A Hierarchical Architecture for Integrating Dynamic Tie-Line Ratings: Japan's Nationwide Generation Scheduling

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***Abstract*—Japan's power system is rapidly evolving and facing challenges of renewables integration into the grid due to limited tie-line capacity. Dynamic tie-line rating (DTLR) offers a promising solution, but its use in planning may increase the risk of network constraint violation if forecasted values differ from real-time conditions. Given Japan's unique system structure, this paper proposes a hierarchical framework for nationwide generation scheduling to address these risks. In the first two stages, DTLR scheduled are determined by a reliability coordination entity using scenario-based analysis of risk and return. In the third stage, transmission system operators incorporate DTLR as a constraint in generation scheduling. This approach enables robust, cost-effective scheduling by evaluating the probability of various operational scenarios. We also conduct a case study to demonstrates the method's potential to improve efficiency (-1.2%) and reduce renewable energy sources curtailment (-99.7%) in simplified two-area system representing the western region of Japan in 2035.**

***Index Terms*—Security-constrained unit commitment, Dynamic line rating, Two-stage stochastic programming problem**

I. Introduction

Historically, Japan's geography as a vertically elongated island nation has led to the division of its power system into ten distinct regions, each managed by a dedicated transmission system operator (TSO). Under regulatory constraints, these TSOs operated independently, resulting in the establishment of region-specific operational philosophies: for instance, generation scheduling in Japan was conducted independently by each TSO. Due to this independent nature of generation scheduling per region, under the rapid expansion of renewable energy sources (RES) in recent years, there have been concerns that RES is not effectively utilized across regional boundaries.

To address this inefficiency and promote the broader utilization of electricity resources, the Japanese government adopted a policy for electric power system reform through a cabinet decision in 2013 [1]. As the initial step in this reform, the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) was established in 2015 to support nationwide power system operations [2]. This organization serves as the tie-line reliability coordinator (TRC) in Japan, responsible for maintaining and managing interconnection lines. The TRC functions as a neutral entity, comparable to the FERC in North America and ENTSO-E in Europe, facilitating coordination among TSOs and monitoring the reliability of the power system. However, unlike its counterparts in North America and Europe, the TRC possesses the authority to intervene in the operation of tie-lines between areas. In other words, it not only supervises TSOs but can also directly influence nationwide generation scheduling.

Since the establishment of the TRC, an interim operational framework has been adopted in which the TRC determines the scheduled power flow across tie-lines between TSOs on a day-ahead basis. Based on the balancing group generation schedules submitted by generators in each area, the TRC sets the tie-line flow schedule and notifies the TSOs. Each TSO then treats these scheduled flows as fixed inflows and outflows and prepares its own generation schedule accordingly.

The next phase of reform involves a transition from regionally independent to nationwide integrated generation scheduling. This enables full utilization of previously underutilized tie-line capacity and reduces costs through optimized generator dispatch. In this framework, the TRC notifies TSOs of the upper operational limits of tie-line capacity, which are incorporated as security constraints in the nationwide generation schedule. This shift allows the TRC to focus on setting appropriate tie-line limits to enhance efficiency while ensuring system reliability. Within this context, dynamic line rating (DLR), which adjusts transmission capacity using weather sensors installed on transmission lines and forecasting systems, can be applied to tie-lines. Compared with conventional static line rating (SLR), DLR allows higher power flows, reducing RES curtailment and yielding further cost savings. To distinguish DLR applied to tie-lines, it is hereafter referred to as dynamic tie-line rating (DTLR).

Nevertheless, particular attention must be paid when applying DTLR: in the future, the TRC will be responsible for determining tie-line capacities, whereas each TSO formulates the day-ahead generation schedule based on the notified tie-line capacities. To further complicate the situation, these capacities must be established on the day prior to operation, based on weather forecasts available at that time. In this study, we will refer to these forecast-based values as scheduled DTLR.

Naturally, discrepancies may arise between the scheduled and actual DTLR on the day of operation due to weather forecast inaccuracies. Given the close linkage between scheduled DTLR and the day-ahead generation schedule, significant over- or underestimation of DTLR may require costly operational adjustments in response to forecast errors. Therefore, determining the scheduled DTLR with appropriate accuracy is essential. To this end, the scheduled DTLR should

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be established by incorporating the probabilistic distribution of forecast errors, thereby ensuring a robust and cost-effective scheduling framework.

One example of a coordination method between DTLR and generation scheduling is to incorporate DTLR as an optimization variable within the generation scheduling problem [3][4], thereby determining transmission capacity and unit commitment simultaneously. However, due to Japan's long-standing history of regionally independent generation scheduling, each TSO has developed its own operational preferences and philosophies. These differences appear in aspects such as the level of uncertainty tolerated in the trade-off between forecast deviation and economic efficiency, and the policies for setting operational margins based on supply–demand conditions. Consequently, Japanese TSOs require the ability to review and adjust system constraints, including those related to DTLR, prior to executing security-constrained unit commitment (SCUC). A fully integrated optimization approach does not accommodate these preferences.

Therefore, this study proposes a hierarchical architecture that simulates information exchange between entities in Japan, specifically between the TRC and TSOs, by separating the process of DTLR determination (1st and 2nd stages) from generation scheduling (3rd stage).

In the 1st stage, the unit commitment plan for the following day is simulated. In the 2nd stage, multiple scenarios of DTLR variation from the day-ahead plan to real-time operation are considered. The scheduled DTLR is determined based on the expected values of risk and return associated with the scenarios, In the 3rd stage, the determined DTLR is incorporated as a system constraint in the generation scheduling process.

By decoupling the DTLR determination from the generation scheduling, TSOs are given the opportunity to review and adjust the constraints used in their generation schedules after the DTLR are finalized but before the scheduling process begins. This allows each TSO to reflect its operational preferences more effectively. Furthermore, the same SCUC algorithm is employed for both DTLR determination and generation scheduling, contributing to reduced development effort and mitigating risks associated with new algorithm implementation.

The main contributions of this work are as follows:

- **Hierarchical architecture for incorporating inter-entity coordination:** A planning architecture that separates DTLR determination by TRC from generation scheduling by individual TSOs. This separation enables each TSO to reflect its operational preferences within a flexible planning process.
- **Proposal of a scenario-based stochastic programming method for DTLR determination:** This paper proposes a method for determining DTLR values based on the expected trade-off between risk (e.g., increased operational costs) and return (e.g., reduced RES curtailment).
- **Validation through case study on simplified two-area model:** A case study targeting Japan's projected power system in 2035 demonstrates the effectiveness of the proposed approach. The results indicate a potential reduction in RES curtailment.

II. Multi-Entity Coordination in Generation Scheduling and Associated Challenges

A. *Operational Shifts in Japan's Power System*

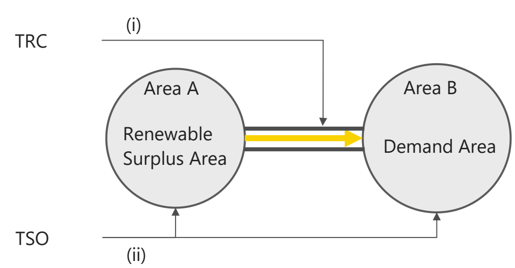
We must first understand the operational shift in Japan's power system to narrow the scope of this paper.

In Japan, generation scheduling has traditionally been conducted on a regional basis. However, with the integration of the Energy Management System (EMS), it will be possible to formulate a nationwide generation schedule in the future. Historically, the interconnection lines linking different areas have been maintained and operated by the TRC, which supports wide-area power system operation. Based on the generation offers submitted by generators in each area, the TRC calculates the scheduled daily power flows for each interconnection line. These scheduled flows are then communicated to each regional generation scheduling system as inflow/outflow quantities, and regional generation schedules are formulated accordingly.

Due to the integration of the EMS, future power system operation in Japan will adopt a two-stage structure: (1) the TRC will notify the upper limits of operational capacity for each interconnection line, and (2) the TSO will formulate a nationwide generation schedule, including interconnection line flows, using SCUC. The ability to create a nationwide generation schedule enables the transmission of surplus RES from generation-rich areas to demand centers via interconnection lines.

However, when surplus RES areas and demand centers are geographically separated, congestion tends to occur on the interconnection lines connecting these regions. According to projections by the Agency for Natural Resources and Energy, thermal capacity-based congestion is expected to occur on several interconnection lines by 2035 [5]. The application of DLR, more specifically DTLR, is anticipated as a congestion mitigation measure to address this issue.

Given the traditional structure of Japan's power system, the expected future framework for incorporating DTLR at the planning stage involves the TRC notifying the next-day interconnection line capacity using DTLR, based on which the TSO will formulate the generation schedule for each area. The relationship is summarized graphically in Fig. 1.



	Now	Next Gen	Proposed Method
(i)TRC	TRC decides Tie-line flow	TRC decides tie-line limit (SLR)	TRC decides tie-line limit (DTLR)
(ii)TSO	Plans generation according to tie-line flow	Uses SCUC to determine tie-line flow.	Uses SCUC to determine tie-line flow with DTLR

Figure 1. Tie-line and generation scheduling in Japan

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B. Issues in Applying DTLR to Generation scheduling

By adopting DTLR, transmission congestion can be alleviated, thereby avoiding curtailment of RES and reducing generation costs. In this study, such benefits are referred to as the return of DTLR implementation.

Conversely, when forecast-based scheduled DTLR is utilized during the planning stage, weather fluctuations may result in the actual DTLR being lower than anticipated at the time of operation. In such cases, TSOs may direct RES curtailment to prevent overloading, leading to insufficient supply capacity in demand areas. This may necessitate emergency generator startups or load shedding just before dispatch, resulting in operational losses for the TSO due to the need to secure and activate balancing resources (Fig. 2).

Alternatively, if TSOs preemptively secure expensive balancing resources to hedge against DTLR variability from planning to operation, generation costs may increase. In this study, such potential losses are referred to as risk.

Therefore, when implementing DTLR, it is essential to determine the planned DTLR in a manner that appropriately balances return and risk. To address this challenge, this study proposes a hierarchical stochastic scheduling architecture that incorporates DTLR variability as a risk factor in the generation scheduling process. The details of this architecture are presented in Section 3.

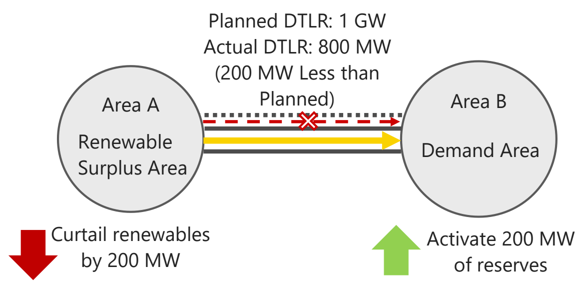

Figure 2. Resource balancing due to scheduled DTLR forecast error

III. Proposed Approach

A. Architecture for a Hierarchical Generation Scheduling

This study proposes hierarchical architecture designed to determine the planned capacity of DTLR. The rationale for adopting a hierarchical structure is as follows:

- Separate responsibilities between entities: To reflect the distinct roles of entities such as TRC and TSOs, the architecture introduces a clear separation between the DTLR determination process (1st and 2nd stages) and the generation scheduling process (3rd stage).
- Ensure implementation feasibility through algorithm unification: To facilitate implementation, the architecture avoids solving a scenario-based stochastic optimization problem in a single step. Instead, it separates Stage 1 and Stage 2, allowing the use of a common generation scheduling algorithm across stages.

An overview of the entire process of the proposed architecture is shown in Fig. 3. The premise of the architecture is to allow the TRC to determine a scheduled DTLR ($\hat{\boldsymbol{\xi}}$) from a set of candidates DTLR values ($\boldsymbol{\Xi}$**),** then allow the TSO to solve SCUC using the determined $\hat{\boldsymbol{\xi}}$.

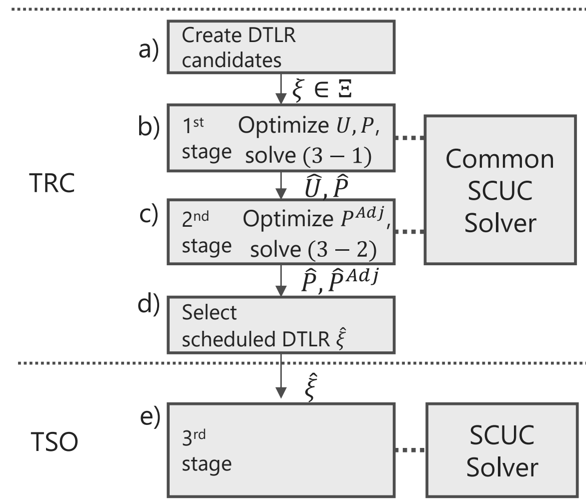

Figure 3. Hierarchical architecture for generation scheduling

Here, the SCUC algorithm used in each stage is common, and by utilizing existing systems, the proposed architecture contributes to reducing new development costs, minimizing system failure risks, and shortening development timelines.

The details of the individual processes are explained in detail in the following:

a) Create DTLR Candidates

As a preliminary step, a set of candidates scheduled DTLR values are constructed. We denote each candidate scheduled DTLR as $\boldsymbol{\xi}$, and the whole set of candidates as $\boldsymbol{\Xi}$. Hence, $\boldsymbol{\xi} \in \boldsymbol{\Xi}$. By having a discrete set of candidate values, this first limits the search space of DTLR values.

b) 1st Stage Optimization

We then move to the 1st stage optimization, where day-ahead generation scheduling is solved for each $\boldsymbol{\xi} \in \boldsymbol{\Xi}$. We solve SCUC for each $\boldsymbol{\xi}$ to determine the unit commitment ($\boldsymbol{U}_{\boldsymbol{\xi}}$) and dispatch ($\boldsymbol{P}_{\boldsymbol{\xi}}$) by minimizing generation cost.

This stage computes the benefit (return) of employing $\boldsymbol{\xi}$.

c) 2nd Stage Optimization

After the 1st stage optimization, the 2nd stage optimization is solved to model the real-time economic dispatch.

Specifically, $\hat{\boldsymbol{U}}_{\boldsymbol{\xi}}$ and $\hat{\boldsymbol{P}}_{\boldsymbol{\xi}}$ obtained in the 1st stage and forecast error scenarios ($\boldsymbol{s}$) , are used to solve for adjusted generation schedule ($\boldsymbol{P}^{\boldsymbol{Adj}}_{\boldsymbol{\xi},\boldsymbol{s}}$) for each scenario using SCUC with $\hat{\boldsymbol{U}}_{\boldsymbol{\xi}}$ as fixed variables. Here, $\boldsymbol{s} \in \boldsymbol{S}$ where $\boldsymbol{S}$ indicates the set of distinct scenarios. In essence, this process is security-constrained economic dispatch (SCED) but solving it on the SCUC solver reduces the number of modules needed.

Based on $\hat{\boldsymbol{P}}^{\boldsymbol{Adj}}_{\boldsymbol{\xi},\boldsymbol{s}}$, the cost of securing and activating balancing resources is calculated for each forecast error scenario $\boldsymbol{s}$. By multiplying these costs by the probability of each scenario, the expected balancing cost (risk) is obtained.

d) Select Scheduled DTLR

The sum of the return and risk calculated in the 1st and 2nd stages represents the expected generation cost for each $\boldsymbol{\xi}$. The candidate with the minimum expected cost is selected and passed to the 3rd stage as $\hat{\boldsymbol{\xi}}$.

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e) 3rd Stage

In the 3rd stage, the scheduled DTLR $\hat{\boldsymbol{\xi}}$ is used as a constraint, and the generation scheduling problem is formulated as an SCUC. Since the SCUC is formulated as a commonly used MILP with a linearized fuel cost objective function and transmission line capacity constraints based on DC power flow, a detailed explanation is omitted and referred to in [3].

B. Formulation of the 1st and 2nd Stages

Given the architecture discussed in the previous subsection, this subsection outlines the formulation of the 1st stage and 2nd stage optimization.

1) Formulation of 1st Stage Optimization.

In the 1st stage, $\boldsymbol{U}_{\xi}$ and $\boldsymbol{P}_{\xi}$ are determined for each $\boldsymbol{\xi}$. The optimization problem to be solved is as follows:

$$\min\{f_{\xi}(\boldsymbol{U}_{\xi}, \boldsymbol{P}_{\xi})\}$$
$$s.t.\ g(\boldsymbol{U}_{\xi}, \boldsymbol{P}_{\xi}) \qquad (3-1)$$

Here, $g(\boldsymbol{U}_{\xi}, \boldsymbol{P}_{\xi})$ denotes the constraints described in reference [6]. The solution to the above problem is denoted by $\boldsymbol{c}$, which is passed onto the 2nd stage.

2) Formulation of 2nd Stage Optimization

In the 2nd stage, for each $\boldsymbol{\xi}$, $\widehat{\boldsymbol{P}}_{\xi}, \widehat{\boldsymbol{U}}_{\xi}$ determined in the 1st stage is constant, and $\boldsymbol{P}^{Adj}_{\xi,s}$ for each $\boldsymbol{\xi}, \boldsymbol{s}$ pair is solved.

To accomplish this, we solve the following SCUC problem.

$$\min\left\{f_s\left(\widehat{\boldsymbol{U}}_{\xi}, \boldsymbol{P}^{Adj}_{\xi,s}\right) + Q_s(\boldsymbol{\xi})\right\}$$
$$s.t.\ g(\widehat{\boldsymbol{U}}_{\xi}, \boldsymbol{P}_{\xi}), \qquad (3-2)$$

where,

$$Q_s(\boldsymbol{\xi}) = \boldsymbol{C}^{\boldsymbol{b}} \cdot \left(\widehat{\boldsymbol{P}}_{\xi} - \boldsymbol{P}^{Adj}_{\xi,s}\right). \qquad (3-3)$$

Here, $\boldsymbol{f_s}$ denotes the generation cost, $Q_s(\boldsymbol{\xi})$ denotes the balancing cost for each $\boldsymbol{\xi}, \boldsymbol{s}$ pair, and $\boldsymbol{C}^{\boldsymbol{b}}$ indicates the balancing power unit price.

The balancing cost $Q_s(\boldsymbol{\xi})$ is calculated based on the difference between the day-ahead schedule $\widehat{\boldsymbol{P}}_{\xi}$ and the real-time adjusted schedule $\boldsymbol{P}^{Adj}_{\xi,s}$, multiplied by the price $\boldsymbol{C}^{\boldsymbol{b}}$.

3) Formulation for Selecting Scheduled DTLR

After solving the 2nd stage, we can now compute $f_s\left(\widehat{\boldsymbol{U}}_{\xi}, \boldsymbol{P}^{Adj}_{\xi,s}\right)$ and $Q_s(\boldsymbol{\xi})$ for all $\boldsymbol{\xi}, \boldsymbol{s}$ pairs.

To determine $\hat{\boldsymbol{\xi}}$, we compute the expected value for each $\boldsymbol{\xi}$ using the expected value.

$$E[Q(\boldsymbol{\xi})] = \sum_{s=1}^{S}\{Q_s(\boldsymbol{\xi}) \cdot p_s\}. \qquad (3-4)$$

The DTLR candidate $\boldsymbol{\xi}$ that minimizes this total cost is adopted as the scheduled DTLR $\hat{\boldsymbol{\xi}}$ and passed to the 3rd stage.

C. Benefits of the Proposed Method

The inclusion of the expected value in the objective function is intended to incorporate information regarding the probability distribution of DTLR forecast errors.

Conventional approaches that rely on a single forecast error scenario, such as methods using the most frequent scenario or robust optimization considering the most severe case, fail to account for the probabilistic nature of forecast deviations. As a result, the scheduled DTLR may become excessively conservative or overly optimistic depending on the assumptions.

In contrast, the proposed scenario-based stochastic planning method enables the determination of an appropriate scheduled DTLR by incorporating the probability distribution of forecast errors, specifically the expected balancing cost, which is then included in the objective function.

IV. Case Study

A. Overview

In this study, we assume that DLTR will be introduced and operational on Japan's tie-lines by 2035. Based on this assumption, the following computational conditions were established (Fig. 4).

- We calculated the DLTR deviation and its probability based on the standard deviation of prediction errors at the average wind speed, assuming that the prediction errors follow a normal distribution.
- To isolate and analyze the impact of DLR forecast errors, other sources of uncertainty, namely demand and RES output forecast errors, were excluded from consideration.
- The power system model used in this study is a simplified two-area system representing the western region of Japan in 2035. The installed capacity of RES and the tie-line capacity were set based on projections for 2035.
- The model assumes a scenario in which a large amount of RES (primarily photovoltaic power) is introduced in the Kyushu area. Under such system conditions, significant tie-line power flows are expected from the Kyushu area (a surplus RES area) toward the Chugoku, Shikoku, and Kansai areas (demand areas) [7][8].
- Costs associated with the generators are shown in Fig. 5.
- To represent the temporal correlation between DLR and generation planning, we used actual meteorological data from January to December 2024 and created 24-hour generation schedules for each of the 8,760 hourly time steps (1 hour × 8,760 steps) over the year.

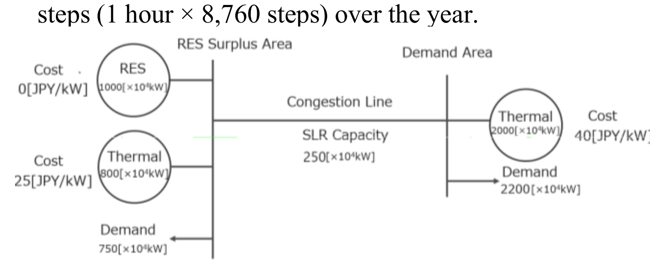

Figure 4. Simplified two-area system representing the western region of Japan in 2035

B. Results and Observations

This section discusses the effectiveness of the proposed method in reducing the expected generation cost. In the annual simulation, the proposed method achieved a reduction in expected annual generation cost of 42.4 billion yen (-1.2%) compared to conventional operations. To further explain the reason for this cost reduction, we analyze the results from a representative day are analyzed. Fig. 5 illustrates the improvement in generation cost under forecast error scenarios. On the representative day, the proposed method sets the DTLR to 373 MW, while the conventional operation sets it to 250 MW.

In scenarios with small or no forecast errors (highlighted in red in Fig. 5), the proposed method assigns a higher DTLR

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value, which alleviates congestion and enables the use of lower-cost generation resources, thereby reducing overall generation costs. However, in scenarios with significant forecast errors (highlighted in blue in Fig. 5), the proposed method results in higher costs. This is because a higher DTLR setting relative to the conventional method leads to increased congestion when forecast errors occur, resulting in greater curtailment of renewable output and supply shortages. Consequently, more expensive power must be procured from the day-ahead market.

Nevertheless, such forecast error events that worsen the cost under the proposed method are infrequent. As shown in Table I, the expected cost increase under these scenarios is estimated at +1.95 million yen, and the total expected reduced cost is -12.1 million yen in this operation day.

Next, we discuss the effectiveness of the proposed method in reducing RES curtailment through optimized DTLR capacity. The adjusted DTLR capacity is optimized to minimize the expected operational cost, the detailed analysis of cost reduction is presented in the following section.

In this simulation, generation scheduling was conducted for one full year under the conditions described in Section 4.1. By determining DTLR values based on expected cost, the proposed method increased the average annual operational transmission capacity by 134 MW, and the amount of RES curtailment was reduced to 60.18 GWh: a 99.7% reduction in congestion-induced RES curtailment compared to conventional system operation (Fig. 6).

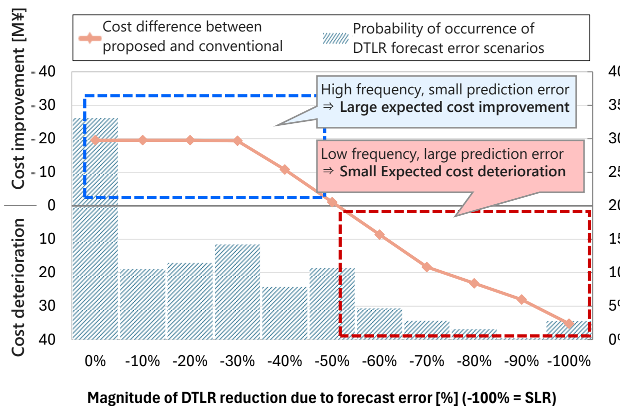

Figure 5. Expected cost difference with each method

TABLE I. EXPECTED COST DIFFERENCE WITH PROPOSED AND CONVENTIONAL METHOD FOR EACH FORECAST ERROR SCENARIO

DTLR Forecast Error Scenario	Cost Difference ($\times 10^6$ JPY)	Scenario Probability	Expected Cost Improvement ($\times 10^6$ JPY)
-0%	-19.5	20%	-3.9
-10%	-19.5	15%	-2.9
-20%	-19.5	15%	-2.9
-30%	-19.3	15%	-2.9
-40%	-10.7	12%	-1.3
-50%	-0.1	10%	-0.1
-60%	+8.6	7%	+0.6
-70%	+18.3	3%	+0.55
-80%	+23.1	1.5%	+0.35
-90%	+28.0	1%	+0.28
-100%	+35.2	0.5%	+0.18
Total	-	-	**-12.1**

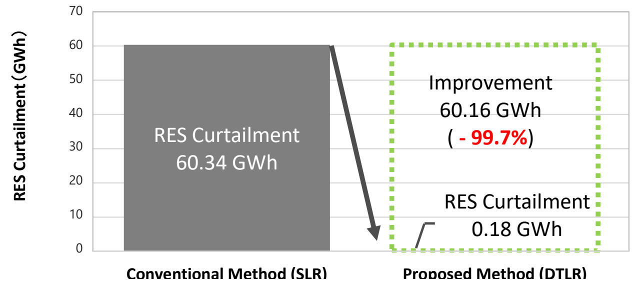

Figure 6. Reduction of renewable curtailment reduce with proposed method.

V. CONCLUSION

This paper introduced a hierarchical generation scheduling architecture for implementing DTLR in Japan's power system. The method optimizes scheduled DTLR while maintaining the existing organizational relationship among power system entities. A simplified case study shows that under projected 2035 conditions in Japan, the proposed method reduces cost by 1.2% and renewable curtailment by 99.7%.

The proposed hierarchical architecture decoupling DTLR determination from generation scheduling enables different aspects of the grid schedule to be determined separately with distinct operational responsibilities. This approach applies not only to Japan-specific configurations but can also be used to apply Dynamic Line Rating to interconnecting assets, such as tie-lines and transformers, between entities operating at different voltage levels or in distinct service areas.

In future work, we plan to conduct case studies on a larger power system to confirm the scalability of the method's effectiveness. However, DTLR's limitations remain not yet fully understood, as interactions between meteorological variability and spatially correlated RES fluctuations may introduce uncertainty. Refining this approach requires overcoming challenges in characterizing these risk factors.

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