The Impact of FTR on LSE's Strategic Bidding Considering Coupon Based Demand Response

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***Abstract*— Financial transmission rights (FTR) is a financial instrument for the electricity market participant to hedge the transmission congestion cost. With growing development in demand response, load serving entities (LSEs) may participate in the electricity market as a strategic bidder by offering coupon-based demand response (C-DR) programs to customers. In the LSE's bidding process, the impact of FTR which the LSE holds should be considered. To address this challenge, a new strategic bidding model is proposed in which the primary objective is to maximize the LSE's profit including the benefit from FTR by providing C-DR to customers. The proposed strategic bidding is a bi-level optimization problem with the LSE's net revenue maximization as the upper level problem and the ISO's economic dispatch (ED) for generation cost minimization as the lower level problem. This bi-level model is then converted to a mathematic problem with equilibrium constraints (MPEC) by recasting the lower level problem as its Karush-Kuhn-Tucher (KKT) optimality conditions. Futher, this MPEC is transformed to a mixed-integer linear programming (MILP) problem based on the strong duality theory, which is solvable using available optimization software. In addition, the validity of the proposed method has been verified with case studies.**

***Index Terms*-- Financial transmission rights (FTR), Coupon-based demand response (C-DR), Strategic bidding, Load Serving Entity (LSE), mathematic problem with equilibrium constraints (MPEC).**

NOMENCLATURE

N	number of buses;
M	number of lines;
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;
π_i	locational marginal price at bus i;
$\eta_{i,k}$	electricity retail price for customer k at bus i (\$/MWh);
$D_{i,k}$	energy consumption of customer k at bus i;
$D^0_{i,k}$	energy consumption baseline of customer k at bus i;
A	bus set of the LSE strategic bidder;
B_i	customer set at bus i belong to the LSE strategic bidder;
λ	dual variable associated with the power balance equation in economic dispatch;
μ_l^{min}, μ_l^{max}	dual variables associated with the lower and upper limits of transmission line l;
ω_i^{min}, ω_i^{max}	dual variables associated with the lower and upper limits of the generator at bus i.

I. INTRODUCTION

Financial transmission right is a financial instrument that entitles the holders to receive compensation for transmission congestion charges that arise when the transmission grid is congested in the Day-ahead market and differences in Day-ahead congestion prices result from the dispatch of generators out of merit order to relieve the congestion [1]. 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 charges collected from the market participants. The purpose of FTRs is to protect transmission services customers from increased cost due to transmission congestion when their energy deliveries are consistent with their FTR reservations.

Meanwhile, the increasing demand-side participation in electricity market has presented new challenges and opportunities for the market participants [2, 3]. For power system operators, various demand response (DR) programs have been deployed as potential resources to balance supply and demand, reduce peak-hour loads, and enhance the generation efficiency [4]. For consumers, electricity consumption is expected to be responsive to the fluctuant pricing signals to reduce their electricity payments [5, 6]. In a fully competitive electricity market, load serving entities (LSEs) play a critical role to fill the gaps between end consumers and wholesale market operators to connect them into an optimal operation framework [7].

As a profit-seeking organization, the objective of an LSE is to maximize the expected payoff considering the uncertainty from both the wholesale market and end customers. The majority of customers pay electricity bills with flat rates [8], while LSEs purchase electricity at a time-varying price. Therefore, LSEs will have the motivation to induce the consumers' inherent elasticity by demand response (DR) programs [9, 10], especially when the system is under stress or close to the next binding constraint, which is termed as a critical load level (CLL) in [11]. When the LMP is higher than the flat rate, the LSE have the incentive to stimulate the consumers to reduce their electricity consumption. While if the LSE holds the FTR with a positive LMP difference, it can utilize this congestion to get compensation and have less motivation to decrease its demand. Therefore, in the LSE's market operation, the impact of FTR should also be considered.

To study the operation of an LSE under this condition, a strategic bidding approach considering the coupon-based demand response (C-DR) and the benefit of FTR is proposed in this paper. In the proposed method, an LSE offers a C-DR program to customers first. Then, the path of FTR is chosen for the analysis. Next, the LSE mimics the ISO's market-clearing procedure. Finally, the LSE can obtain the optimal bidding strategy with the maximal possible net revenue including the benefit from FTR. The final decision variables of LSE bidders are the optimal load dispatches, which can be obtained by the proposed method. The impact of FTR on LSE's strategic bidding can also be analyzed.

The rest of this paper is organized as follows: Section II presents the overall bi-level model of strategic bidding for LSEs and the baseline load. Section III proposes the actual solution to solve the bi-level optimization model including the procedure of transforming it into MPEC problem, and the conversion from MPEC to MILP. Section IV demonstrates the simulation results and numerical analyses on the PJM 5-bus system to clearly verify the proposed method. Section V presents the summary and conclusion of this paper.

II. Strategic Bidding Model for LSEs

The three-layer electricity market framework is shown in Fig. 1. The details of an LSE's strategic bidding under this market structure will be discussed later. First, a LSE obtains hourly LMPs from the DA market. Then, the LSE broadcasts the coupon price for the hours in which the LSE wants to perform C-DR to stimulate the customers to reduce the electricity demand. After gathering all the potential demand reduction information, the LSE mimics ISO's economic dispatch process to identify the optimal demand reduction. Finally, the LSE bids with this revised demand in the actual market.

The LSE receives a gross revenue from each customer k, ($k \in B_i$), at bus i ($i \in LSE$), given by the product of retail price $\eta_{i,k}$ and the electricity consumption $D_{i,k}$ (as shown in Fig. 2). Then, the payment (i.e., the product of spot price π_i and the electricity consumption $D_{i,k}$) is subtracted since the LSE purchases electricity from ISOs in wholesale market at volatile nodal prices. In the next, the financial incentives that the LSE pays to customers should be subtracted as well, which is the product of coupon price $r_{i,k}$ and the deviation between the actual electricity demand and the baseline electricity consumption. Finally, the benefit from FTR should be included which is the product of FTR amount and the LMP difference between the delivery and receipt nodes of the FTR path. The objective of the LSE strategic bidding is to maximize this net revenue. If the last term in the objective function is omitted, FTR is not considered in the bidding model. In the bidding process, the decision variables are the demand dispatches. Since the LMP depends on ISO's ED, the strategic bidding problem is formulated as a bi-level problem below in (1a) to (1h), where *LSE* in the model identifies the LSE strategic bidder whose customers may be connected at several buses shown in Fig. 2.

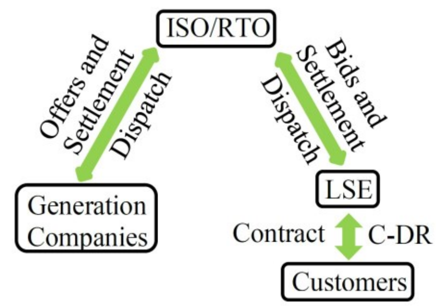

Fig. 1. Structure of the electricity market

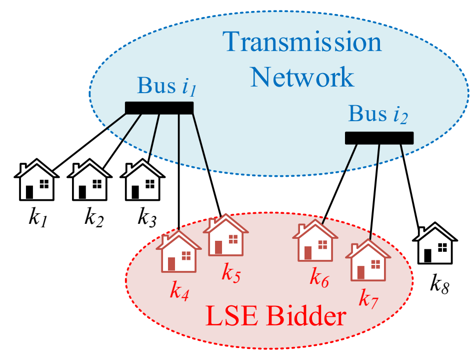

Fig. 2. The illustrative figure of a LSE and its customers

$$\textbf{Maximize} \quad \sum_{i\in A}\Big(\sum_{k\in B_i}(\eta_{i,k}\times D_{i,k} - r_{i,k}\times(D^{0}_{i,k}-D_{i,k})) - \pi_i\times D_i\Big) + \sum_{\{ij\in\Gamma\}}\left[\Delta\pi_{ij}\cdot FTR_{ij}\right] \tag{1a}$$

$$\text{s.t.}\ D^{\min}_{i,k} \le D_{i,k} \le D^{\max}_{i,k}, \forall i\in LSE, k\in B_i \tag{1b}$$

$$\forall \pi_i \in \arg\left\{ min\sum_{i=1}^{N} c_i \times G_i \right. \tag{1c}$$

$$\text{s.t.}\ \sum_{i=1}^{N} G_i = \sum_{i=1}^{N} D_i : \lambda \tag{1d}$$

$$D_i = \sum_{k\in B_i} D_{i,k}, \forall i\in LSE \tag{1e}$$

$$-Limit_l \le \sum_{i=1}^{N} GSF_{l-i}\times(G_i - D_i) \le Limit_l : \mu_l^{\min}, \mu_l^{\max}, \forall l = 1,2,\ldots,M \tag{1f}$$

$$G_i^{\min} \le G_i \le G_i^{\max} : \omega_i^{\min}, \omega_i^{\max}, \forall i = 1,2,\ldots,N \tag{1g}$$

$$\pi_i = \lambda + \sum_{l=1}^{M} GSF_{l-i}(\mu_l^{\min} - \mu_l^{\max}) \Big\} \quad (1h)$$

where $\Delta\pi_{ij}$ is the LMP difference on the ij path of FTR, FTR_{ij} is the reserved FTR amount (quantity) on path ij, and Γ is the set of FTR which the LSE bidder holds. $D_{i,k}^{\min}$ and $D_{i,k}^{\max}$ are the minimum and maximum demand values, respectively, of demand k at bus i. B_i is the set of customers on bus i who have the C-DR contract with LSE bidder. The LMP π_i from the ED depends on demand, $D_{i,k}$, as well as the bid prices/quantities of generators. In the ED model (1c)-(1h), the variables on the right side of the colon are the dual variables associating the equality or inequality constraints on the left side of the colon.

III. Mathematical Solution of the Proposed Model

As presented in Section II, the strategic bidding problem in (1) to (8) is formulated as a bi-level optimization problem. The upper level is to maximize the LSE's profit including the benefit from the FTR; and the lower level is to minimize the generation cost to model the ISO's market-clearing process.

Because of the existence of dependent variables in each level, these two optimization problems are coupled. For instance, the LMP in the upper level problem is decided by the lower level problem of ISO's market clearing, while the demands at load buses of LSE bidders in the lower level market clearing problem depends on the upper level. In this paper, DCOPF is implemented to clear the ISO's market. Due to the linearity of DCOPF [12, 13], its optimal solution should be a unique point that satisfies the Karush-Kuhn-Tucher (KKT) optimality conditions. Consequently, the bi-level optimization problem is formulated as a mathematical problem with equilibrium constraints (MPEC) by integrating the lower level problem into the upper level problem using its KKT conditions as the extra complimentary constraints [14]. According to the strong duality theory [14], this MPEC model can be converted to a MILP that is solved by available software.

A. Formulation as a MPEC

Given that the lower level ED is a LP problem, the bi-level strategic bidding model can be transformed to a MPEC by adding the lower level problem's KKT optimality condition into the upper level problem as a set of additional complimentary constraints shown in (2a)-(2g).

$$\textbf{Maximize} \quad \begin{aligned} &\sum_{i\in A}\Big(\sum_{k\in B_i}(\eta_{i,k}\times D_{i,k} - r_{i,k}\times(D_{i,k}^0 - D_{i,k})) - \pi_i\times D_i\Big) \\ &+ \sum_{\{ij\in\Gamma\}}\big[\Delta\pi_{ij}\cdot FTR_{ij}\big] \end{aligned} \quad (2a)$$

$$\text{s.t. } D_{i,k}^{\min} \le D_{i,k} \le D_{i,k}^{\max}, \forall i\in LSE, k\in B_i \quad (2b)$$

$$c_i = \lambda + \sum_{l=1}^{M} GSF_{l-i}\times(\mu_l^{\min} - \mu_l^{\max}) + \omega_i^{\min} - \omega_i^{\max} \quad (2c)$$

$$0 \le \mu_l^{\min} \perp Limit_l + \sum_{i=1}^{N} GSF_{l-i}\times(G_i - D_i) \ge 0 \quad (2d)$$

$$0 \le \mu_l^{\max} \perp Limit_l - \sum_{i=1}^{N} GSF_{l-i}\times(G_i - D_i) \ge 0 \quad (2e)$$

$$0 \le \omega_i^{\min} \perp G_i - G_i^{\min} \ge 0 \quad (2f)$$

$$0 \le \omega_i^{\max} \perp G_i^{\max} - G_i \ge 0 \quad (2g)$$

B. Mixed-integer Linear Programming (MILP)

The MPEC model is nonlinear due to the product term $\pi_i{\cdot}D_{i,k}$ in the objective function (2a) and the complementarity constraints (2d)-(2g).

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:

$$\begin{aligned} &\lambda\times\sum_{i=1}^{N} D_i + \sum_{l=1}^{M}\mu_l^{\max}\times(-Limit_l - \sum_{i=1}^{N} GSF_{l-i}\times D_i) \\ &+ \sum_{l=1}^{M}\mu_l^{\min}\times(-Limit_l + \sum_{i=1}^{N} GSF_{l-i}\times D_i) \\ &+ \sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max}) + \sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min}) \\ &= \sum_{i=1}^{N} c_i\times G_i \end{aligned} \quad (3)$$

And from the LMP expression in (1h), the product term $\pi_i{\cdot}D_{i,k}$ in (2a) can be transformed as (4).

$$\sum_{i\in A}\pi_i\times D_i = \lambda\times\sum_{i\in A} D_i + \sum_{l=1}^{M}\sum_{i\in A} GSF_{l-i}(\mu_l^{\min} - \mu_l^{\max})\times D_i \quad (4)$$

Taking (4) into (3),

$$\begin{aligned} &\sum_{i\in A}\pi_i\times D_i + \lambda\times\sum_{i\notin A} D_i + \sum_{l=1}^{M}\mu_l^{\max}\times(-Limit_l - \sum_{i\notin A} GSF_{l-i}\times D_i) \\ &+ \sum_{l=1}^{M}\mu_l^{\min}\times(-Limit_l + \sum_{i\notin A} GSF_{l-i}\times D_i) \\ &+ \sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max}) + \sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min}) \\ &= \sum_{i=1}^{N} c_i\times G_i \end{aligned} \quad (5)$$

Therefore, the objective in (2a) can be expressed as (6a) and the MPEC problem is converted as a MILP problem as:

$$\begin{aligned} \boldsymbol{max} &\sum_{i\in A}\sum_{k\in B_i}(\eta_{i,k}\times D_{i,k} - r_{i,k}\times(D_{i,k}^0 - D_{i,k})) \\ &- \sum_{i=1}^{N} c_i\times G_i + \lambda\times\sum_{i\notin A} D_i + \sum_{l=1}^{M}\mu_l^{\max}\times(-Limit_l - \sum_{i\notin A} GSF_{l-i}\times D_i) \\ &+ \sum_{l=1}^{M}\mu_l^{\min}\times(-Limit_l + \sum_{i\notin A} GSF_{l-i}\times D_i) \\ &+ \sum_{i=1}^{N}\omega_i^{\max}\times(-G_i^{\max}) + \sum_{i=1}^{N}\omega_i^{\min}\times(G_i^{\min}) \\ &+ \sum_{\{ij\in\Gamma\}}\big[\Delta\pi_{ij}\cdot FTR_{ij}\big] \end{aligned} \quad (3a)$$

s.t. Constraints in (2b) and (2c) (3b)

$$0 \le \mu_l^{\min} \le M_\mu^{\min}\nu_\mu^{\min} \quad (3c)$$

$$0 \le Limit_l + \sum_{i=1}^{N} GSF_{l-i}\times(G_i - D_i) \le M_\mu^{\min}(1-\nu_\mu^{\min}) \quad (3d)$$

$$0 \le \mu_l^{\max} \le M_\mu^{\max}\nu_\mu^{\max} \quad (3e)$$

$$0 \le Limit_l - \sum_{i=1}^{N} GSF_{l-i}\times(G_i - D_i) \le M_\mu^{\max}(1-\nu_\mu^{\max}) \quad (3f)$$

$$0 \le \omega_i^{\min} \le M_\omega^{\min} \nu_\omega^{\min} \tag{3g}$$
$$0 \le G_i - G_i^{\min} \le M_\omega^{\min}(1-\nu_\omega^{\min}) \tag{3h}$$
$$0 \le \omega_i^{\max} \le M_\omega^{\max} \nu_\omega^{\max} \tag{3i}$$
$$0 \le G_i^{\max} - G_i \le M_\omega^{\max}(1-\nu_\omega^{\max}) \tag{3j}$$

where $M_\mu^{\min}$, $M_\mu^{\max}$, $M_\omega^{\min}$, and $M_\omega^{\max}$ are suitable large constants, and $\nu_\mu^{\min}$, $\nu_\mu^{\max}$, $\nu_\omega^{\min}$, and $\nu_\omega^{\max}$ are the auxiliary binary variables [15].

IV. Case Studies

In this section, the proposed strategic bidding approach is performed on a modified PJM 5-bus system [16], which is chosen for the easiness to illustrate the concept. The simulation has been done in the General Algebraic Modeling System (GAMS) and the MILP is solved by CPLEX.

A. *Test System*

The test system is modified from the PJM 5-bus system. The system parameters are from [16]. The total load is equally distributed between buses B, C, and D. The modified system is depicted in Fig. 3.

In the case study, the LSE bidder is located at bus B. The flat electricity rate offered to the customers at bus B by the LSE is set as \$20/MWh. This study also assumes that the coupon price is \$5/MWh and the customers have 20% demand responsive to this coupon. The system locational marginal price (LMP) under different system load level is depicted in Fig. 4. Table I lists the LSE's profit under different load level without strategic bidding with C-DR and the corresponding LMP results. It shows that the LSE will lose their money for all cases because the LMP on Bus B is higher than the flat rate.

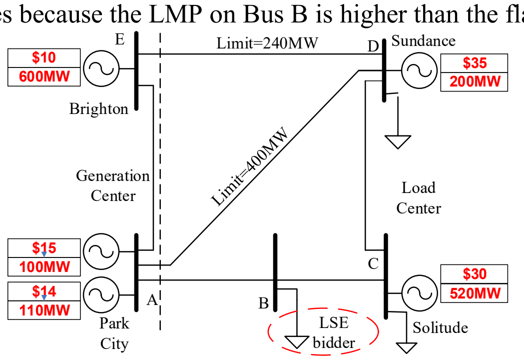

Fig. 3. PJM 5-bus system

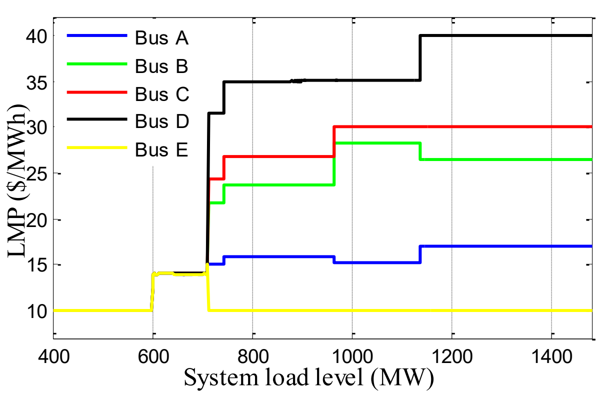

Fig. 4. LMPs in PJM 5-bus system under different load level

B. *Different Load Levels*

In this subsection, the impact of FTR is analyzed under different load levels. Table II lists the strategic bidding results considering C-DR while FTR is not included in the bidding model and Table III is the results in which FTR is considered in the proposed bidding model. The LSE bidder hold the FTR from Bus E to Bus B with the amount 200 MW. The implication of FTR path and amount on the strategic bidding will be analyzed in the following subsections.

Table I. Strategic Bidding Results not Including FTR

Base Load (MW)	Profit (\$)	LMP (\$/MWh)	
		Bus B	Bus E
240	-417.9	21.7	10
300	-1103.9	23.7	10
340	-2781.8	28.2	10
420	-2681.5	26.4	10

The first column of Table II and Table III is the load level on Bus B and the loads on the other two load buses are equal to the load on Bus B. The second column is the optimal demand level on Bus B which is the most profitable load for the LSE. The third and the fourth columns in Table II are the profits without FTR compensation and with FTR benefits. Note that in this Table, FTR is not considered in the bidding model, the FTR benefits (LMP @ Bus E – LMP @ Bus B)×FTR is obtained with the LMP from the ED results. While FTR is included in the strategic bidding model in Table III.

Table II. Strategic Bidding Results not Including FTR in Bidding

Base Load (MW)	Opt. D. (MW)	Profit (\$)	Profit w FTR (\$)	LMP (\$/MWh)	
				Bus B	Bus E
240	226.8	1295.1	1295.1	14	14
300	300	-1103.9	1632.0	23.7	10
340	307.6	-1293.9	1442.1	23.7	10
420	336	-2565.2	711.7	26.4	10

Table III. Strategic Bidding Results Including FTR in Bidding Model

Base Load (MW)	Opt. D. (MW)	Profit (\$)	LMP (\$/MWh)	
			Bus B	Bus E
240	228.2	1958.0	19.4	10
300	300	1632.0	23.7	10
340	307.6	1442.1	23.7	10
420	336	711.7	26.4	10

Table II and Table III demonstrate that the FTR from Bus E to Bus B changes the strategic bidding results when the system load level is 240 MW on Bus B. While on the other system load level, this FTR will not change the strategic bidding results. When the FTR is considered in the bidding model, although the LMP on Bus B increases (from \$14 to \$19.4) and the LSE can obtain less profit from the customers' electricity consumption, the LSE can gain more profit from the FTR congestion compensation. Because the LMP difference between two nodes of FTR increases from 0 to \$9.4/MWh. Therefore with the consideration of FTR in the bidding model, the optimal results change. On the load level, this LMP difference cannot change to a profitable value. Therefore including FTR in the bidding model does not change the bidding results.

Table I to Table III also show that if the difference between the LMP on Bus B and the flat rate is less than the coupon price (\$5/MWh), the LSE will have no incentive to reduce the demand such as the case in load level 300 MW. Under the load level 340 MW and 420 MW, the original LMP on Bus B are $28.2/MWh and $26.4/MWh and the difference between the LMP and the flat rate ($20/MWh) is larger than the coupon price. Therefore, the LSE reduce the demand. Also, if the difference of LMP with $20/MWh is larger than the coupon price, the LSE will keep reducing the load to the lower limit such as that in 420 MW load level. If this difference is smaller than the coupon price, the LSE will not keep reducing the load because reducing load is not profitable under this condition such as that in 340 MW load level.

C. Implication of Different FTR Paths and Amount

The impact of different FTR paths and amount are analyzed and the results are listed in Table IV and Table V. In Table IV, the load level on Bus B is 240 MW because from the study in the previous subsection FTR impacts the strategic bidding results under this load level and the amount of FTR is 200 MW.

TABLE IV. BIDDING RESULTS UNDER DIFFERENT FTR PATHS

FTR Path	Opt. D. (MW)	Profit ($)	LMP ($/MWh)	
			Bus B	Inject Bus
Bus A-Bus B	226.8	1295.1	14	14
Bus C-Bus B	226.8	1295.1	14	14
Bus D-Bus B	226.8	1295.1	14	14
Bus E-Bus B	228.2	1958.0	19.4	10

Table IV shows that different FTR paths have different influence on the strategic bidding of LSEs. In this study, only path from Bus E to Bus B are the profitable FTR path for the LSE on Bus B. While the other FTR paths are not profitable under this condition. The observation is that the generation on Bus E is the cheapest such that the LMP difference between this FTR is large. The price of the generation on Bus C and Bus D is higher than the flat rate such FTRs with Bus C and D as injection buses are not profitable.

TABLE V. RESULTS UNDER DIFFERENT FTR AMOUNT FROM BUS E TO B

FTR Amount (MW)	Opt. D. (MW)	Profit ($)	LMP ($/MWh)	
			Bus B	Bus E
0	226.8	1295.1	14	14
50	226.8	1295.1	14	14
100	226.8	1295.1	14	14
150	228.2	1488.3	19.4	10
200	228.2	1958.0	19.4	10

Table V demonstrates that the FTR can change the bidding results when it is greater than a specific amount. Because only when the profit from the congestion compensation is larger than the loss of the profit obtained from the customers' electricity consumption, the LSE will bid a different demand after considering FTR. It also can conclude that under this load level, if the cost of FTR is less than $3.3/MWh ((1958-1295.1)/200), the LSE is profitable to obtain 200 MW FTR from Bus E to Bus B.

V. CONCLUSIONS

In this paper, the impact of financial transmission rights (FTR) on the strategic bidding for the LSE with C-DR is analyzed. The bidding model is formulated as a bi-level optimization which is converted to a MPEC problem. Then, the strong duality theory is utilized to transform the MPEC model to a MILP which is solvable by available software. The simulation results demonstrate that considering FTR in the strategic bidding process will change the bidding results under some specific load levels when the injection bus of FTR paths has cheaper generation than the LSE's flat electricity rate. While in other cases, considering FTR does not change the bidding results. Also the influence of FTR on the strategic bidding changes with the FTR amount. Only when the FTR greater than some amount, it can change the bidding results. This work can also provide some cost benefit analysis information for the LSE in the FTR auction. Note that this is a preliminary study concerning the impact of FTR on the LSE's strategic bidding with C-DR. The uncertainty from renewable energy such as wind power and the volatile electricity consumption behavior of customers under different coupon prices will be analyzed in the future work.

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