Strategic CBDR bidding considering FTR and wind power

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Abstract: The independent system operators (ISOs) usually offer financial transmission right (FTR) as a financial instrument for electricity market participants to hedge against the transmission congestion cost. Meanwhile, the development of demand response (DR) provides load serving entities (LSEs) opportunities to perform coupon based demand response (CBDR) programs, and thus LSEs can behave as strategic bidders in the whole-sale market by adjusting its demand level. In the existing approaches for modelling CBDR, the potential impact of FTR which leads LSEs to obtain the congestion compensation under a high load level is overlooked. Therefore, this study proposes a comprehensive strategic CBDR model in which the LSE's profit is maximised by providing CBDR to customers and the congestion compensation from the LSE bidder's FTR holding is also considered. The proposed model is formulated as a bi-level optimisation problem with the LSE's net revenue maximisation as the upper level and the ISO's economic dispatch considering wind power uncertainty as the lower level problem. The bi-level model is addressed with mathematic program with equilibrium constraints technique and mixed-integer linear programming, which can be solved using available optimisation software tools. In addition, the case studies of an illustrative two bus system, the PJM 5-bus system, and IEEE 39-bus system verify the proposed method.

Nomenclature

Indexes

N	number of buses
M	number of lines
Γ	FTR path set of the LSE bidder
A	bus set of the LSE strategic bidder
B_i	customer set at bus i belong to the LSE strategic bidder
s	index of wind power scenario (in superscript)
ψ	Lagrangian function of ISO's ED problem

Parameters

c_i	generation bidding price at bus i (\$/MWh)
G_i	generation dispatch at bus i (MWh)
$G_i^{\max}$, $G_i^{\min}$	maximum and minimum generation output at bus i
D_i	demand at bus i (MWh)
GSF_{l-i}	generation shift factor to line l from bus i
Limit_l	transmission limit of line l
$\eta_{i,k}$	electricity retail price for customer k at bus i (\$/MWh)
$D_{i,k}^0$	energy consumption baseline of customer k at bus i
p_s	probability of wind power scenario s
$p_{j,d}$	probability of dth demand reduction block under the jth coupon price
FTR_{ij}	FTR amount from the path of bus i to bus j

Variables

$r_{i,k}$	coupon price offered to customer k at bus i (\$/MWh)
π_i	locational marginal price (LMP) at bus i
$\Delta\pi_{ij}$	LMP difference between bus i and bus j
$D_{i,k}$	energy consumption of customer k at bus i
λ	dual variable associated with the power balance equation in economic dispatch
$\mu_l^{\min}$, $\mu_l^{\max}$	dual variables associated with the lower and upper limits of transmission line l
$\omega_i^{\min}$, $\omega_i^{\max}$	dual variables associated with the lower and upper limits of the generator at bus i
$P_{W,i}^s$	power output of wind farm at bus i in wind power scenario s

1 Introduction

Financial transmission right (FTR) is a financial instrument that entitles the holders to receive compensation for transmission congestion charges arising when the transmission grid is congested in the day-ahead (DA) market and differences in DA congestion prices resulting from the dispatch of generators out of merit order (i.e. the ranking of available electrical generation based on ascending order of marginal cost) to relieve the congestion [1, 2]. Each FTR is defined from a point of receipt (where the power is injected on to the transmission grid) to a point of delivery (where the power is withdrawn from the transmission grid). For each hour in which congestion exists on the transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the transmission congestion surplus (CS) collected from the market participants. The purpose of FTRs is to protect transmission service customers from increased cost due to transmission congestion when their energy deliveries are consistent with their FTR reservations [3].

Illustrated in Fig. 1, when the load connected to Bus B exceeds the transmission limit from Bus A to Bus B, i.e. 200 MW, congestion will occur. Thus, the locational marginal price (LMP) on Bus A and Bus B will be different which leads to the imbalance between generator revenue and load payment. Such imbalance is also called CS, collected by independent system operators (ISOs). In this case, CS equals load payment (\$30 × 250 = \$7500) minus generator revenue

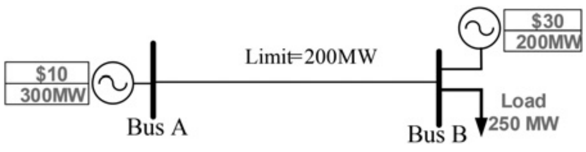

Fig. 1 *Illustration of congestion impact on the market clearing*

($\$10 \times 200 + \$30 \times 50 = \$3500$), which is a total of $4000. If an LSE holds FTR from Bus A to Bus B with same amount of MW as the transmission limit, $4000 will be reimbursed to compensate for the over payment due to congestion. Therefore, FTR holdings of an LSE has big financial impact in its daily operations. An optimal bidding strategy of LSEs for any load portfolio [including demand response (DR) program] should almost always involve congestion analysis to be robust. Congestion pattern is tied up to many factors such as demand, outage etc. and is subjected to the uncertainties due to the renewable power output and DR program.

For the FTR optimisation concerning the best paths and their MW amounts, there are several research literatures. In [3], the FTR portfolio optimisation based on identification of congested network elements is proposed which overcomes the data handling and heaving computing burden of LMP difference based methods. In [4], a joint bidding model considering both FTR and energy market is proposed which is based on a two-tier matrix game approach. These papers focus on FTR portfolio optimisation while DR and wind power uncertainty are not considered. In this paper, the impact of FTR on the LSE's bidding will be modelled in DA market instead of bidding FTR in the annual or monthly FTR auction.

DR programs in smart grids have been consistently gaining increasing popularity as alternative resources to help alleviate the grid pressure during peak load time [5] and improve overall system operating efficiency and reliability. Achieving an optimal operation framework to dispatch DR resources has become a fast-growing interest in both industry and academia [6–12]. While DR brings economic value to the system as a whole, it can also contribute to load serving entities' (LSEs) earnings. As LSEs continue to learn how to strategically utilise DR in the market to maximise the expected payoff in practice, most of the research works are focused on coordinating DR with the renewables [13, 14] and inducing consumers' inherent elasticity through DR program [15, 16]. In [15], an optimal bidding model for retailers is proposed considering the time-of-use DR program and the market price uncertainties. In [16], the opportunity of DR to reduce the potential wind curtailment in Ireland power system is analysed.

In these previous studies, the viewpoints are mostly from system operators to dispatch DR resources for system optimal operation. Different from the aforementioned works, this paper investigates coupon based demand response (CBDR) from the LSE's perspective. CBDR is similar to direct load control (DLC) program [12, 17], but customers have more flexibility in CBDR. Specifically, customers participate in CBDR programs voluntarily whereas the LSE directly controls the customer's appliances for DR events as long as the customer have a DLC contract with the LSE. As the survey stated in [18], DLC will have a promising potential through smart grid technologies in the future. Consequently, with more flexibility to the customers, CBDR will have a better implementation potential.

It is clear that CBDR program will change the demand level in certain area. Therefore, by offering strategic coupon prices to DR participants (i.e. strategic CBDR bidding in this paper), LSEs have the capability of altering congestion patterns which in turn lead to different earnings from their own holdings. With both physical and financial instruments in hand, there is a growing need for LSEs to make sound decisions with the help of a framework that can help investigate the coupling effects among various assets to achieve the maximisation of its revenue or in another word, minimising customers' cost through strategic participation in power market. The abovementioned papers focus on FTR portfolio optimisation [3, 4] or DR optimisation [5–17] but did not provide a comprehensive framework to analyse the optimal bidding strategy (i.e. providing the best coupon to consumers to achieve the best

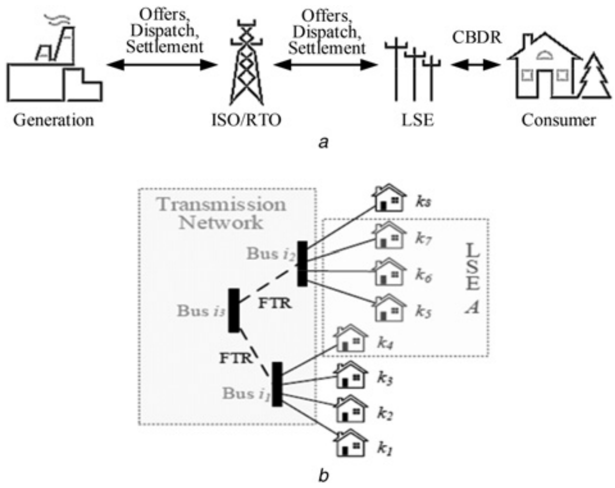

Fig. 2 *Structure of the electricity market*

a Structure of a deregulated electricity market
b Illustrative diagram of a LSE considering FTR

financial benefit to a LSE) over an array of the LSE's physical and financial assets under current market clearing methodology. This paper proposes a comprehensive strategic CBDR model that starts with FTR and CBDR and considers wind uncertainty as well. More specifically, an LSE offers a CBDR program to customers through the communication technique of smart grid and chooses the path of FTR for assessment. Next, the ISO's market-clearing procedure is implemented. Finally, the LSE can obtain the optimal bidding strategy with the maximum expected revenue including the congestion compensation from a specific FTR. The decision variables of LSE bidders are the optimal demand amount bids to the ISO and the corresponding coupon price offered to customers considering a specific FTR holding regarding the MW amount and path. Furthermore, the impact of different FTRs on LSE's strategic CBDR bidding regarding the FTR paths and amount can be analysed based on the simulation results. To the knowledge of the authors, considering both physical measurement such as CBDR and financial instrument such as FTR in the strategic bidding has not been discussed in the previous literature. It should be noted that while the FTR policy may vary at different ISOs, this paper points out a possible strategic CBDR bidding to maximise the LSE's financial benefit. The results presented in this paper can be used by ISOs to better regulate DR programs with FTRs, especially with wind power uncertainty.

The rest of this paper is organised as follows: Section 2 presents the overall strategic CBDR bidding model for LSEs considering both FTR and CBDR. Section 3 presents the demand baseline model and the probabilistic demand reduction model under different coupon prices. Section 4 proposes the mathematic solution required to solve the stochastic bi-level model including the procedure of transforming it into a single level mathematic program with equilibrium constraints (MPEC) problem, and the conversion from MPEC to mixed-integer linear programing (MILP) problem. Section 5 demonstrates the simulation results and numerical studies of an illustrative two bus system, PJM 5-bus system and IEEE 39-bus system to clearly verify the proposed method. Section 6 presents the summary and conclusion of this paper.

2 Bidding model for LSEs considering FTR and CBDR

2.1 Strategic CBDR bidding in deregulated market

Fig. 2*a* demonstrates the structure of a deregulated electricity market which includes both wholesale and retail market. Generation companies enter the wholesale market by offering their generating resources in the ISO/regional transmission organisations (RTO) controlled area. Similarly, LSEs provide their demand bids which are to be cleared together with all the generation bids. After ISO/RTO clears the market by performing least cost unit commitment and economic dispatch (ED), the generation company will receive revenue once their resources are picked up in the corresponding market and LSEs will pay for the electricity procurement for their cleared energy bids.

The illustration of LSEs' strategic CBDR bidding under this market structure will be discussed in the following Sections 2.2–2.4. The congestion compensation from FTR can be obtained from DA market when the transmission lines are congested. Therefore, in this paper, the strategic CBDR bidding is performed in DA market.

2.2 Revenue of LSEs considering FTR and CBDR

There are two contributors to an LSE's revenue in the framework shown in Fig. 2*b*, i.e. (i) retail sales from each customer k ($k \in B_i$) at bus i ($i \in A$), as shown in k_4 to k_7 of LSE A and (ii) FTR revenue if the upstream transmission network has seen congestions. The revenue from (i) is calculated as the product of the retail price $\eta_{i,k}$ and the electricity consumption $D_{i,k}$ minus the cost of serving load includes payment to ISO from purchasing power in the wholesale market (i.e. the product of spot price π_i and the electricity consumption $D_{i,k}$) as well as the financial incentives paid to customers to schedule DR resources (i.e. the product of coupon price $r_{i,k}$ and the demand reduction from the baseline electricity consumption to the actual electricity demand). The revenue from (2) is derived from the product of LMP difference between the injection bus and delivery bus, and the MW amount of FTR. Thus, the LSE's net revenue is expressed as (1)

$$\sum_{i\in A}\left(\sum_{k\in B_i}(\eta_{i,k}\times D_{i,k}-r_{i,k}\times(D_{i,k}^0-D_{i,k}))-\pi_i\times D_i\right) + \sum_{\{ij\in\Gamma\}}\left[\Delta\pi_{ij}\cdot \mathrm{FTR}_{ij}\right] \quad (1)$$

The decision variables are the optimal demand bids $D_{i,k}$ and optimal coupon price $r_{i,k}$. It should be noted that the LMP π_i and the LMP difference $\Delta\pi_{ij}$ in (1) is obtained from the ISO's ED [19], which will be discussed in Section 2.3.

2.3 ISO's market clearing

There are different operational rules in different markets, but they share the same critical element in the market clearing process, i.e. a security constrained unit commitment to bring the most economic units online and a security constrained economic dispatch to determine the optimal schedule from each generating units. As the CBDR program is between LSEs and customers, the demands in the ISOs' ED model are assumed to hold no elasticity. A lossless DC optimal power flow (DCOPF) model with fixed transmission network is assumed, and generations are considered fully competitive and rational in bidding at their marginal costs [20, 21], which is aligned with various DCOPF models utilised by many ISOs [19]. Thus, the DCOPF approach is employed here to model the electricity market clearing process and simulate LMPs. The decision variable in this level is the optimal generation dispatch G_i. The DCOPF is essentially a linear programming (LP) problem as

$$\min \sum_{i=1}^{N} c_i\times G_i \quad (2a)$$

$$\text{s.t.} \sum_{i=1}^{N} G_i = \sum_{i=1}^{N} D_i : \lambda \quad (2b)$$

$$D_i = \sum_{k\in B_i} D_{i,k}, \quad \forall i\in A \quad (2c)$$

$$-\mathrm{Limit}_l \le \sum_{i=1}^{N}\mathrm{GSF}_{l-i}\times(G_i-D_i)\le \mathrm{Limit}_l : \mu_l^{\min},\mu_l^{\max}, \quad \forall l=1,2,\ldots,M \quad (2d)$$

$$G_i^{\min}\le G_i\le G_i^{\max} : \omega_i^{\min},\omega_i^{\max}, \quad \forall i=1,2,\ldots,N \quad (2e)$$

The LMP can be calculated with the Lagrangian function of the above ED optimisation model. This function and LMP can be written as: (see (2f))

$$\pi_i=\frac{\partial\psi}{\partial D_i}=\lambda+\sum_{l=1}^{M}\mathrm{GSF}_{l-i}(\mu_l^{\min}-\mu_l^{\max}) \quad (2g)$$

From the expression of LMP in (2g), the LMP difference $\Delta\pi_{ij}$ between bus i and bus j can be derived as

$$\Delta\pi_{ij}=\sum_{l=1}^{M}\left(\mathrm{GSF}_{l-i}-\mathrm{GSF}_{l-j}\right)\cdot\left(\mu_l^{\min}-\mu_l^{\max}\right) \quad (2h)$$

2.4 Bi-level model of LSE's strategic CBDR bidding

LSE's bidding process considering CBDR and FTR is essentially a bi-level optimisation problem, where the decision variables (demand bids and coupon prices) affect not only the LSE's own condition and constraints but also the ISO's clearing result. In addition, different levels of demand reduction will lead to different congestion pattern and FTR earnings. Assuming the capacity of CBDR resources have enough market impact, the dynamics between market clearing price, both LMP and marginal congestion component is well worth studied. Therefore, the bi-level strategic CBDR bidding problem is formulated as follows in (3a)–(3c). The upper level is to maximise the LSE's profit, and the lower level is to minimise the generation cost to model the ISO's market-clearing process [21–23]

$$\text{Max} \sum_{i\in A}\left(\sum_{k\in B_i}(\eta_{i,k}\times D_{i,k}-r_{i,k}\times(D_{i,k}^0-D_{i,k}))-\pi_i\times D_i\right) + \sum_{\{ij\in\Gamma\}}\left[\sum_{l=1}^{M}\left(\mathrm{GSF}_{l-i}-\mathrm{GSF}_{l-j}\right)\cdot\left(\mu_l^{\min}-\mu_l^{\max}\right)\cdot FTR_{ij}\right] \quad (3a)$$

$$\text{s.t. } D_{i,k}^{\min}\le D_{i,k}\le D_{i,k}^{\max}, \quad \forall i\in A, 4k\in B_i \quad (3b)$$

where

$$\pi_i, \forall i\in \arg\{(2a)-(2e),(2g),(2h)\} \quad (3c)$$

where $D_{i,k}^{\min}$ and $D_{i,k}^{\max}$ are the minimum and maximum demand values of demand k at bus i, respectively. The LMP π_i and the difference $\Delta\pi_{ij}$ among the injection and delivery buses of FTR from the ED depends on the demand, $D_{i,k}$, as well as the bid prices/quantities of generators.

$$\psi=\left(\sum_{i=1}^{N}c_i\times G_i\right)-\lambda\left(\sum_{i=1}^{N}G_i-\sum_{i=1}^{N}D_i\right)-\sum_{l=1}^{M}\mu_l^{\min}\left(\sum_{i=1}^{N}\mathrm{GSF}_{l-i}\times(G_i-D_i)+\mathrm{Limit}_l\right) -\sum_{l=1}^{M}\mu_l^{\max}\left(\mathrm{Limit}_l-\sum_{i=1}^{N}\mathrm{GSF}_{l-i}\times(G_i-D_i)\right)-\sum_{i=1}^{N}\omega_i^{\min}\left(G_i-G_i^{\min}\right)-\sum_{i=1}^{N}\omega_i^{\max}\left(G_i^{\max}-G_i\right) \quad (2f)$$

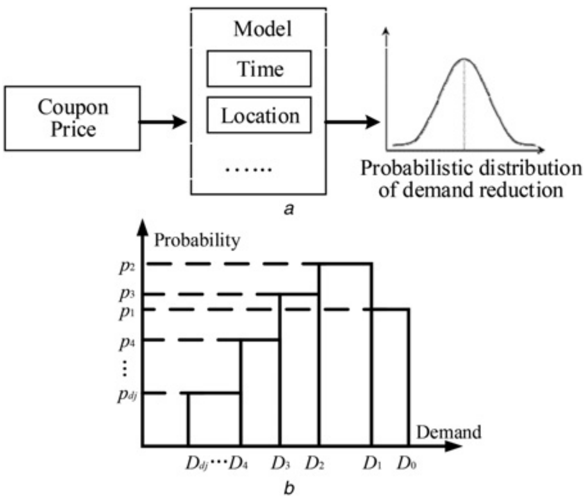

Fig. 3 *Schematic of the demand reduction model and probabilistic demand reduction*

a Illustration of the demand reduction model
b Probabilistic residential demand reduction model

The demand baseline D^0, and potential demand reduction block $D_{i,k}^{\min}$ and $D_{i,k}^{\max}$ are covered in Section 3 Then, the mathematic algorithm to solve (3a)–(3c) will be presented in Section 4.

3 Baseline demand and probabilistic demand reduction

3.1 Baseline demand model

The CBDR programs are critically dependent on the customers' demand baseline [24] from which the demand reduction in DR can be calculated. Due to the strong cyclic pattern of customers' electricity consumption over time [25], the demand baseline can be forecast with historical data. For instance, Southern California Edison employs an approach called '10-day average baseline' [26]. More details concerning the baseline calculation have been introduced in [27], though it is out of the research scope of this paper to discuss the pros and cons of various consumer demand baseline methods.

3.2 Probabilistic demand reduction model

This paper adopts a practical and validated probabilistic model of potential demand reduction under different coupon prices, which has been introduced in [28]. This model is able to directly assess the probability distribution of residential demand reduction to certain coupon price for a given time, location and customers' portfolios as shown in Fig. 3*a*.

With this probabilistic demand reduction model, under the *j*th coupon, the probabilistic demand blocks are $[D_{j,1}, D_{j,2}]$, $[D_{j,2}, D_{j,3}]$,…, $[D_{j,d}, D_{j,d}]$,…, $[D_{j,dj}, D_{j,dj}]$ with a probability set of $\{p_d\}$ as shown in Fig. 3*b* where *dj* is the total number of demand block under the *j*th coupon price.

4 Mathematical solution of the proposed model

As introduced in Section 2, the strategic CBDR bidding problem in (3a)–(3c) is formulated as a bi-level optimisation problem with a coupling effect due to the existence of dependent variables in each level. More specifically, the LMP in the upper level is determined by the lower level ISO's market clearing, while the demands at load buses of LSE bidders in the lower level depend on the upper level's demand. In this paper, DCOPF is implemented to clear the ISO's market.

4.1 Formulation of single level optimisation model

The bi-level strategic CBDR bidding model can be transformed to a single level MPEC by recasting the lower level problem as its KKT optimality conditions due to the linearity of lower level ED problem [21, 29, 30], and then adding these conditions into the upper level as a set of additional complementarity constraints [31, 32]. Therefore, the bi-level strategic CBDR bidding model (3a)–(3c) is transformed as a MPEC problem in (4a)–(4g)

$$\begin{aligned}\textbf{Max}\quad & \sum_{i\in A}\left(\sum_{k\in B_i}(\eta_{i,k}\times D_{i,k}-r_{i,k}\times(D_{i,k}^0-D_{i,k}))-\pi_i\times D_i\right)\\ & +\sum_{\{ij\in\Gamma\}}\left[\sum_{l=1}^{M}\left(\mathrm{GSF}_{l-i}-\mathrm{GSF}_{l-j}\right)\cdot\left(\mu_l^{\min}-\mu_l^{\max}\right)\cdot \mathrm{FTR}_{ij}\right]\end{aligned} \tag{4a}$$

$$\text{s.t. Constraint in (2b), (2c), (2g), (2h) and (3b)} \tag{4b}$$

$$c_i=\lambda+\sum_{l=1}^{M}\mathrm{GSF}_{l-i}\times(\mu_l^{\min}-\mu_l^{\max})+\omega_i^{\min}-\omega_i^{\max} \tag{4c}$$

$$0\le\mu_l^{\min}\perp\ \mathrm{Limit}_l+\sum_{i=1}^{N}\mathrm{GSF}_{l-i}\times(G_i-D_i)\ge 0 \tag{4d}$$

$$0\le\mu_l^{\max}\perp\ \mathrm{Limit}_l-\sum_{i=1}^{N}\mathrm{GSF}_{l-i}\times(G_i-D_i)\ge 0 \tag{4e}$$

$$0\le\omega_i^{\min}\perp\ G_i-G_i^{\min}\ge 0 \tag{4f}$$

$$0\le\omega_i^{\max}\perp\ G_i^{\max}-G_i\ge 0 \tag{4g}$$

where (4c)–(4g) are the ED problem's KKT optimality conditions; the perpendicular sign $\perp$ denotes a zero cross product of the corresponding variables in vector form.

4.2 Congestion surplus

As introduced previously, when the transmission system is congested in ISO's market clearing, the CS exists. This surplus is the deviation between the revenue collected from all the consumers and the payment to all the generation which can be expressed as

$$\mathrm{CS}=\sum_{i=1}^{N}\pi_i\cdot\left(D_i-G_i\right) \tag{5}$$

The transformation of CS is given below:

From (2g) and (4c), LMP can be expressed as

$$\pi_i=c_i+\omega_i^{\max}-\omega_i^{\min} \tag{6}$$

With the KKT conditions (4f), we have

$$\omega_i^{\min}\cdot\left(G_i-G_i^{\min}\right)=0 \tag{7}$$

and $\omega_i^{\min}\cdot G_i=\omega_i^{\min}\cdot G_i^{\min}$

Similarly, with (4g), it can be derived that

$$\omega_i^{\max}\cdot G_i^{\max}=\omega_i^{\max}\cdot G_i \tag{8}$$

Therefore

$$\sum_{i=1}^{N}\pi_i\cdot G_i=\sum_{i=1}^{N}\left(c_i\cdot G_i+\omega_i^{\max}\cdot G_i^{\max}-\omega_i^{\min}\cdot G_i^{\min}\right) \quad (9)$$

According to the strong duality theory, the objective of the primal problem is equal to the objective of the corresponding dual problem. For the ED problem, the relationship between the objectives of the dual and primal problems can be expressed as follows

$$\begin{aligned}\lambda\times\sum_{i=1}^{N}D_i&+\sum_{l=1}^{M}\mu_l^{\max}\times\left(-\text{Limit}_l-\sum_{i=1}^{N}\text{GSF}_{l-i}\times D_i\right)\\&+\sum_{l=1}^{M}\mu_l^{\min}\times\left(-\text{Limit}_l+\sum_{i=1}^{N}\text{GSF}_{l-i}\times D_i\right)\\&+\sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max})+\sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min})=\sum_{i=1}^{N}c_i\times G_i\end{aligned} \quad (10)$$

From the LMP expression in (2g), the product term $\pi_i\times D_i$ can be transformed as (11) below.

$$\sum_{i=1}^{N}\pi_i\times D_i=\sum_{i=1}^{N}\left[\lambda\times D_i+\sum_{l=1}^{M}\text{GSF}_{l-i}(\mu_l^{\min}-\mu_l^{\max})\times D_i\right] \quad (11)$$

Taking (10) into (11),

$$\begin{aligned}\sum_{i=1}^{N}\pi_i\times D_i=&\sum_{i=1}^{N}c_i\times G_i-\sum_{l=1}^{M}\mu_l^{\max}\times(-\text{Limit}_l)\\&-\sum_{l=1}^{M}\mu_l^{\min}\times(-\text{Limit}_l)-\sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max})\\&-\sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min})\end{aligned} \quad (12)$$

Finally, considering (9) and (12), we have CS expressed as:

$$\begin{aligned}&\sum_{i=1}^{N}\pi_i\times D_i-\sum_{i=1}^{N}\pi_i\cdot G_i\\&=\sum_{i=1}^{N}c_i\times G_i-\sum_{l=1}^{M}\mu_l^{\max}\times(-\text{Limit}_l)\\&-\sum_{l=1}^{M}\mu_l^{\min}\times(-\text{Limit}_l)-\sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max})\\&-\sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min})-\sum_{i=1}^{N}\left(c_i\cdot G_i+\omega_i^{\max}\cdot G_i^{\max}-\omega_i^{\min}\cdot G_i^{\min}\right)\\&=\sum_{l=1}^{M}\left(\mu_l^{\max}+\mu_l^{\min}\right)\times(\text{Limit}_l)\end{aligned} \quad (13)$$

4.3 MILP with FTR and CBDR

The objective function (the product term $\pi_i\times D_{i,k}$) and the complementarity constraints (4d)–(4g) leads the non-linearity of the MPEC model (4a)–(4g). First, through the strong duality theory, the objective function can be linearised [32–34]. Then with the method proposed in [35], the constraints (4d)–(4g) are transformed in a set of linear constraints.

Therefore, the objective in (4a) considering FTR and CBDR can be expressed as (14a) and the MPEC problem is converted as a MILP problem as

$$\begin{aligned}\max\sum_{i\in A}\sum_{k\in B_i}&(\eta_{i,k}\times D_{i,k}-r_{i,k}\times(D_{i,k}^0-D_{i,k}))-\sum_{i=1}^{N}c_i\times G_i\\&+\lambda\times\sum_{i\notin A}D_i+\sum_{l=1}^{M}\mu_l^{\max}\times\left(-\text{Limit}_l-\sum_{i\notin A}\text{GSF}_{l-i}\times D_i\right)\\&+\sum_{l=1}^{M}\mu_l^{\min}\times\left(-\text{Limit}_l+\sum_{i\notin A}\text{GSF}_{l-i}\times D_i\right)\\&+\sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max})+\sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min})\\&+\sum_{\{ij\in\Gamma\}}\left[\sum_{l=1}^{M}\left(\text{GSF}_{l-i}-\text{GSF}_{l-j}\right)\cdot\left(\mu_l^{\min}-\mu_l^{\max}\right)\cdot\text{FTR}_{ij}\right]\end{aligned} \quad (14a)$$

$$\text{s.t. Constraints in (4b) and (4c)} \quad (14b)$$

$$0\le\mu_l^{\min}\le M_\mu^{\min}\nu_{\mu,l}^{\min} \quad (14c)$$

$$0\le\text{Limit}_l+\sum_{i=1}^{N}\text{GSF}_{l-i}\times(G_i-D_i)\le M_\mu^{\min}(1-\nu_{\mu,l}^{\min}) \quad (14d)$$

$$0\le\mu_l^{\max}\le M_\mu^{\max}\nu_{\mu,l}^{\max} \quad (14e)$$

$$0\le\text{Limit}_l-\sum_{i=1}^{N}\text{GSF}_{l-i}\times(G_i-D_i)\le M_\mu^{\max}(1-\nu_{\mu,l}^{\max}) \quad (14f)$$

$$0\le\omega_i^{\min}\le M_\omega^{\min}\nu_{\omega,i}^{\min} \quad (14g)$$

$$0\le G_i-G_i^{\min}\le M_\omega^{\min}(1-\nu_{\omega,i}^{\min}) \quad (14h)$$

$$0\le\omega_i^{\max}\le M_\omega^{\max}\nu_{\omega,i}^{\max} \quad (14i)$$

$$0\le G_i^{\max}-G_i\le M_\omega^{\max}(1-\nu_{\omega,i}^{\max}) \quad (14j)$$

where $M_\mu^{\min}$, $M_\mu^{\max}$, $M_\omega^{\min}$, and $M_\omega^{\max}$ are large enough constants, and $\nu_{\mu,l}^{\min}$, $\nu_{\mu,l}^{\max}$, $\nu_{\omega,i}^{\min}$, and $\nu_{\omega,i}^{\max}$ are the auxiliary binary variables [35].

4.4 Integrating uncertainty of wind power and CBDR

In this subsection, the extensions of the above model, including the uncertainty of wind power and demand reduction under a certain coupon price, will be discussed. The forecasted wind power production is expressed as a set of probabilistic scenarios ($s = 1\sim S$) with a probability set of $\{p_s\}$. Assume that under the jth coupon, the probabilistic demand blocks are $[D_{j,1}, D_{j,2}]$, $[D_{j,2}, D_{j,3}]$,…, $[D_{j,d}, D_{j,d}]$,…, $[D_{j,dj}, D_{j,dj}]$ with a probability set of $\{p_d\}$, where dj is the total number of demand block under the jth coupon price. The model below in (15a)–(15e) is an example of an ED model that includes one scenario of wind power and demand reduction.

$$\min \sum_{i=1}^{N} c_i \times G_i^{j,d,s} \quad (15a)$$

$$\text{s.t.} \sum_{i=1}^{N} (G_i^{j,d,s} + P_{W,i}^s) = \sum_{i=1}^{N} D_{i,j,d} : \lambda^{j,d,s} \quad (15b)$$

$$D_{i,j,d} = \sum_{k \in B_i} D_{i,k,j,d}, \quad \forall i \in A \quad (15c)$$

$$-\text{Limit}_l \le \sum_{i=1}^{N} \text{GSF}_{l-i} \times (G_i^{j,d,s} + P_{W,i}^s - D_{i,j,d}) \le \text{Limit}_l : \mu_l^{j,d,s,\min}, \mu_l^{j,d,s,\max}, \quad \forall l = 1, 2, \ldots, M \quad (15d)$$

$$G_i^{\min} \le G_i^{j,d,s} \le G_i^{\max}: \omega_i^{j,d,s,\min}, \omega_i^{j,d,s,\max}, \quad \forall i = 1, 2, \ldots, N \quad (15e)$$

where $G_i^{j,d,s}$ is the generation dispatch at bus i (MWh) under the dth demand block of the jth coupon price and the sth wind scenario.

The LMP is given by

$$\pi_i^{j,d,s} = \lambda^{j,d,s} + \sum_{l=1}^{M} \text{GSF}_{l-i}(\mu_l^{j,d,s,\min} - \mu_l^{j,d,s,\max}) \quad (15f)$$

Therefore, the net revenue of LSE can be formulated as (16a) and then transformed to (16b), and the constraints are modelled in (16c)–(16m).

$$\max \sum_{d=1}^{dj} p_{j,d} \times \left\{ \sum_{i \in A} \left(\sum_{k \in B_i} \left(\eta_{i,k} \times D_{i,k,j,d} - r_{i,k,j} \times \left(D_{i,k}^0 - D_{i,k,j,d} \right) \right) \right) - \sum_{s=1}^{S} p_s \times \left(\pi_i^{j,d,s} \times D_{i,j,d} - \sum_{\{ij \in \Gamma\}} \left(\Delta \pi_{ij}^{j,d,s} \cdot \text{FTR}_{ij} \right) \right) \right\} \quad (16a)$$

(see (16b))

$$\text{s.t. Constraints (4b)} \quad (16c)$$

$$D_{i,k,j,d}^{\min} \le D_{i,k,j,d} \le D_{i,k,j,d}^{\max}, \quad \forall i \in A, \quad k \in B_i \quad (16d)$$

$$c_i = \lambda^{j,d,s} + \sum_{l=1}^{M} \text{GSF}_{l-i} \times (\mu_l^{j,d,s,\min} - \mu_l^{j,d,s,\max}) + \omega_i^{j,d,s,\min} - \omega_i^{j,d,s,\max} \quad (16e)$$

$$0 \le \mu_l^{j,d,s,\min} \le M_\mu^{\min} \nu_{\mu,l}^{j,d,s,\min} \quad (16f)$$

$$0 \le \text{Limit}_l + \sum_{i=1}^{N} \text{GSF}_{l-i} \times (G_i^{j,d,s} + P_{W,i}^s - D_{i,j,d}) \le M_\mu^{\min}(1 - \nu_{\mu,l}^{j,d,s,\min}) \quad (16g)$$

$$0 \le \mu_l^{j,d,s,\max} \le M_\mu^{\max} \nu_{\mu,l}^{j,d,s,\max} \quad (16h)$$

$$0 \le \text{Limit}_l - \sum_{i=1}^{N} \text{GSF}_{l-i} \times (G_i^{j,d,s} + P_{W,i}^s - D_{i,j,d}) \le M_\mu^{\max}(1 - \nu_{\mu,l}^{j,d,s,\max}) \quad (16i)$$

$$0 \le \omega_i^{j,d,s,\min} \le M_\omega^{\min} \nu_{\omega,i}^{j,d,s,\min} \quad (16j)$$

$$0 \le G_i^{j,d,s} - G_i^{\min} \le M_\omega^{\min}(1 - \nu_{\omega,i}^{j,d,s,\min}) \quad (16k)$$

$$0 \le \omega_i^{j,d,s,\max} \le M_\omega^{\max} \nu_{\omega,i}^{j,d,s,\max} \quad (16l)$$

$$0 \le G_i^{\max} - G_i^{j,d,s} \le M_\omega^{\max}(1 - \nu_{\omega,i}^{j,d,s,\max}) \quad (16m)$$

where the model above in (16b)–(16m) gives the optimal profit under a certain coupon price. When the profits under different coupon prices are obtained, the LSE can choose the optimal coupon price with the maximum profit and the corresponding demand dispatch to bid in ISO's market. Note, the uncertainty of other LSEs' demand bids as well as the generation prices can be included as an additional set of scenarios which can be extended based on the proposed method in future studies.

5 Case studies

In this section, the proposed strategic CBDR bidding approach considering both CBDR and FTR is performed on three systems. The investigation of the first simple system (two buses, two generators and one load) is aimed to validate our methodology. The rest case studies on a modified PJM 5-bus system [21] and IEEE 39-bus system further verify the proposed method. The MILP problem is solved with GAMS [36].

5.1 Illustrative two-bus system

The two-bus system depicted in Fig. 1 is utilised to illustrate the impact of FTR on LSE's bidding. The system parameters such as generators' capacities, bid prices, transmission line limits and loads are shown in Fig. 1. The flat rate that the LSE offers to customers is \$25/MWh. Three cases are investigated to demonstrate the impact of CBDR and FTR on the LSE's bidding, respectively.

Case 1: without CBDR and FTR;
Case 2: with CBDR but without FTR;
Case 3: with both CBDR and FTR.

In the CBDR, the coupon price is set to be \$10/MWh and 25% of load is responsive to this coupon price. The FTR amount from Bus A to B is 200 MW. The results in three cases are listed in Table 1 and (17) and (18) illustrate the LSE's net revenue in Case 2 and Case 3

$$\max \sum_{d=1}^{dj} p_{j,d} \times \left\{ \sum_{i \in A} \left(\sum_{k \in B_i} \left(\eta_{i,k} \times D_{i,k,j,d} - r_{i,k,j} \times \left(D_{i,k}^0 - D_{i,k,j,d} \right) \right) \right) - \sum_{s=1}^{S} p_s \times \left\{ \sum_{i=1}^{N} c_i \times G_i^{j,d,s} - \lambda^{j,d,s} \times \left(\sum_{i \notin A} D_i - \sum_{i=1}^{N} P_{W,i}^s \right) \right. \right.$$
$$- \sum_{l=1}^{M} \mu_l^{j,d,s,\max} \times [-\text{Limit}_l + \sum_{i=1}^{N} \text{GSF}_{l-i} \times P_{W,i}^s - \sum_{i \notin A} \text{GSF}_{l-i} \times D_i] - \sum_{l=1}^{M} \mu_l^{j,d,s,\min} \times [-\text{Limit}_l - \sum_{i=1}^{N} \text{GSF}_{l-i} \times P_{W,i}^s - \sum_{i \notin A} \text{GSF}_{l-i} \times D_i]$$
$$\left. \left. - \sum_{i=1}^{N} \omega_i^{j,d,s,\max} \times (-G_i^{\max}) - \sum_{i=1}^{N} \omega_i^{j,d,s,\min} \times (G_i^{\min}) - \sum_{\{ij \in \Gamma\}} \left[\sum_{l=1}^{M} \left(\text{GSF}_{l-i} - \text{GSF}_{l-j} \right) \cdot \left(\mu_l^{j,d,s,\min} - \mu_l^{j,d,s,\max} \right) \cdot \text{FTR}_{ij} \right] \right\} \right\} \quad (16b)$$

Table 1 Bidding results in three cases

Cases	Opt. load, MW	Profit, $	LMP at bus A, $/MWh	LMP at bus B, $/MWh
Case 1	250.00	−1250.00	10	30
Case 2	199.99	2499.75	10	10
Case 3	250.00	2750.00	10	30

under different load level.

$$R = \begin{cases} 25 \times D - 30 \times D - 10 \times (250 - D), & 200 \le D \le 250 \\ 25 \times D - 10 \times D - 10 \times (250 - D), & D < 200 \end{cases} \quad (17)$$

$$R = \begin{cases} 25 \times D - 30 \times D - 10 \times (250 - D) + 200 \times 20, & 200 \le D \le 250 \\ 25 \times D - 10 \times D - 10 \times (250 - D), & D < 200 \end{cases} \quad (18)$$

The results in Table 1 shows that the LSE will have a negative profit (−$1250) if it does not perform CBDR and does not hold the FTR from Bus A to Bus B. In other words, the LSE on Bus B loses money at this operating point. In Case 2, from (17), the LSE will reduce its load to decrease the LMP at Bus B. In this case, the optimal load level is infinitely close to but lower than 200 MW. Because if its load is lower than 200 MW, the LMP at Bus B is $10/MWh which equals the bid price of the generator at Bus A. However, if the load is equal to or higher than 200 MW, the LMP at Bus B will increase to $30/MWh. When LMP at Bus B is $10/MWh lower than the flat rate of $25/MWh, the LSE is profitable under this LMP level. Therefore, it will increase the load to its highest level while maintains this lower LMP of $10/MWh at Bus B unchanged. Consequently, the optimal load at Bus B should be close to but lower than 200 MW.

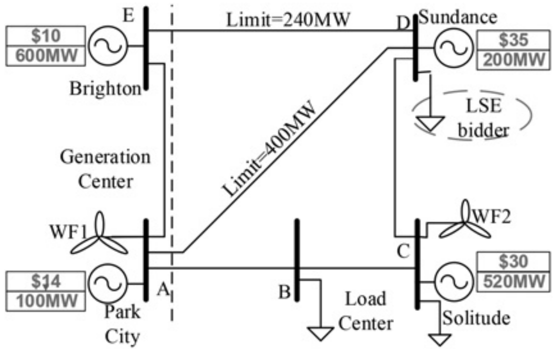

Fig. 4 *PJM 5-bus system with two wind farms*

In Case 3, from (18), the LSE holds a 200 MW FTR from Bus A to B. Since the LMP at Bus B is $30/MWh, higher than the flat rate, the LSE will make a negative profit from selling electricity to customers. However, it obtains more profit from the FTR's congestion compensation which is $(30-10) × 200. Therefore, in this case, after considering the benefit from FTR's congestion compensation, the LSE has no incentive to perform CBDR to reduce its load. This is a simple case to illustrate the impact of FTR on LSE's bidding and the simulation performed on the complex system will be presented in the following subsections.

5.2 PJM 5-bus test system

The test system is modified from the PJM 5-bus system depicted in Fig. 4. The system parameters are from [21]. The forecast power output of two wind power plants (WF1 and WF2) are 180 MW under a normal distribution with 18 MW as its standard deviation [37]) added into the system at buses A and C, while one of the

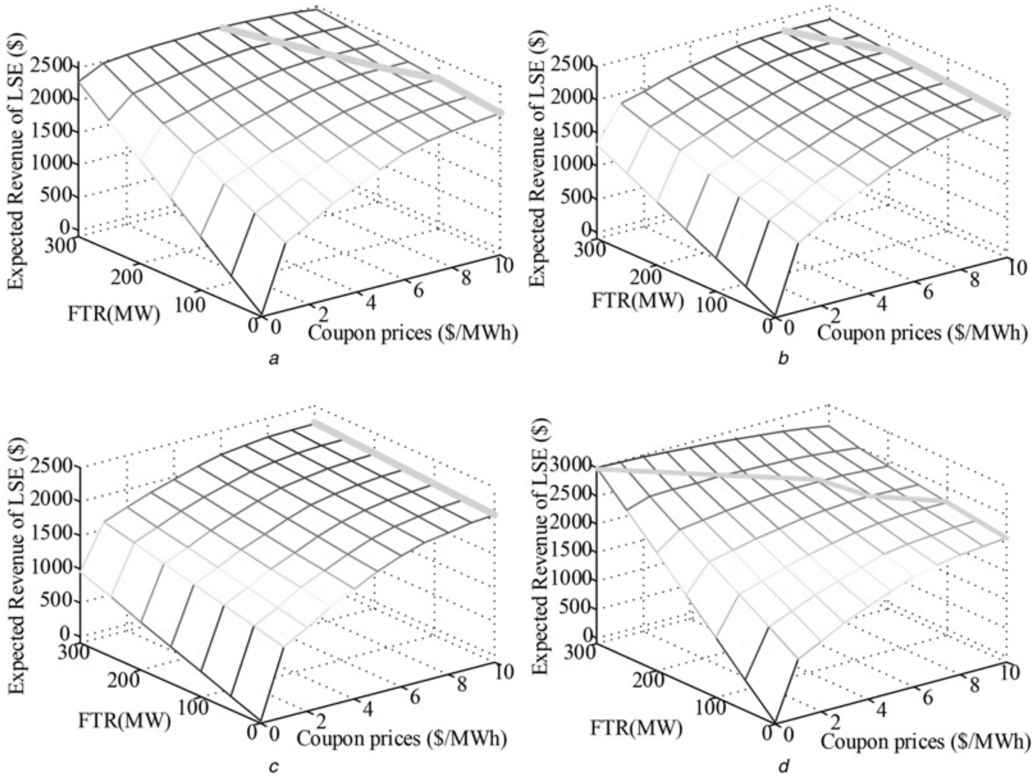

Fig. 5 *Expected revenue under different coupon prices and different FTRs*

a FTR from Bus A to Bus D
b FTR from Bus B to Bus D
c FTR from Bus C to Bus D
d FTR from Bus E to Bus D

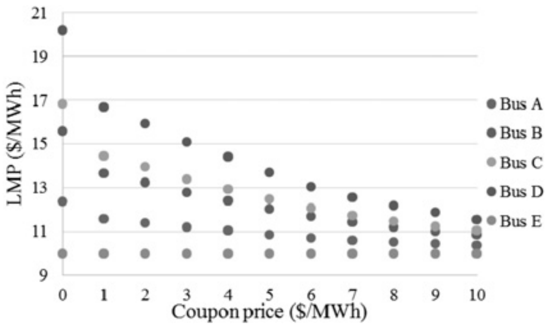

Fig. 6 *Bus LMPs with different coupon prices*

two original generators at bus A is removed. The total load is equally distributed between buses B, C, and D.

In the case study, the LSE bidder is located at Bus D. The flat electricity rate offered to the customers at Bus D is set to $20/MWh. Moreover, this study assumes the coupon price is between $0/MWh and $10/MWh with $1 as the incremental step such that there are 11 different coupon prices aligned with 11 probabilistic distribution of demand reduction generated by the demand reduction model in Section 3.

Table 3 Generation parameter

Unit	Price, $/MWh	Pmax	Unit	Price, $/MWh	Pmax
1	10	1040	6	27	687
2	15	646	7	28	580
3	16	725	8	11	564
4	25	652	9	12	865
5	26	508	10	17	1100

The impact of FTR on the strategic CBDR bidding is investigated on different FTR paths and amounts. The base load level is 300 MW on all three load buses. Figs. 5*a–d* are the LSE's expected net revenue with various paths and amounts of FTRs under different coupon prices. Figs. 5*a–d*, specify the FTR paths from Bus A to Bus D, Bus B to Bus D, Bus C to Bus D, and Bus E to Bus D, respectively. The green lines on the figures identify the optimal coupon prices under the specific FTR path and MW amount, which cause the LSE to obtain the highest revenue. These figures show that the impact of FTR on the strategic CBDR bidding varies w.r.t. FTR paths and amounts.

Fig. 6 is the buses' expected LMPs under different coupon prices when the LSE on Bus D does not hold FTR. This figure demonstrates that the LMPs, except Bus E, decrease with the coupon price. Because, with the increasing coupon price, the load on LSE's bus

Table 2 Bidding results with Different FTR paths

FTR path	*R*, $	Opt. D, MW	Opt. coupon, $/MWh	Bus LMP, $/MWh				
				A	B	C	D	E
None	2086.4	276.5	10	10.36	10.85	11.03	11.55	10.00
A–D	2562.6	284.9	6	10.75	11.75	12.14	13.20	10.00
B–D	2307.6	280.3	8	10.52	11.21	11.48	12.21	10.00
C–D	2240.7	276.5	10	10.36	10.85	11.04	11.55	10.00
E–D	3000	300	0	12.38	15.58	16.82	20.21	10.00

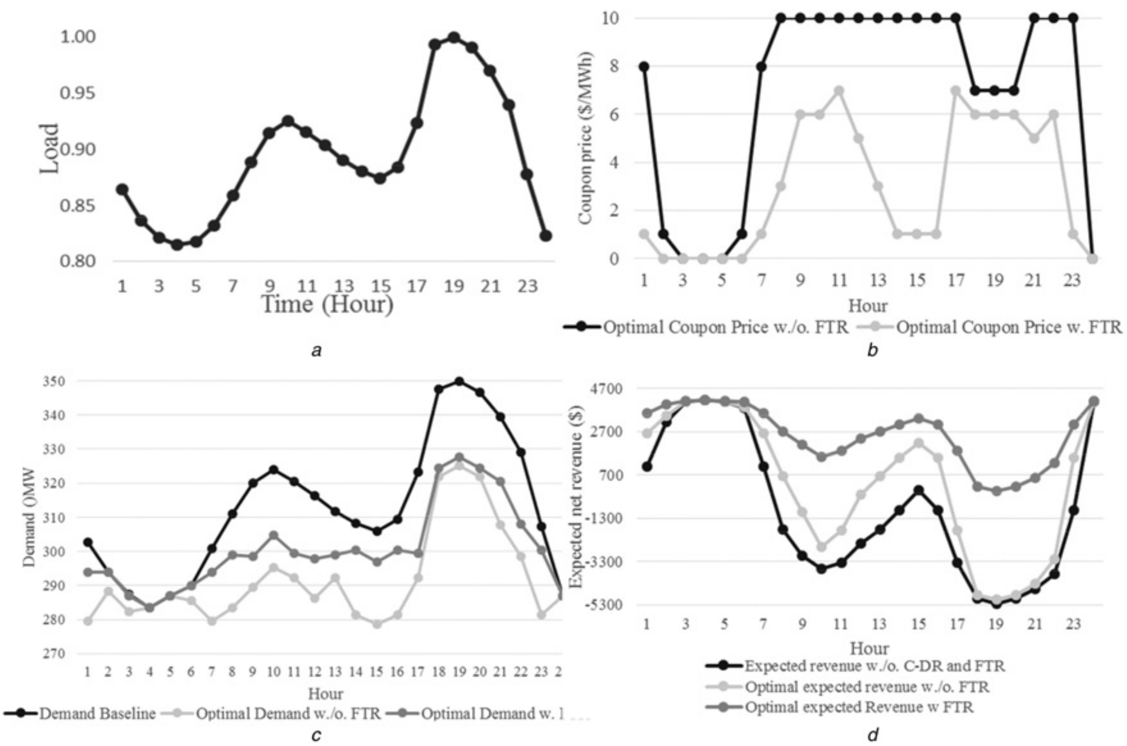

Fig. 7 *Daily load curve and optimal coupon prices, demand and expected net revenue at different hours w./o. FTR and w. FTR*

a Daily load curve
b Optimal coupon price ($/MWh)
c Optimal demand (MW)
d Expected net revenue ($)

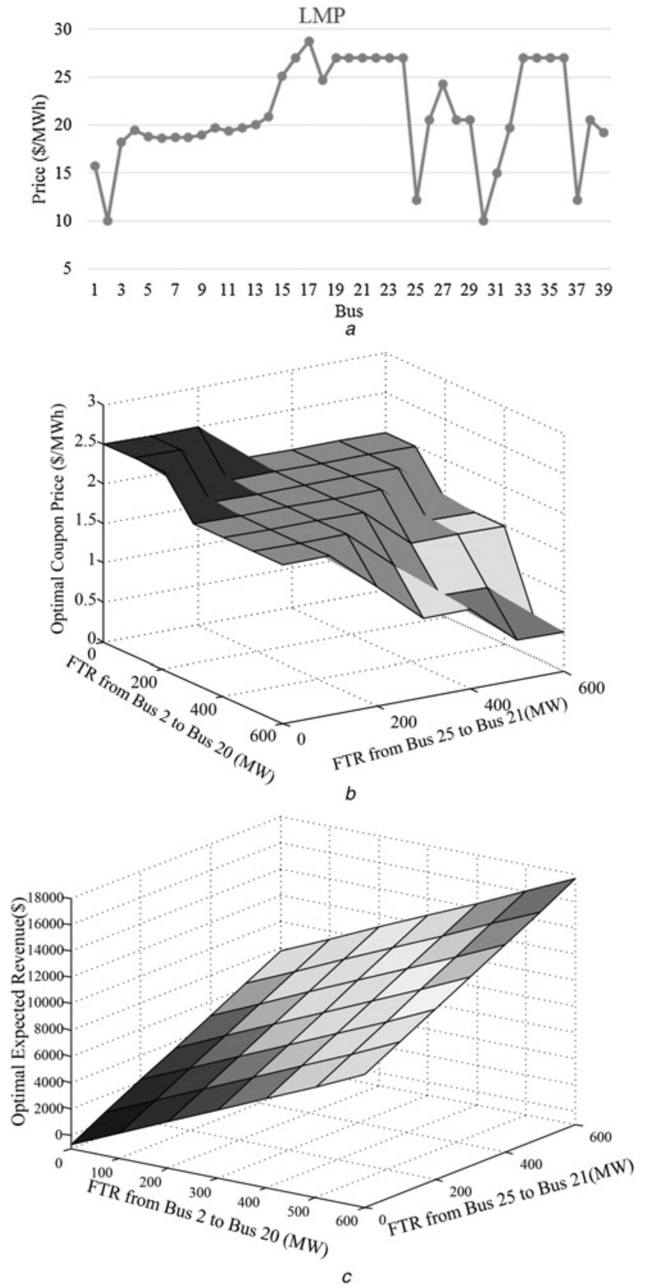

Fig. 8 *Expected bus LMPs considering wind uncertainty and optimal coupon price and expected net revenue under different FTR holding*

a Expected bus LMPs
b Optimal coupon price with different FMTR holdings
c Optimal expected net revenue with different FTR holdings

decreases which leads to a reduction of the bus LMPs. Moreover, it can be observed that the LMP difference between Bus D and other buses decreases w.r.t. coupon price. This means that the congestion benefit from the LSE's FTR holding from other buses to Bus D will decrease with the increasing coupon price. Therefore, in the LSE's strategic CBDR bidding considering both CBDR and FTR, it should consider the benefit from FTR through maintaining high load level to obtain the congestion compensation and the benefit from selling electricity to customers with a lower LMP cost. With the method proposed in this paper, the global optimal strategic CBDR bidding decision can be obtained.

Table 2 lists the optimal demand level and coupon prices with which the LSE can obtain the maximum profit with 300 MW FTR on different paths. It shows that with this FTR amount, when the path is from Bus E to D, the LSE has no incentive to offer coupons to customers. While on the path from Bus C to D, the FTR does not change the bidding results regarding the demand amount and coupon price. However, the LSE can still obtain more profit through congestion compensation. The maximum profit that the LSE can obtain with CBDR and FTR decreases with the LMP differences between the injection buses and delivery buses of different FTR paths.

Fig. 7*a* is a typical double peak load curve with the higher peak occurring at night for PJM system on Nov. 23, 2014. Here, the total system peak load is 1050 MW and equally distributed at Buses B, C and D. The hourly optimal coupon prices without FTR and with FTR are shown in Fig. 7*b*, the optimal demands are in Fig. 7*c* and the hourly profits are depicted in Fig. 7*d*. In this simulation, the FTR is from Bus E to D with 200 MW.

Fig. 7*b* demonstrates that when the LSE holds 200 MW FTR from Bus E to D, the coupon prices offered to customers decrease. Without FTR, the LSE offers a higher coupon price such as $10/MWh during the peak hours from 8 AM to 17 PM and from 21 PM to 23 PM to stimulate the customers to reduce their electricity demand. While with this FTR holding, the LSE's coupon price decreases.

Fig. 7*c* shows that, with the help of FTR, the LSE can bid higher demand to the ISO. With the FTR considered in the bidding process, the LSE has the opportunity to obtain more profit as shown in Fig. 7*d*. FTR provides more flexibility to the LSE to obtain a higher profit if it is considered in the LSE's strategic bidding model with CBDR.

5.3 IEEE 39-bus system

IEEE 39-bus system integrated with 3 wind farms is shown in [38]. This system has ten generators with total capacity of 7367 MW and total demand is 6254 MW. The detail system parameters are in [38]. Three wind farms are integrated to bus 11, 24 and 26. The generation parameter is in Table 3. Four transmission lines are applied to the following thermal limits: 800 MW for lines 1–39, 500 MW for lines 2–3, 500 MW for lines 3–18, and 600 MW for lines 16–17.

At the operating point investigated in this study, assume that the forecast wind power outputs are 360 MW for three wind farms under a normal distribution with 36 MW as its standard deviation. The expected bus LMPs considering three wind farms' power output uncertainty under original load level is shown in Fig. 8*a*.

In this study, the LSE bidder contains the demand under Bus 20, 21, 23 and 24 and the electricity flat rate offered to the customers are $26/MWh. The coupon price varies from $0.5/MWh to $2.5/MWh with $0.5/MWh as the increment step. From the expected LMPs in Fig. 8*a*, it demonstrates that Bus 2 (Bus 30 is equivalent with Bus 2) and Bus 25 (Bus 37 is equivalent with Bus 25) have the largest LMP difference with the LSE's buses. From the conclusion in the previous subsection that the largest LMP difference can impact the

Table 4 Dispatched load, LMP on buses and LSE's revenue under different coupon prices with 400 MW FTR on each path

Coupon, $/MWh	Dispatched load, MW				LMP, $/MWh	Revenue, $
	Bus 20	Bus 21	Bus 23	Bus 24		
0	680	274	247.5	308.6	26.984	11217.139
0.5	645.093	259.564	234.460	293.340	26.700	11436.306
1.0	643.358	255.641	230.917	287.908	26.582	11464.220
1.5	637.348	253.034	227.236	283.218	26.476	11473.769
2.0	626.214	248.886	223.155	278.245	26.346	11467.517
2.5	622.396	245.622	220.025	274.342	26.254	11418.169

Table 5 Dispatched load, LMP on buses, optimal coupon price and LSE's R under different FTR amount on each path

FTR, MW	Dispatched load, MW				LMP, $/MWh	Opt. coupon	Revenue, $
	Bus 20	Bus 21	Bus 23	Bus 24			
0	610.683	243.150	219.634	273.150	26.214	2.5	−724.829
100	610.683	243.150	219.634	273.150	26.214	2.5	2308.135
200	621.135	247.049	223.155	277.857	26.328	2.0	5356.810
300	626.214	248.886	223.155	277.857	26.345	2.0	8410.752
400	637.348	253.034	227.236	283.218	26.476	1.5	11473.769
500	643.358	255.641	239.917	287.908	26.582	1.0	14565.368
600	645.093	259.564	234.460	292.340	26.700	0.5	17681.794

bidding results obviously, the impact of FTR holding from Bus 2 to Bus 20 and Bus 25 to Bus 21 on the LSE's strategic CBDR bidding will be investigated.

Fig. 8*b* demonstrates the optimal coupon prices under different FTR holding. Similar with the observation in Fig. 5, it shows that the optimal coupon price decrease with the FTR amounts on these two FTR paths. Fig. 8*c* is the optimal expected revenue under different FTR holding. Obviously the optimal expected revenue of the LSE bidder increases with FTR amounts.

Table 4 is the example of load dispatch results, LMPs on the LSE's buses and expected revenue with 400 MW FTR on each path. With this FTR holding, the optimal coupon price is $1.5/MWh and the corresponding expected revenue is $11,473.769. Table 5 is the results of optimal dispatched load and LMPs on the LSE's bus, optimal coupon price and LSE's expected revenue under different FTR amount for both paths. As shown in Fig. 8*b* and Table 5, the optimal coupon price decreases with the FTR amount on both paths. With a higher FTR holding, the LSE bidder has fewer incentive to reduce its demand on buses to reduce the LMPs. Although this will lead a loss of the electricity payment from the customers, the revenue loss under this higher LMPs can be compensated with the higher FTR revenue from CS.

6 Conclusions

In this paper, a strategic CBDR bidding approach for the LSE considering the impact of FTR and wind power is proposed. In this model, the uncertainty of wind power output and customers' electricity consumption behaviour patterns toward different coupon prices are included. The main contributions of this work can be summarised as follows:

(i) FTR's congestion compensation is modelled in the LSEs' strategic CBDR bidding process. This model utilises a bi-level optimisation which is transformed to a MPEC problem by a recasting of the lower-level problem into the KKT optimality condition, and then further converted into a MILP problem which can be solved using available software tools.
(ii) The impact of FTR on the strategic CBDR bidding of LSE is analysed with different FTR paths. It demonstrates that FTR's influence on LSEs' strategic CBDR bidding results varies w.r.t. different FTR paths. The impact increases with the LMP differences between the injection and the delivery buses of FTRs' paths.
(iii) With an increasing FTR amount, the coupon prices which the LSE offers to customers are prone to decrease if the FTR holding can impact the bidding results. Under this circumstance, the LSE's incentive to stimulate customers to reduce their demand is decreasing with its FTR holding amount.
(iv) The simulation results demonstrate the benefit of the congestion compensation of FTR under high load level and the profit obtained from the LMP reduction through CBDR should be co-optimised. Moreover, LSEs can obtain higher profit by considering FTR in its bidding process.

It should be noted that although this paper discuss the impact of FTR on the LSE's strategic CBDR bidding, the results can be utilised to determine the profitable FTR path and the FTR bidding curve which is valuable for LSEs to participate in ISO's FTR auction process. Moreover, the potential impact of FTR on DA market can be considered in the LSE's FTR bidding model and this can be a future work. It should be further noted again that this paper points out a possible strategic CBDR bidding for LSEs to maximise their benefit. The results can be also used by ISOs to better regulate DR programs with FTRs under variable wind generation.

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