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RESEARCH ARTICLE

# Transmission Pricing Incorporating the Impact of System Fault and Renewable Energy Uncertainty on the Transmission Margin

**SAN KIM AND SUNG-KWAN JOO, (Member, IEEE)**

School of Electrical Engineering, Korea University, Seoul 136-701, South Korea

Corresponding author: Sung-Kwan Joo (skjoo@korea.ac.kr)

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**ABSTRACT** To ensure system reliability against unexpected and sudden disturbances, system operators must secure a portion of the transmission capacity of the power system as transmission reserve, which is not used under normal conditions. However, with the recent increase in renewable energy penetration, a transmission reliability margin has been employed under both conditions of system failures and normal operation conditions due to renewable energy uncertainty. Therefore, in the process of transmission pricing, the degree of use of the transmission facilities due to renewable energy uncertainty and system failures should be examined. This paper proposes transmission pricing using usage and reliability contribution factors, which are computed using the degree of use of the transmission lines over all periods. The probabilistic power flow is applied to consider changes in line flows through the forecasting error of renewable energy sources (RES). The proposed method is tested with an IEEE-5 bus system and an IEEE-24 bus system. The test results demonstrate the effectiveness of the proposed method in reasonably allocating transmission costs to network users, taking into account the reliability contribution due to system failures and renewable energy uncertainty.

**INDEX TERMS** Transmission pricing, transmission reserve, renewable energy uncertainty, reliability contribution, usage contribution.

## NOMENCLATURE

### ACRONYMS

| | |
|---|---|
| RES | Renewable energy source. |
| FOR | Forced outage rate. |
| GSF | Generation shift factor. |
| LODF | Line outage distribution factor. |
| PDF | Probabilistic density function. |
| TRI | Transmission reserve index. |
| RREF | Relative reliability evaluation factor. |

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### SET AND INDICES

| | |
|---|---|
| $N$ | Set of nodes, indexed by $i$. |
| $L$ | Set of lines, indexed by $l$. |
| $S$ | Set of scenarios. |
| $K$ | Set of line faults, indexed by $k$. |

### PARAMETERS

| | |
|---|---|
| $P_i^{forecast}$ | Forecasted output for the RES at node $i$. |
| $P_i^{actual}$ | Actual output for the RES at node $i$. |
| $a_{l,i}$ | The change in flow on line $l$ owing to a change in power injection at bus $i$. |
| $d_{l,k}$ | LODF of line $l$ by system fault on line $k$. |

| | |
|---|---|
| $pf_l^{'}$ | Criteria of use of transmission reserve. |
| $Ca_l$ | Capacity of line $l$. |
| $FOR_k$ | Forced outage rate of the line $k$. |
| $Pr_s$ | Probability of occurrence of state $s$. |
| $TC_l$ | Transmission cost on line $l$. |
| $TC_l^C$ | Transmission cost on line $l$ recovered from capacity-use. |
| $TC_l^R$ | Transmission cost on line $l$ recovered from reliability-benefit. |
| $a, b$ | Ratio of transmission cost recovered based on capacity-use and reliability-benefit. |

### VARIABLES

| | |
|---|---|
| $\varepsilon_i$ | Renewable energy forecast error at node $i$. |
| $\Delta P_i^{error}$ | Nodal injection variation at node $i$ due to output uncertainty. |
| $\Delta pf_l$ | Change in flow on line $l$. |
| $\Delta P_i$ | Change in output of RES $i$. |
| $pf_l^0$ | Power flow on line $l$ during a normal state. |
| $pf_l^1$ | Power flow changes on line $l$ owing to renewable energy uncertainty. |
| $pf_l^2$ | Contingency power flow on line $l$ owing to system fault. |
| $X_i, Y_i$ | Random variables of a single supply uncertainty at node $i$. |
| $f_X(x), f_Y(y)$ | Probability density functions of random variables $X$ and $Y$. |
| $f_{PF_l}\left(\Delta pf_l^0\right)$ | Power flow change PDF on line $l$. |
| $f_{PF_{l,i}}\left(\Delta pf_{l,i}^0\right)$ | Power flow change PDF on line $l$ induced by the renewable energy uncertainty at node $i$. |
| $f_{PF_l}\left(pf_l^1\right)$ | The probabilistic power flow PDF on line $l$. |
| $TRI_{l,k}$ | TRI of line $l$ under the outage of line $k$. |
| $TRI_{l,s}$ | TRI of line $l$ under uncertainty state $s$. |
| $W_{l,k}$ | RREF of line $l$ under the outage of line $k$. |
| $W_{l,s}$ | RREF of line $l$ in the state $s$. |
| $UC_{i,l}^1$ | Contribution to the impact on the change in flow on line $l$ owing to the uncertainty of generator $i$. |
| $RC_{l,i}$ | Reliability contribution of generator $i$ to line $l$. |
| $UC_{k,i}^0$ | Usage contribution of generator $i$ to the flow on line $k$ during a normal condition. |
| $NRC_{l,i}$ | Reliability contribution of generator $i$ to line $l$. |
| $C_i^C$ | Transmission cost based on capacity-use to generator $i$. |
| $C_i^R$ | Transmission cost based on reliability-benefit to generator $i$. |

## I. INTRODUCTION

In recent years, electric power utilities have experienced dramatic restructuring owing to the ongoing clean energy transition in the power industry [1]. There is a gradual shift in power systems from vertically integrated structures towards competitive, deregulated, and decentralized models. In the deregulated power industry, the allocation of transmission costs in the electricity market requires fairness and rationality. Transmission tariffs have been used as a means to recover costs incurred in the network business, and are mainly based on the basic principles governing tariff structure. The core principles of tariff design typically include the following criteria: cost-causality, efficiency, transparency, fairness, simplicity, and stability [2]. Another purpose of the transmission tariff is to send right price signals to network users. A well-designed price signal should not only promote cost-efficient use of power systems in the short term but also lead to optimal investment in the long term [3]. The price signals are normally determined by considering the tariff basis and targeted user groups.

The embedded cost allocation approaches are classified as four types: i) postage stamp method, ii) contract path method, iii) MW-Mile method, and iv) power tracing method [4], [5], [6]. In a contract path method, the buyer and seller are assumed to exchange the power between the two points via a specific path agreed upon in advance. However, this method does not reflect the branch flow caused by network users [7], and the route is selected only through negotiations between users. Consequently, the network cost allocation in this approach is calculated as a proportion of transacted power and all the transacted power of network users that are involved in transmission lines. Therefore, this approach may lead to unnecessary network reinforcement and expansion owing to branch flow outside the contract path, and issues such as system operation and congestion problems are neglected [8]. In contrast, the power tracing technique is topological in nature and deals with problems of the distribution of line flows in a meshed network [9]. It functions based on a proportional sharing principle for power between lines at nodes and establishes physical paths linking the generators and loads. This method was introduced by Bialek and is implemented in two forms: upstream and downstream looking algorithms. The upstream looking algorithm is used to determine the distribution of power from the generators to loads, whereas the downstream looking algorithm is applied to describe the manner in which the demand is supplied by generators [10]. The graph theory was first introduced in [11], wherein the concept of link, common, and domain was proposed. It was further simplified to facilitate the tracing process in the power system. Finally, the sophisticated power tracing method was developed in [12] and traces complex power flow without requiring assumptions and modifications of the previous power tracing approaches.

The primary function of transmission lines is to deliver electric power from generators to demands. However, the maximum transmission utilization is limited from the transmission reserve or transmission spare capacity required to ensure the reliability of the overall power system [13]. These reserves of a transmission line should be secured to keep the system reliability in case of power system failures. Thus, network users receive reliability benefits obtained from the transmission spare capacity in the process of power transmission.

The allocation of transmission costs is implemented in two aspects: using capacity-use and individual transaction reliability [14], [15]. The reliability benefit of transmission lines used for transactions is computed as the increase in the probability of transaction failure resulting from the line outage. The explicit expression of reliability aspects in transmission cost allocation was introduced in [16]. The reliability value of transmission lines is expressed in terms of the impact of individual transactions on the transmission reliability of both native consumers and wheelers. Consequently, transmission costs are allocated by the system usage during normal and contingency conditions. The transmission pricing scheme taking into account maximum line loading for N-1 security is introduced in [17]. The network usage is proposed using the degree of use of network lines during a contingency condition. The transmission usage charge which can reflect both operating and owning costs and unreliability costs is presented in [18], where Expansion Fund was proposed to offer economic incentives for the transmission system expansion to increase system reliability. Reliability indices such as loss of load expectation and expected unserved energy are used to compute the transmission reliability charge. The probabilistic network pricing considering uncertainty on the demand side is described in [19]. The long-run incremental cost (LRIC) algorithm in the distribution network is used to compute the network charge, taking into account the reliability-benefit under system failures. The ratio of the capacity-use and reliability-benefit is calculated using the reliability index [20]. However, it is not determined based on individual opinions but by the probability of system failure. The max flow algorithm is employed to determine the success or failure of individual transactions. The calculation procedure of the reliability contribution by network users was proposed in [21]. These indices were computed considering the usage of the transmission reserve incurred by individual resources and the forced outage rate (FOR) of each line under a single line outage. Further, the reliability cost of each line was allocated using the reliability contribution of individual generators [22], [23]. The reliability contribution is computed depending on the usage of transmission reserves in transmission facilities.

In existing studies, transmission reliability costs are only distributed based on reliability benefits during contingency conditions. However, this approach primarily applies to power grids where conventional generators are the primary power source, and it cannot effectively capture the impact of renewable energy uncertainties on the transmission reserves. With the increasing penetration of variable energy sources in recent years, transmission reserves have been used not only for contingency conditions but also in the normal state to handle the uncertainties of RES output. Also, the variability of RESs can lead to additional network investments and reinforcements in the power system. Hence, the distribution of transmission reliability costs needs to take into account the uncertainty of renewable energy for reasonable transmission reliability pricing.

This paper presents a transmission cost allocation method incorporating the uncertainties of renewable energy. Transmission costs are distributed to network users using the capacity-use and reliability-benefit. The reliability contribution by network users consists of two types of reliability benefits. The first is the usage of transmission margin during contingency conditions, and the second is the usage of transmission margin due to the renewable energy uncertainty in a normal state. The reliability contribution factors by network users are computed using the probabilistic approach, and the probabilistic power flow is applied to incorporate the impact of renewable energy uncertainty on a transmission line. The proposed method is tested with an IEEE-5 bus system and an IEEE-24 bus system to show its effectiveness. The main contributions of this paper can be summarized as follows:

1) The probabilistic power flow is computed using the convolution method to consider variations in line flow resulting from RES uncertainty. The probability distribution of power flows is obtained based on the probability distribution of nodal inputs using the convolution technique.
2) The reliability contribution factors are applied to incorporate the impact of system faults and uncertainties in renewable energy on transmission reserves. These factors can take into account not only the network usage but also the probabilities in each scenario.
3) The proposed transmission pricing is designed to reasonably distribute transmission costs to network users considering both the network usage and the reliability benefit of each resource obtained from transmission reserve over all periods.

The remainder of this paper is organized as follows. Section I introduces the concept of transmission reliability benefits under unexpected and sudden disturbances, and a probabilistic power flow analysis is performed to consider renewable energy uncertainty. Section II describes the transmission reliability cost allocation using the reliability contribution factor, which represents the transmission reserve usage by network users owing to system failure and uncertain conditions. Subsequently, numerical results are demonstrated in Section III. Finally, Section IV presents the conclusion of this study.

## II. RELIABILITY BENEFIT CONSIDERING RENEWABLE ENERGY UNCERTAINTY

To set reasonable transmission charges, considering the transmission reliability benefits derived from transmission reserves or transmission margins in the process of

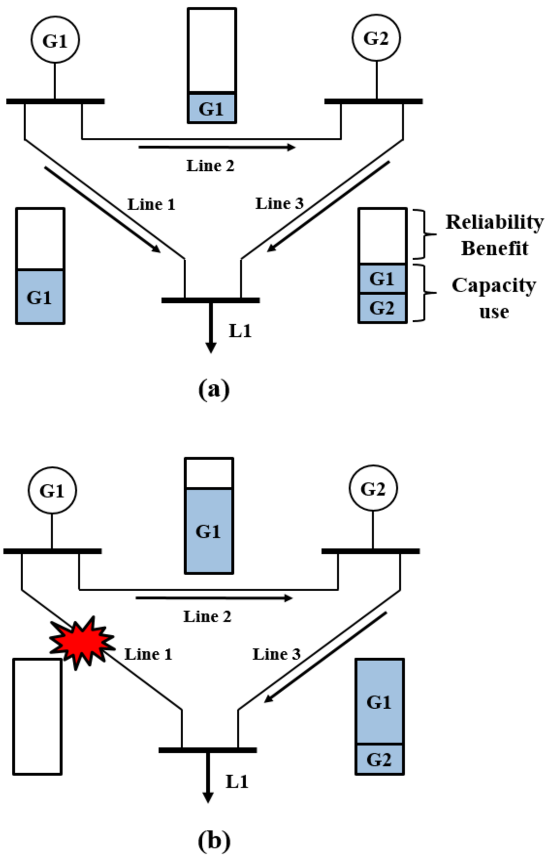


**FIGURE 1.** Reliability benefits of transmission margin under (a) normal state (b) contingency state.

transmission cost distribution is desirable [24]. The transmission reserve should be secured to maintain the system reliability even in the event of sudden disturbances such as line outage, generation loss, and demand variation. Fig.1 shows the reliability benefits of transmission margin during normal and contingency conditions. Under a normal state, the spare capacities were not used to transfer power as shown in Fig.1 (a). However, it does not mean that the spare capacity of lines is unnecessary. The spare capacity of lines 2 and 3 was used to accommodate the power flow of line 1 when line 1 was faulted as shown in Fig.1 (b). Thus, the transmission capacity used on each line received reliability benefits from the spare capacity of the other lines. Therefore, network costs should be allocated using the capacity-use in a normal state as well as reliability-benefit from contingency analysis.

The contingency analysis to evaluate reliability benefits is commonly classified under generation loss and line outage [25]. It facilitates the identification of the post-contingency power flows in the transmission lines because of sudden disturbances and the evaluation of reliability benefits obtained from the transmission reserve. However, in recent years, the penetration of RESs has led to system reliability problems owing to the uncertain characteristics of renewable energy [26], [27], [28], as shown in Fig. 2. The uncertainty of power output can be represented as the

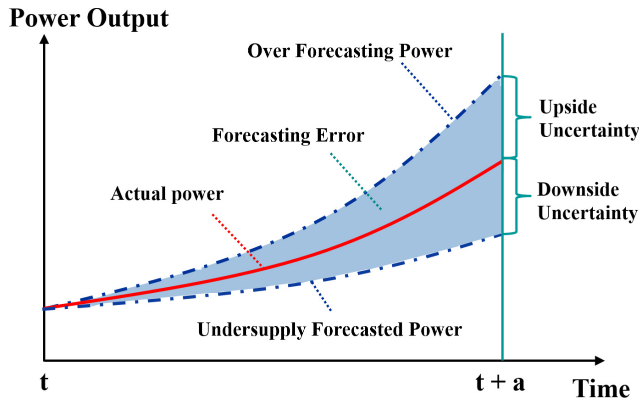


**FIGURE 2.** Output uncertainty of a wind farm with 10-min increments.

difference between the forecast value and actual power output. These output uncertainties can yield a result different from the expected output dispatch and thus cause the line flow to exceed a limited range [29]. The transmission reserve can be used more frequently to respond to erroneous power dispatch owing to renewable energy uncertainty. This means that RES obtains reliability benefits from transmission spare capacity not only under a contingency state but also under a normal state with forecasting error. Therefore, transmission reliability costs should be allocated considering both line outages and the renewable energy uncertainty in the power system with high penetration of variable renewable energies. The proposed method in this paper reasonably allocates transmission reliability costs to network users considering the reliability benefits of network users obtained from the transmission reserve over all periods. This is carried out by procedures such as probabilistic power flow considering uncertainty, reliability contribution calculation, and network cost allocation. etc.

### *A. POWER FLOW CHANGE DUE TO UNCERTAINTY*

The power flow change by output uncertainty can be computed using the renewable energy forecasting error and generation shift factor (GSF). The uncertainty due to forecast exhibits the same form as the expected nodal injection variations because of output uncertainty [28], [30]. Thus, the error is equal to the forecast value minus the actual value. This uncertainty due to forecast error can be represented as follows:

$$\varepsilon_i = \Delta P_i^{error} = P_i^{forecast} - P_i^{actual} \tag{1}$$

The GSF is a linear estimate of the ratio: change in power line flow to change in power injection at a specific location. It can be calculated from the DC line flow which is a linear model. The sensitivity factor for a branch connecting buses $n$ and $m$ with respect to the injection at node $i$ is computed as follows [25]:

$$a_{l,i} = \frac{\Delta pf_l}{\Delta P_i} \tag{2}$$

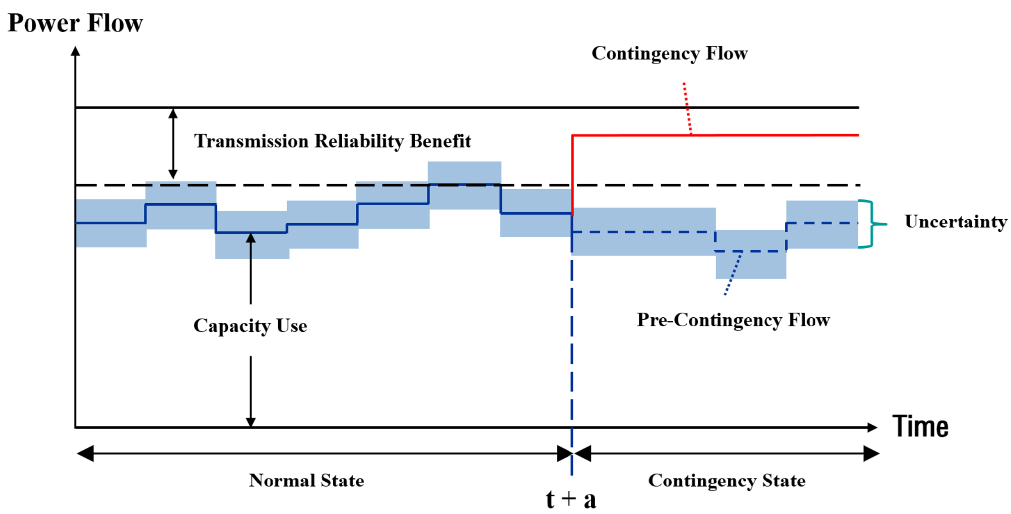


**FIGURE 3.** Ranges of normal and contingency power flow due to uncertainty.

Equation (2) represents the change in flow on line $l$ by the change in power injection at bus $i$, $i$ and $j$ are the bus numbers connected to line $l$, $m$ and $n$ are bus numbers connected to line $k$, and $X_{ni}$ and $X_{mi}$ are the elements of matrix $X$ at position $(n, i)$, $(m, i)$.

Combining the GSF and renewable energy forecast error on each node, the power flow changes due to renewable energy uncertainty can be computed as below [29]:

$$pf_l^1 = pf_l^0 + a_{l,i} \times \Delta P_i^{error} \tag{3}$$

Similarly, the contingency power flow due to the line outage can also be expressed as follows:

$$pf_l^2 = pf_l^0 + d_{l,k} \times pf_k^0 \tag{4}$$

Fig. 3 shows the ranges of power flow because of renewable energy uncertainty. These output uncertainties can cause incorrect power dispatch and thus cause the power flow to deviate from the reference operating point [31]. Thus, RES should be allocated additional transmission reliability costs because they derive greater benefit from the transmission reserve than conventional generators.

### B. PROBABILISTIC POWER FLOW

This paper uses an analytical method to compute probabilistic power flow considering renewable energy uncertainty. Based on the probability distribution of nodal inputs, the convolution method is applied to derive the probability distribution of power flows. This can describe the power flow changes owing to the impact of dispatch errors from renewable energy forecasting errors. Thus, renewable energy uncertainties can be reflected in the power flows.

The sum of probabilistic density functions (PDFs) is calculated as the convolutions of individual PDFs. $X_i$ and $Y_i$ are defined as the random variables of a single supply uncertainty [32], [33], [34]. Here, $X$ and $Y$ are the random variables for the total system. Consequently, $Z = X + Y$ denotes the system uncertainty, and the probability density function $f_Z(z)$ is expressed as follows:

$$\begin{aligned} f_Z(z) &= f_X(x) \oplus f_Y(y) \\ &= \int_{-\infty}^{\infty} f_Y(z-x) f_X(x)\, dx \end{aligned} \tag{5}$$

Using the convolution technique, the probabilistic power flow change on the network can be expressed as follows:

$$f_{PF_l}\left(\Delta pf_l^0\right) = f_{PF_{l,1}}\left(\Delta pf_{l,1}^0\right) \oplus \ldots \oplus f_{PF_{l,i}}\left(\Delta pf_{l,i}^0\right) \tag{6}$$

Subsequently, the probabilistic power flow PDF induced by the renewable energy uncertainty can be formulated as follows:

$$f_{PF_l}\left(pf_l^1\right) = f_{PF_l}\left(\Delta pf_l^0 - pf_l^0\right) \tag{7}$$

## III. TRANSMISSION RELIABILITY COST ALLOCATION METHOD

This section introduces the transmission cost allocation method using reliability benefits. This focuses on transmission reserve usage in contingency and normal states. Contingency analysis and probabilistic power flow analysis are performed to compute the usage of transmission reserve over all periods. The reliability contribution by network users is computed using the relative reliability evaluation factor (RREF) and contribution by network users. Then, normalized reliability contribution is computed to distribute transmission reliability costs to network users.

### A. TRANSMISSION RESERVE INDEX

The transmission reserve index (TRI) is introduced to represent the degree of reliability reserve use for a particular line owing to system accidents and renewable energy uncertainties. This is expressed as a value in the range of 0 to 1, which can provide an intuitive understanding of the utilization of the reliability margin. The use of transmission reserve is only considered if the line flow increases by 5% or more over the power flow under normal conditions. The contingency states only consider system faults owing to line outages. The TRI can be classified into indices for contingency and uncertainty states, and is expressed as follows:

$$TRI_{l,k} = \begin{cases} \dfrac{pf_l^k - pf'_l}{Ca_l - pf'_l} & \left|pf_l^k\right| > \left|pf'_l\right| \\ 0 & else \end{cases} \tag{8}$$

$$TRI_{l,s} = \begin{cases} \dfrac{pf_{l,s} - pf'_l}{Ca_l - pf'_l} & \left|pf_{l,s}\right| > \left|pf'_l\right| \\ 0 & else \end{cases} \tag{9}$$

$$pf'_l = 1.05 \times pf_l^0 \tag{10}$$

Equations (8) and (9) represent the TRI of line $l$ due to the system fault and output uncertainty, respectively. Equation (10) is the criteria for the use of transmission reserve.

### B. RELATIVE RELIABILITY EVALUATION FACTOR

RREF is computed using the TRI, FOR, and uncertainty probability. This can take into account the degree of use of transmission reserve as well as the likelihood of that scenario. The RREF can be expressed as follows [22]:

$$W_{l,k} = TRI_{l,k} \times FOR_k \tag{11}$$

$$W_{l,s} = TRI_{l,s} \times Pr_s \tag{12}$$

Equations (11) and (12) are the RREF of line $l$ due to system fault and output uncertainty, respectively.

### C. RELIABILITY CONTRIBUTION

The reliability contribution by network users is defined as the usage of transmission reliability margin during the contingency and uncertainty conditions. In the contingency state, reliability contribution by network users can be computed using the RREFs and usage contribution of the resource to the line flow during a normal state. In contrast, the reliability contribution of the RES in an uncertainty state can be computed considering the contribution to the impact on the change in flow on a specific line owing to the uncertainty and reliability evaluation factors. Then, the reliability contribution of each generator to a specific line is described as follows:

$$RC_{l,i} = \sum_{k=1,k\neq l} W_{l,k} \cdot UC_{i,k}^0 + \sum_{s=1} W_{l,s} \cdot UC_{i,l}^1, \quad \forall k \in K, s \in \tag{13}$$

$$UC_{i,l}^1 = \begin{cases} \dfrac{a_{l,i} \cdot \Delta P_{i,s}}{\sum_{i=1} a_{l,i} \cdot \Delta P_{i,s}}, & pf_{l,s} \cdot a_{l,i} \cdot \Delta P_{i,s} > 0 \\ 0, & else \end{cases} \quad \forall i \in I \tag{14}$$

Equation (13) is the reliability contribution of each generator to a specific line. Equation (14) is the contribution to the impact on the change in flow on line $l$ owing to the uncertainty of the RES. Then, the normalized reliability contribution for each network user is represented as below:

$$NRC_{l,i} = \frac{RC_{l,i}}{\sum_{i=1} RC_{l,i}}, \quad \forall i \in I \tag{15}$$

### D. TRANSMISSION COST ALLOCATION

Transmission costs can be divided into two parts: capacity-use and reliability-benefit. The transmission cost based on the capacity-use includes costs allocated from the benefits of actual network use. This is an element in traditional transmission pricing. In contrast, the transmission cost based on reliability-benefit implies costs allocated by the reliability contribution in the contingency and uncertainty states. The transmission costs of line $l$ can be expressed as follows:

$$\begin{aligned} TC_l &= TC_l^C + TC_l^R \\ &= a \times TC_l + b \times TC_l \end{aligned} \tag{16}$$

Equation (16) represents the ratio of transmission cost between capacity-use and reliability-benefit. $a + b = 1$ with values of $a$ and $b$ being exogenously specified [15], [35]. Here, $a = 0.8$ and $b = 0.2$ are taken for the analysis. Using capacity-use and reliability-benefit, transmission costs are distributed to customers as follows:

$$C_i^C = \sum_l UC_{i,l}^0 \times TC_l^C, \quad \forall l \in L \tag{17}$$

$$C_i^R = \sum_l NRC_{l,i} \times TC_l^R, \quad \forall l \in L \tag{18}$$

Equations (17) and (18) are the transmission costs based on capacity-use and reliability-benefit to generator $i$, respectively.

### E. FLOWCHART

The flowchart of the proposed transmission pricing is shown in Fig. 4. The flowchart of the proposed approach consists of two stages. First, transmission usage pricing in stage 1 is performed using the usage contribution of each resource to lines during normal conditions. The usage contribution, which considers the use of transmission lines, is computed using a power flow tracing technique. In stage 2, variations in line flow resulting from RES uncertainty or line outage are computed to evaluate the reliability-benefit derived from transmission reserve. The transmission reliability contribution is computed using the RREF and contribution by network users. This can consider not only the usage of transmission reliability benefits but also the probabilities in each scenario. Then, transmission reliability pricing is performed using the normalized reliability contribution of each generator to lines during contingency and uncertainty states. The proposed transmission pricing method can be easily applied to calculate transmission charges for generators in the power system.

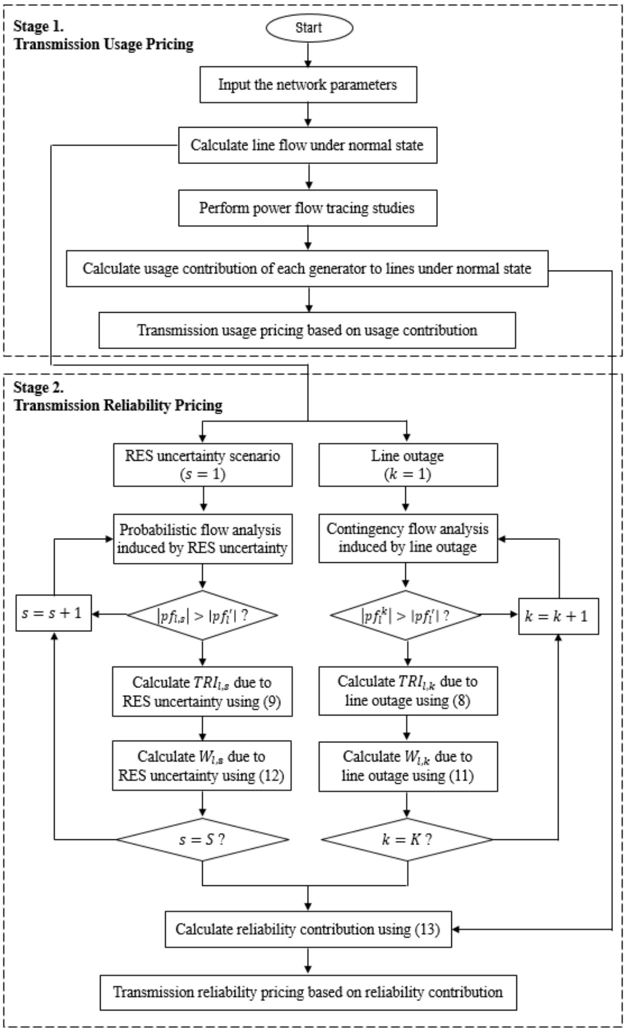


**FIGURE 4.** Flowchart for the proposed transmission pricing method.

## IV. NUMERICAL RESULTS

To show the effectiveness of the proposed transmission pricing method incorporating the impact of system uncertainty on the transmission margin, three methods are tested and compared using both an IEEE-5 bus test system and an IEEE-24 bus test system as follows:

- Method 1: Transmission pricing based on reliability-benefit during system fault without FOR [21].
- Method 2: Transmission pricing based on reliability-benefit during system fault with FOR [22].
- Method 3: Transmission pricing based on reliability-benefit obtained from transmission reserve over all periods.

The proposed method, which is method 3, is a transmission pricing that considers the degree of use of transmission lines under normal state and contingency state. This can allocate transmission reliability costs to network users based on reliability -benefit that incorporate the impact of RES uncertainty. Simulations are carried out using MATLAB 2020b, on a computer with an Intel(R) Core(TM) I7-970 CPU with 8 GB memory.

### A. IEEE 5 BUS TEST SYSTEM

An IEEE five-bus test system is used to demonstrate the effectiveness of the proposed transmission pricing method. Fig. 5 shows the topology of the test system, which is comprised of five buses, seven branches, three loads, and four generation units. The system peak load is 165 MW. The total output of wind farms is 70 MW, comprising 35 MW each at buses 2 and 5, respectively. Table 1 lists the transmission line parameters and branch thermal limits. Table 2 presents the failure rate and cost data of transmission lines. The detailed parameters of units, buses, and branches are obtained from Reference [16].

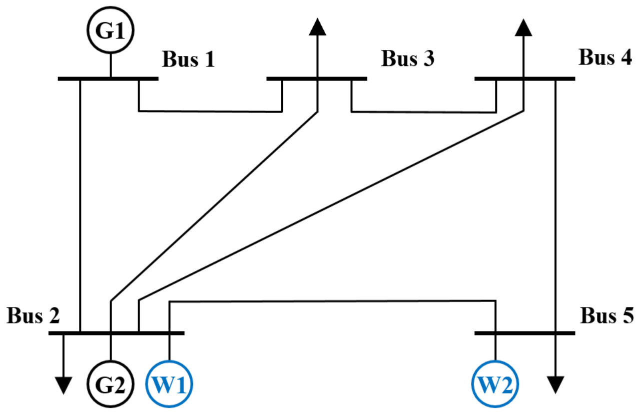


**FIGURE 5.** IEEE 5-bus test system.

**TABLE 1.** Transmission line data.

| Line | From | To | Reactance (p.u) | Capacity (MW) |
|---|---|---|---|---|
| 1 | 1 | 2 | 0.60 | 60 |
| 2 | 1 | 4 | 0.24 | 50 |
| 3 | 2 | 4 | 0.18 | 50 |
| 4 | 5 | 6 | 0.18 | 50 |
| 5 | 3 | 6 | 0.12 | 70 |
| 6 | 2 | 3 | 0.03 | 60 |
| 7 | 4 | 5 | 0.12 | 60 |

Table 3 presents the usage contribution results under the normal state computed using the Bialek power tracing method. It can be seen that generators at bus 1 use all lines from lines 1 to 7, those at bus 2 use lines from 3 to 7, and those at bus 5 only use line 7. This indicates the usage of transmission lines during normal conditions, and transmission costs based on capacity-use are allocated considering the network usage contribution.

Based on the usage and reliability contributions, the transmission usage and transmission reliability charges are distributed to network users. This study assumes that 90% of the transmission cost for each line is recovered via usage charges, and the remaining 10% is recovered via reliability

**TABLE 2. Failure rate, repair time, and cost of transmission line.**

| Line | Failure rate (f/year) | Repair time (hours) | Cost ($) |
|---|---|---|---|
| 1 | 0.5 | 12 | 300 |
| 2 | 0.2 | 24 | 100 |
| 3 | 0.8 | 15 | 100 |
| 4 | 0.4 | 48 | 100 |
| 5 | 0.6 | 20 | 300 |
| 6 | 0.3 | 25 | 150 |
| 7 | 0.7 | 20 | 150 |

**TABLE 3. Usage contributions of each generator to the transmission lines under normal state.**

| Line | G1 | G2 | W1 | W2 | Total |
|---|---|---|---|---|---|
| 1 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 |
| 2 | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 |
| 3 | 0.28 | 0.39 | 0.34 | 0.00 | 1.00 |
| 4 | 0.28 | 0.39 | 0.34 | 0.00 | 1.00 |
| 5 | 0.28 | 0.39 | 0.34 | 0.00 | 1.00 |
| 6 | 0.65 | 0.19 | 0.17 | 0.00 | 1.00 |
| 7 | 0.13 | 0.18 | 0.16 | 0.52 | 1.00 |

**TABLE 4. Transmission usage charge to the generators.**

| Line | G1 | G2 | W1 | W3 |
|---|---|---|---|---|
| 1 | 270.00 | 0.00 | 0.00 | 0.00 |
| 2 | 90.00 | 0.00 | 0.00 | 0.00 |
| 3 | 25.00 | 34.67 | 30.33 | 0.00 |
| 4 | 25.00 | 34.67 | 30.33 | 0.00 |
| 5 | 74.99 | 104.00 | 91.00 | 0.00 |
| 6 | 87.10 | 25.55 | 22.35 | 0.00 |
| 7 | 17.98 | 24.94 | 21.82 | 70.26 |
| Total ($) | 590.07 | 223.82 | 195.85 | 70.26 |
| Total ($/MWh) | 10.73 | 5.60 | 5.60 | 2.01 |

charges. Table 4 presents the transmission usage charge under the normal state. This is distributed according to the actual usage of transmission lines that generators use to deliver power to the loads. This means that generators farther away from the load will bear the transmission costs as they use more lines than generators located near the demand. As evident from Table 4, G1 located at bus 1 is charged the highest transmission rate at 10.73 [$/MWh], which is charged 8.72 [$/MWh] higher than that for W2 located at bus 5, which is high-load area. The transmission usage charge provides locational price signals, and generators in the same location are charged the same rates. Table 5 presents the results of normalized reliability contributions of the generators to the lines during a contingency condition. This indicates the degree of use of transmission reserves owing to line outages.

The results of normalized reliability contributions of the generators to the lines due to renewable energy uncertainty are presented in Table 6. This indicates the degree of use of the transmission reserve due to the renewable energy uncertainty under a normal state. In contrast to traditional generators, the output of RES is uncertain, which can cause dispatch errors. Therefore, in a system with a high renewable energy penetration, transmission reserves can be used even under a normal state. The transmission reliability contribution should be computed considering the degree of use of the transmission reserve under uncertain conditions.

Table 7 presents the normalized reliability contribution of the generators to the lines based on the reliability contribution affected by the system fault and output uncertainty. This is applied to distribute transmission reliability costs to network users.

Table 8 presents the results of the transmission reliability charge computed by the proposed method. The transmission reliability costs are traditionally distributed using the degree to which transmission reserves are utilized under system faults. However, the proposed approach allocates transmission reliability costs considering both the use of the transmission reserve under a contingency state and that of the transmission reserve due to the renewable energy uncertainty under a normal state. As a result, it can be seen that wind generators are imposed on higher transmission reliability charges than conventional generators.

Table 9 shows the results of the total transmission charge for the three methods. Total transmission charge is the sum of the transmission usage charge and the transmission reliability charge. Methods 1 and 2 only consider reliability benefits under contingency states caused by line outages. The main distinction between these two methods is whether or not the FORs are taken into account in the calculation of reliability contributions. In method 1, transmission charges of 12.51, 7.08, 7.08, and 2.03 [$/MWh] are applied to G1, G2, W1, and W2, respectively. Generators located adjacent to the load use fewer transmission lines than those located farther away, resulting in lower transmission charges for those close to the load. Method 2 applies FORs to consider realistic reliability contribution. In method 2, G1 is charged a transmission charge of 12.87 [$/MWh], which is approximately 0.36 [$/MWh] higher than that in method 1. On the other hand, in method 2, G2, W1, and W2 are charged transmission charges of 6.82, 6.82, and 2.02, respectively, which are approximately 0.26, 0.26, and 0.01 [$/MWh] lower than those in method 1. Considering the FORs can provide a more accurate reflection of the use of transmission reliability benefits during system faults. However, they are still not able to account for the use of transmission reliability benefits under the output uncertainty of RES. It is evident that generators, regardless of their type, located in the same bus are charged the same rate. On the other hand, the results obtained using method 3, which is the proposed method, show that the wind farm is subject to a higher transmission charge compared to a conventional generator located on the same bus. For example, W1 located on bus 2 bears a total transmission charge of 7.16[$/MWh], approximately 0.43 [$/MWh] more than the charge for G2 on the same bus. Thus, resources with output uncertainty have a greater responsibility for transmission reliability compared to traditional generators. For comparison, W2 in the proposed method bears a transmission charge of 3.47 [$/MWh], approximately 1.44 and 1.45 [$/MWh] higher than those obtained by methods 1 and 2, respectively. This

**TABLE 5.** Normalized reliability contributions of the generator to the lines under the contingency state.

| Line | G1 | G2 | W1 | W2 | Total |
|---|---|---|---|---|---|
| 1 | 0.15 | 0.00 | 0.00 | 0.00 | 0.15 |
| 2 | 0.58 | 0.22 | 0.19 | 0.00 | 1.00 |
| 3 | 0.37 | 0.33 | 0.29 | 0.01 | 1.00 |
| 4 | 0.35 | 0.34 | 0.30 | 0.01 | 1.00 |
| 5 | 0.35 | 0.35 | 0.30 | 0.00 | 1.00 |
| 6 | 0.25 | 0.21 | 0.18 | 0.01 | 0.65 |
| 7 | 0.00 | 0.01 | 0.00 | 0.00 | 0.02 |

**TABLE 6.** Normalized reliability contributions of the generator to the lines under the uncertainty state.

| Line | G1 | G2 | W1 | W2 | Total |
|---|---|---|---|---|---|
| 1 | 0.00 | 0.00 | 0.47 | 0.37 | 0.85 |
| 2 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 6 | 0.00 | 0.00 | 0.02 | 0.33 | 0.35 |
| 7 | 0.00 | 0.00 | 0.01 | 0.97 | 0.98 |

**TABLE 7.** Normalized reliability contributions of the generator to the lines.

| Line | G1 | G2 | W1 | W2 | Total |
|---|---|---|---|---|---|
| 1 | 0.15 | 0.00 | 0.47 | 0.37 | 1.00 |
| 2 | 0.58 | 0.22 | 0.19 | 0.00 | 1.00 |
| 3 | 0.37 | 0.33 | 0.29 | 0.01 | 1.00 |
| 4 | 0.35 | 0.34 | 0.30 | 0.01 | 1.00 |
| 5 | 0.35 | 0.35 | 0.30 | 0.00 | 1.00 |
| 6 | 0.25 | 0.21 | 0.20 | 0.34 | 1.00 |
| 7 | 0.00 | 0.01 | 0.02 | 0.97 | 1.00 |

**TABLE 8.** Transmission reliability charge based on proposed method.

| Line | G1 | G2 | W1 | W3 |
|---|---|---|---|---|
| 1 | 4.60 | 0.01 | 14.15 | 11.24 |
| 2 | 11.63 | 4.45 | 3.90 | 0.02 |
| 3 | 7.32 | 6.67 | 5.84 | 0.17 |
| 4 | 7.04 | 6.76 | 5.92 | 0.28 |
| 5 | 20.81 | 20.90 | 18.29 | 0.01 |
| 6 | 7.48 | 6.24 | 6.09 | 10.20 |
| 7 | 0.15 | 0.17 | 0.53 | 29.14 |
| Total ($) | 59.03 | 45.20 | 54.71 | 51.06 |
| Total ($/MWh) | 1.07 | 1.13 | 1.56 | 1.46 |

**TABLE 9.** Total transmission charges based on three methods in IEEE 5 bus test system.

| Generator | Transmission charge ($/MWh) | | |
|---|---|---|---|
| | Method 1 | Method 2 | Method 3 |
| G1 | 12.51 | 12.87 | 11.80 |
| G2 | 7.08 | 6.82 | 6.73 |
| W1 | 7.08 | 6.82 | 7.16 |
| W2 | 2.03 | 2.02 | 3.47 |

implies that the proposed method can consider the usage of transmission reserve due to the output uncertainty of RES located in high-load areas.

### B. IEEE 24 BUS TEST SYSTEM

An IEEE 24 bus system in Fig. 6 is used to show the effectiveness of the proposed method. This system has 24 buses, 32 conventional generating units, 3 wind generators, and 38 transmission lines. The total output of wind generators is 300 MW, consisting of 100 MW each at buses 3, 13, and 17, respectively. The detailed system data are taken from references [36] and [37].

Tables 10 and 11 show the results of transmission cost allocation to generators for line 2 between bus 1 and bus 3, and line 12 between bus 8 and bus 9. These lines are selected for two reasons. Firstly, regarding transmission cost allocation, line 12 is a transmission line utilized by a majority of generators, thus being the primary line for power transfer. Secondly, line 2 is the most expensive facility within this system, significantly influencing transmission pricing. As shown in Table 10, transmission costs for capacity-use are allocated using network usage contribution. G5, G7, G8, G9, G10, W1, and W3 use line 2 to transfer the power under normal conditions. They are allocated transmission costs of 105.11, 1.59, 81.53, 95.58, 0.46, 222.43, and 12.76 [$], respectively. Particularly, W1, located on bus 3, incurs higher transmission costs due to its dominant usage of line 2. This

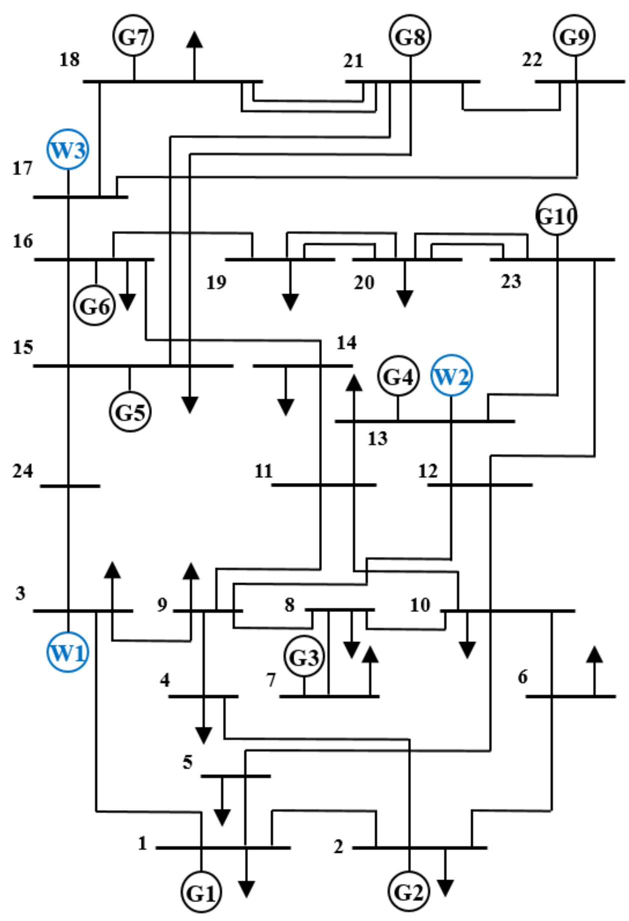


**FIGURE 6.** IEEE 24-bus test system.

**TABLE 10. Line 2 transmission cost allocation based on the proposed method.**

| Generator | Cost allocation ($) | |
|---|---|---|
| | Capacity use | Reliability benefit |
| G1 | 0.00 | 0.00 |
| G2 | 0.00 | 0.00 |
| G3 | 0.00 | 0.00 |
| G4 | 0.00 | 0.24 |
| G5 | 115.11 | 0.05 |
| G6 | 0.00 | 0.10 |
| G7 | 1.59 | 0.01 |
| G8 | 81.53 | 0.04 |
| G9 | 95.58 | 0.12 |
| G10 | 0.46 | 0.59 |
| W1 | 222.43 | 28.98 |
| W2 | 0.00 | 13.47 |
| W3 | 12.76 | 17.45 |

**TABLE 11. Line 12 transmission cost allocation based on the proposed method.**

| Generator | Cost allocation ($) | |
|---|---|---|
| | Capacity use | Reliability benefit |
| G1 | 0.00 | 0.45 |
| G2 | 0.00 | 0.27 |
| G3 | 0.00 | 0.00 |
| G4 | 99.68 | 12.73 |
| G5 | 16.92 | 0.02 |
| G6 | 34.94 | 1.20 |
| G7 | 0.88 | 0.10 |
| G8 | 12.72 | 0.12 |
| G9 | 21.49 | 1.13 |
| G10 | 192.12 | 26.43 |
| W1 | 32.69 | 0.03 |
| W2 | 34.94 | 4.46 |
| W3 | 7.03 | 0.77 |

implies that even if generators transfer power to nearby loads, transmission costs can be highly allocated if lines with high investment costs are used or the line is exclusively used. The transmission reliability cost for line 2 is allocated using the degree of use of transmission reliability-benefit. W1, W2, and W3 mainly use line 2 under contingency conditions caused by line outages and under normal conditions caused by output uncertainty.

Table 11 represents a transmission cost allocation of line 12 based on the proposed method. This line is utilized by 10 generators under normal states and is utilized by 12 generators under contingency states. It can be also confirmed that conventional generators mainly allocated transmission reliability costs. This means that line 12 is used to transfer the power from generators to loads under a contingency state.

Table 12 shows the total transmission charge obtained by three methods in the IEEE-24 bus test system. It can be confirmed that there is almost no difference between the results of method 1 and method 2. Thus, the degree of network utilization during system faults has limited influence on the variations in total transmission charges. Particularly, in both methods, generators located at the same bus are charged the same rates. On the other hand, it can be seen from the results obtained by method 3 that RES is charged a higher transmission reliability charge than conventional generators located on the same bus. For example, W2 located on bus 13 is charged a transmission reliability charge of 3.50 [$/MWh], approximately 0.36 [$/MWh] more than the charge for G4 on the same location. The test results show that the proposed transmission pricing method can effectively account for the impact of RES on the usage of the transmission reserve over all periods.

**TABLE 12. Total transmission charges based on three methods in IEEE 24 bus test system.**

| Generator | Transmission charge ($/MWh) | | |
|---|---|---|---|
| | Method 1 | Method 2 | Method 3 |
| G1 | 1.85 | 1.76 | 1.75 |
| G2 | 4.54 | 4.46 | 4.45 |
| G3 | 0.67 | 0.67 | 0.67 |
| G4 | 3.16 | 3.22 | 3.14 |
| G5 | 1.67 | 1.71 | 1.68 |
| G6 | 2.16 | 2.08 | 2.03 |
| G7 | 0.20 | 0.20 | 0.19 |
| G8 | 3.09 | 3.10 | 3.07 |
| G9 | 4.11 | 4.09 | 4.05 |
| G10 | 3.63 | 3.67 | 3.59 |
| W1 | 4.21 | 4.17 | 4.63 |
| W2 | 3.16 | 3.22 | 3.50 |
| W3 | 1.94 | 1.85 | 2.26 |

## V. CONCLUSION

This paper proposes a transmission pricing method for incorporating the impact of the system fault and the renewable energy uncertainty on transmission reserves. The proposed transmission pricing method can distribute transmission costs to customers based on the usage of transmission lines under both normal and contingency states. The probabilistic power flow was performed using a convolution technique to reflect the change of line flows due to dispatch error. Numerical results demonstrate the effectiveness and rationality of the proposed approach in an IEEE-5 bus system and an IEEE-24 bus system. Compared to existing methods, which only consider the degree of transmission reliability benefits under line outages, the proposed approach can consider the degree of use of transmission reliability benefits in both contingency states and normal states. Further, it can differentiate transmission reliability charges according to the uncertainty of individual resources even at the same location. This implies that the proposed approach can incorporate the impact of system uncertainty on transmission reserves. Consequently, the proposed approach can reasonably allocate transmission costs to network users, considering not only capacity-use but also reliability-benefit obtained from the transmission reserve over all periods.

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**SAN KIM** received the B.S. degree from the University of Ulsan, Ulsan, South Korea, in 2017, and the M.S. degree from Chung-Ang University, Seoul, South Korea, in 2019. He is currently pursuing the Ph.D. degree with Korea University, Seoul. His current research interests include power economics, power system planning, and renewable energy systems.

**SUNG-KWAN JOO** (Member, IEEE) received the M.S. and Ph.D. degrees from the University of Washington, Seattle, in 1997 and 2004, respectively. From 2004 to 2006, he was an Assistant Professor with the Department of Electrical and Computer Engineering, North Dakota State University, Fargo, USA. He is currently an Associate Professor with the School of Electrical Engineering, Korea University, Seoul, South Korea. His current research interests include multi-disciplinary research related to power systems, involving economics, information technologies, optimization, and intelligent systems.