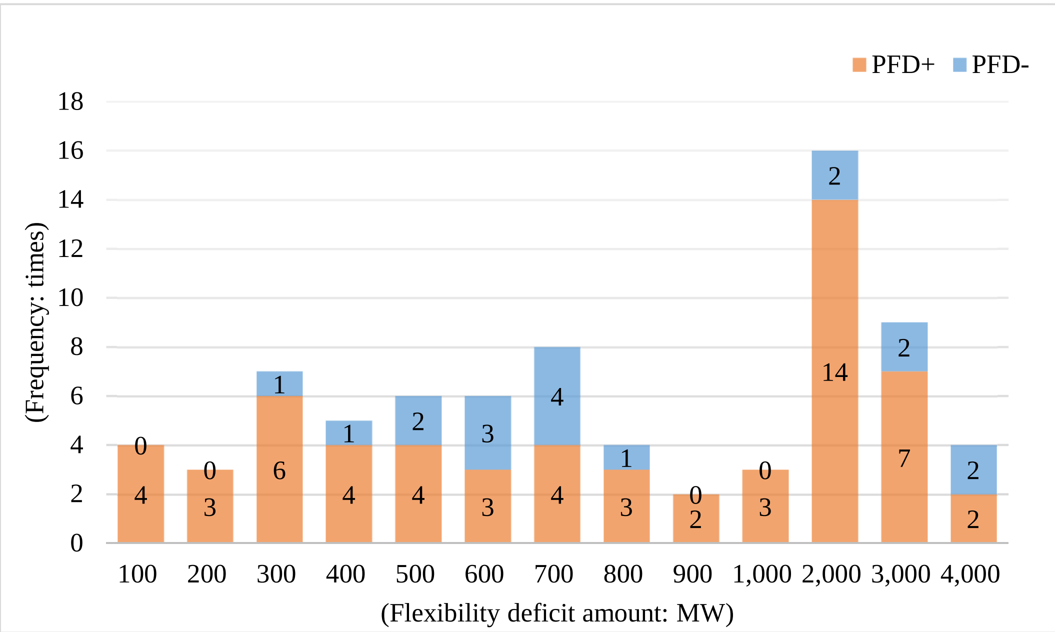


Figure 23. Flexibility evaluation result of Scenario 4b

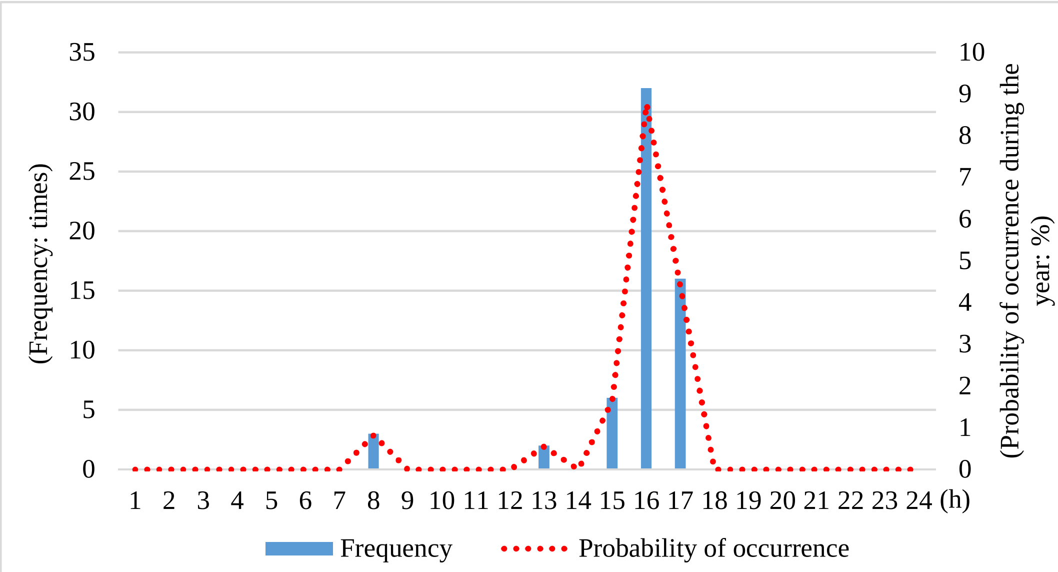


Figure 24. PFD+ distribution of Scenario 4b

The analysis result for the PFD- distribution of Scenario 4b was not presented because it was the same as the periods of downward flexibility deficit of Scenario 2. The number of downward flexibility deficits is low until the share of renewable energy generation is 20%. However, if the share of renewable energy generation continuously increases in the future, the renewable energy output constraint may increase due to the lack of power grid acceptance and flexibility. Therefore, measures to cope with downward flexibility should also be researched in a timely manner.

To summarize the analysis results regarding the periods and frequency of flexibility deficit for each flexibility capacity supply scenario, it is believed that additional flexibility supply to the power system is necessary in 2031. It is necessary to increase the operational reserve or quick-start generators especially because periods of flexibility deficit occurred even though 2GW, which is the current criterion for quick-start generators, was reflected in terms of upward flexibility supply. The flexibility evaluation result of Scenario 2 indicates that approximately 94% of renewable energy volatility in 8,760 h can be responded to only with the operational reserve. Therefore, this study proposes consideration of the measures to increase the criterion for the secured amount of quick-start generators that are operated in emergencies. The criteria need to be improved to utilize the variable-speed pumped-storage power plant of 2GW determined to be installed in the 8th ESDP, LNG power plants of 3.2GW that can operate gas turbines alone, and 0.7GW of ESS as additional quick-start generators, and a compensation system to guarantee participation incentive should be prepared. Regarding the improvement of the criteria for securing quick-start generators, the maximum upward flexibility deficit is 3,349 MW in Scenario 4b. Thus, upward flexibility deficit will not occur if the current criterion of 2GW is increased by the deficit amount. What is important here is that the regulation for securing flexibility resources must be flexible, instead of being fixed. This is because increasing the secured amount of operational reserve on average for the 6% volatility to which response is uncertain by such reserves can be inefficient in terms of cost. While the criteria for securing operational reserves were operated statically in preparation for emergencies in the traditional power system, the criteria for securing renewable energy volatility can be cost-effective flexibility response measures only if they are operated flexibly in accordance with the weather conditions and the range of securing operation reserves is set dynamically. For example, rather than regulating to secure 10,362 MW, which is the maximum fluctuation of net load in 2031 for all 8,760 hours, a more economical alternative can be to secure fixed operational reserves for 95% of a year and to use quick-start generators for 5% with a large fluctuation level.

4.2 Composition of flexibility resources and ability to respond to volatility

In this section, the problems that may arise under the current system are analyzed in terms of the composition of flexibility resources and the ability to cope with volatility around operational reserves and quick-start generators, which are used as resources to respond to renewable energy volatility. First, the settlement regulations about power generation sources participating in the operational reserve service are examined, and the incentive effect of participating in reserve service of coal and LNG power generation sources is then analyzed. The composition of flexibility supply resources that can occur when the resources included in the operational reserves are reflected in the order of variable cost due to the characteristics of the CBP market is forecast, and the flexibility responsiveness to renewable energy volatility within one hour is analyzed. Finally, improvement of the reserve system to respond to the renewable energy volatility and the need for separation of the energy market and the auxiliary reserve service market are examined.

4.2.1 Incentive effect for participation in operational reserve service

The settlement amounts for power generation sources participating in the domestic power market can be largely classified into scheduled energy, available capacity (largely representing fixed costs of generation), auxiliary service, and additional settlement (constrained-on energy and constrained-off energy) (Korea Power Exchange, 2019a, 2020b). Different settlement prices are applied when calculating the settlement amount depending on whether the price setting schedule established one day ahead as shown in Table 24. The settlement for available capacity is based on the bidding amount.

Table 24. Standard prices for power trading settlement amount

<table>
<tr><th>Classification</th><th>Scheduling included</th><th colspan="2">Scheduling not included</th></tr>
<tr><td rowspan="2">Generation</td><td rowspan="2">Market price
+
Capacity price</td><td>Request by power generation company</td><td>Min (market price, variable cost)
+
capacity price</td></tr>
<tr><td>Request by ISO</td><td>Max (market price, variable cost)
+
capacity price</td></tr>
<tr><td>Non-

generation</td><td>(Market price – Variable cost)
+
Capacity price</td><td colspan="2">Capacity price</td></tr>
</table>

Source: Settlement Regulation Manual (KPX, 2019), reconstructed by the author

Table 25 outlines the detailed settlement method by the type of power trading settlement amount. The settlement amount that can be received additionally by participating in an operational reserve service is the constrained-off energy payment (COFF), which is a compensation for the loss of electricity sales caused by restricting the maximum generation output to secure reserves, and the auxiliary service settlement amount for the generation capacity participating in reserve service.

Table 25. Settlement calculation method for power generation sources participating in the power market

Classification	Calculation method
Scheduled energy payment (SEP)	Power generation x market price (MP)[5]
Capacity payment (CP)	Bidding amount x capacity price
Auxiliary service payment	Frequency tracking, automatic generation control, reserve, self-starting service Unit price for each service x supply amount
additional settlement (Uplift)	System constrained-on (CON) = Max (market price, variable cost) x constrained power generation System constrained-off (COFF) = (market price-variable cost) x constrained power generation

Source: Settlement Regulation Manual (KPX, 2019), reconstructed by the author

In the domestic power market, whether to include generation scheduling and operational reserve service is determined by the KPX, but the profit changes resulting from participation in the energy and auxiliary service markets will directly affect power

[5] Market Price (MP) is calculated as follows considering the system marginal price (SMP), the upper limit price of settlement (PC), stack price (SP), transmission loss factor (TLF), and impact mitigation factor (IMF). However, in this study, SMP was used as the MP because it is similar to SMP.

$$MP = \{max(min(SMP, PC), SP)\} \times \{1-(1-TLF) \times IMF\}$$

generation companies. If the profit decreases by participating in the reserve auxiliary service market compared to the energy market, power generation companies may not want to participate in the operational reserve service. Thus, it is important to maintain the reserve service price at an appropriate level.

According to the 2018 power market statistics published by the KPX (Korea Power Exchange, 2019b), the contributions of frequency adjustment reserve and standby / substitute reserves[6] to operational reserves by power generation source were estimated based on the auxiliary service settlement amount for system operation in 2018 as shown in Figure 25. Bituminous coal and LNG contributed approximately 91% to the frequency adjustment reserve, whereas pumped storage, and hydro power contributed approximately 98% to the standby/substitute reserves. Thus, to analyze the incentive effect on the participation in operational reserve service, this study calculates the representative power plants of coal and LNG power generations, which are major power generation sources of operational reserve in the on state (Table 26). At this time, each rated capacity is assumed to be the same, and the actual value of referenced power plants is used for the fuel cost, variable cost, and settlement adjustment coefficient. The increase or decrease in the net profit when the generation upper limit for participation in the reserve market is decreased to 95%–90% based on the net profit of each representative power plant when participating 100% in the energy market is also evaluated.

[6] After the revision of the Power Market Operation Regulation in December 2019, frequency adjustment reserves correspond to frequency control reserve, and first and second reserves, and standby/substitute reserves correspond to third reserve in the off state.

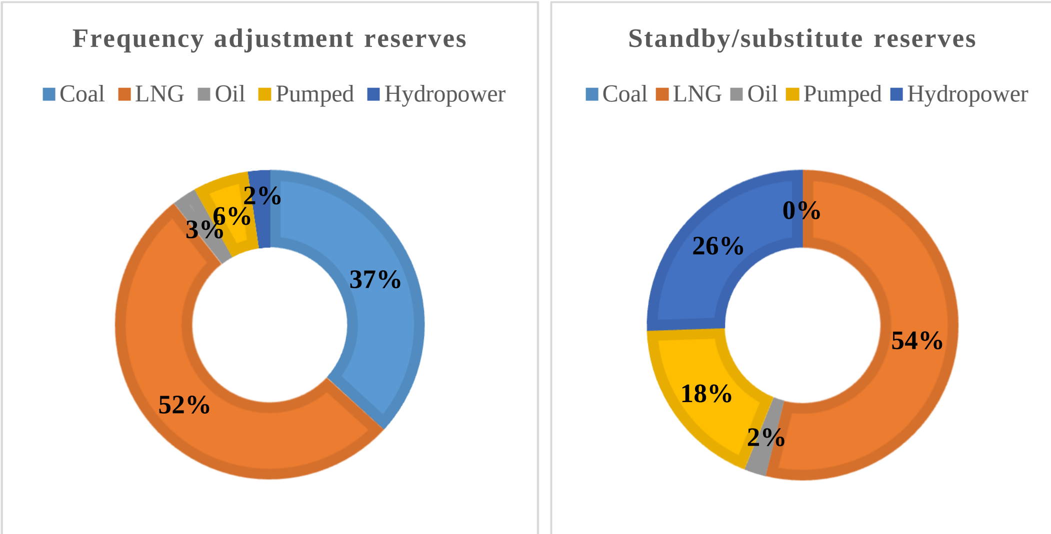


Figure 25. Share of operational reserve auxiliary service settlement amount by fuel source in 2018

Source: Power market statistics 2018 (KPX, 2019), reconstructed by the author

Table 26. Comparison of the characteristics of representative power plants

Classification	Coal-fired power plant A	LNG power plant B
Rated capacity (MW)	959	959
Physical characteristics benchmark	△△ thermal power plant (Southern Power Co.)	◇◇ combined power plant (Western Power Co.)
Unit price of heat (1,000 KRW)	21.333	55.157
Settlement adjustment coefficient	0.7037	1
variable cost (KRW/kWh) (100% output)	49.2	93.8
SMP (KRW/kWh)	100	
Settlement unit price (KRW/kWh)	85	100

When the reserve participation amount is increased by applying the upper limit of power generation to secure operational reserves, the revenue of coal-fired power plant increases gradually and that of LNG power plant decreases gradually, as shown in Figure 26.

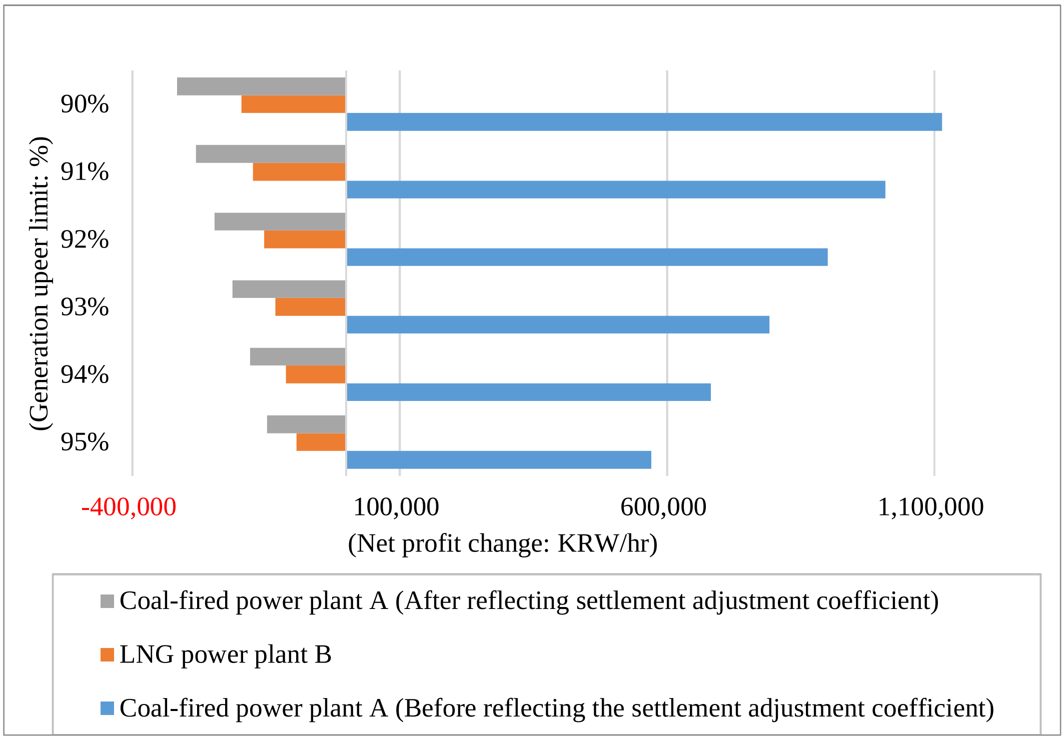


Figure 26. Comparison of revenue change according to the generation upper limit

The reason for this phenomenon is that the regulation for calculating the additional settlement amount for constrained off-generation is designed to increase the compensation amount for a power plant with a lower variable cost (Ahn, 2018). To respond to the renewable energy volatility, fast compliance is required, and LNG power is better than coal power in terms of this physical characteristic. However, facilities with high flexibility have a high variable cost and would want to participate in the energy market rather than the reserve auxiliary service market. If the settlement adjustment coefficient is considered when calculating the settlement payment amount for constrained off-generation, it can be seen that not only LNG plant's but also coal-fired plant's profits decrease. In sum, it shows the problem of the market structure where the incentive to participate in the reserve service is lower than that of energy production. In this respect, to cope with the increasing share of renewable energy, it is necessary to consider the improvement from the current single reserve service price to a differential compensation plan for participation in the reserve service in view of the characteristics required to respond to flexibility such as start-up time, ramp-up/down rates, and hold time.

4.2.2 Composition of operational reserve resources for flexibility supply

In unit commitment and economic dispatch scheduling with the minimization of total power generation cost in the CBP market, the composition of operational reserve resources secured by the upper limit of power generation is influenced by the variable cost that determines the merit order. Table 27 presents the merit order of centrally dispatched generators (excluding hydro and pumped storage) in 2031 is determined by the order of variable cost based on the rated output. After the power generation fuel tax reform in April 2019, the tax charge for bituminous coal increased from 36 KRW to 46 KRW per kg. The tax burden for LNG decreased from 91.4 KRW to 23 KRW per kg. Since this study used the power generation fuel cost data in 2018 for 2031, the unit price of heat per generator before the power generation fuel tax reform was applied. However, as can be seen in Table 27, the section in which a change in the merit orders of coal power and LNG power generation is between coal groups 1 and 8. However, in terms of facility capacity, it can be seen that the order of nuclear, coal, and LNG is maintained in general.

If the reserve resources are allocated in ascending order of variable cost through the upper limit of power generation, the net load can be satisfied only with the base generations (nuclear, coal) during the day with a high renewable energy generation, it may be unnecessary to start-up LNG power generation, and a reserve can be secured from the coal power plant determined as being in an on state. LNG power plants can be started but there is a limit to them as reserve resources due to heat, fuel, and transmission constraints. When the periods that can satisfy the net load only by the base generation are analyzed, the total number of periods of net load below 20,400MW based on the nuclear facility capacity in 2031 is 30 times. When the coal power generation capacity of 36,923MW (Coal group 1 in Table 27) is additionally considered, the total number of periods of net load smaller than the sum of nuclear and coal 1 power plant capacities is 5,862 times. In this situation, the higher the share of renewable energy generation, the lower the net load will become. Eventually, as the periods in which only the base power generation source is operated increase, it may be difficult to construct an appropriate operational reserve mix with only the upper limit of power generation.

Table 27. Comparison of merit order stack in 2031

Before tax reform			After tax reform		
Group name	Facility capacity (MW)	Cumulative facility capacity (MW)	Group name	Facility capacity (MW)	Cumulative facility capacity (MW)
			Oil 5	509	107,224.1
			LNG 12	1069.2	106,715.1
			Oil 4	146.3	105,646.0
			LNG 11	24	105,499.7
			Oil 3	83.5	105,475.7
			LNG 10	21	105,392.2
			Oil 2	40	105,371.2
			LNG 9	273.3	105,331.2
			Oil 1	26.3	105,057.8
			LNG 8	36,456.4	105,031.5
Oil 5	465.8	107,224.1	Coal 8	578.6	68,575.1
LNG 7	151.5	106,758.3	LNG 7	3,060	67,996.5
Oil 4	45.8	106,606.8	Coal 7	340	64,936.5
LNG 6	1,061.3	106,561.0	LNG 6	4,435	64,596.5
Oil 3	128.5	105,499.7	Coal 6	500	60,161.5
LNG 5	313.3	105,371.2	LNG 5	927.6	59,661.5
Oil 2	26.3	105,057.8	Coal 5	700	58,733.9
LNG 4	2,673.8	105,031.5	LNG 4	97	58,033.9
Oil 1	37	102,357.7	Coal 4	500	57,936.9
LNG 3	42,659.3	102,320.7	LNG 3	114	57,436.9
Coal 3	515	59,661.5	Coal 3	1,200	57,322.9
LNG 2	412.6	59,146.5	LNG 2	481.7	56,122.9
Coal 2	797	58,733.9	Coal 2	24,283	55,641.2
LNG 1	614	57,936.9	LNG 1	989.2	31,358.2
Coal 1	36,922.9	57,322.9	Coal 1	9,969	30,369.0
Nuclear	20,400	20,400.0	Nuclear	20,400	20,400.0
Total	107,224.1		Total	107,224.1	

Figure 27 shows a histogram of the net load in 2031. When this is compared with the cumulative facility capacity in Table 27, the composition of reserve resources can be roughly identified under conditions that do not consider other constraints.

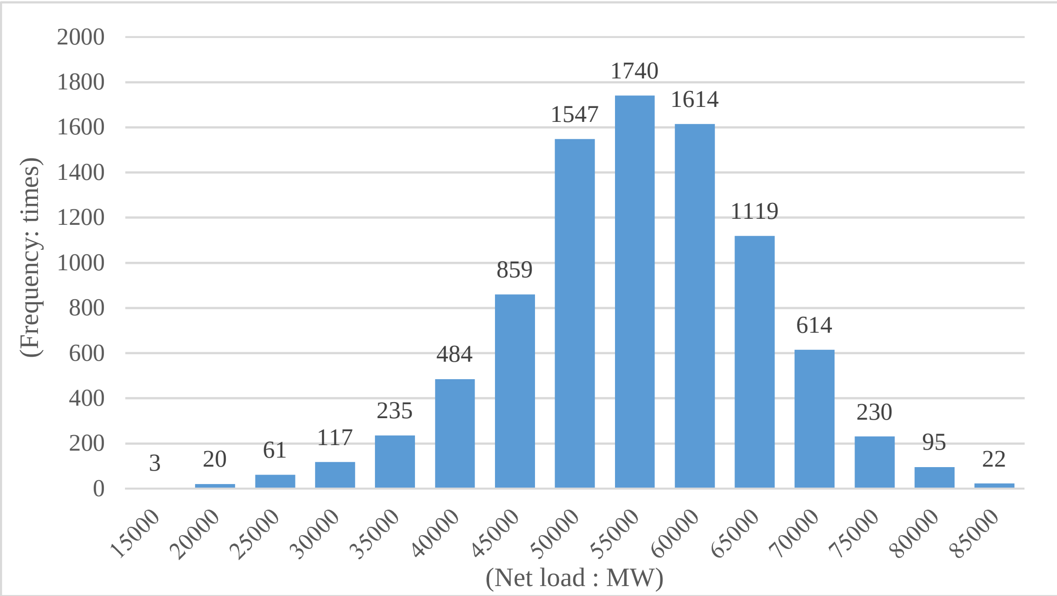


Figure 27. Net load histogram in 2031 (Net load = Demand – Renewables)

Furthermore, to use the operational reserve as flexibility supply resource, the ramp-up/down rates should be considered among the physical constraints of the power generation sources constituting the reserves. Even if the hourly flexibility supply amount is sufficient, the ability to respond to the renewable energy volatility within one hour can show different patterns due to this characteristic. Since there are no actual measurement data on the volatility of domestic renewable energy in units of less than one hour, this study assumes a few situations for variations of volatility response ability according to the composition of operational reserve resources.

All the power generation sources excluding nuclear and renewable energies can constitute the domestic operational reserves. In a situation where the net load fluctuation is forecast as 2,500 MW, 2,500 MW of operational reserve in an on state can be secured as a flexibility response resource. Consequently, hourly renewable energy volatility can be responded to, and it was assumed that reserve resources are configured in the following four scenarios (Table 28).

Table 28. Scenarios for composition of operational reserve resources

Classification	Component power generation sources	Description
1	10 coal power plants	A period in which the share of renewable energy generation is high
2	8 coal power plants, 2 LNG-combined power plants	A period in which the share of renewable energy generation is medium
3	3 coal power plants, 5 LNG-combined power plants, 2 pumped-storage power plants	A period in which the share of renewable energy generation is low (based on the share of operational reserves in 2018)
4	10 pumped-storage power plants	Assumed to analyze the effect of ramp-up rate

The scenarios for the composition of power generation source are assumptions of situations according to the share of renewable energy generation. The ramp-up rate for each power generation source was realistically set as 9 MW/min for coal, 18 MW/min for LNG, and 135 MW/min for pumped storage. To analyze the ability to respond to renewable energy volatility within the time range of [h, h+1] according to each scenario, the renewable energy output within 60 min was randomly generated within the range of [0, 2500] using the random function. This flexibility evaluation could be made more precise if the accurate measurement data for the characteristics of renewable energy volatility within one hour can be acquired in the future. The analysis result reveals that when response is started with dispatch instruction from the time when the renewable energy volatility occurs, it can be responded to only with Scenario 4, which includes the fluctuation areas of volatility 1 and 2 in Figure 28. This is because the time required for securing 2,500MW within one hour with the ramp-up rate constraint of the power generation sources comprising each scenario is different at 28, 24, 7, and 2 min for Scenarios 1 to 4, respectively.

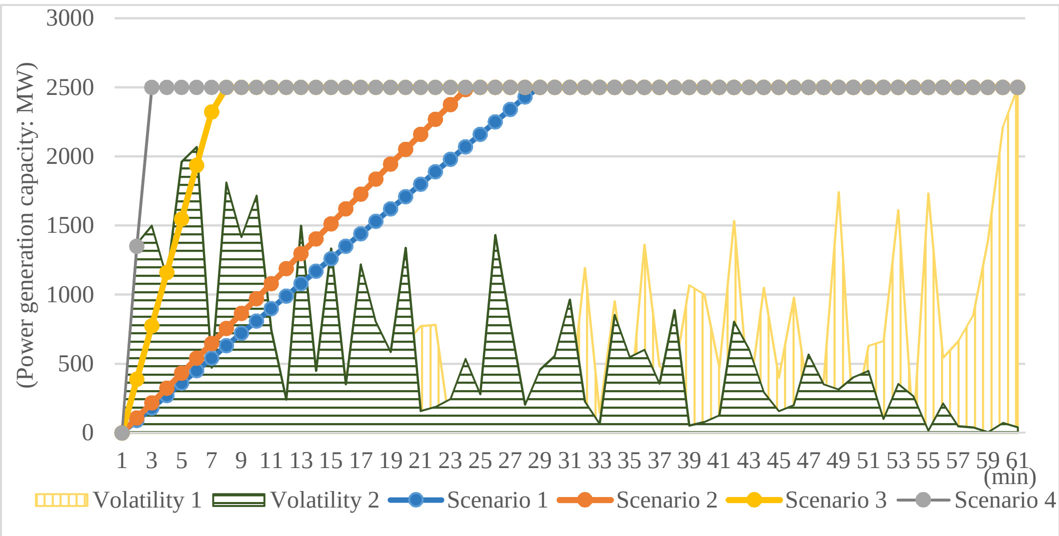


Figure 28. Comparison of the degree of response to volatility for each scenario for composition of operational reserve resources

Therefore, to improve the upper limit method to secure operational reserves, the reserve resources should be composed considering the physical characteristics of power generation sources that will constitute the operational reserves to improve their usability as flexibility resources.

4.2.3 Volatility response mechanism of operational reserves and quick–start generators

Although it may be different according to the characteristics of the power system of each country, every country operates reserves to prepare for frequency adjustment and the failures of maximum unit capacity power generation facilities and operational reserves to respond to demand forecast errors and multiple failures of transmission and substation facilities. The response mechanism of operational reserves is activated at when a major contingency that can interfere with the balance of demand and supply in the power system occurs. The response time limits for the operational reserves and quick-start generators of the domestic power market can be arranged in ascending order as follows: first reserve (within 10 s), frequency control reserve (within 5 min), second reserve (within 10 min), quick-start generators (within 20 min), and third reserve (within 30 min) (Table 20). Among them, the frequency control reserve complies within 5 min through the automatic generation control (AGC) and the remote output control of the energy storage system. The first, second, and third reserves, which are frequency recovery reserves, comply within the specified time in the event of a failure and are used for frequency recover through the governor free operation and additional AGC operation (Korea Power Exchange, 2020a).

To use the operational reserves and quick-start generators as flexibility resources, the differences in the response mechanism between a ramping event and a major contingency of the existing power system should be considered. If the KPX manages the renewable energy output forecasts in the same time intervals as those of the demand forecasts (every 5 min), considering that the compliance time of the quick-start generators is less than 20 min, the dispatch instruction for quick-start generators must be given at least 20 min before the volatility occurrence. The output of the online operational reserve can be controlled by the power system at all times, but for the third reserve in an off state, the dispatch instruction must be given 30 min in advance like the quick-start generators so that it can be an available flexibility resource at the time of volatility occurrence. The response measures according to the forecasted size of net load variation can be classified into a zone where it is possible to respond with operational reserve in an on state (Zone 1), one where it is possible to respond including the operational reserve in an off sate (Zone 2), and one where the quick-start generators must be included to respond (Zone 3) (Figure 29).

If the accuracy and precision of the forecast system for renewable energy volatility is low or the forecast system is not established, increasing the secured amount of online operational reserves can be one method to respond to hourly volatility. However, as the secured amount of operational reserve is increased, the constrained non-generation amount will also increase, and the total power generation cost will rise sharply due to this operation constraint.

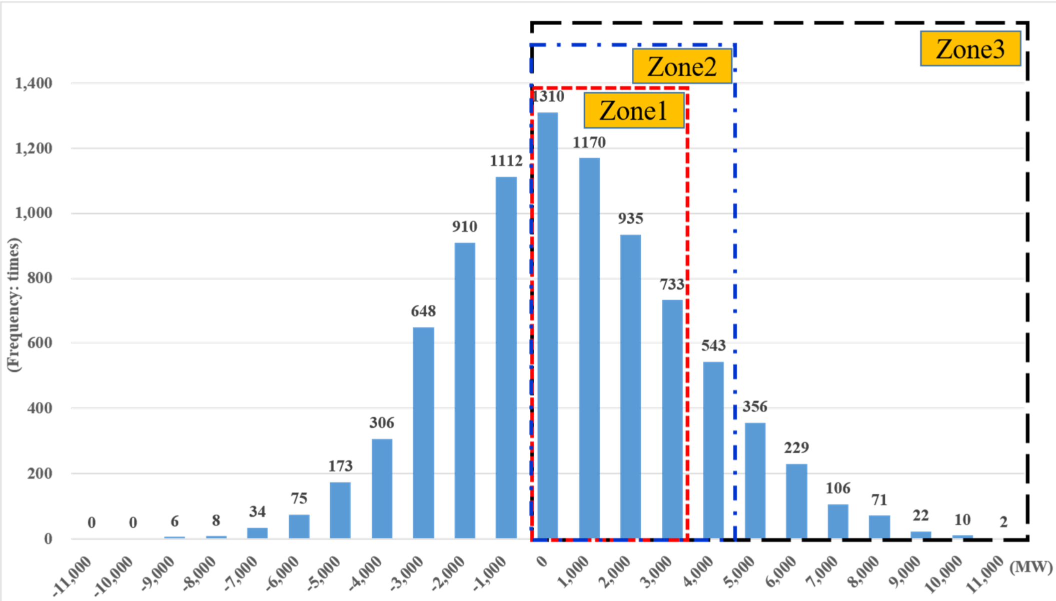


Figure 29. Classification by the resources for responding to net load variations

Under the current operation regulations for operational reserves and quick-start generators, if the renewable energy volatility in 2031 is expected to increase to about 10 GW or more, this corresponds to Zone 3 as shown in Figure 29. Thus, as shown in Figure 30, three dispatch instructions (ⓐ, ⓑ, ⓒ) to secure the flexibility supply amount must be given before the ramping event to input the flexibility resources at the right time.

The traditional response to major contingency of the power system gives dispatch instructions from the resources with a short compliance time according to the acquisition time standard from immediately after occurrence. However, to secure the flexibility in a ramping event, a situation arises in which a dispatch order must be given from the resource with a long compliance time, as shown in Figure 30. This is because, to secure the flexibility supply amount that satisfies the predicted fluctuation of renewable energy at the right time, the time it requires to start the offline power generation sources must be considered. Therefore, a system that can predict renewable energy volatility considering the start-up preparation time of flexibility resources needs to be introduced to enable the economic operation of power generation facilities while minimizing the inefficient standby time by accurately issuing the dispatch instruction in advance. However, the advance reservation of operational reserve to respond to flexibility also has a risk of lowering the response ability in the event of a major contingency in a traditional power system. Especially for the domestic power market, which has an isolated power grid that is not interconnected with those of other countries, a worst contingency for stable power supply should be assumed. Hence, it is necessary to examine a separate operation plan between operational reserves and flexibility supply resources while the share of renewable energy generation gradually increases. In addition, with respect to the construction of the Northeast Asian Super Grid mentioned in the 8th ESDP, when the connection line operation method is determined before the construction, a method of using the total capacity of facilities for electricity trading and a trading method of combining electricity and reserve by allocating them partially as resources for responding to flexibility need to be compared in terms of economics and system operation safety.

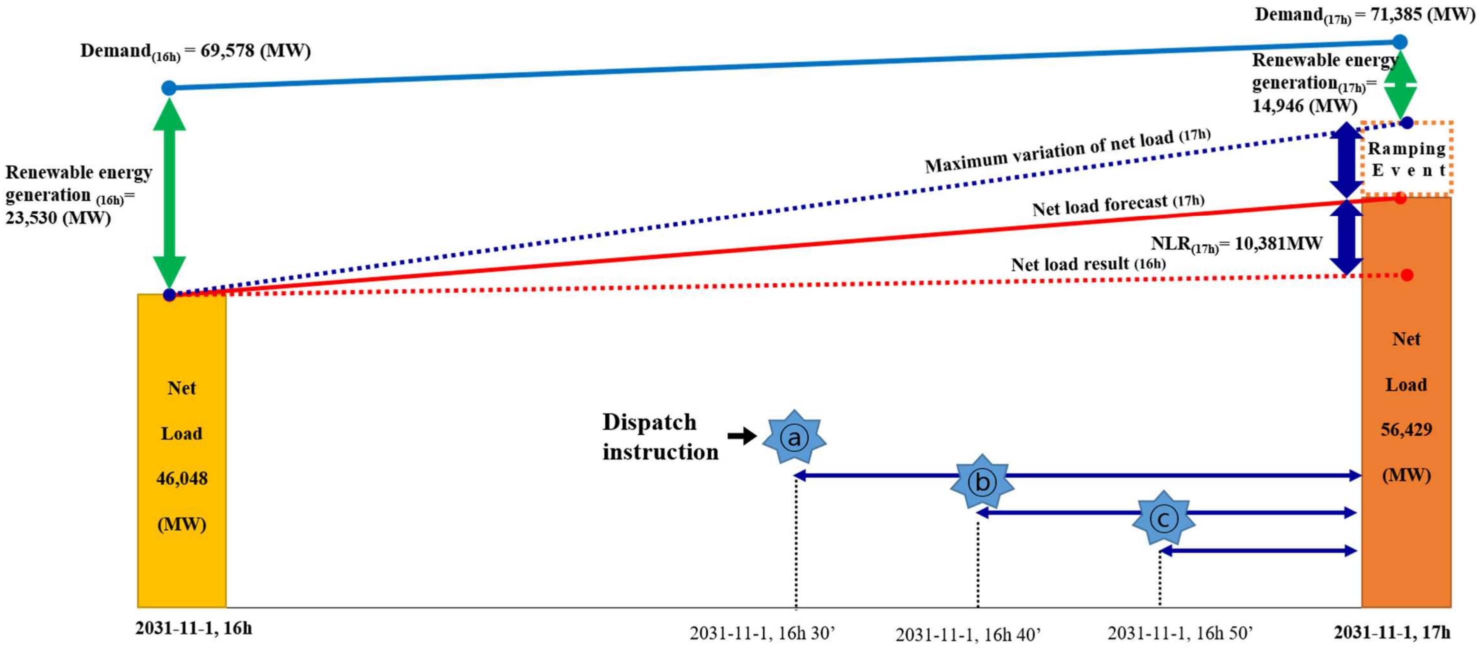


Figure 30. Net load variability response mechanism for 16–17h on November 1, 2031

4.2.4 Improvement of reserve system and separation of the auxiliary service market

This study assumed the secured amount standard for each type of operational reserve as the minimum value. However, the Power Market Operation Regulation actually prescribes it as the minimum or higher as shown in Table 20. Thus, different secured amounts can be applied depending on the power market situation. However, the renewable energy volatility inevitably generates errors from the real-time output because it has the inherent characteristic of uncertainty according to weather conditions. Thus, a probability distribution should be assumed based on the output forecasts and flexibility resources to respond to the entire fluctuation should be secured. In other words, the method of applying different criteria for securing operational reserve by period should consider both a fixed reserve to prepare for a major contingency of the traditional power system and a variable reserve for responding to renewable energy volatility.

In the day-ahead unit commitment and economic dispatch scheduling, power generation companies only bid for the available supply amount, and whether they participate in the energy market for trading power generation or in the auxiliary service market for supplying operational reserve is determined by the KPX. At this time, the secured amount in preparation for flexibility with a large uncertainty is obtained through the generation constraint of generators included in the price setting scheduling. Therefore, the constrained generation and non-generation costs increase, and the revenue imbalance among power generation sources can increase if the incentive to participate in the operational reserve is insufficient. If the limitation of reserve resources composed by the power output upper limit method proposed in section 4.2.3 and the problem due to the difference in mechanism between the operational reserve and flexibility response resource are to be considered, the resources for responding to flexibility should be separated from the operational reserves and the energy and auxiliary service markets should be separately operated to minimize the uncertainty and complexity of power market operators and generation companies.

When an auxiliary service market is established by separating the reserve service from the energy market, the market size is a crucial issue for flexibility suppliers. To analyze this, this study distinguishes the unit commitment and economic dispatch methods depending on the consideration of the constraint for securing the operational reserve. The auxiliary service market size is estimated by comparing the total power generation cost for one year in 2031 obtained from the simulation result of each method. A total of four methods of unit commitment and economic dispatch scheduling were considered, as shown in Table 29.

Table 29. Scenarios for generation scheduling methods to secure operational reserves

Classification	Scenario name	Description
1	Operational reserve not included	Price setting scheduling without the constraint for securing operational reserves (100% upper limit)
2	Optimization of reserve allocation	Addition of a constraint equation for securing operational reserves without upper limit

3	95% upper limit	Addition of a constraint equation for securing operational reserves by 95% upper limit
4	90% upper limit	Addition of a constraint equation for securing operational reserves by 90% upper limit

Here, unlike the upper limit method that collectively secures a certain ratio for each power generation source as reserve, Scenario 2 secures reserves in such a manner that the utilization rate of power generation sources with a low variable cost is increased while that of power generation sources with a high variable cost and good compliance is lowered to minimize the hourly total power generation cost.

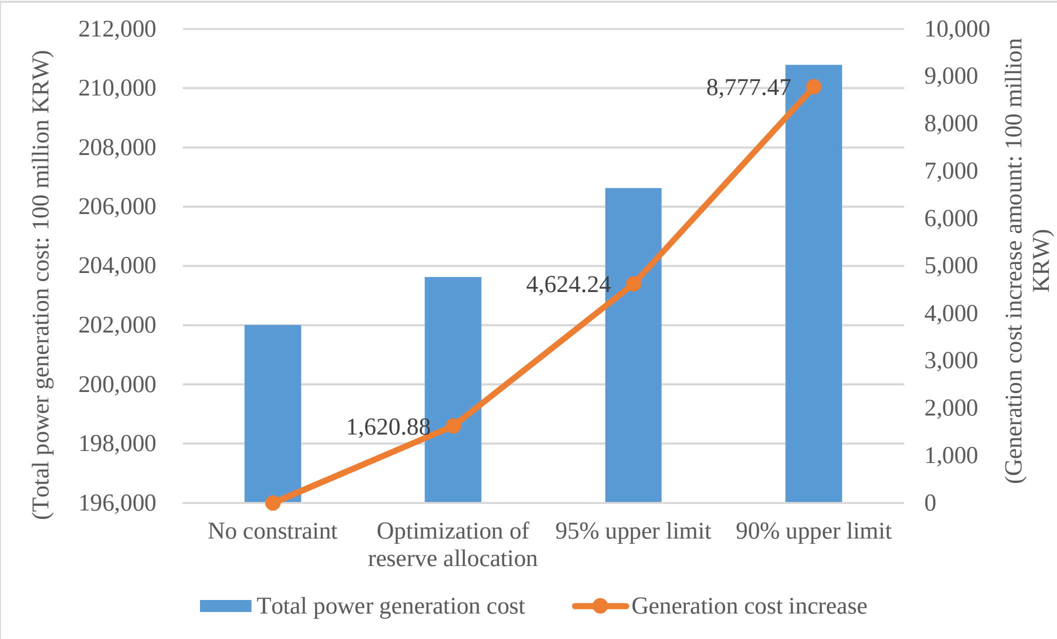


Figure 31. Comparison of total power generation costs for one year according to the method of securing reserves in 2031

In comparison with the result of price setting scheduling without operational reserves, adding the operational reserve acquisition as a constraint equation, an output constraint for each generator is generated, and the total power generation cost increases as generators with a high variable cost are additionally included in the power generation operation plan. Figure 31 shows that when the reserve acquisition optimization method established to minimize the power generation cost by only adding the reserve acquisition condition is compared with the price setting scheduling, an additional cost of 162,088 million KRW is occurred for one year. This amount is a generation cost that is increased when only the reserve acquisition condition is added without other constraints. It can be considered as the minimum market size that can be paid to power generation companies when the reserve auxiliary service market is separated from the energy market. However, the proposed method of estimating the auxiliary service market size is based on the unit commitment and economic dispatch scheduling simulation and has the limitation of not considering the compensation for offline third reserves and quick-start generators. Therefore, if this limitation is additionally considered, it can be seen that the size of the auxiliary service market is further increased.

4.3 Analysis of the economic impact

This section analyzes the changes in the SMP of the domestic power system and the power purchase cost of vendors in 2031 due to the expansion of renewable energy. The electricity purchase settlement principles are examined and the changes of the SMP in the power wholesale market are estimated.

The changes in the scheduled energy payment, available capacity payment, RPS obligation fulfillment cost, and emissions trading cost, which constitute the power purchase cost of vendors, are analyzed to investigate the increase of power purchase cost due to the energy transition policy. Finally, the degree of the pressure to increase electricity rates is evaluated.

4.3.1 Premises for economic impact analysis

The wholesale purchasers of electricity in the domestic power market are classified into direct purchasers using power purchase agreement (PPA), community electricity business companies, and KEPCO, which is (for the most part) the sole retailer of electricity in Korea. In the power market operation results in 2018, the total settlement amount is 50,700 billion KRW and can be divided by the settlement factor as shown in Table 30.

Table 30. Classification of electricity settlement amount by power market settlement factor in 2018

Electricity settlement amount		Capacity payment	Other settlements[1)]	Total
Scheduled energy payment	Constrained-on energy payment			
36,175.7 billion KRW (71.3%)	5,260.4 billion KRW (10.4%)	6,152.8 billion KRW (12.1%)	3,114.0 billion KRW (6.2%)	50,702.9 billion KRW (100.0%)

Source: Annual power market operation results 2018 (KPX), reconstructed by the author

1) Other settlements: Settlement amount for RPS obligation fulfillment cost, trial operation generation settlement, constrained-off energy payment, difference settlement, emissions trading cost settlement, etc.

The settlement unit price by energy source (KRW/kWh) is calculated by dividing the total transaction amount by volume for a specific period ex post facto when the constrained-on and constrained-off generations are determined through real-time dispatch operation after operation scheduling. The settlement unit prices by energy source in 2018 are listed in Table 31. It can be seen that those for nuclear and bituminous coal powers are lower than the average unit price. Renewable energies are included, and the average settlement unit price is 98.6KRW/kWh. This value only includes the SMP settlement amount and does not include the transaction price for renewable energy certificate (hereafter REC).

Table 31. Settlement unit price by fuel source in 2018 (unit: KRW/kWh)

Classification	Nuclear	Bituminous	Anthracite	LNG	Oil	Pumped	Others	Total
2018	62.1	81.8	104.6	121	179.4	125.4	98.5	90.1

Source: Electric Power Statistics Information System (EPSIS), reconstructed by the author

To predict changes in the power market in 2031 compared to 2018, the scheduled energy payment determined as a result of simulation was used for the electricity settlement amount, and the additional settlement amount due to constrained-on and off energy payment was not considered. This is because if the criteria for securing operational reserves are maintained until 2031, it can be assumed that the constrained-on generation and constrained-off generation capacities related to them would not be much different from 2018. The settlement amounts that are expected to be most affected by the renewable energy expansion policy are the RPS obligation fulfillment cost and the emissions trading cost settlement amount. Therefore, the settlement amount factors considered herein to analyze the power purchase cost are the generation output, available capacity, RPS obligation fulfillment cost, and emissions trading cost. Simulations were performed by defining scenarios with these factors.

4.3.2 Forecasting SMP and electricity settlement amount

The SMP in 2031 was estimated to decrease by 13.7 KRW/kWh on average compared to 2018 (Table 32). Similarly, Song et al. (2018) also forecast that the SMP would decrease from 81.18 KRW/kWh in 2017 to 68.75 KRW/kWh in 2031. This is because with the expansion of renewable energy, the generation requirement of the conventional power generation sources decreases, and as a result, the marginal price setting generators are increasingly determined among those with a lower variable cost.

Table 32. Comparison of SMP estimates between 2018 and 2031

Month	1	2	3	4	5	6	7	8	9	10	11	12	Aver -age
2018	91.6	89.8	100.2	89.5	85.5	86.9	84.3	86.9	89.6	100.7	104.1	109.2	93.2
2031	78.9	79.9	86.3	72.7	72.7	73.2	74.5	71.6	79.5	80.3	91.2	93.5	79.5

When the electricity settlement amount calculated by reflecting the settlement adjustment coefficient using the SMP estimates for each period and the scheduled generation by fuel source was compared, it was found to decrease by approximately 1.65 trillion KRW from 43.46 trillion KRW in 2018 to 41.81 trillion KRW in 2031. Table 33 shows the forecast data for power purchase cost calculated based on the generation output by fuel source. It shows that LNG has the largest amount of decrease, and the settlement amount of renewable energy increases rapidly. However, as the amount of renewable generation output increases, the SMP, which is the standard market price for settlement, decreases, so the scheduled energy payment for the total generation amount may rather decrease slightly. Therefore, if the market structure in which the SMP that determines the power market price decreases continuously due to the expansion of renewable energy is maintained, the electricity settlement amount would decrease and this can cause an adverse effect on the profit structure of power generation companies. As the net load decreases due to expansion of renewable energy, and there may be many times where the conventional power sources are not included in the power generation plan, thus limiting opportunities to participate in the power market.

Table 33. Changes in electricity settlement amount by fuel source (unit: trillion KRW)

Classification	Nuclear	Coal	LNG	Oil	Pumped storage	Renewable	Total
2018	7.78	19.36	13.10	0.03	0.02	3.17	43.46
2031	7.19	17.35	7.30	-	0.28	9.69	41.81
Difference	-0.59	-2.01	-5.8	-0.03	0.26	6.52	-1.65

Moreover, as the generation scheduling is performed for net load instead of demand, the pattern of high SMP at peak demands is no longer valid. On the contrary, the SMP is low during the day when the solar power generation reaches the peak and it is high in late afternoon when such generation decreases sharply. Figure 32 shows the daily SMP patterns for 10 days from July 1 in 2018 and 2031. Due to the expansion of renewable energy, periodic pattern changes appear as the SMP follows the net load peak instead of the demand peak. This change of pattern necessitates the re-examination of the systems designed in relation to SMP reduction effect such as demand management and demand-responding resource market because the period that requires peak demand management may not be the peak SMP period in a day.

In terms of generation cost, the total power generation cost in 2018 was estimated as 25.89 trillion KRW, but decreased by 5.69 trillion KRW to 20.20 trillion KRW in 2031. The reason for this must be that due to the expansion of renewable energy, many situations will occur in which the net load can be satisfied with power generation sources having a low variable cost as the generations of the existing power generation sources decrease.

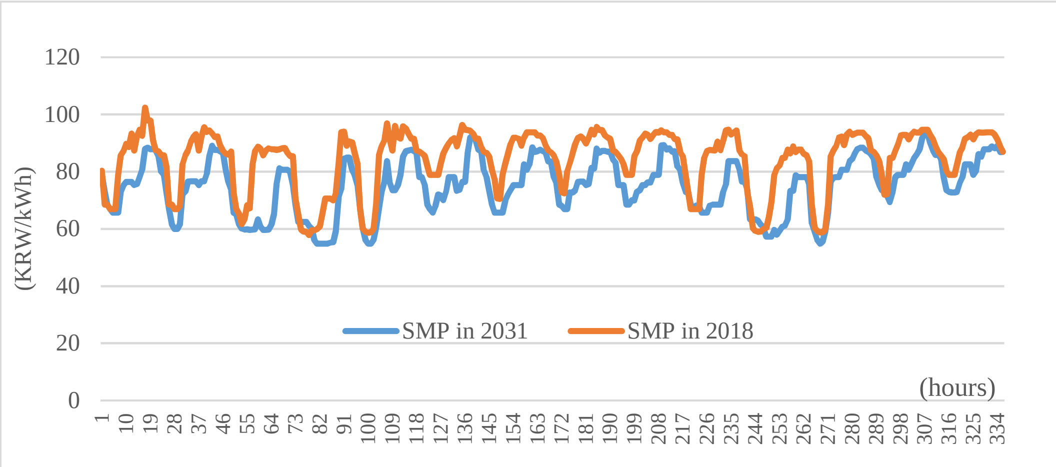


Figure 32. Comparison of SMP trend for 10 days from July 1 (240 hours in total)

4.3.3 Analysis of the impact of policies related to the expansion of renewable energy

The RPS system was introduced in Korea from 2012 and is now in operation. According to Article 18-11 of the Enforcement Decree of the Renewable Energy Act, the government shall endeavor to ensure that the supply obligor for RPS is able to conserve the appropriate level of additional costs incurred in fulfilling the supply obligation through the power market, and electricity sellers participating in the power market should be made an effort to recover the cost by reflecting it in the electricity bill. In this regard, as shown in Figure 33, the obligation fulfillment cost of power generation companies subject to RPS are compensated by vendors.

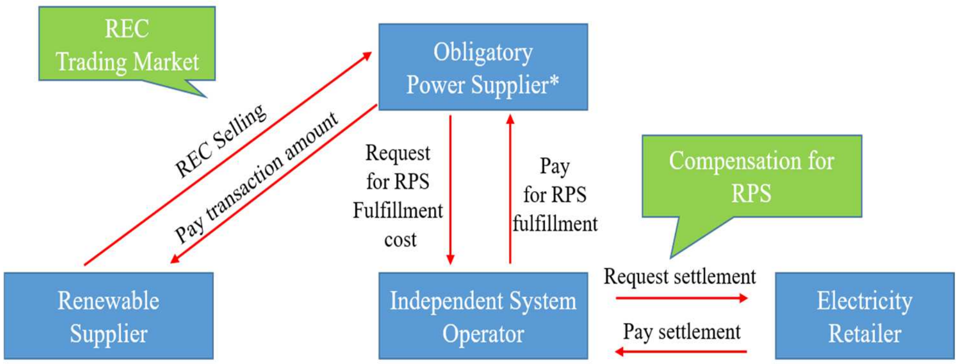


Figure 33. Compensation process for RPS obligation fulfillment cost

* Obligatory power suppliers: Power generation companies of 500 MW or large scale (22 companies in 2020)

Source: Enforcement Decree of the Renewable Energy Act (Article 18-11), reconstructed by the author

The REC is used as a means to assist the revenues of renewable energy business by giving a weight to businesses that require high facility investment cost. When the REC issuance amount is calculated, the renewable energy generation (MWh) is multiplied by the REC weight of the corresponding power generation source. When the weight is revised, the new weight is applied to new business operators who applied for REC facility checks after the notified revision date. For the existing business operators who have applied for facility checks and received the weight before the notified revision date, the weight effect continues for a certain period. The price of the issued REC must be considered separately for external purchase (spot market, self-contract), self-construction, and fixed price contract (self-contract, selection contract). As of 2018, the REC price for external purchase and self-construction is 87,833 KRW/REC. For fixed price contracts, the base price is the contract price minus the monthly average SMP for 20 years and 15 years as the contract term for solar power and ESS in general, and various prices are formed by facility and by month. In other words, to estimate the trend of REC settlement unit price, the base price and weight revisions for each contract method of the past need to be tracked. Moreover, since there is too much uncertainty in the REC unit price outlook for future aspects of supply and demand, this study simply used the REC settlement unit price (79,119 KRW/REC), which was determined by dividing the settlement amount of the RPS obligation fulfillment cost in 2019 by the obligatory supply amount[7] in the same year. This

[7] REC settlement unit price = 2.25 (trillion KRW)/28,438(GWh) = 79,119 KRW/REC. According to the Ministry of Trade, Industry, and Energy, the RPS obligatory supply in 2019 is 28,438 GWh. According to the

price can roughly reflect the price data of the RECs traded by the obligatory suppliers in 2019 and can be considered to include the price data of the contracts of the previous year.

The number of power plants with 500 MW or larger capacities, which are subject to the RPS system, is expected to increase from 95 (73.7 GW) in 2018 to 113 (88.4 GW) in 2031 based on the simulation input data. The total generation of power plants of 500 MW or larger capacities calculated through the price setting scheduling simulation is 351,229 GWh in 2018 and 441,141 GWh in 2031. The RPS obligation fulfillment ratio is fixed at 10% after 2023 (Table 17). Thus, as shown in Table 34, the settlement amount for the RPS obligation fulfillment cost in 2032 can increase by approximately 1.823 trillion KRW compared to the amount in 2019. Assuming that the obligation ratio in 2031 is 28% according to the 2017 National Five-Year Plan, the cost of fulfilling the RPS obligation will increase by 8.107 trillion KRW. However, the RPS settlement unit price applied in this study is based on historical data rather than prediction analysis, then there is uncertainty in the future depending on REC market environment.

In addition, since the settlement amounts for RPS obligation fulfillment cost in 2019 and 2032 were estimated, the conversion value was used for 2018 by applying the ratio of the market performance value of 0.91[8] to 2019. For 2031, the estimate for 2032 was applied as it is, considering that there is no difference in power plants subject to RPS and the power mix forecasts are similar between 2030 and 2031.

EPSIS, the result of RPS obligation fulfillment cost in 2019 is 2.25 trillion KRW.

[8] According to the EPIS (http://epsis.kpx.or.kr), the settlement result for RPS obligation fulfillment cost was 2.05 trillion KRW in 2018, and 2.25 trillion KRW in 2019. Thus, the conversion rate of 0.91 was applied.

Table 34. Results of calculation of obligatory supply and estimation of RPS fulfillment cost

Classification	Power generation (GWh)	Obligatory supply by obligatory ratio (GWh)			Settlement for obligation fulfillment cost (trillion KRW)		
		6 %	10 %	28 %	2019	2032	
2018	351,229	21,074	-	-	1.667	-	-
2031	441,141	-	44,114	123,519	-	3.490 (10%)	9.774 (28%)

Among the national GHG reduction goals in the conversion sector, the emissions goal for 2030 based on BAU has been set to 192.7 million tons, which was reduced from the emissions forecast of 333.2 million tons (Ministry of Environment, 2018). According to the third basic plan for emissions trading scheme published in 2019 by the government (Ministry of Economic and Finance & Ministry of Environment, 2019), the average paid allocation rate for the fourth planning period (2026–2030) is 15% and the emission credit price was assumed to be fixed at 27,000 KRW/ton (average for Jan–Aug 2019), which were used to calculate the emission trading amount of the future. Therefore, this study assumed the emissions target after reduction of the conversion sector in 2031 as 192.7 million tons CO_2e. For the paid allocation rate, two cases of 15% and 20% of the fourth planning period were assumed and compared because it corresponds to the fifth planning period, which has not been announced yet. The emission credit price forecasting for 2031 was performed in two ways. First, the case where the unit price of 27,000 KRW/ton of 2019 is maintained was analyzed. Second. 85,000 KRW/ton estimated by exponential smoothing method was applied using the closing price data of the Korean Allocation Unit (KAU) and the Korean Credit Unit (KCU) for 2015–2019 of the Korea Exchange.

For the available capacity settlement amount, the capacity settlement unit price per unit capacity was calculated using the result data of 6.15 trillion KRW (Table 30) for 121 GW of the generation facility capacity as of 2018. It was then multiplied by the generation facility capacity of 174 GW in 2031 to produce 8.84 trillion KRW and this was applied to every scenario. Table 35 shows the calculation results for the emissions trading cost settlement amount and available capacity settlement amount (capacity payment) according to the changes of the paid allocation rate and emission credit price.

Table 35. Calculation results for emissions trading cost and available capacity settlement amount

Classification	Credit price (KRW/ton)	Settlement amount according to paid allocation rate (trillion KRW)			Capacity payment (trillion KRW)
		3%	15%	20%	
2018	22,250	0.08	-	-	6.15
2031	27,000	-	0.78	1.04	8.84
	85,000	-	2.46	3.28	8.84

4.3.4 Empirical results and discussion

The analysis scenarios for power purchase cost in 2031 compared to 2018 are summarized in Table 36. As shown in this table, a total of eight scenarios were defined. First, Scenarios 1 and 2 were divided according to the RPS obligation fulfillment ratio. Each of these two scenarios was then subdivided into four sub-categories according to the assumptions for paid allocation rate of emissions credit and the emissions credit price.

Table 36. Forecast scenarios for power purchase cost in 2031

Classification	RPS obligation fulfillment ratio (%)	Paid allocation rate of emissions credit (%)	Emission credit price (KRW/ton)
Scenario 1-1	10%	15%	27,000
Scenario 1-2			85,000
Scenario 1-3		20%	27,000
Scenario 1-4			85,000
Scenario 2-1	28%	15%	27,000
Scenario 2-2			85,000
Scenario 2-3		20%	27,000
Scenario 2-4			85,000

The settlement forecast analysis results for each scenario are summarized in Figure 34. As shown in this figure, in Scenario 1-1, 1-3 the average electricity purchase price in 2031 is 91.42-91.85 KRW/kWh, which is lower than the average electricity purchase price of 93.87 KRW/kWh in 2018. The total settlement amount of the power market in 2031 increases in every scenario. However, in Scenario 1-1 where the increase of the total settlement amount is less than 10%, the average purchase price drops by 2.6% as the total power supply for one year increases by approximately 10% from 545,955 GWh in 2018 to 600,767 GWh in 2031 to satisfy the increased demand in 2031.

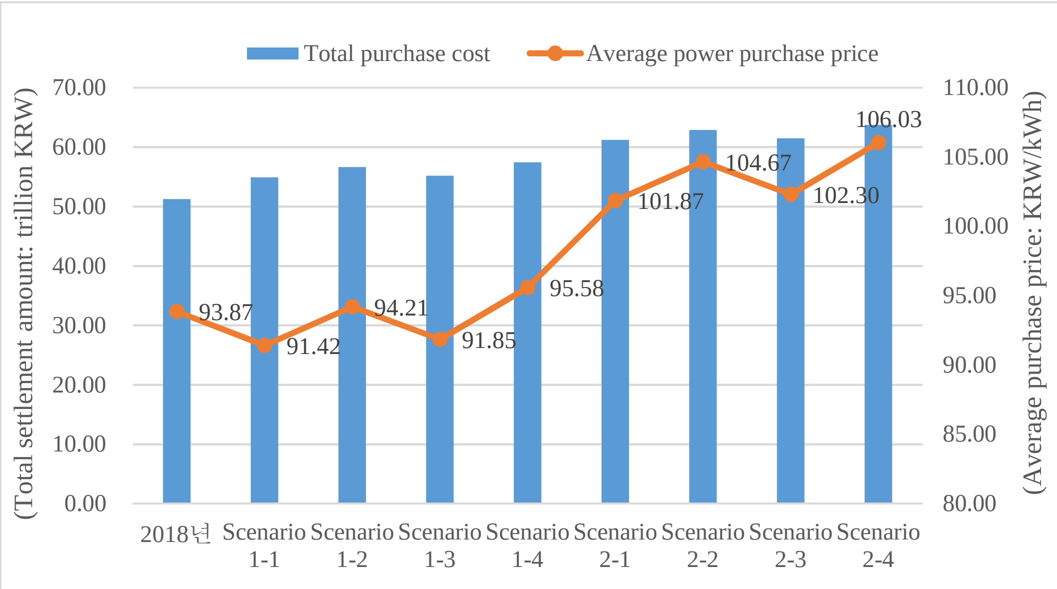


Figure 34. Electricity purchase cost analysis result by scenario in 2031

If the RPS obligation fulfillment ratio increases up to 28%, the average electricity purchase price can increase from 8.53% to 12.96%, and this causes a greater financial burden of vendors and act as a factor to induce an increase of the electricity retail rates.

According to the past performance trend of the power market operation (Appendix 2), the amount of electricity settled continues to increase as the amount of generation increases. In addition, looking at the power transaction unit price calculated including the RPS and

ETS costs (Figure 38), it can be seen that the recent increase in renewable energy generation has turned to an increasing trend since 2016. Moreover, to continuously increase the share of renewable energy to 30–35% until 2040, incentives must be given to participants in the renewable energy generation business, and renewable energy expansion policies will be continuously improved to maintain the incentive effect. Therefore, when renewable energy-related polices such as RPS and emissions trading scheme are improved or newly established, policy makers need to predict changes in the power purchase cost due to the new policy and analyze the pressure to raise the electricity rates in advance; the results of this study can be used for this purpose. Furthermore, since this study simulated the unit commitment and economic dispatch scheduling of 2031 based on the generation data of the power market in 2018, it has a limitation in not reflecting the reorganization of power plant fuel tax when calculating the variable costs of power plants. However, as shown in Table 27, it is believed that the differences in analysis results would not be large because the fluctuations of merit order due to generation fuel tax reorganization only appear in some sections. Moreover, large changes in the merit order may occur if we include the environmental improvement cost resulting from the introduction of environmental dispatch in the future. Even if the merit order is changed or the power market operation regulations are revised, the changes in the market environment can be easily reflected and analyzed by modifying the input data, constraint equations, or objective function of the power market simulation based on the day-ahead unit commitment and economic dispatch scheduling proposed herein.

Chapter 5. Summary and Conclusion

5.1 Concluding Remarks and Contribution

This study analyzed the changes of the domestic power market that may occur when the share of renewable energy generation is expanded to 20% by 2030 through the energy transition policy in terms of flexibility and economics. To this end, a day-ahead generation scheduling model for market price setting, unit commitment, and operation scheduling in the power market was implemented using the MILP. In addition, the flexibility level that can respond to the renewable energy volatility of the power market system in 2031 designed using the composition of power generation sources, demand, and renewable energy generation forecasted in the 8th ESDP was evaluated in comparison with the power market operation results in 2018. The flexibility evaluation results reveal that the spare power and quick-start generators including the operational reserves available for flexibility supply resources need to be expanded by approximately 3,349 MW from the currently secured amount. One important result here is that even if the current standard for operational reserves of 3.1 GW is maintained, it is possible to respond to approximately 94% of the renewable energy volatility of 8,760 h in total in 2031. In other words, even though the uncertainty level of coping only with the operational reserves is approximately 6%, the policy to continuously increase the secured amount of operational reserves to satisfy the forecasted level of renewable energy volatility can be inefficient in terms of cost. Therefore, the appropriate level for operational reserves needs to be maintained statically at all times to respond to contingencies in the traditional power system. As a response to renewable energy volatility, a method of flexibly operating the standard for secured quick-start generators to be constructed should be considered.

When using operational reserves as flexibility resources, the physical characteristics of the resources constituting the operational reserves such as ramp up-down rates must be considered to properly respond to volatility within one hour. However, if the spare power secured by the generation upper limit method is specified as operational reserves as it is now, the reserves are composed from the generators with a low variable cost among the generators determined to be committed excluding nuclear power plants. Therefore, to compose the resources for operational reserves with power generation sources that have the physical characteristics (e.g., start-up time, ramp up-down rates, and output holding time) that is needed to the power system to respond the flexibility, it is necessary to consider the separation of the energy market and the reserve service market. According to result in section 4.2, when the reserve service market promotes separation from the energy market, the size of auxiliary service market in 2031 was estimated to be approximately 162 billion KRW. This could be referred to as the minimum market size because offline operational reserves were not reflected in the market size estimation.

Despite the increase of demand in 2031, it was forecast that the SMP would decrease by approximately 13.7 KRW/kWh on average as the renewable energy generation increases and the net load supplied by the existing power generation resources decreases. More importantly, since the increasing renewable energy generation also increases the mismatches of demand and net load peaks, demand management policies should also consider this pattern change. Furthermore, the analysis results for power purchase cost show that while the SMP decline will reduce the electricity settlement amount, the impact of energy policies such as RPS and emissions trading scheme can increase the power purchase cost in 2031 by up to approximately 12.96%. Since this increase in the power purchase cost can act as a pressure to increase the electricity rates, this should not be overlooked when analyzing the effects of the renewable energy expansion policy on the power market.

5.2 Limitations and Future Studies

The power market simulation based on the generation scheduling model implemented herein only reflects the standard for operational reserves for day-ahead operation scheduling, and thus has the limitation that it can be different from the result of real-time dispatch operation that comprehensively considers heat, fuel, and transmission network constraints. Furthermore, the pattern and level of the flexibility requirement contain uncertainty because the power generation pattern in 2031 was assumed based on the hourly renewable energy volatility and solar and wind power generation data for 2016–2018.

In particular, from the perspective of wind power generation, if past output data are used, since large-scale offshore wind farms are not in operation yet, changes in the output of offshore wind farms have not been accurately reflected. According to the provisional plan for the 9th ESDP, offshore wind power is expected to exceed the capacity of onshore wind power from 2026 and expand to about 38%[9] of solar power generation by 2034.

Therefore, if the research on renewable energy volatility is conducted in district units nationwide in the future and detailed analysis results for volatility can be used, more realistic flexibility evaluation will be possible.

Regarding the acquisition of downward flexibility capacity in terms of the power system flexibility, the number of flexibility deficits in 2031 was estimated to be approximately 18. As a countermeasure to the lack of downward flexibility capacity, curtailment of renewable energy output, P2G or electricity storage devices was suggested, but the specific methods of using them or the economic feasibility were not analyzed. Therefore, it will be meaningful to study the method of managing downward flexibility through economic analysis of compensation due to curtailment and utilization of storage devices. In particular, since the expansion of the demand-responding resources market is being promoted by policy regarding their utilization as flexibility preparation resources, the opening of the flexibility DR market or deriving improvements of the economic DR market through comparison of the patterns of demand and net load peaks can be timely research topics.

Finally, if the auxiliary service market is separated from the energy market, the reserve market requires the composition of resources that have physical characteristics such as high

[9] In 2034, solar power plant forecast: about 45.5GW, offshore wind power plant forecast: about 17.5GW

ramp rates according to the forecasted volatility of renewable energy. Thus, a different regulation for securing method from the CBP, PBP market is required. One example that can be considered here is to announce capacities separately by category of physical characteristics and to operate the market through price bidding. Thus, studies to analyze the operation regulations for the separated auxiliary service market, the price setting method, and the method of securing capacity in terms of economics are also necessary.

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Appendix 1: The results of power generation scheduling of pumped-storage power plants

In this section, the operating patterns of pumped storage power plants in 2031 were analyzed. In Figure 35, it can be seen that it is operated in power generating mode at 2h-9h, and it is operated in pumping mode at 10h-16h, 20h-24h. However, compared with the net load pattern (Figure 36), it seems that the power generating mode operation is relatively needed at the time of the peak of net load, from 18h to 20h. This error is estimated to reflect the consideration of minimization of start-up cost as a result of analyzing the UC plan of the generators.

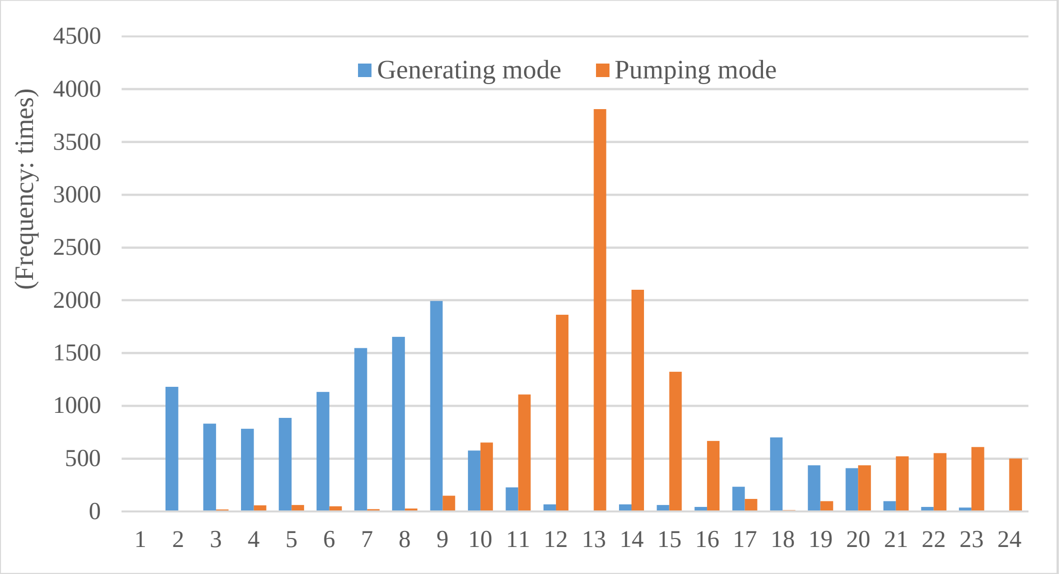

Figure 35. Annual number of operation by pumped-storage generators' operation mode in 2031

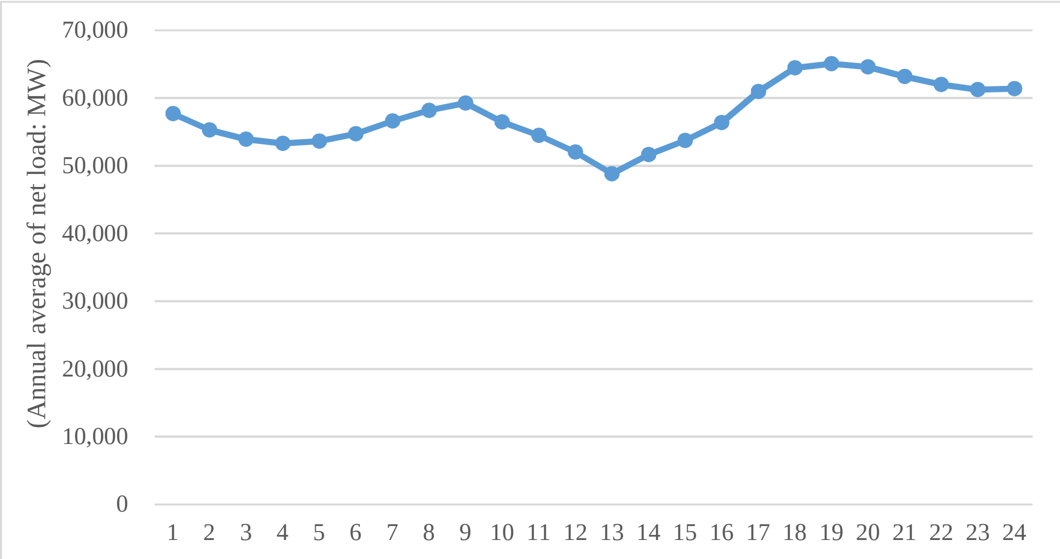

Figure 36. Annual average of net load by 24 hour in 2031

Appendix 2: Power market operation performance trend (2001-2019)

In this section, based on the performance of the power market operation in 2001-2019, the trends in power settlement amount, generation amount, and settlement unit price are presented.

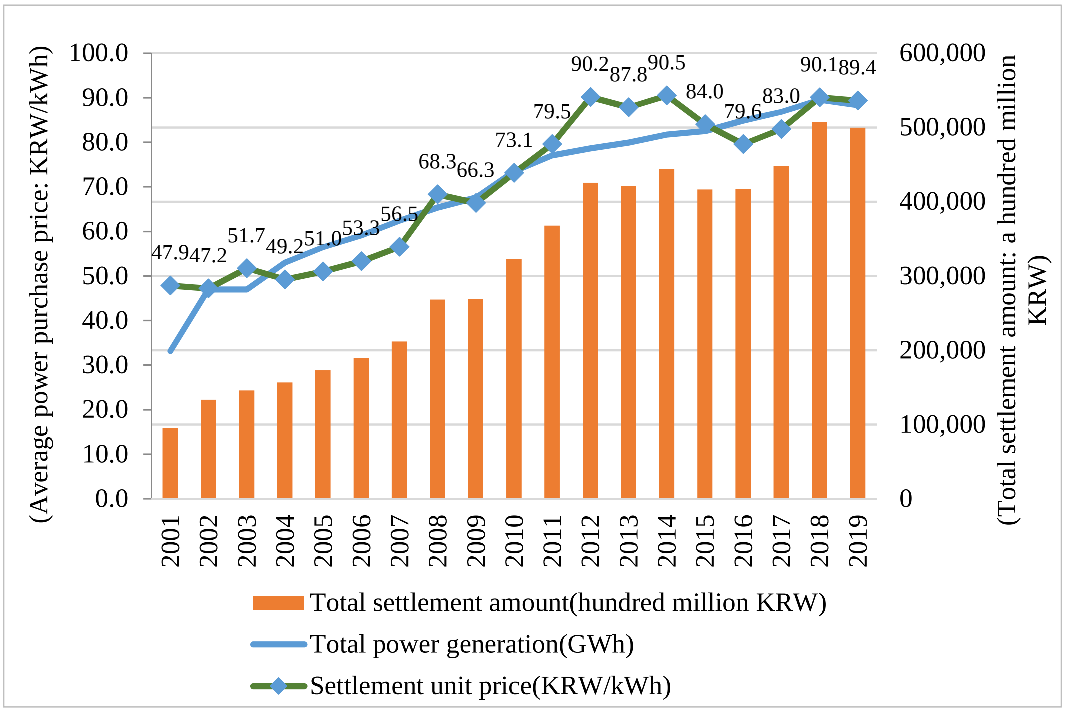

Figure 37. Power market operation performance trend (2001-2019)

Source: Electric Power Statistics Information System (EPSIS), reconstructed by the author

As the amount of power generation continues to increase, the amount of power settlement also increases. However, the average settlement unit price has turned to a decreasing trend since 2015 and has been again since 2017. In particular, in the case of including RPS cost from 2016 and ETS cost from 2017, the settlement unit price increased by about 4.3% from 90.5 KRW/kWh in 2014 to 94.4 KRW/kWh in 2018 (Figure 38).

Although there is uncertainty about the future, the difference in the power settlement unit price is getting deeper depending on whether RPS and ETS transaction costs are included, and it can be expected that environment costs such as RPS and ETS will have a significant impact on determining future power transaction prices.

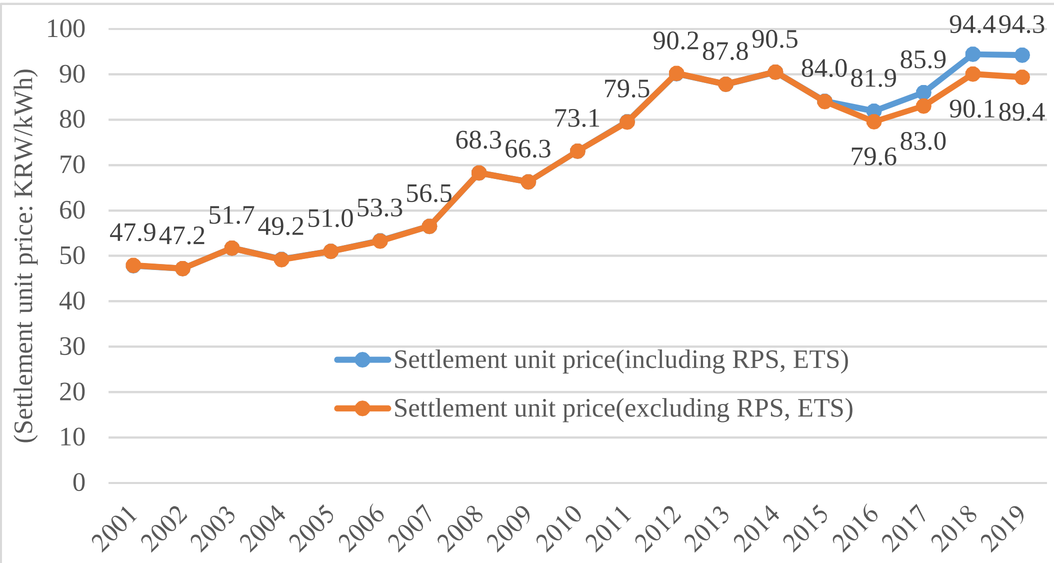

Figure 38. Comparison of settlement unit price trends depending on whether RPS and ETS costs are included (2001-2019)

Source: Electric Power Statistics Information System (EPSIS), reconstructed by the author

Abstract (Korean)

전력시장 시뮬레이션 기법을 활용한 재생에너지 확대가 전력시스템 유연성 및 경제성에 미치는 영향 분석

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전 세계적으로 온실가스 감축 목표를 달성하기 위해서 재생에너지 비중을 확대하는 에너지 전환 정책이 시행되고 있다. 하지만, 출력 변동성과 불확실성 특성을 가지고 있는 재생에너지 확대는 전력시스템의 유연성에 문제를 일으킬 수 있으며, 낮은 운영 비용과 국가 정책상의 목적 등에 의해 전력 시장에서 우선 구매되면서 전통 발전원의 급전 우선순위 결정에도 많은 영향을 주게 된다. 이와 같은 맥락에서, 본 연구는 한국의 재생에너지 확대 정책에 의해 재생에너지 발전 비중이 20%를 초과 하는 2031년을 대상으로 전력 시스템의 유연성 평가 및 재생에너지 확대가 전력 시장에 미치는 경제적 영향 분석을 목적으로 한다. 이를 위해서 우선, 혼합정수계획법을 활용하여 하루 전 발전계획 수립 모형을 구축하고, 재생에너지 발전 비중이 6.2%로 상대적으로 낮은 2018

년을 기준으로 2031년의 전력 시장 운영 실적과 비교하기 위해서, 구축한 발전계획 수립 모형을 기반으로 전력 시장 시뮬레이션을 수행하였다.

2031년 전력 시스템의 유연성 평가를 위해서 5가지 유연성 공급 용량 산정 시나리오를 설정하고 각 시나리오에 따른 유연성 공급량과 순수요 변동 폭인 유연성 요구량의 시간 단위 비교를 통해서 총 8,760시간에 대한 증·감발 유연성 부족 횟수를 산출하였다. 유연성 공급 자원으로 운영 예비력만을 고려할 경우, 증발 유연성 측면에서 재생에너지 변동성을 약 94%까지 대응할 수 있지만, 운영 예비력 확보량보다 큰 변동 폭인 약 6% 변동성에 대해서는 속응성 자원의 역할이 필요한 것으로 분석되었다. 반면에, 감발 유연성 측면의 유연성 부족 횟수는 약 18회 수준으로 매우 낮은 발생확률을 보였다.

재생에너지 변동성 분포에 대한 분석 결과를 보면, 고정적으로 운영하던 전통적인 운영 예비력 기준과 다르게 재생에너지 변동성 대응을 위한 유연성 자원은 확보 기준을 탄력적으로 운영할 필요가 있는 것으로 나타난다. 또한, 유연성 측면에서 효율적 대응을 위한 물리적 특성인 높은 증 · 감발률과 짧은 기동 준비시간을 보유한 발전원들이 운영 예비력에 포함되게 하려면 현행 발전 출력 상한제약 방법 개선 및 예비력 보조 서비스 시장의 분리 운영을 검토할 필요가 있겠다. 이때 고려할 수 있는 예비력 보조 서비스 시장 최소 규모는 약 1,620억 원으로 추정되었다.

재생에너지 확대로 인해 2031년의 계통한계가격이 평균적으로 13.7원/kWh 낮아질 것으로 분석되었으며, 더욱이 재생에너지 발전량 비중이 높아질수록 전통 발전원으로 충족시켜야 하는 순수요 크기가 감소하면서 계통한계가격 하

락은 더욱 심화할 수도 있다. 이와 같은 시장 가격 하락은 판매사업자의 전력 도매 요금의 동반 하락을 유도할 것처럼 보이지만, 기후변화 대응을 위한 RPS 제도와 배출권거래제를 고려한 전력 구입비 변화에 대한 분석 결과를 보면, 전력량 정산금을 제외한 용량 정산금, 배출권거래비용 및 RPS 의무이행 비용이 상승할 것으로 예측되었다. RPS 의무이행비율, 배출권 유상할당비율 및 배출권 가격 시나리오에 따른 전력 시장 시뮬레이션 결과에 의하면, 평균 전력 구매 단가는 2018년 93.87원/kWh에서 2031년 106.03원/kWh까지 최대 약 13% 상승할 수 있으며, 이는 향후 전력 소매 요금의 인상 압력 요인으로 작용할 수 있다.

본 연구 결과를 종합해보면 다음과 같은 정책적 함의를 끌어낼 수 있다. 첫째, 2031년 전력 시스템의 유연성을 적정 수준으로 확보하기 위해서는 운영 예비력 확보 방법을 발전출력 상한 제약 방식 대신 유연성 요구사항을 충족하는 자원들을 대상으로 한 경쟁 입찰을 통해 확보하는 방안 등 새로운 운영예비력 확보 대안이 고려되어야 한다. 또한, 재생에너지 변동성 대응 목적으로 운영 예비력과 별도로 운영하는 속응성 자원을 차질없이 계획대로 보급하고, 각 유연성 공급 자원별 변동성 대응 메커니즘을 고려하여 재생에너지 발전량 예측 시스템을 정교화하여 속응성 자원에 대한 탄력적인 유연성 공급량 확보 기준을 적용해 나가야 할 것이다. 둘째, 재생에너지 확대와 관련한 정책을 개정하거나 신설하고자 할 때는 직접적인 정책의 기대효과뿐만 아니라 판매사업자의 전력 구입비 증가로 인한 전기 요금 인상 압력과 같은 간접적인 파급효과까지 함께 고려해 주어야겠다. RPS 의무할당비율, 배출권거래제 유상할당비율, 배출

권 거래 비용 등의 변화로 최대 13%까지 전력 도매가격이 상승할 수 있기 때문이다. 셋째, 재생에너지 발전량과 시장 가격이 점점 상반된 패턴으로 변화할 것으로 예측되기 때문에, 변동비 반영 시장의 정산 규칙이나 시장 가격 산정 방법에 대한 개선 검토 시 이런 패턴 변화를 반드시 고려해야 한다. 또한, 유연성 공급에 참여한 발전사업자들의 보상이 적정한 수준으로 설정되어야 에너지 시장 대비 보조 서비스 시장 참여가 활성화 될 것이다. 마지막으로, 미래 전력 시장에서는 수요 피크와 시장 가격 피크의 불일치가 점점 증대될 수 있으므로, 수요 관리, 경제성 DR, 전기 요금 산정 등 수요 패턴을 고려하는 다양한 정책들이 향후에는 순수요 패턴도 함께 고려하는 방향으로 재검토되어야 할 것이다.

주요어 : 재생에너지 확대, 발전계획모형, 혼합정수계획법, 유연성 평가, 전력 시장 시뮬레이션, 경제적 영향분석
학 번 : 2017-36365