


ORIGINAL RESEARCH PAPER

Spot electricity market design for a power system characterized by high penetration of renewable energy generation

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Abstract

The continuous growth of renewable generation in power systems brings serious challenges to electricity markets due to their characteristics different from conventional generation technologies. These challenges come from two dimensions, including short-term (energy and ancillary service markets) and long-term (long-term bilateral and capacity markets) aspects. Under this background, the design of energy and ancillary service markets is studied for power systems with a high penetration level of variable renewable generation. In the proposed spot market mechanism, energy and frequency regulation service (FRS) bids are jointly cleared, where renewable generators are motivated to proactively manage the intermittency and uncertainty of their power outputs. The proposed market mechanism can also ensure the adequacy of FRS capacity for compensating variability of renewables. Besides, in order to ensure the execution of spot market clearing outcomes, this paper established a penalty scheme for mitigating the real-time fluctuations of renewable generation outputs in the spot market. Differences between real-time generation outputs and market clearing outcomes are managed within a certain limit by imposing the designed penalty prices on deviations. Finally, the feasibility and efficiency of the developed market mechanism and algorithms are manifested in the case studies.

1 | INTRODUCTION

1.1 | Research motivation and necessity

Due to concerns on climate change, air pollution and security of energy supply, renewable energy (RE) technologies are favoured by countries during the past decades. Global penetration level, capital investment, and installed capacity of RE generations have been increasing significantly in recent years. By the end of 2019, the global renewable generation capacity has amounted to 2537 GW which accounts for a third of global power capacity (including hydro) [1]. On the other hand, the variable renewable generation is primarily an energy resource that has limited capacity value relative to its rated capacity. There

is usually a mismatch between the periods of high RE generation output and the times of high load demand. The special characteristics of RE create challenges to reliably operating the power system at least cost and planning for the expansion of the power system to meet the changing needs of the future. In the following decades, electricity market operators are expected to deal with challenges from accommodating high penetration levels of RE in power systems. Thus, the study on innovative electricity market design for improving the accommodation capability of RE in power systems is of great significance. The results of this research not only provide the industry and regulators with a better understanding of the impacts of RE on wholesale energy and ancillary service markets, but also will contribute to a more rapid and cost-effective transition to the cleaner sources of electricity.

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1.2 | Related work

Electricity markets with high penetration levels of RE are featured by several key characteristics, including the variability and intermittency, low short-run marginal costs, as well as non-synchronous generation (such as wind and solar photovoltaics) [2]. The participation of RE generations in electricity markets will impact the market price, equilibrium state, transaction risk, social welfare and system carbon emission. In [3, 4], the decision-making problem of participants in electricity markets with high-penetration levels of RE is studied. Generation output of renewable generators (RGs) is modelled by various probabilistic prediction methods. RGs can also develop trading strategies by jointly participating in electricity markets with other entities, such as demand response resources and energy storage systems (ESS), in order to enhance their benefits [5, 6]. The integration of intermittent RE generation brings significant variability to the operation of power systems. Meanwhile, the output intermittency of RE generation without adequate firm capacity may cause significant excursions in generation that can be far away from the results accounted for in traditional security standards. Therefore, coordinated planning and operation of power systems are investigated in [7, 8] using stochastic programming or multistage stochastic optimization methods. In [9–11], impacts of RE generation on the electricity prices, consequences of various market designs on the remuneration of generators, and the problem of insufficient investment recovery caused by the integration of RE generation are studied, respectively. However, in these publications, RGs are usually assumed to be paid by regulated fixed tariff (or premium) or bid a zero price to pool-based electricity markets as price-takers. In [12], an energy management strategy for multiple cooperative microgrids is proposed with an objective of minimizing the total daily operation cost of microgrids, while time-variant and intermittent attributes of RE generation are also considered.

The impacts of RE integration on the requirement of reserve and flexibility in power systems have also attracted extensive research interests. In [13], a literature survey on the concepts of power system reserve and flexibility is presented, where the focus is the impact of RE on power system flexibility, attributed mainly to RE volatility. It is found that the main impact of RE is the higher requirement of regulating reserve, specifically, load-following services. Thus, modification of market mechanisms and independent system operator (ISO) codes and standards appears necessary to exploit the full potential for flexibility provision. Meanwhile, in [14], a demand response-based operation approach empowered by a two-stage stochastic programming is proposed for operational scheduling of the electricity market in the presence of RE. One of the key findings is that the employment of demand response programs made it possible to compensate for RE's uncertainties and to maximize operator benefits, while inappropriate types of demand response programs might decrease market efficiency. In order to enhance the flexibility of power systems with a high proportion of RE, a bilevel model is developed to co-optimize the locations of variable series reactor and phase shifting transformer under a high penetration of wind power in [15]. The proposed planning

model seeks to identify the investment decisions on series flexible AC transmission systems within a market environment. The various load-wind scenarios are utilized to capture the intermittent nature of wind power. In [16], a method is presented to assess the fluctuating discrepancies between RE generation and load demand for power system planning purposes. Rather than modelling the uncertain output of RE, the residual load is analysed using the method of Fourier transform.

Currently, RE is gradually accepted as a regular power source participating in the power market, so it is essential to supervise and regulate the strategic behaviours of RE generators. In [17], a framework is proposed to analyze the strategic offering behaviors of variable RE generators considering their volatility and uncertainty and analyze the efficiency loss during their participants in power markets. Notably, the uncertainty of the RE outputs is modelled by multiple-scenario settings, generated by the Monte Carlo method. Similarly, in [18], the market equilibrium analysis for power systems with a high proportion of renewable and gas-fired generation is carried out using a modified Nash-Cournot approach. Gas-fired units are introduced to provide flexible generation capacity required by the increasing of RE generation in the power system. The impacts of the strategic behaviours of different types of generators on the electricity prices, renewable energy integration, carbon emissions and air pollutant emissions are studied through empirical analysis. Besides, in [19], a brief overview of some important challenges related to technical, environmental and socio-economic aspects at elevated renewable penetration is presented. The integrated analytical framework is also proposed for interlinked technical, environmental, and socio-economic systems.

As current electricity markets are originally designed based on the premise that most generation resources are fully dispatchable, challenges arise with the rapid growth of variable and less dispatchable RE generation, especially on the power system flexibility. Flexibility in power systems is the ability to provide supply–demand balance, maintain continuity in unexpected situations, and cope with uncertainty on supply–demand sides. In [20], a comprehensive survey about the challenges of renewable energy penetration on power system flexibility is presented. In practice, due to the insufficient flexibility in the real-time operation, the high penetration of renewable generations has results in tremendous economic loss caused by power outages, such as the South Australian blackout in September 2016, the rolling blackouts of Adelaide in February 2017 and California in August 2020. The lack of incentives in existing electricity markets can result in the inadequacy of flexible regulation resources. Besides, frequency regulation service (FRS) reserve capacity in existing systems (such as ISOs in North America) is determined in an ex-ante and static manner, which may fail to meet the requirements of future power systems. For example, in PJM [21], the regulation capacity requirement is fixed as 800 MW for peak period and 525 MW for off-peak period, despite the proportion of variable renewable generations in the dispatch plan. Thus, the design of a new spot market mechanism is highly demanded to overcome the above problems and is the focus of this paper.

Since variations of generation output can result in changes of locational marginal prices (LMP) in power systems, the concept of probabilistic LMP is proposed in [22] to quantitatively

model the impact of load forecasting uncertainty on LMP. Furthermore, a bi-level optimization model is developed in [23] to calculate the LMP intervals under wind uncertainty and this enables a much faster LMP forecasting compared with Monte Carlo based methods. In [24], a new concept of uncertainty marginal price (UMP) is introduced to define the marginal cost of immunizing the next increment of uncertainty at a specific node of power systems. Under a robust optimization framework, both UMPs and LMPs are derived. The UMP helps allocate the cost of generation reserves to corresponding entities that bring uncertainty. In [25], a dynamic spot market is proposed to enhance the accommodation capability for RE generation by smart grids. Demand response resources are used to compensate for the intermittent RE generation. In [26], the Cournot gaming based energy-only and capacity-energy market models are presented to compare their performances under a significant penetration of wind and solar generation. The results indicate that the capacity-energy market outperforms the energy-only one in terms of inducing new capacity and lowering electricity prices to the competitive level. It is emphasized in [27] that the integration of a large quantity of RE generation needs to ensure adequate access to highly flexible generation capacity, thus many electricity market regulators have begun to implement capacity remuneration mechanisms (CRMs) so as to attain adequate capacity for maintaining power system reliability. However, CRMs are limited to national scopes and impede the cross-border sharing of generation resources. To overcome these shortcomings, a flow-based forward capacity mechanism is proposed by [28]. Moreover, a day-ahead stochastic market clearing model with high-penetration levels of wind generation is developed in [29]. Similarly, a two-stage stochastic electricity market mechanism using the Vickrey-Clarke-Groves auction is proposed in [30], but the revenue adequacy cannot be guaranteed by this method.

1.3 | Novelty and contributions

It can be found that in existing research, the intermittent RE generations are usually managed from the perspective of centralized system operators. Through stochastic programming, robust optimization or scenario-based methods, the impacts of RE variability on system operations can be minimized in the optimal solutions. However, in this research, the idea of motivating RGs to initiatively manage the intermittent outputs is proposed through an innovative spot electricity market design. Meanwhile, comparing with current electricity markets, the proposed mechanism can reveal the system requirement for flexible regulation services to compensate for the intermittency of RE in an accurate way, since more information about output uncertainty is contained in the designed bids submitted by RGs. To summarize, existing markets are insufficient in producing an efficient price signal by considering output variability of RE and revealing the system requirement for flexible regulation services to compensate for the intermittency of RE. The main contributions of this paper are summarized below.

First, a new electricity spot market mechanism for power systems with high penetration levels of RE is proposed. Under this mechanism, RGs are motivated to proactively manage the intermittency and uncertainty of outputs, which is beneficial to the secure operation of the power system concerned.

Second, a penalty scheme is proposed to guarantee the execution of spot market clearing outcomes considering the variability of RE generations. The market volatility can be controlled within an expected limit through properly setting penalty prices. Besides, under the penalty scheme, RGs are motivated to truly report the output uncertainty in their bidding parameters, in order for attaining higher trading profit.

Third, the proposed market mechanism provides an efficient way to determine the requirement of FRS capacity in power systems with high penetration levels of RE, which is not yet addressed in existing publications. FRS reserve capacity in existing systems (such as ISOs in North America) is determined in an ex-ante and static manner, which may fail to meet the requirements of future power systems. The proposed mechanism can overcome this problem.

The rest of the paper is structured as follows. Section 2 introduces the proposed electricity spot market clearing mechanism. Then, the proposed penalty scheme for ensuring the execution of spot market clearing outcomes is elaborated in Section 3. Section 4 provides case study results and discussions. Finally, the paper is concluded in Section 5.

2 | PROPOSED SPOT MARKET CLEARING MECHANISM

2.1 | Fundamental assumptions

Before establishing the proposed mechanism, fundamental assumptions about electricity markets are made as follows.

1. The proposed spot market mechanism is operated as an ex-ante market, which can be used for minute-ahead, hour-ahead, or day-ahead transactions. Notably, existing electricity markets are all operated as ex-ante markets to ensure the security of real-time operation. Even the real-time market is also cleared 5-min ahead. This paper assumes the proposed mechanism to be an hour-ahead market.
2. The electricity market concerned is a competitive market where participants are required to schedule their real-time generation output by following market clearing results. Otherwise, the uninstructed deviations of real-time output beyond a certain tolerance band will subject to penalties. In existing markets, the uninstructed deviation penalty is assessed based on uninstructed imbalance energy caused by excessive or insufficient generation beyond a tolerance band. For instance, the tolerance band that is practically adopted for renewable generation is 5% of the day-ahead schedule in PJM, and 8% of day-ahead schedule (for deviations occurred within four or more consecutive 5-min dispatch intervals) in MISO [31].

3. When using the proposed mechanism for real-time electricity market, imbalance between the ex-ante scheduled RGs output and their real-time generation will be covered by FRS that is jointly purchased with energy bids. The dispatch of FRS is carried out based on the merit order of bid prices. Bids of outputs in the ex-ante spot market are obtained by forecasting, due to inherent uncertainty and intermittency of RE, difference between their real-time outputs and ex-ante forecasting values is inevitable. Thus, FRS reserve capacity is needed to guarantee the execution of transaction outcomes.

The above assumptions are presented for an easier understanding of the proposed spot market mechanism. However, these assumptions are mild conditions because they all comply with the practice in existing electricity markets.

2.2 | Formulation of the proposed spot market mechanism

In the designed mechanism, each generator submits a three-parameter bid $(r_i^s, p_i^{s,frm}, p_i^{s,ucrt})$ ($i \in N^{Gtr}$) and a vector of forecasted generation output for the target dispatch interval $p_{i,t}^s$ ($i \in N^{Gtr}$ and $t \in T$) to the market operator. Considering that the continuous balance of generation and load is maintained by FRS at a very granular level. Resolution of $p_{i,t}^s$ should at least be aligned with the frequency of FRS signal. r_i^s denotes the offered price of generation. The outputs of RGs are featured by uncertainty and intermittency, $p_i^{s,ucrt}$ and $p_{i,t}^s$ contain information about the uncertain outputs of RGs. With the adoption of ESSs and advanced control technologies, RGs are attaining more and more controllability over outputs. Therefore, $p_i^{s,frm}$ represents the firm output of RGs. For conventional dispatchable generators, $p_i^{s,ucrt}$ and $p_{i,t}^s$ can be set as 0 and constant output, respectively. Meanwhile, in the regulation market, each participant can also submit a bid $(r_n^{rsv,up,c}, r_n^{rsv,up,mil}, p_n^{rsv,up,max})$ ($n \in N^{rsv,up}$) for providing up FRS or a bid $(r_m^{rsv,dw,c}, r_m^{rsv,dw,mil}, p_m^{rsv,dw,max})$ ($m \in N^{rsv,dw}$) for providing down FRS to the power system concerned. $r_n^{rsv,up,c}$, $r_n^{rsv,up,mil}$, $p_n^{rsv,up,max}$, $r_m^{rsv,dw,c}$, $r_m^{rsv,dw,mil}$, $p_m^{rsv,dw,max}$ indicate the bidding capacity price, mileage price and maximum capacity for up/down FRS, respectively. After receiving energy and FRS bids from all participants, a co-optimized market clearing of energy and FRS bids will be carried out. Figure 1 illustrates the proposed spot market clearing mechanism and its mathematical formulation is given as follows.

$$\min \sum_{i \in N^{Gtr}} r_i^s (p_i^{crt} + p_i^{ucrt}) + \sum_{n \in N^{rsv,up}} r_n^{rsv,up} p_n^{rsv,c,up} + \sum_{m \in N^{rsv,dw}} r_m^{rsv,dw} p_m^{rsv,c,dw} \quad (1)$$

$$\text{s.t. } B^{hb} = \frac{1}{|T^{avl}|} \sum_{t \in T^{avl}} \left| b_1 \Delta p_{1,t}^{el,s} + b_2 \Delta p_{2,t}^{el,s} + \dots + b_{N^{Gtr}} \Delta p_{N^{Gtr},t}^{el,s} \right| \quad (2)$$

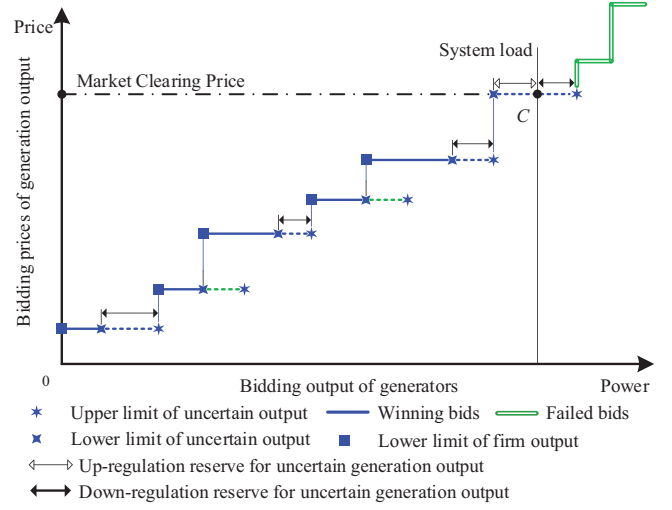


FIGURE 1 Schematic diagram of the proposed spot market mechanism

$$B^{hb,max} = \frac{1}{|T^{avl}|} \sum_{t \in T^{avl}} \left(\left| b_1 \Delta p_{1,t}^{el,s} \right| + \left| b_2 \Delta p_{2,t}^{el,s} \right| + \dots + \left| b_{N^{Gtr}} \Delta p_{N^{Gtr},t}^{el,s} \right| \right) \quad (3)$$

$$\Delta p_{i,t}^{el,s} = p_{i,t}^{el,s} - p_{i,t-1}^{el,s}, \forall t \in T^{avl} \quad (4)$$

$$\sum_{i \in N^{Gtr}} (p_i^{crt} + p_i^{ucrt}) = \sum_{j \in N^{bus}} p_j^{load}, [\lambda^{e,bal}] \quad (5)$$

$$P_{syn}^{rsv} + \left(\sum_{i \in N^{Gtr}} p_i^{ucrt} \right) \cdot (B^{hb} / B^{hb,max}) = \sum_{n \in N^{rsv,up}} p_n^{rsv,c,up} \quad (6)$$

$$\left[\sum_{i \in N^{Gtr}} (p_i^{s,ucrt} - p_i^{ucrt}) \right] \frac{B^{hb}}{B^{hb,max}} = \sum_{m \in N^{rsv,dw}} p_m^{rsv,c,dw} \quad (7)$$

$$\left| \sum_{j \in N^{bus}} \rho_{l,j} \left[\sum_{i \in j} (p_i^{crt} + p_i^{ucrt}) - p_j^{load} \right] \right| \leq p_l^{max}, [\mu_l^{ts}] \quad (8)$$

$$p_i^{ucrt} - b_i \eta_i = 0 \text{ and } \eta_i > 0 \quad (9)$$

$$r_n^{rsv,up} = \frac{r_n^{rsv,up,c} + r_n^{rsv,up,mil}}{p_n^{rsv,up,max}}; r_m^{rsv,dw} = \frac{r_m^{rsv,dw,c} + r_m^{rsv,dw,mil}}{p_m^{rsv,dw,max}} \quad (10)$$

$$p_i^{crt} \in [0, p_i^{s,frm}]; p_i^{ucrt} \in [0, p_i^{s,ucrt}] \quad (11)$$

$$p_n^{rsv,c,up} \in [0, p_n^{rsv,up,max}]; p_m^{rsv,c,dw} \in [0, p_m^{rsv,dw,max}] \quad (12)$$

where the objective function (1) is to minimize the overall system cost of dispatching energy and FRS. Although RGs

introduce variability to power systems, variable RGs also help compensate the fluctuation of each other in their collective output. Equations (2)–(4) calculate the complementarity of RGs using output forecasting results from variable generators, where the absolute change of output is considered. T^{vl} is the trading interval. $\hat{p}_{i,t}^{\text{el},s}$ is the expected value of forecasting outputs and is an element of the output vector $\mathbf{p}_{i,t}^s$ submitted by generator i . When $B^{\text{hb}} = 0$ it means that the changes of RGs outputs can cancel each other out completely. Otherwise, a larger value of B^{hb} means a lower complementarity of RGs. B^{hb} equals to its largest value $B^{\text{hb},\text{max}}$ when outputs of all RGs increase or decrease simultaneously. Equations (5)–(7) indicate the market equilibrium of energy, up and down regulations, respectively, where complementarity is also considered to avoid excessive FRS reserve. In (6), $P_{\text{syn}}^{\text{rsv}}$ denote the minimum required reserve capacity even when the forecasted changes of RG output can cancel each other, to cope with the inherent variability of RGs and load demand. Similar to PJM, here $P_{\text{syn}}^{\text{rsv}}$ equals to capacity of the potential largest single contingency which can be determined by surveying the greatest capacity loss due to a single contingency in the system [21]. Equation (8) is the network transmission constraint. Equation (9) ensures that the FRS cost is triggered only when uncertain output p_i^{ucrt} is dispatched. Equations (11) and (12) are constraints on decision variables.

Regarding the FRS market, the settlement rules of regulation services in typical electricity markets of North America are comprehensively reviewed in [32], including PJM, MISO, CAISO, and NYISO. In particular, the Federal Energy Regulatory Commission are requiring ISOs to distinguish the payment for different FRS resources by using a two-part pricing plan, which includes a capacity price and a mileage price [33]. The capacity price compensates the opportunity cost of providing FRS while the mileage price rewards the FRS provider based on its actual up and down regulations.

Although FRS is finally paid by both capacity and mileage prices, the market clearing of FRS bids in these markets is carried out using a weighted average value of capacity and mileage bidding prices, as is expressed by (10). $r_n^{\text{rsv},\text{up}}$ and $r_m^{\text{rsv},\text{dw}}$ is the weighted average of up/down regulation bidding prices.

Besides, p_i^{crt} and p_i^{ucrt} indicate the winning firm and uncertain output of the i th generator. $p_n^{\text{rsv},\text{c},\text{up}}$ and $p_m^{\text{rsv},\text{c},\text{dw}}$ are the winning FRS bids of the n th and m th FRS provider. B^{hb} and $B^{\text{hb},\text{max}}$ are complementarity metrics for RGs. j is the bus index and $j \in N^{\text{bus}}$. p_j^{load} represents the load demand at bus j . $\lambda^{\text{e},\text{bal}}$ is the Lagrangian multiplier for (5). p_l^{max} is the transmission limit of branch l ($l \in L$) and $\rho_{l,i}$ denotes the power transfer distribution factor. Since the final dispatched output of RGs is composed of firm and uncertain parts, the binary variable b_i and the auxiliary variable η_i in (9) are introduced to ensure that the FRS cost is triggered only when the uncertain output p_i^{ucrt} is a positive value.

In (1)–(12), decision variables are p_i^{crt} , p_i^{ucrt} , $p_n^{\text{rsv},\text{c},\text{up}}$, $p_m^{\text{rsv},\text{c},\text{dw}}$, b_i and η_i . Parameters are r_i^s , $p_i^{\text{s},\text{frm}}$, $p_i^{\text{s},\text{ucrt}}$, $p_i^{\text{s},\text{c}}$, $r_n^{\text{rsv},\text{up},\text{c}}$, $r_n^{\text{rsv},\text{up},\text{mil}}$, $p_n^{\text{rsv},\text{up},\text{max}}$, $r_m^{\text{rsv},\text{dw},\text{c}}$, $r_m^{\text{rsv},\text{dw},\text{mil}}$, $p_m^{\text{rsv},\text{dw},\text{max}}$, p_j^{load} , and p_l^{max} .

Since $\lambda^{\text{e},\text{bal}}$, $\mu^{\text{rsv},\text{up},\text{bal}}$ and $\mu^{\text{rsv},\text{dw},\text{bal}}$ denote the Lagrangian multipliers of constraints (5), (6) and (7), then the proposed spot

market model can be transformed into an unconstrained optimization problem. As is known, in mathematical optimization, a Lagrange multiplier is the change in the optimal value of the objective function (which is overall cost here) due to the relaxation of a given constraint. Therefore, the nodal energy price r_i at node i can be formulated as follows.

$$r_i = -\lambda^{\text{e},\text{bal}} - \sum_{j \in N^{\text{bus}}} \mu_j^{\text{ts}} \rho_{l,j} \quad (13)$$

After solving the proposed spot market model, the dispatch plan and system total cost is determined. Bidding capacity and mileage prices of marginal FRS units will determine the market clearing price (MCP). Let $r^{\text{rsv},\text{c},\text{up}}$, $r^{\text{rsv},\text{mil},\text{up}}$, $r^{\text{rsv},\text{c},\text{dw}}$, $r^{\text{rsv},\text{mil},\text{dw}}$ denote the capacity and mileage prices of up/down FRS in the MCP.

Then, the i th generator will be paid for its winning output $p_i^{\text{crt}} + p_i^{\text{ucrt}}$ at the nodal energy price r_i . Meanwhile, generator i should pay for its allocated cost of up/down FRS reserve capacity, as given below.

$$C_i^{\text{rsv},\text{c},\text{up}} = p_i^{\text{ucrt}} (B^{\text{hb}} / B^{\text{hb},\text{max}}) r^{\text{rsv},\text{c},\text{up}} \quad (14)$$

$$C_i^{\text{rsv},\text{c},\text{dw}} = (p_i^{\text{s},\text{ucrt}} - p_i^{\text{ucrt}}) (B^{\text{hb}} / B^{\text{hb},\text{max}}) r^{\text{rsv},\text{c},\text{dw}} \quad (15)$$

where $C_i^{\text{rsv},\text{up}} / C_i^{\text{rsv},\text{dw}}$ is allocated up/down FRS capacity cost to generator i .

Regarding the mileage cost, because the actual regulation mileage can only be known ex-post, so the allocation of mileage cost can be determined as follows.

$$M_t^{\text{mil},\text{acl}} = \sum_{i \in N^{\text{Gtr}}} b_i \left(p_{i,t}^{\text{acl}} - p_{i,t-1}^{\text{acl}} \right) \quad (16)$$

$$C^{\text{mil},\text{cost}} = \sum_{t \in T^{\text{vl}}} \left[\left(M_t^{\text{mil},\text{acl}} \right)^+ r^{\text{rsv},\text{mil},\text{dw}} + \left(M_t^{\text{mil},\text{acl}} \right)^- r^{\text{rsv},\text{mil},\text{up}} \right] \quad (17)$$

$$C_i^{\text{rsv},\text{mil}} = \left[p_i^{\text{ucrt}} / \left(\sum_{i \in N^{\text{Gtr}}} p_i^{\text{ucrt}} \right) \right] C^{\text{mil},\text{cost}} \quad (18)$$

where $p_{i,t}^{\text{acl}}$ is the actual output of generator i at time t . $M_t^{\text{mil},\text{acl}}$ is the actual deviation mileage of variable generation from $t-1$ to t . $(M_t^{\text{mil},\text{acl}})^+$ and $(M_t^{\text{mil},\text{acl}})^-$ means that when excessive or insufficient generation occurs, down and up regulation is needed. $C_i^{\text{rsv},\text{mil}}$ is the mileage cost allocated to generator i .

Equations (14)–(18) only allocate the FRS cost caused by the variations from market clearing outcomes but not the total system FRS cost, where the later also needs to be allocated to load demand. Due to the non-linearity of constraints (6), (7) and (9) and the introduced binary variable b_i , the proposed market mechanism is finally formulated into a mixed-integer non-linear programming problem (MINLP). The online optimization solvers provided by the NEOS (Network-Enabled Optimization System) server are used to solve the MINLP.

2.3 | Advantages of the proposed spot market mechanism

The advantages of the proposed market mechanism are many-fold. It is not only as flexible as existing market mechanism in providing various forms of ex-ante electricity market clearing, including minute-ahead, hour-ahead, or day-ahead transactions, but also can help further improve the market efficiency and ensure the operation security under a high proportion of RE.

1. The proposed mechanism is beneficial to improve the operation efficiency of power systems with high penetration levels of RE. The dispatch of generation units is not merely based on the merit order of energy bids, but also by taking into account the cost of FRS reserved for the variable RE generation. Besides, the proposed mechanism can also be further extended to incorporate bids of responsive load demand, which enables an optimal trade-off between the costs of energy supply, reserve capacity and load shedding in the final market results.
2. The proposed market formulation provides a methodology to determine the amount of FRS in a more accurate way. Many existing systems (including PJM, NYISO, ERCOT, CAISO, and MISO in North America) determine FRS requirements in an ex-ante and static manner, which may vary depending upon the day, hour, or season [34]. Differently, the Australian National Electricity Market (NEM) determines its FRS dynamically based upon the accumulated deviation of the frequency from its desired set point over time. It can help reduce reserve requirements and therefore reduce costs [35]. When the penetration level of RE is not high, this dynamic but passive way of determining FRS works well since the power system has a large inertia. However, with the increasing of renewable generation, the NEM operator noticed that its method of determining FRS should be adjusted to cope with the increased variability and reduced inertia.

Notably, co-optimization of energy and FRS bids is already adopted in existing markets to attain the overall least cost dispatch plan, but the amount of FRS needed is ex-ante determined using the above-mentioned static or dynamic approaches [36]. This paper shows the FRS required under different portfolio of energy dispatch co-optimized with the energy market.

3 | EXECUTION OF MARKET CLEARING OUTCOMES

Despite the intermittency and uncertainty of RE generation, once electricity spot market clearing outcomes are released, winning generators need to schedule their outputs in accordance with market clearing results. Otherwise, the difference between their cleared bids and the real-time outputs will be subject to penalty. For generators without self-owned ESS, they can buy the FRS from the regulation market to compensate the real-time

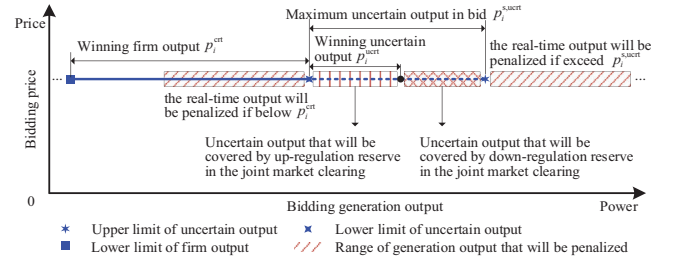


FIGURE 2 Illustration of a generation bid and the penalty on deviation

deviations. Let Δt denote the interval of transaction in the spot market. In the proposed penalty scheme, deviations of generation output from the dispatch signal are penalized by three performance indexes: the maximum power deviation, total mileage of regulation, as well as the cumulative difference of energy during Δt . Meanwhile, generators can initiatively manage the deviations of output through the following ways: truly reporting the uncertainty of output in their bids; allocating the usage of their own ESS; improving their generation control capability by adopting new technologies; cooperating with other entities for purchasing beforehand a certain amount of FRS through signing contracts. Figure 2 illustrates a winning bid and the penalty on its real-time deviations.

As the costs of adopting new generation control technologies and signing FRS contracts are sunk costs for decision-making in the spot market, and therefore can be neglected. The decision-making problem for a generator when participating in the proposed spot market is thus formulated as follows.

$$\max R_i = R_i^{\text{ess,rsv}} + R_i^{\text{ess,mkt}} + R_i^{\text{rev}} - C_i^{\text{rsv,c}} - C_i^{\text{pnl,c}} - C_i^{\text{pnl,mil}} - C_i^{\text{pnl,e}} \quad (19)$$

$$R_i^{\text{ess,rsv}} = p_i^{\text{ess,rsv}} (r^{\text{e,mcp,max}} - r^{\text{e,mcp,min}}) \Delta t \quad (20)$$

$$R_i^{\text{ess,mkt}} = p_i^{\text{ess,mkt}} \max(r^{\text{rsv,up,mcp}}, r^{\text{rsv,dw,mcp}}) \quad (21)$$

$$\hat{p}_i^{\text{ess}} = p_i^{\text{ess,rsv}} + p_i^{\text{ess,mkt}} + p_i^{\text{ess,reg}} \quad (22)$$

$$R_i^{\text{rev}} = r^{\text{e,mcp}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \Delta t \quad (23)$$

$$C_i^{\text{rsv,c}} = b_i [r^{\text{rsv,c,up}} (p_i^{\text{ucrt}} - p_i^{\text{ess,reg}}) + r^{\text{rsv,c,dw}} (p_i^{\text{s,ucrt}} - p_i^{\text{ucrt}} - p_i^{\text{ess,reg}})] + r^{\text{mil}} \sum_{b \in \Delta t} |p_{i,b}^{\text{acl}} - p_{i,b}^{\text{acl}}| \quad (24)$$

$$p_{i,b}^{\text{low,dev}} = (p_i^{\text{crt}} + p_i^{\text{ucrt}} - p_{i,b}^{\text{acl}}) + -b_i p_i^{\text{ucrt}} - p_i^{\text{ess,reg}} \quad (25)$$

$$p_{i,b}^{\text{up,dev}} = (p_{i,b}^{\text{acl}} - p_i^{\text{crt}} - p_i^{\text{ucrt}}) + -b_i (p_i^{\text{s,ucrt}} - p_i^{\text{ucrt}}) - p_i^{\text{ess,reg}} \quad (26)$$

$$C_i^{\text{pnl},c} = r^{\text{pnl},c} \max_{b \in \Delta t} \left(p_{i,b}^{\text{low,dev}}, p_{i,b}^{\text{up,dev}}, 0 \right) \quad (27)$$

$$C_i^{\text{pnl},\text{mil}} = r^{\text{pnl},\text{mil}} \sum_{b \in \Delta t} \max \left(\left| p_{i,b+1}^{\text{acl}} - p_{i,b}^{\text{acl}} \right| - b_i p_i^{\text{s,uct}} - p_i^{\text{ess,reg}}, 0 \right) \quad (28)$$

$$C_i^{\text{pnl},c} = r^{\text{pnl},c} \left[\left| \int_{b \in \Delta t} \left(p_{i,b}^{\text{acl}} - p_i^{\text{crt}} - p_i^{\text{uct}} \right) db \right| - \int_{b \in \Delta t} p_i^{\text{ess,reg}} db \right]^+ \quad (29)$$

$$\text{s.t. } 0 \leq p_i^{\text{ess,rsv}}, p_i^{\text{ess,mkt}}, p_i^{\text{ess,reg}} \quad (30)$$

where the objective function (19) is the maximization of total benefit for the i th generator. In the future, more ESS will join the system as hybrid resources, which pairs ESS with renewable generation units. Therefore, Equations (20)–(22) represent the amount of ESS capacity that is allocated for either energy arbitrage, self-FRS, or providing FRS to other users. Equations (20) and (21) denote the profit from arbitrage and providing FRS to others. Equation (23) denotes the revenue of generation in the spot market. Equation (24) is the cost of purchasing up and down FRS. Equations (25) and (26) express the deviation of real-time output for the i th generator at time b when the output is lower/larger than the winning bids. Equations (27)–(29) calculate the penalties on the real-time maximum power deviation/mileage of FRS/cumulative energy difference of generation.

Specifically, p_i^{ess} is the capacity of ESS paired with or owned by RGs. For RGs without ESS, then the decision-making problem evolves into a simpler case of $p_i^{\text{ess}} = 0$. $p_i^{\text{ess,rsv}}/p_i^{\text{ess,mkt}}/p_i^{\text{ess,reg}}$ indicates the amount of ESS capacity that is used for energy arbitrage/providing FRS to other users/self-FRS. $r^{\text{rsv},\text{mil}}$ denotes the mileage price of FRS in the regulation market. $p_{i,b}^{\text{acl}}$ is the actual generation output of generator i at time b . $r^{\text{pnl},c}/r^{\text{pnl},\text{mil}}/r^{\text{pnl},e}$ indicates penalty price on the real-time maximum power deviation/mileage of FRS/cumulative energy difference of generation output.

In the decision-making model for a generator, decision variables are $p_i^{\text{ess,rsv}}$, $p_i^{\text{ess,mkt}}$, and $p_i^{\text{ess,reg}}$. Parameters are p_i^{crt} , p_i^{uct} , p_i^{ess} , $r^{\text{e,mcp}}$, $r^{\text{e,mcp,max}}$, $r^{\text{e,mcp,min}}$, $r^{\text{rsv},\text{mil}}$, $p_{i,b}^{\text{acl}}$, $r^{\text{pnl},c}$, $r^{\text{pnl},\text{mil}}$ and $r^{\text{pnl},e}$. Specifically, $r^{\text{e,mcp}}$, $r^{\text{e,mcp,max}}$, $r^{\text{e,mcp,min}}$ are the spot market MCP/maximum MCP/minimum MCP and can be obtained from solutions of the proposed spot market model. Given these parameter values, the decision-making model for a generator will be a linear programming problem to be solved by decision-makers for developing optimal market strategies.

3.1 | Setting of penalty prices on output deviations

As each generator bids to maximize its own profit, the priority will be given to mitigating real-time output deviations as long as the corresponding penalties on deviations are higher than the

profit from energy arbitrage, the incurred cost of purchasing FRS and the income of providing ESS FRS to others. Meanwhile, when there are unexpected output deviations, the market operator will have to dispatch contingency FRS to ensure the security of system operation. Let $r^{\text{rsv},\text{ctg},c}$ represent the capacity price of contingency FRS, then, for the i th generator, the following conditions on penalty prices should be respected.

$$r^{\text{pnl},c} \geq r^{\text{e,mcp,max}} - r^{\text{e,mcp,min}} \quad (31)$$

$$r^{\text{pnl},c} \geq \max(r^{\text{rsv,up,mcp}}, r^{\text{rsv,dw,mcp}}, r^{\text{rsv,ctg,c}}) \quad (32)$$

$$r^{\text{pnl},\text{mil}} \geq r^{\text{mil}} \quad (33)$$

Equations (31)–(33) ensure that accepting penalties passively will always result in a larger loss than managing initiatively output deviations. The above conditions can also ensure that the ISO will have adequate funding for purchasing contingency FRS to compensating the unexpected deviation of RGs. In addition, this paper further proves that the range of generation output deviations can be managed within a certain limit under the designed penalty prices.

Theorem 1. For the i th generator i , when the penalty prices on deviation of power rate, mileage of FRS and energy imbalance are set as (34)–(36), the maximum power deviation and regulation mileage that exceed the purchased FRS reserve capacity, as well as the cumulative energy difference can be managed within $L^{\text{dev,max}}(p_i^{\text{crt}} + p_i^{\text{uct}}, M^{\text{mil}}$ and $L^{\text{e,dev,max}}(p_i^{\text{crt}} + p_i^{\text{uct}})\Delta t$, respectively.

$$r^{\text{pnl},c} = r^{\text{e,mcp}} \Delta t / L^{\text{dev,max}} \quad (34)$$

$$r^{\text{pnl},\text{mil}} = r^{\text{e,mcp}} \Delta t / 2N^{\text{disp}} L^{\text{dev,eql}} \quad (35)$$

$$r^{\text{pnl},e} = r^{\text{e,mcp}} / L^{\text{e,dev,max}} \quad (36)$$

$$M^{\text{mil}} = 2N^{\text{disp}} L^{\text{dev,eql}} (p_i^{\text{crt}} + p_i^{\text{uct}}) \quad (37)$$

where $L^{\text{dev,max}}/L^{\text{e,dev,max}}$ indicates the maximum percentage of power and energy deviation on the winning bids during time interval Δt . $L^{\text{dev,eql}}$ is the equivalent percentage of deviations on the winning bids of participants. M^{mil} represents the upper limit of mileage. N^{disp} is the number of FRS signals during Δt .

Figure 3 illustrates the proposed penalty method and concepts in Theorem 1. In Figure 3, the equivalent fluctuation means that for any M^{mil} , there always exists a $L^{\text{dev,eql}}$ that makes (37) hold, namely any deviation with a mileage M^{mil} during Δt can be mathematically equivalent to a fluctuation with the same amplitude each time during Δt .

3.2 | Proof of theorem

In the decision-making model for a generator, the decision maker maximizes its overall profit through calculating the optimal strategies. Because the FRS market is cleared

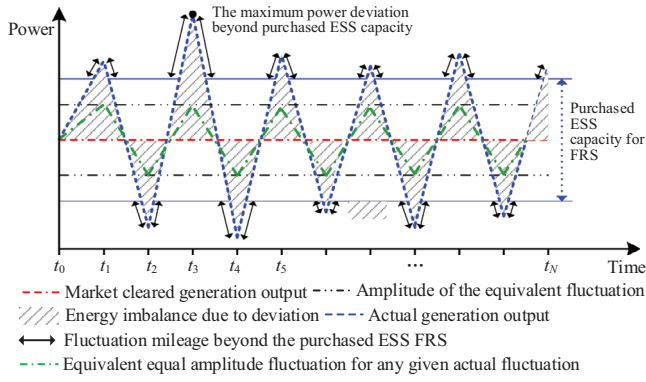


FIGURE 3 The illustration of concepts in Theorem 1

simultaneously with the energy market, namely when applying the proposed penalty scheme, the participants can no longer modify their winning bids. Thus, it is essential to ensure that generators participating in the electricity market will make a positive profits from transactions. Otherwise, the market operation will be less sustainable and the market volatility will also be a severe problem. This can be achieved by releasing parameters (including $L^{\text{dev,max}}$, $L^{\text{dev,eq}}$ and $L^{\text{e,dev,max}}$) that represent the technical requirements for market access to market participants.

Firstly, it is assumed that a generator does not buy FRS from the regulation market for compensating deviation (or the uncertainty of RG output is not reported truly), but choose to accept penalties, which is the worst case. Then, the net profit of this generator will be zero once its power deviation reaches the designed threshold value, namely equals to the maximum percentage on winning bids:

$$\text{When } \max_{b \in \Delta t} (p_{i,b}^{\text{low,dev}}, p_{i,b}^{\text{up,dev}}, 0) = L^{\text{dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \text{ and } b_i = 0, \text{ then } R_i = R_i^{\text{ess,rsv}} + R_i^{\text{ess,mkt}} + R_i^{\text{rev}} - C_i^{\text{rsv,c}} - r^{\text{pnl,c}} L^{\text{dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) - C_i^{\text{pnl,mil}} - C_i^{\text{pnl,e}} \quad (38)$$

$$\text{Since } R_i^{\text{ess,rsv}}, R_i^{\text{ess,mkt}}, C_i^{\text{rsv,c}}, C_i^{\text{pnl,mil}}, C_i^{\text{pnl,e}} \geq 0, \text{ thus } R_i \geq 0 \Rightarrow r^{\text{pnl,c}} \leq r^{\text{e,mcp}} \Delta t / L^{\text{dev,max}} \quad (39)$$

For the regulation mileage, let M^{mil} denotes the threshold value. If the mileage of actual output deviation is below this threshold, the generator will have a positive profit. However, once the actual deviation mileage reaches this threshold value, the net profit of generation reduces to zero.

When $\sum_{b \in \Delta t} \max(|p_{i,b+1}^{\text{acl}} - p_{i,b}^{\text{acl}}| - p_i^{\text{ess,reg}}, 0) = M^{\text{mil}}$ and $b_i = 0$, then

$$R_i = R_i^{\text{ess,rsv}} + R_i^{\text{ess,mkt}} + R_i^{\text{rev}} - C_i^{\text{rsv,c}} - C_i^{\text{pnl,c}} - r^{\text{pnl,mil}} M^{\text{mil}} - C_i^{\text{pnl,e}} \quad (40)$$

$$\text{Since } R_i^{\text{ess,rsv}}, R_i^{\text{ess,mkt}}, C_i^{\text{rsv,c}}, C_i^{\text{pnl,c}}, C_i^{\text{pnl,e}} \geq 0, \text{ thus } R_i \geq 0 \Rightarrow r^{\text{pnl,mil}} \leq r^{\text{e,mcp}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \Delta t / M^{\text{mil}} \quad (41)$$

Furthermore, for any M^{mil} , there always exists a $L^{\text{dev,eq}}$ that makes (37) hold. After substitute (37) into (41), $r^{\text{pnl,mil}}$ can be derived as (35).

Similarly, let $L^{\text{e,dev,max}}$ indicate the threshold value for the cumulative energy difference. The net profit of a generator will also reduce to zero once its actual cumulative energy difference equals to this threshold limit.

When $[\int_{b \in \Delta t} (p_{i,b}^{\text{acl}} - p_i^{\text{crt}} - p_i^{\text{ucrt}}) db] - \int_{b \in \Delta t} p_i^{\text{ess,reg}} db]^+ = L^{\text{e,dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \Delta t$ and $b_i = 0$, then

$$R_i = R_i^{\text{ess,rsv}} + R_i^{\text{ess,mkt}} + R_i^{\text{rev}} - C_i^{\text{rsv,c}} - C_i^{\text{pnl,c}} - C_i^{\text{pnl,mil}} - L^{\text{e,dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \Delta t \quad (42)$$

Since $R_i^{\text{ess,rsv}}, R_i^{\text{ess,mkt}}, C_i^{\text{rsv,c}}, C_i^{\text{pnl,c}}, C_i^{\text{pnl,mil}} \geq 0$, thus

$$R_i \geq 0 \Rightarrow r^{\text{pnl,e}} \leq r^{\text{e,mcp}} / L^{\text{e,dev,max}} \quad (43)$$

In summary, when setting the penalty prices as (34)–(36), the net profit R_i for generator i will always reduce to zero once the actual deviations of generation outputs reaches the threshold values $L^{\text{dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}})$, M^{mil} and $L^{\text{e,dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \Delta t$ that are set for the fluctuation of power rate, mileage of regulation, and the cumulative energy difference, respectively. In the words, for each generator, the deviation between its actual generation outputs and the winning bids can always be managed within a certain limit when making decisions for a positive profit R_i .

Otherwise, if a generator chooses to initiatively manage the uncertainty of RG output, this will increase its net profit R_i , as the payment for buying FRS is less than the penalty fee under the above penalty scheme. Moreover, the actual fluctuations of RG outputs could exceed the purchased FRS capacity. Accordingly, the R_i will decrease to zero before the power rate deviation, the mileage of fluctuation, or the cumulative energy difference reaches their threshold values because the purchasing of FRS has already incurred costs. Meanwhile, the maximum power deviation and mileage of fluctuations that go beyond the purchased FRS reserve capacity, as well as the cumulative energy difference between actual outputs and winning bids can still be managed within the threshold values of $L^{\text{dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}})$, M^{mil} and $L^{\text{e,dev,max}} (p_i^{\text{crt}} + p_i^{\text{ucrt}}) \Delta t$, respectively, in order for a positive R_i . Theorem 1 is hence proved.

The proposed penalty method enables the market volatility to be managed within a certain limit through properly setting the penalty prices. Before bidding to the spot market, RGs may purchase reserve capacity through signing contracts with any other entities to compensate the potential output fluctuation. Alternatively, the RGs may strategically choose to bid an uncertainty of output that is smaller than its actual generation, and then accept the penalties on the real-time output deviation. Since penalty prices on real-time deviations of outputs are always higher than FRS prices in the regulation market (as shown in (31)–(33)), RGs will always suffer a larger loss by bidding a fraud parameter for its uncertain output. Thus, this penalty scheme can motivate participants to truly report their output uncertainty.

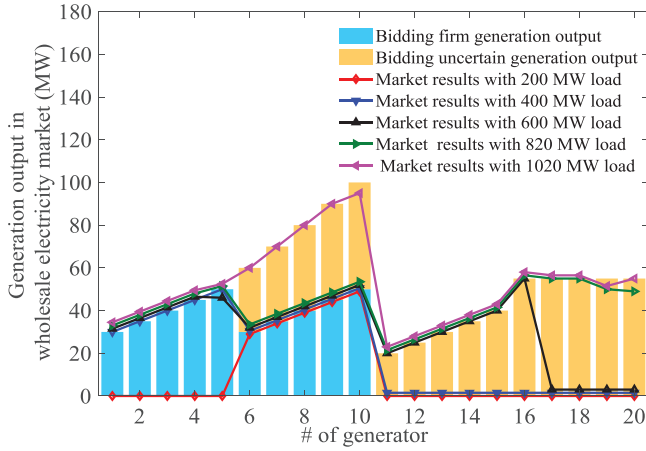


FIGURE 4 Spot market clearing outcomes when FRS price is high. Note: In the high scenario, FRS bid prices range from 75 to 120 \$/MW

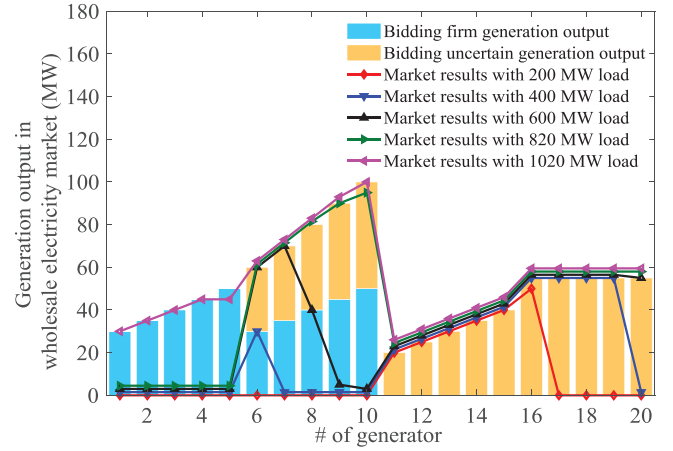


FIGURE 5 Spot market clearing outcomes when FRS price is low. Note: In the low scenario, FRS bid prices range from 30 to 39 \$/MW

4 | CASE STUDY AND DISCUSSIONS

4.1 | Simulation dataset

The IEEE standard 57-bus transmission system [37] is adopted and modelled as a single-phase (positive sequence) network to test the proposed spot market mechanism. Various generation units are considered in the 57-bus transmission system, including fossil-fuelled generators, renewable generators, as well as FRS providers. Each of these participants is connected to a specific bus of the 57-bus system, where Bus 1 is selected as the reference bus. Data of bid prices and quantities for generators and FRS providers are borrowed from the Australian national electricity market [38].

4.2 | Results and discussions

In the case study, 40 participants are assumed to participate in the spot market, including thermal and renewable generators. Generators 1–5 are assumed to be fully dispatchable ones and submit bids only with firm output. Generators 6–10 are half dispatchable ones, so bid to the spot market with both firm and uncertain output. Generators 11–20 are volatile generators, and thus bid to the market only with uncertain output. Another 20 participants are assumed to be regulation service providers. The market simulation is carried out under various scenarios of load demand and FRS prices. Figures 4 and 5 present the spot market clearing outcomes under different FRS prices. It is assumed that energy and FRS bids are submitted simultaneously, namely when generators set their bidding parameters for firm and uncertain outputs, the FRS price is unknown. Thus, the bidding firm and uncertain outputs are the same in Figures 4 and 5.

In the results, although volatile generators 11–20 have much lower bidding prices than others, due to the high FRS price, the market operator will firstly dispatch firm generation output without purchasing regulation services to compensate poten-

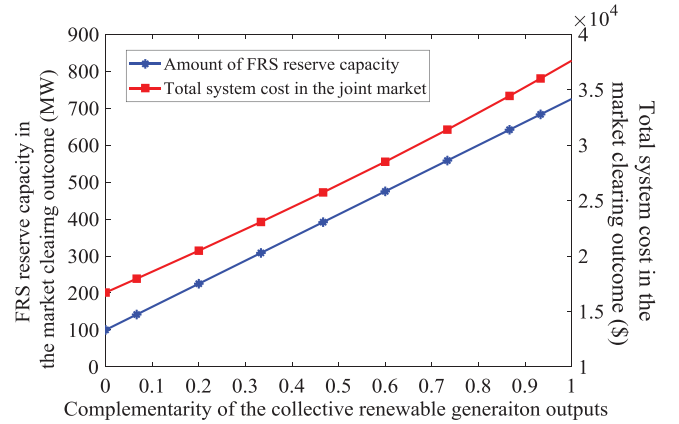


FIGURE 6 Sensitivity study of FRS reserve capacity and total system costs

tial intermittency and uncertainty. With the increase of load demand, the uncertain output will start to be dispatched to satisfy the constraint on equilibrium of demand and supply, while minimizing the total system cost. On the contrary, when FRS price is low, volatile generators will be able to compete with dispatchable resources with the advantages of lower bidding prices. Uncertain generation output with the lowest bidding prices is dispatched first and the conventional dispatchable units with the highest bidding price are dispatched lastly due to the growth of load, as shown in Figure 5. Therefore, under the proposed mechanism, market bids are not cleared solely based on their bidding prices, but also by considering the cost of purchasing FRS. Besides, the joint clearing of energy and FRS bids can also ensure that the adequacy of regulation services for the reliable and secure operation of power systems.

Besides, Figure 6 gives the amount of FRS reserve capacity and corresponding system overall costs under different complementarity levels of RGs, where the x-axis indicates values of $B^{hb}/B^{hb,max}$. With the increasing of $B^{hb}/B^{hb,max}$, namely the decreasing of complementarity among RGs outputs, more FRS are needed and accordingly the overall system

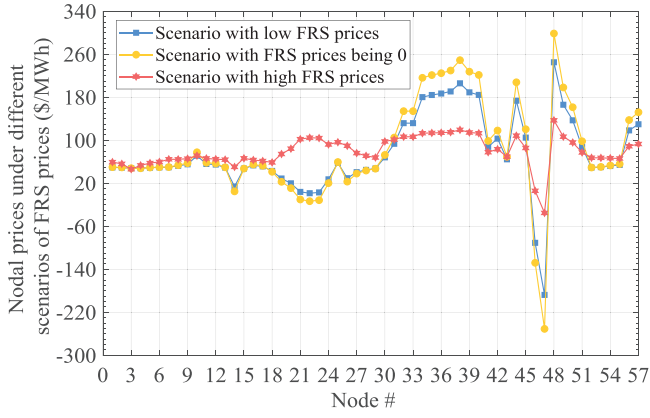


FIGURE 7 Nodal prices in the 57-bus system under different scenarios

cost increases as well. Both of them achieve their largest values when $B^{hb}/B^{hb,max} = 1$, namely all RGs outputs simultaneously increase or decrease under the worst case.

Simulation is also carried out when transmission congestion happens. Four branches in the 57-bus system are randomly selected where congestion occurs. The nodal energy prices under different scenarios of FRS prices are given in Figure 7.

When the FRS price is low, there will be more types of generators being dispatched in the system, including the dispatchable, half dispatchable and volatile ones. Consequently, the shadow prices of each transmission constraints are higher due to the flexible portfolios of generation. Accordingly, there is much larger difference among the nodal prices, as shown in Figure 7. When FRS price is high, the firm generation output will have priority in dispatch. Then, the shadow price of each transmission constraint is smaller because of the limited portfolios of generation resources in the case study, which results in a more flatten nodal price profile. In a word, the nodal prices change with the FRS prices impacts of FRS on the energy prices can be manifested under the proposed mechanism.

The proposed penalty scheme is simulated under the case when the spot market MCP is 53.048 \$/MWh. As is given in (34)–(36), the penalty prices are determined by the maximum percentage of power deviation on the winning bid $L^{dev,max}$, the upper limit of deviation mileage M^{mil} , and the maximum percentage of energy imbalance $L^{e,dev,max}$, respectively. Table 1 gives the penalty prices under different cases of $L^{dev,max}$, $L^{dev,eql}$

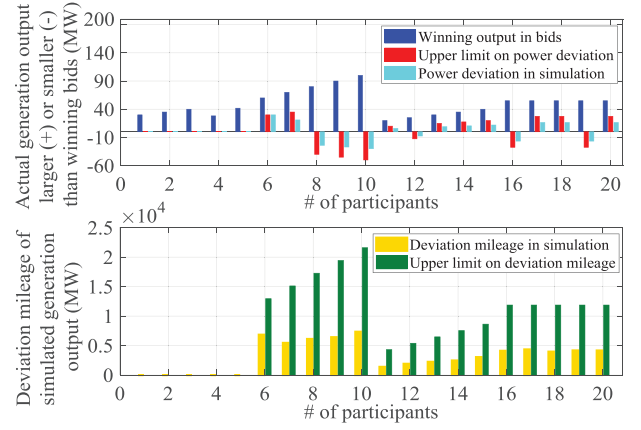


FIGURE 8 Market clearing outcomes and simulated real-time outputs

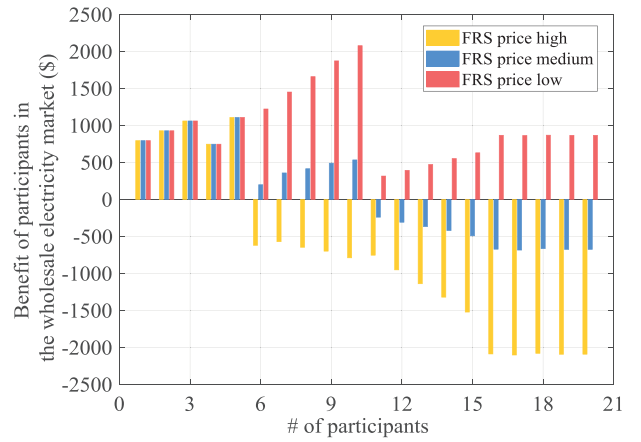


FIGURE 9 Benefits of participants under different FRS prices

and $L^{e,dev,max}$. The spot market is simulated as a half hourly market and the time interval of FRS signal is set as 5 s.

Furthermore, Figure 8 presents the market outcomes and the simulated deviations of real-time outputs under case 1. It can be observed that the power deviations of generations and deviation mileages are capped by the upper limits calculated using $L^{dev,max}$ and $L^{dev,eql}$. In order for a maximum trading benefit, participants will control output deviations within these limits. As generators 1–5 are fully dispatchable ones, their output deviations are thus 0 in the simulation. Figure 9 gives the benefits of

TABLE 1 Parameters and penalty prices under different cases

Case	Deviation parameters			Penalty prices		
	$L^{dev,max}$	$L^{s,dev,eql}$	$L^{e,dev,max}$	$r^{s,pnl,c}$ (\$/MW)	$r^{s,pnl,mil}$ (\$/MW)	$r^{s,pnl,e}$ (\$/MWh)
1	50%	30%	30%	53.05	0.123	176.83
2	40%	25%	25%	66.31	0.147	212.19
3	30%	20%	20%	88.41	0.184	265.24
4	20%	15%	15%	132.62	0.246	353.65
5	10%	5%	5%	265.24	0.737	1060.96

participants in the spot market under different FRS prices. With the decrease of FRS price, participants will have a higher trading benefit as there will be fewer expenses spent on purchasing FRS for compensating uncertain outputs. Meanwhile, for the fully dispatchable generation units, their benefit is independent of the FRS price changes. Comparing the results for half-dispatchable (participants 6–10) and volatile units (participants 11–20) in Figure 9, it can be found that with the changes of the FRS price, the firm output will help generators secure more benefits. Thus, the proposed mechanism can motivate generators improve the controllability of the generation outputs.

5 | CONCLUSIONS

The rapid growth of RE brings challenges to the operation of electricity markets and calls for the design of innovative mechanisms to ensure the secure and economic operation of power systems. This paper designs a new electricity spot market mechanism with the following advantages: (1) The MCP is able to reflect the cost of compensating the variability of RE generation outputs; (2) RGs are motivated to proactively manage the intermittency and uncertainty of outputs; (3) It provides an efficient way to determine the demand of FRS capacity for systems with high renewable generations; (4) It can help reveal the true value of FRS in a more accurate way through market bidding, and will foster the development flexible regulation services. Besides, a penalty scheme is also proposed for mitigating real-time deviation of RE outputs, in order to ensure the execution of spot market clearing outcomes. Case study results verify the feasibility and efficiency of the proposed market mechanism and algorithms. In the future, impacts of the proposed spot market mechanism on long-term resource adequacy will be studied.

NOMENCLATURE

Indices and sets

- i Index of generator in the energy market, $i \in N^{Gtr}$
- J Index of bus, $j \in N^{bus}$
- L Index of branch, $l \in L$
- m Index of participants for down FRS, $m \in N^{rsv,dw}$
- n Index of participants for up FRS, $n \in N^{rsv,up}$
- t Index of time, $t \in T$

Parameters

- $C_i^{rsv,dw}$ Allocated cost of down FRS capacity to generator i
- $C_i^{rsv,mil}$ Mileage cost allocated to generator i
- $C_i^{rsv,up}$ Allocated cost of up FRS capacity to generator i
- $L^{dev,eql}$ The equivalent percentage of deviations on the winning bids of participants
- $L^{dev,max}/L^{e,dev,max}$ The maximum percentage of power/energy deviation on the winning bids

- $M_t^{mil,acl}$ Deviation mileage of generation from $t-1$ to t
- p_i^{acl} Actual output of generator i at time t
- p_i^{ess} Capacity of ESS paired with or owned by RG i
- p_j^{load} Load demand at bus j
- p_l^{max} Transmission limit of branch l
- $p_m^{rsv,dw,max}$ Bidding maximum capacity for down FRS
- $p_n^{rsv,up,max}$ Bidding maximum capacity for up FRS
- $p_{i,t}^s$ The vector of forecasted generation output
- $p_i^{s,frm}$ Offering firm output of the i th generator
- $p_i^{s,ucrt}$ Offering uncertain output of the i th generator
- $r^{e,mcp}$ MCP in the spot market
- $r^{e,mcp,max}$ The maximum spot market MCP
- $r^{e,mcp,min}$ The minimum spot market MCP
- $r^{pnl,c}$ Penalty price on the real-time maximum power deviation
- $r^{pnl,e}$ Penalty price on the real-time cumulative energy difference of generation output
- $r^{pnl,mil}$ Penalty price on the real-time mileage of FRS
- $r_m^{rsv,dw,c}$ Bidding capacity price for down FRS
- $r_m^{rsv,dw,mil}$ Bidding mileage price for down FRS
- $r^{rsv,mil}$ Mileage price of FRS in the regulation market
- $r_n^{rsv,up,c}$ Bidding capacity price for up FRS
- $r_n^{rsv,up,mil}$ Bidding mileage price for up FRS
- r_i^s Offering price of the i th generator
- $\rho_{l,j}$ Power transfer distribution factor

Variables

- b_i/η_i Introduced ancillary variables in the model
- p_i^{crt} Dispatched firm output the i th generator
- $p_{rsv,i}^{ess}$ Amount of ESS capacity that is used for energy arbitrage/providing FRS to other users/self-FRS
- $p_{mkt,i}^{ess}$ Amount of ESS capacity that is used for energy arbitrage/providing FRS to other users/self-FRS
- $p_{reg,i}^{ess}$ Amount of ESS capacity that is used for energy arbitrage/providing FRS to other users/self-FRS
- $p_m^{rsv,c,dw}$ Winning bids of the m th down FRS provider
- $p_n^{rsv,c,up}$ Winning bids of the n th up FRS provider
- p_i^{ucrt} Dispatched uncertain output the i th generator
- r_i Nodal energy price

Abbreviations

- CRM Capacity remuneration mechanism
- ESS Energy storage system
- FRS Frequency regulation service
- ISO Independent system operator
- LMP Locational marginal prices
- MCP Market clearing price
- RE Renewable energy
- RG Renewable generator
- UMP Uncertainty marginal price

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