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A proposed hedge-based energy market model to manage renewable intermittency

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ABSTRACT

Renewable energy power producers are exposed to significant volatility in revenue due to intermittency associated with wind and solar energy. Moreover, higher penetration of variable renewable energy in the electric grids is significantly increasing the cost associated with procuring reserves, resulting in higher electricity costs to consumers. Hence, a market that can appropriately distribute the cost of procuring reserves whilst ensuring revenue stability for renewable energy producers is crucial. In this work, the authors propose a novel hedge-based energy market model that allows renewable generators to secure hedge contracts from flexible generating technologies as insurance against weather-driven energy deficits. The proposed model supplements a representative day-ahead market model and maximizes the revenue of market participants whilst diminishing the costs of procuring reserves and generating investment signals for green projects. A mathematical model is formulated to determine market equilibrium based on the Karush Kuhn Tucker (KKT) optimality conditions. Simulation studies are carried out to demonstrate the efficacy of the proposed model on a test network using MATLAB. The theoretical results are verified by simulation results and provide a feasible region in which mutually acceptable hedge contracts result in higher overall revenues. The results show that a hedge-based energy market model can be deployed to manage renewable intermittency in a day-ahead energy market model to address the risk management needs of renewable power producers.

1. Introduction

Various nations across the globe are seeking ways to accelerate the integration of renewable energy into power grids [1]. Advancements in technology and initiatives to tackle climate change have brought green energy projects, such as wind and solar photovoltaics (PV) farms [2], into the limelight [3]. Green projects are often associated with various financial and nonfinancial risks [4]. These risks have a varied nature and can be either mechanical, technological or weather-driven. Energy generation from most green projects rely on weather conditions, such as sunlight and wind speeds. The intermittent nature of the wind speeds and solar irradiation at a specific geographical location can substantially affect the energy generation and feasibility of such projects. Furthermore, variable renewable energy (VRE) is characterized by significant variability [5] and uncertainty [6], therefore, many system operators have devised policies to impose real-time penalties on variable renewable generators (VRGs) upon failing to meet set commitments in a day-ahead market [7]. As a result, VRGs bid with less confidence in the day-ahead market, thereby diminishing the share of renewable energy in the grid [8]. Such penalty mechanisms can result in lower profits for VRGs and hinder investments in new green projects.

Government subsidies and public funding are conventionally the main sources of financing for green projects. However, effectively financing green projects through private and non-for-profit sectors remains a challenge [9]. In context of private funding, green projects are typically financed either through debt financing or equity financing [10]. In energy-only markets, renewable power producers are exposed to both market price volatility and weather-driven revenue volatility that can significantly affect their expected profits, thus making it harder to finance green projects [11]. The interest rates for debt financing are substantially dependent on the expected revenue of the green energy projects. Similarly, in the matter of equity financing, the investor values the asset based on revenue risk, implying capital-raising is tied to weather-driven volatility and other market risks. Therefore, a market mechanism needs to be developed that can efficiently support

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Nomenclature

U_R^P	Utility function of a renewable generator in penalty-based market
U_{NG}^P	Utility function of a natural gas generator in penalty-based market
U_C^P	Utility function of a coal generator in penalty-based market
U_R^H	Utility function of a renewable generator in hedge-based market
U_{NG}^H	Utility function of a natural gas generator in hedge-based market
U_C^H	Utility function of a coal generator in hedge-based market
λ	Day-ahead market clearing price
η	An interest factor to determine the strike price in options market
π	Premium for options contract
ε	Penalty factor for power deficit
ζ	Production cost function of a natural gas generator
a, b, c	fuel cost-coefficients for natural gas generators
x, y, z	fuel cost-coefficients for coal generator
k	Linear cost-coefficient for renewable generator
P_R^c	Power committed by the renewable generator in the day-ahead market
P_R^g	Power generated by the renewable generator
P_R^δ	Power deficit experienced by the renewable generator
P_{NG}^c	Power committed by the natural gas generator in the day-ahead market
P_C^c	Power committed by the coal generator in the day-ahead market
P_R^r	Power reserved via options contract
μ	Lagrange multiplier vector
PV	Photovoltaic
VRE	Variable Renewable Energy
VRG	Variable Renewable Generator
FCG	Flexible Conventional Generator
ICG	Inflexible Conventional Generator
NEM	National Electricity Market (Australia)
AEMO	Australian Energy Market Operator
KKT	Karush Kuhn Tucker
PDF	Probability Distribution Function

investments in green projects through capital markets [12].

As access to credit, for a green project, is significantly impacted due to the associated risks within the market, it is necessary to develop risk mitigation techniques to drive new investments in green projects. Financial de-risking is one of the strategies proposed in Ref. [13], in which the perceived risk is minimized by transferring a substantial amount of risk to insurance risks of governments or development banks, thereby reducing investment costs. However, attempts to address financial de-risking for weather-driven volatility are limited. In this work, a mechanism to cope with weather-driven volatility is proposed by means of financial derivatives. The authors attempt to minimize revenue risk associated with uncertainty in weather for renewable power producers, thus making it easier to fund green projects through debt financing and/or equity financing.

Financial derivatives have conventionally been used by generators and retailers to mitigate risks associated with revenue volatility [14]. The financial derivative market was developed mainly for conventional generators and minimal changes have been made to the financial contracts since then [15]. However, the risk management needs of market participants are changing due to the rapid transition in energy mix and proliferation of VRE. This research work aims to develop new financial instruments that act as risk management tools for VRE assets. The lack of risk management tools available to green energy market participants inhibits choice and impacts market liquidity, thereby hindering investments in green projects [16].

In this paper, authors propose a market framework that requires a VRG to purchase a hedge contract from a flexible generator with more power output certainty. Two types of conventional generators are studied in this work, a flexible conventional generator (FCG), such as, a natural gas power plant and an inflexible conventional generator (ICG), such as a coal power plant. A hedge contract, such as a call option, is set between two generators before bidding into the day-ahead market. A call option is flexible in nature, as the buyer of a call contract has the right, but not the obligation, to buy energy. This allows a VRG to exercise the contract based on their actual realization of generated power and the day-ahead market price behavior. A VRG can purchase a hedge contract from an FCG as insurance against real-time energy deficits by procuring the right to a reserve. An energy deficit is defined as the difference between the energy committed by a VRG in the day-ahead market and the energy generated at the actual time of delivery. The hedge contract will give the VRG the right to use the purchased reserve and the FCG will have an obligation to fulfil the requirement if the VRG choses to exercise the hedge contract in case of an energy deficit.

Rich literature exists to tackle the intermittency introduced in the grids by VRE. Various researchers have proposed solutions to mitigate variability from renewable resources by associating a VRG with other energy sources. The authors of [17,18] presented a framework that combines wind and hydropower plants to bid collaboratively in the market that requires varying the hydropower generation according to the expected energy deficit of wind. Moreover, large-scale battery energy storage systems are coupled with VRG in Refs. [19–21] to meet any generation shortfall. However, the existing work mainly depends on the co-ownership of the two energy sources which is not always practicable.

The authors of [22] propose the use of options contract that allows market participants to diminish individual revenue volatility. The options contract in Ref. [22] allows the buyer the right to claim a payment for an energy deficit experienced by the VRG by paying an upfront fee to a conventional generator, who would typically provide energy for this deficit in the market. The results show that revenue volatility of market participants is reduced through these options contracts, however, no actual delivery of energy takes place in such market models. The studies conducted in Refs. [23,24] are the most relevant to the proposed work. The authors in Refs. [23,24] propose setting up options contract between a VRG and an FCG, in which the FCG reserves some amount of the energy in case a VRG experiences an energy deficit. However, research studies in Refs. [23,24] only consider a single payment made to the FCG to buy the rights to the reserve, which is the premium fee, and that does not account for actually purchasing the energy in case a VRG is unable to meet the set commitments in the day-ahead market. Thus, options trading has not been comprehensively represented in the previous work. In light of extant literature, the research gap is identified as the lack of financial instruments that can address the risk management needs of VRE assets to mitigate risk and generate new investments in green projects.

The novelty of the proposed work is in developing a sound financial instrument by harnessing the benefits of options trading to create a hedge-based market alongside a conventional market. In contrast to previously conducted work, this work aims to comprehensively represent the nature of options trading within a competitive environment. Moreover, the hedge contracts set-up between the stakeholders are not merely financial, but also result in actual trading of energy. In the proposed market, a premium fee is paid to the FCG to secure a portion of the

FCG's capacity that may be used to compensate for any realized energy deficit in the committed output of a VRG. The VRG compensates the FCG for the realized deficit according to an agreed strike price. The proposed framework does not modify dispatch and pricing schemes of conventional electricity market models thereby making it compatible with conventional market models studied in the existing literature.

The major contributions of this paper are.

1) Designing a hedge-based market framework that reduces weather-driven revenue volatility for VRGs by means of hedge contracts.
2) Providing a mechanism for better utilization of renewable energy, as VRGs can offer into the market with greater confidence without having to pay high penalties in cases of weather-driven energy deficits.
3) Creating an ad-hoc capacity market alongside an energy market that can reduce the system operator intervention and contingency planning costs due to weather-driven energy deficits.
4) Developing a mechanism to ensure higher and more stable revenues for VRGs as compared to penalty-based mechanisms, thus supporting investments in green projects.

The major findings stemming from this research work are summarized as follows. There are more efficient mechanisms to quantify renewable energy intermittency in the market other than imposing penalties on VRGs. Setting up hedge contracts between VRGs and FCGs can be an effective means of managing the weather-driven volatility in energy markets. It also addresses the risk management needs of VRE assets and reduces the costs associated with procuring reserves by the system operator. Policy-makers should consider strategies that are effective in managing renewable intermittency while ensuring that such strategies do not hinder investments in green projects.

The structure of this paper is as follows: Section II details the outline and assumptions for modeling the market. The mathematical market model is presented in Section III with optimization problems formulated for each market participant. Section IV presents simulation studies carried out on a test network along with simulation results. Section V provides concluding remarks and policy recommendations.

2. Outline and assumptions

To analyze the proposed framework, authors consider two types of market models: a penalty-based market model and a hedge-based market model. A penalty-based market represents the structure of a conventional market, in which all generators bid into the market 24 h ahead of market settlement. The market is settled based on forecasted demand by the system operator. If a scheduled generator fails to meet its committed generation at the actual time of delivery, then a penalty is imposed on the generator. A hedge-based market model is the proposed market model, in which bidding and market settlement takes place exactly like the penalty-based market, however, hedge contracts are set between a VRG and an FCG as an insurance against weather-driven energy deficits of the VRG.

In a penalty-based market, the day-ahead offers from all the generators are accepted and settled 24 h ahead of the delivery time. There exists a real-time balancing mechanism to compensate for any energy deficits from a VRG. The bidding structure allows the market participants to change the quantity, but not the price, of the offers up to 5 min ahead of the actual time of delivery. Five minutes ahead of the time of delivery, the system operator re-runs the market dispatch algorithm again according to the updated bids from the market participants. In case of an energy deficit, the VRG has to pay a penalty for not meeting the energy commitment. The penalty is calculated by multiplying a penalty factor by the amount of energy deficit. The penalty is paid to the market participant who provides for the energy for the energy deficit. In this research work, the purpose of the penalty-based market model is to compare the performance of the proposed market model with a representative conventional market model.

The proposed market model consists of a conventional electricity market model supplemented by a hedge-based market model, in which a VRG has a hedge contract with an FCG to ensure that the VRG will be able to meet their day-ahead energy commitments at the actual time of delivery. As seen in Fig. 1, the decisions in the hedge-based market are made before participating in the day-ahead market; however, the options are exercised at actual time of delivery. The VRG and the FCG settle upon a hedge contract based on a forecasted generation profile. Once the generators settle upon a hedge contract, each generator bids into the day-ahead market; the market is cleared based on the offer from the marginal unit: the unit that is split by the intersection of the forecasted demand and generator offer stacks ranked in a merit-order.

To describe further how the hedge-based market would work, consider a VRG who participates into the electricity market along with other generators. The VRG decides to purchase a reserve from an FCG. The FCG will then reserve a set amount of their capacity for the VRG. The FCG can now only offer into the day-ahead market with the remaining capacity. If the VRG is unable to provide their committed capacity at the time of delivery due to a shortfall in their generation, then the former will have the right to exercise the hedge contract and call upon the latter to compensate for the energy deficit. In the case that there is no energy deficit, the VRG will not exercise the hedge contract.

The VRG will buy the hedge contract at a premium fee per unit of the reserve procured from an FCG. This allows the FCG to make a profit for reserving the capacity instead of offering their full capacity into the day-ahead market. In the event of a VRG experiencing an energy deficit, the VRG will also have to pay a strike price per unit of energy deficit to the FCG if the VRG decides to exercise the hedge contract. The premium and strike price will be decided at the time upon which the hedge contract is agreed between the two market participants. The market participants are referred to as players as they play a game to maximize their individual profits.

In this competitive market model, it is necessary to determine how each player will strategize their set of actions to maximize their own individual profits. For this model, the set of actions and strategies are the premium fee and strike price upon which the two players will agree to participate in a hedge contract. The players in this game are a VRG and an FCG. As in any other market, it is important for the market model to be designed in such a way that there is an equilibrium point that ensures the market is operating smoothly. The equilibrium point, often referred to as the Nash equilibrium, is a point at which each player will have no incentive to change their strategy, given that the other players remain constant in their strategies [25].

The proposed market model enables VRE assets to manage their individual energy deficits and the financial risks associated with weather-driven intermittency in generation. Both the conventional market model (with penalty mechanisms) and the proposed hedge-based market model require the VRGs to pay for weather-driven energy deficits. However, the hedge-based market model offers greater freedom to VRE assets for paying towards such externalities by engaging in a hedge contract and selecting a set of premium fee and strike price that would generate higher profit for the VRG.

A number of simplifying assumptions have been made when designing the market framework.

- All market participants have perfect information about each other's actions and strategies when participating in the hedge-based market.
- The forecasted load demand is equal to the actual load demand.
- The offer prices of the generators are equal to their marginal cost.
- Conventional generators are 100% reliable and are always able to meet their commitments made in the hedge-based and day-ahead markets; VRG is the only source of uncertainty in the grid.
- Any excess generation from a VRG is curtailed.
- The electricity price at each node is the same.

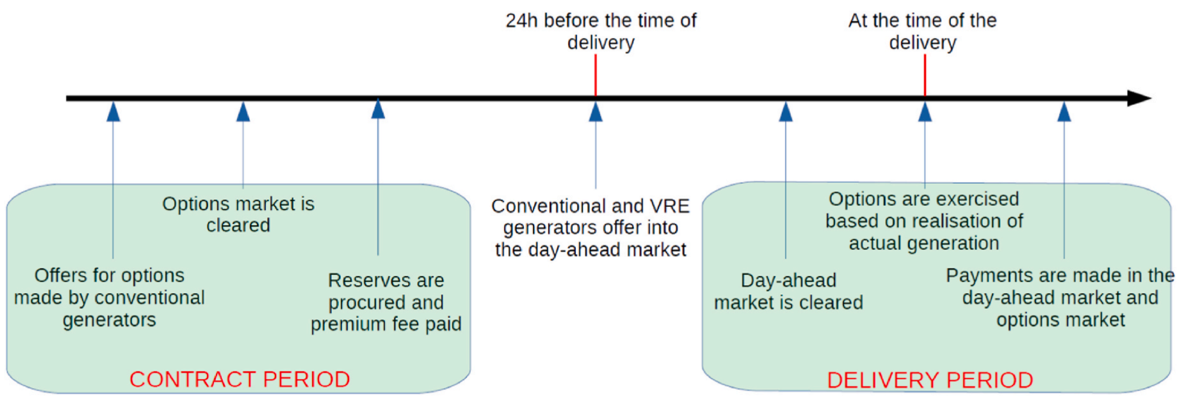

Fig. 1. Proposed market timeline.

- In the hedge-based market, a VRG is required to purchase the reserve based on the forecasted generation determined by the probability distribution function (PDF).
- In case no contract is agreed upon, the market participants can revert to the penalty-based market.
- Each VRG can get into contract with only one FCG at a time.
- All market participants are price-takers in the day-ahead market.
- The penalty factor is equal to the spot price in the real-time market.

3. Market modeling

The penalty-based and the hedge-based markets are both competitive market models. Three generators are considered in both models: a VRG, an FCG and an ICG. Each generator has a marginal cost curve, and these cost curves are used to create blocks of offers, which are then cleared in the market by the system operator. The market is cleared based on the forecasted load demand, which does not vary in real time. Each generator submits an offer for the amount of energy they are willing to sell at their marginal cost. The system operator then clears the market by stacking the offers from each generator in a merit order, dispatching the least-cost generator first. The market is cleared 24 h ahead of the delivery time and generators are scheduled based on their submitted offers.

3.1. Utility functions

Each generator has a utility function representing their expected profit. The utility function for each generator is crucial, as it is used to determine the motivation for the strategy that each generator will be adhering to in both penalty-based and hedge-based markets.

3.1.1. Penalty-based market

For a VRG, the energy deficit P_R^δ is calculated as the difference between the committed energy in day-ahead market P_R^c and the energy generated at the actual time of delivery P_R^g:

$$P_R^\delta = \begin{cases} \left|P_R^c - P_R^g\right|, P_R^g < P_R^c \\ 0, P_R^g \geq P_R^c \end{cases} \tag{1}$$

A penalty is imposed on the VRG for its failure to meet the committed energy generation in the day-ahead market. In case the VRG experiences any shortfall in generation, a penalty factor ε per unit is multiplied by the amount of the energy deficit. To model the cost curve for the VRG, a linear operation and maintenance factor k is multiplied by the actual energy generation. The VRG has the following utility function:

$$U_R^P = \lambda P_R^g - \varepsilon P_R^\delta - kP_R^g \tag{2}$$

The first term in the utility function, λP_R^g, is the revenue in the day-ahead market, which is calculated by multiplying generated power with the day-ahead market clearing price λ. The second term, εP_R^δ, is the penalty imposed on the VRG in case of an energy deficit and the third term, kP_R^g, is the production cost.

For both FCG and ICG, there is no penalty imposed, as it is assumed that conventional generators are always able to meet their energy commitments in the market. The utility function consists of three terms: revenue made in the day-ahead market, the production cost and any payments received for providing energy in case of energy deficits.

The utility function for an FCG, such as a natural gas power plant is given as:

$$U_{NG}^P = \lambda P_{NG}^c + \varepsilon P_R^\delta - \left[a + b\left(P_{NG}^c\right) + c\left(P_{NG}^c\right)^2\right] \tag{3}$$

where a, b and c are cost curve coefficients for the natural gas power plant and P_{NG}^c is the committed energy of a natural gas generator in the day-ahead market. Natural gas power plant is an FCG and therefore provides for the energy deficit experienced by the VRG in the penalty-based market and receives the penalty payment, εP_R^δ, from VRG.

The utility function for an ICG, such as a coal power plant is given as:

$$U_C^P = \lambda P_C^c - \left[x + y\left(P_C^c\right) + z\left(P_C^c\right)^2\right] \tag{4}$$

where x, y and z are cost curve coefficients for the coal power plant and P_C^c is the committed energy of a coal generator in the day-ahead market.

3.1.2. Hedge-based market

In the proposed model, it is necessary for a VRG to procure a reserve from an FCG via a hedge contract before participating in the day-ahead market. A VRG will buy the right to use the reserve P_R^r at a premium fee π per unit of the reserve purchased. In case there is an energy deficit, the VRG has the right to exercise the hedge contract and buy the energy deficit from the FCG at a strike price per unit of the energy deficit. The strike price is computed as a product of strike price factor η and λ.

The utility function for the VRG in the hedge-based market is given as:

$$U_R^H = \lambda P_R^c - \pi P_R^r - \eta\lambda P_R^\delta - kP_R^g \tag{5}$$

The first term, λP_R^c, in the utility function is the expected revenue of the VRG in the day-ahead market. The second term, πP_R^r, is the cost of buying the right to use a reserve from the FCG. The third term, $\eta\lambda P_R^\delta$, is the cost of purchasing the energy at a strike price and kP_R^g is the production cost.

The utility function for the FCG is given as:

$$U_{NG}^H = \lambda P_{NG}^c + \pi P_R^r + \eta\lambda P_R^\delta - \left[a + b\left(P_{NG}^c + P_R^\delta\right) + c\left(P_{NG}^c + P_R^\delta\right)^2\right] \tag{6}$$

The first term, λP_{NG}^c, in the utility function is the expected revenue of the FCG in the day-ahead market. The second term, πP_R^r, is the payment

FCG receives by holding a reserve for the VRG. The third term, $\eta\lambda P_R^\delta$, is the payment the FCG will receive for selling the energy to the VRG when there is an energy deficit. The term $a + b(P_{NG}^c + P_R^\delta) + c(P_{NG}^c + P_R^\delta)^2$ is the production cost of the FCG that varies based on the amount of energy deficit experienced by the VRG. Henceforth, for simplification purposes, the production cost of the FCG is stated as a function:

$$\zeta\left(P_{NG}^c + P_R^\delta\right) = a + b\left(P_{NG}^c + P_R^\delta\right) + c\left(P_{NG}^c + P_R^\delta\right)^2 \tag{7}$$

Conventional generators that are not willing to associate themselves in any hedge trading due to reasons such as low ramp rate or being risk-averse are represented as ICG. Thus, the utility function for such generators is the same as (4). These generators participate in the day-ahead market but do not play a role in determining the outcomes of the hedge contracts.

3.2. Problem formulation

The main aim of this paper is to propose a market model that ensures a VRG is able to meet the day-ahead market commitments, so that there is no real-time energy mismatch due to weather-driven volatility in generation. In a hedge-based market, it is necessary to set a hedge contract between a VRG and an FCG to avoid this mismatch. The VRG will only purchase a hedge contract if it is more profitable than paying a penalty. Likewise, the FCG will only sell a hedge contract if they are able to make more profit by holding a reserve for the VRG, than by offering their full capacity in the day-ahead market. Therefore, the expected profit made by each player in the penalty-based market is considered a reference to ensure that each player is able to generate a higher profit by participating in hedge contract.

The hedge-based market is a competitive market model: each generator participating in the hedge-based market intends to maximize their own individual profits. The pairs of premium fee and strike price that ensures higher profits for the VRG and the FCG are to be determined. As both players are rational players, aiming to maximize own individual profits, an optimization problem can be formulated for each player.

For the VRG, the problem can be formulated as:

$$\max_{\pi,\eta} U_R^H = \lambda P_R^c - \pi P_R^r - \eta\lambda P_R^\delta - kP_R^g \quad \text{s.t.}: \tag{8}$$

$$\eta_{\min} \le \eta \le \eta_{\max} : \mu_1, \mu_2 \tag{9}$$

$$\pi_{\min} \le \pi \le \pi_{\max} : \mu_3, \mu_4 \tag{10}$$

$$U_R^P \le U_R^H : \mu_5 \tag{11}$$

For the FCG, the problem can be formulated as:

$$\max_{\pi,\eta} U_{NG}^H = \lambda P_{NG}^c + \pi P_R^r + \eta\lambda P_R^\delta - \zeta\left(P_{NG}^c + P_R^\delta\right) \quad \text{s.t.}: \tag{12}$$

$$\eta_{\min} \le \eta \le \eta_{\max} : \mu_6, \mu_7 \tag{13}$$

$$\pi_{\min} \le \pi \le \pi_{\max} : \mu_8, \mu_9 \ (14)$$

$$U_{NG}^P \le U_{NG}^H : \mu_{10} \tag{15}$$

Both generators are subjected to upper and lower bounds of premium fee and strike price factor, however, these constraints have a contrasting effect on the optimization problem of both players. The contrasting effect is due to the opposing strategies to maximize profits: an increase in premium fee and strike price will increase the profits of the FCG but decrease the profits of the VRG and vice versa. Moreover, both generators intend to make higher profits than they would make in the penalty-based market, therefore, the VRG is subjected to the constraint in (11) and FCG is subjected to the constraint in (15).

To find the equilibrium point upon which a hedge contract will be agreed between the two players, KKT optimality conditions for each player are constructed and solved. KKT conditions are first-order necessary conditions, as they are constructed using the first-order derivatives, this technique of solving KKT conditions that are mutual to both the optimization and equilibrium problem is called a mixed complementarity problem (MCP). MCP is the most utilized technique in the literature to determine the optimal economic dispatch in an energy market, as it simultaneously solves the KKT conditions of both the optimization and equilibrium problems [26]. The KKT conditions for both players are derived as:

$$\lambda P_R^\delta + \mu_1 - \mu_2 + \lambda P_R^\delta \mu_5 = 0 \tag{16}$$

$$P_R^r + \mu_3 - \mu_4 + P_R^r \mu_5 = 0 \tag{17}$$

$$\lambda P_R^\delta - \mu_6 + \mu_7 + \lambda P_R^\delta \mu_{10} = 0 \tag{18}$$

$$P_R^r - \mu_8 + \mu_9 + P_R^r \mu_{10} = 0 \tag{19}$$

$$0 \le \mu_1 \perp (\eta - \eta_{\max}) \le 0 \tag{20}$$

$$0 \le \mu_2 \perp (\eta_{\min} - \eta) \le 0 \tag{21}$$

$$0 \le \mu_3 \perp (\pi - \pi_{\max}) \le 0 \tag{22}$$

$$0 \le \mu_4 \perp (\pi_{\min} - \pi) \le 0 \tag{23}$$

$$0 \le \mu_5 \perp \left(U_R^P - \left[\lambda P_R^c - \eta\lambda P_R^\delta - kP_R^g - \pi P_R^r\right]\right) \le 0 \tag{24}$$

$$0 \le \mu_6 \perp (\eta - \eta_{\max}) \le 0 \tag{25}$$

$$0 \le \mu_7 \perp (\eta_{\min} - \eta) \le 0 \tag{26}$$

$$0 \le \mu_8 \perp (\pi - \pi_{\max}) \le 0 \tag{27}$$

$$0 \le \mu_9 \perp (\pi_{\min} - \pi) \le 0 \tag{28}$$

$$0 \le \mu_{10} \perp \left(U_{NG}^P - \left[\lambda P_{NG}^c + \eta\lambda P_R^\delta - \zeta\left(P_{NG}^c + P_R^\delta\right) + \pi P_R^r\right]\right) \le 0 \tag{29}$$

By solving the KKT conditions, the feasible region that satisfies the constraints of both players can be determined; in other words, finding the solution to the equilibrium problem. Since the profit of both players can never be mutually maximized, a balance between the two is found where both players are satisfied by determining a feasible region. If more players are added to the game, then the KKT conditions for each additional player can be added to the existing set of KKT conditions and solved simultaneously.

The feasible region upon which a hedge contract can be agreed between a VRG and an FCG can be derived as follows:

$$U_R^P \le \lambda P_R^c - \pi P_R^r - \eta\lambda P_R^\delta - kP_R^g \tag{30}$$

$$\eta\lambda P_R^\delta \le \lambda P_R^c - U_R^P - kP_R^g - \pi P_R^r \tag{31}$$

$$U_{NG}^P \le \lambda P_{NG}^c + \eta\lambda P_R^\delta - \zeta\left(P_{NG}^c + P_R^\delta\right) + \pi P_R^r \tag{32}$$

$$U_{NG}^P + \zeta\left(P_{NG}^c + P_R^\delta\right) - \lambda P_{NG}^c - \pi P_R^r \le \eta\lambda P_R^\delta \tag{33}$$

Combining (31) and (33) gives:

$$U_{NG}^P + \zeta\left(P_{NG}^c + P_R^\delta\right) - \lambda P_{NG}^c - \pi P_R^r \le \eta\lambda P_R^\delta \le \lambda P_R^c - U_R^{Pen} - kP_R^g - \pi P_R^r \tag{34}$$

$$\frac{U_{NG}^P + \zeta\left(P_{NG}^c + P_R^\delta\right) - \lambda P_{NG}^c - \pi P_R^r}{\lambda P_R^\delta} \le \eta \le \frac{\lambda P_R^c - U_R^P - kP_R^g - \pi P_R^r}{\lambda P_R^\delta} \tag{35}$$

The strike price factor range given in (35) defines the feasible region upon which a hedge contract can be settled between a VRG and an FCG, given that the VRG exercises the hedge contract and all KKT conditions are satisfied. It can be observed from (35) that the feasible region is enclosed between two parallel lines; the terms on either side of η are linear and have the same gradient.

4. Simulations and results

Case studies are conducted on a test network for both penalty-based and hedge-based markets. The aim of these case studies is to prove the effectiveness of the proposed market model. The proposed market model is considered effective if the profits generated by each market participant are greater than the penalty-based market model.

4.1. Test system

The test network used for case studies is a modified IEEE 9-bus system [27] and has been illustrated in Fig. 2. The modified system consists of three generators: a coal-fired generator, a natural gas generator and a solar PV generator. Transmission losses of the network are negligible to ensure there is a uniform marginal price of electricity at each node. Technical data for the test system is given in Appendix A.

4.2. Simulation setup

Data from Australian Energy Market Operator (AEMO) is used for a utility-scale solar in NSW to consider variability of solar PV generation for a specific hour of the day [28]. Data across multiple years for a specific season is used to construct a PDF. The constructed PDF is illustrated in Fig. 3.

Simulation studies using MATPOWER [29] are conducted for both the penalty-based and hedge-based markets. The cost curve for each generator is used to create offer blocks for the generators to bid in the market. An optimal power flow-based market solver clears the submitted offers in the day-ahead market to meet the forecasted demand by ranking the blocks in a merit-order. The natural-gas and coal power plants offer their full available capacities; however, the renewable generator offers its forecasted generation at a specific confidence interval. The confidence interval for the conducted simulation studies is considered to be 95%.

Stochastic market-clearing is performed by creating different scenarios for the solar PV generator using the constructed PDF. For both penalty-based and hedge-based markets, excess expected profit matrices are generated for each player based on associated utility functions. The excess expected profit matrices are then used to generate the feasible region by discarding the strategies that provide less profitable to both players in comparison to the penalty-based market. Simulation studies are carried out for four different network loading conditions: 50%, 80%, 100% and 110%.

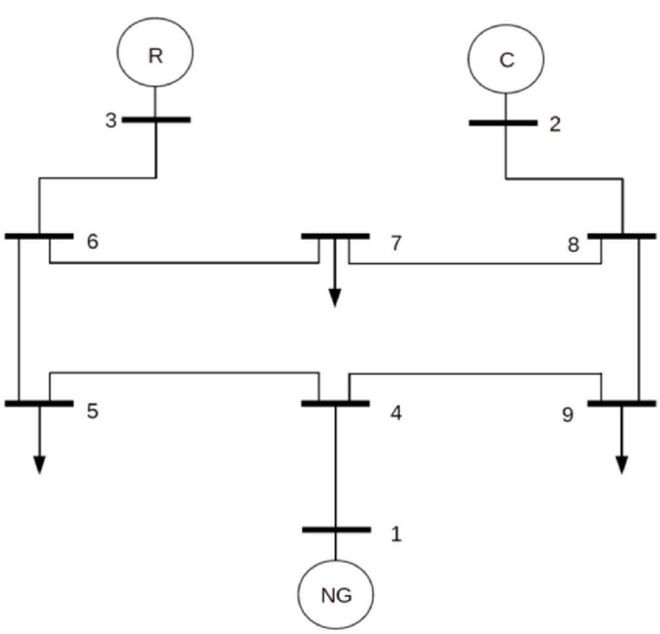

Fig. 2. Modified IEEE 9-bus system.

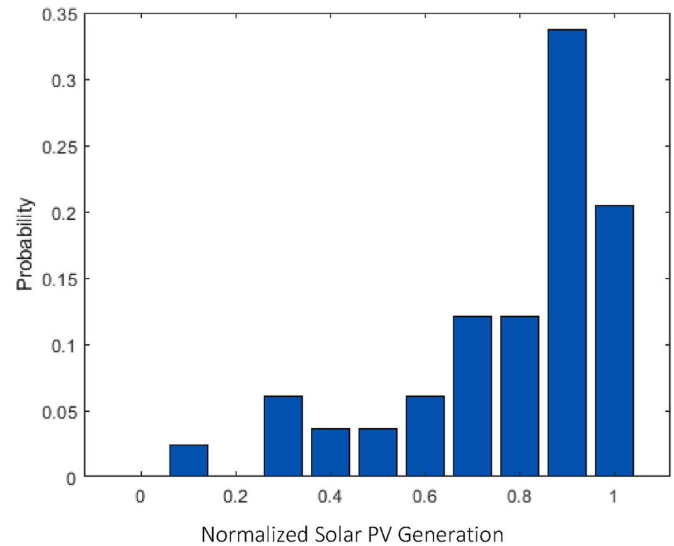

Fig. 3. PDF for the normalized solar PV generation.

4.3. Simulation results

The simulation results, for different network loading conditions, are illustrated in Fig. 4. A visual representation of the contract region is also shown.

The equilibrium problem does not have a unique solution but rather provides a feasible region. The region shaded in yellow represents the feasible region for different network loading conditions in the above figures. A VRG and an FCG can settle upon a contract with a pair of strike price factor and premium fee within the feasible region. The strike price factor and premium fee are subjected to lower and upper bounds based on the market conditions. Accordingly, a minimum of 0 and a maximum of 5 are used in simulation studies.as representative numbers on the basis of theoretical estimations for both strike price factor and premium fee.

In scenarios where the network loading is low, the FCG will have excess capacity left after settling into the day-ahead market. The FCG is able to profitably offer the excess capacity to the VRG at a lower premium fee and strike price combination to secure a hedge contract. Therefore, the number of combinations of premium fee and strike price factor that allow both generators to make excess profit in the hedge-based market are quite high thereby producing a wider feasible region.

However, as the network loading increases, the FCG has the option to bid most or all of the available capacity in the day-ahead market and be able to generate higher expected profits. Therefore, the FCG offers hedge contracts at a higher premium fee and strike price combination to the VRG so that the expected profit of the FCG from hedge contract is higher than bidding the entire capacity into day-ahead market. Thus, the feasible region becomes narrower as the demand increases. This can be further confirmed by observing the graph of the overloaded condition (110% Loading), where a shift towards higher strike prices is observed indicating the necessity for an FCG to sell more expensive contracts to generate higher profits than the penalty-based market.

A visual representation of how the expected excess profits for both

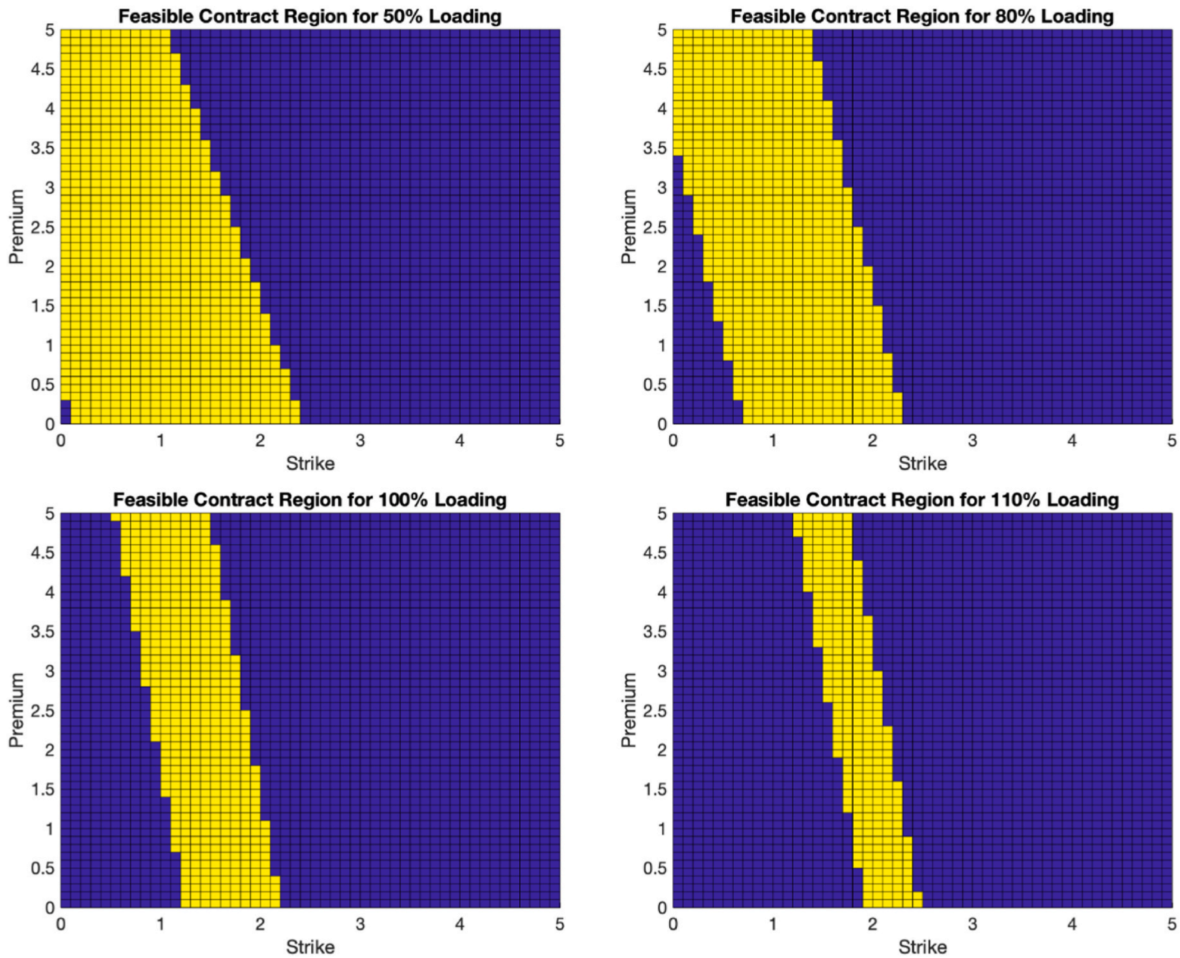

Fig. 4. Feasible contract region for different loading conditions 50%, 80%, 100% and 110%.

the FCG and the VRG vary with different strike price factor and premium fee under 100% loading condition is provided in Fig. 5. The graph in Fig. 5 shows that both generators have contrasting strategies to maximize individual profits; the excess expected profit of the VRG decreases with an increase in strike price and premium fee, and the excess expected profit of the FCG increases with an increase in strike price and premium fee. Therefore, by considering the optimization problem of both market participants, an equivalent equilibrium problem is formulated and solved to obtain the region in which both participants are able to generate higher profits as compared to the penalty-based market.

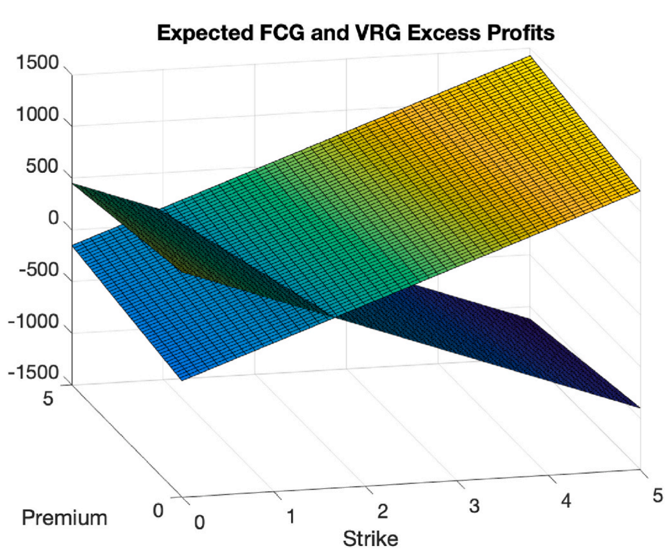

Fig. 5. The expected profits in excess for FCG and VRG vs Strike price factor and Premium fee.

In order to test the cohesiveness between theoretical and simulation observations, two sample pairs of η and π are taken to verify the strike price factor range derived in (35). The theoretical and simulated values for the selected sample pairs are presented in Table 1. It is observed that due to lack of granularity in simulation studies the upper and lower bound values for η are only correct to one decimal place.

However, both theoretical and simulation results indicate an increase in profits for generators participating in hedge contracts compared to penalty mechanisms. Hence, the proposed framework is effective in managing weather-driven intermittency of VRE assets while ensuring higher profits. It is to be noted that there can be instances when a feasible contract between market participants is not found due to reasons, such as network loading conditions, forecasted generation profile of VRE assets and difference in marginal costs. The effects of these parameters on the proposed framework can be studied in the future.

Table 1
Verification of theoretical and simulation studies.

Premium	Theoretical η lower bound	Simulated η lower bound	Theoretical η upper bound	Simulated η upper bound
1	1.052	1.1	2.005	2.1
5	0.481	0.5	1.432	1.5

5. Conclusion and policy recommendations

In this work, a novel solution to mitigate weather-driven intermittency of VRE assets is proposed by means of financial instruments. A hedge market alongside a day-ahead energy market was created by setting up hedge contracts between a VRG and an FCG. Theoretical studies were presented to determine a feasible region within which both market participants are able to generate higher profits through hedge contracts as compared to conventional penalty mechanisms. The hedge contracts are settled before participating in the day-ahead market allowing the VRG to bid in the day-ahead market with more confidence. Simulation studies were also carried out to support the theoretical results. The results indicated an increase in profits for both the VRG and the FCG, thus sending out investment signals for renewable and flexible generation technologies.

Some of the limitations of the proposed research work are as follows. The theoretical and simulation studies undertaken in this paper have been conducted with only three market participants and the hedge-based market model is designed in a fashion that only two market participants can participate in a hedge contract at one given hour. In future, the proposed research work will be studied in the presence of more market participants as well as allowing multiple market participants to engage in hedge contracts at one given hour. Moreover, market participants with energy storage capabilities, such as large-scale batteries, can also be introduced to buy energy surplus from VRGs via hedge contracts instead of curtailing any excess generation.

Based on the conducted work, the authors have the following policy recommendations: the policy-makers should consider implementing more efficient mechanisms to cope with renewable energy intermittency rather than the penalty-based mechanisms, as penalty-based mechanisms can significantly impact the profits of VRE assets and make it harder for such assets to secure financing. A hedge-based market model can be more effective than a penalty-based market model, as the hedge-based market model allows VRE assets to manage individual renewable intermittency. The hedge-based market model provides more freedom to the VRGs in selecting a set of premium fee and strike price, rather than paying a penalty for the energy deficit. The presence of hedge contracts enables VRE assets to mitigate effectively the risks associated with intermittent generation to manage revenue volatility as well as bid into the market with higher confidence thus increasing renewable generation shares in the market. Moreover, it decreases the costs for system operators by not having to procure additional reserves due to weather-driven generation intermittency introduced by VRGs in the grid, lower cost of reserves may result in lower electricity prices for electricity consumers.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Appendix A. Generator Data for the modified IEEE 9-bus system [27]

Generator	Capacity (MW)	Cost Curve Coefficients
Natural Gas Power Plant	230	$a = 0.1$, $b = 0.05$, $c = 100$
Coal Power Plant	160	$x = 0.09$, $y = 3$, $z = 300$
Solar PV	50	$k = 3$

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