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Strategic Biddings of a Consumer demand in both DA and Balancing Markets in Response to Renewable Energy Integration

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A R T I C L E I N F O

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renewable energy generation
strategic bidding

A B S T R A C T

This paper proposes strategic biddings for a consumer demand that participates in both the day-ahead and balancing markets. The strategic behavior of the consumer is represented by the bilevel optimization programming with minimization of consumer costs at the upper level (UL) subject to the co-optimization of energy and reserve in the market clearing process at the lower level problem (LL). Using the Karush-Kuhn-Tucker (KKT) optimality constraints to replace the LL problem, the bilevel model is recast into a single-level mathematical program with equilibrium constraints (MPEC). The resulted model is finally formulated as a mixed-integer linear programming (MILP) problem using the exact linearization technique and Fortuny-Amat transformation to replace bilinear terms and the complementarity constraints, respectively. The results demonstrate a reduction in the electricity consumption payment for the strategic consumer and a decline in social welfare.

1. Introduction

The ever-increasing penetration of renewable energy resources (RERs) into the power grid has significantly changed the operation of power systems. Integration of large-scale RESs such as wind and solar creates different challenges for power systems, hence obliging them to provide sufficient flexibility to accommodate uncertainties arisen from the unpredictable nature of RERs like wind and solar [1][2]. To this end, demand response management (DRM), as an economically and practically efficient way for providing flexibility, has emerged as a key concern in practice and has become the focus of many works for integrating large-scale, intermittent RESs and distributed energy resources (DERs) [3]. Demand response (DR) can be advantageous for both the utility and the consumers. On the one hand, the utility side can utilize the RESs more efficiently, and on the other hand, the consumers can reduce their electricity consumption cost [4].

Generally, there exist two different categories through which consumers participate in the DR program, either as competitive (price takers) or strategic decision-makers. The term "competitive" here refers to bidding at the marginal price, while the term "strategic'' refers to the capability of changing the electricity price in the market clearing process. Most of the works in the literature have addressed the DR by adopting the competitive behavior of consumers [5–14] [15]. In [5], demand-side resources were applied for providing reserve capacity, while to take care of the uncertain nature of wind power generation (WPG), a conditional value at risk (CVaR) based optimization was used. In order to alleviate the issues related to wind power integration into the power system, a combinations of pumped hydro storage (PH) and (DR) was considered in [6] to participate in energy and ancillary service markets. The authors in [7] introduced comprehensive modeling of the DR programs for the operational scheduling of electricity markets considering the uncertainties of wind power generation (WPG). A robust bidding strategy subject to market price uncertainties and resource variability was proposed in [8] for aggregating demand-side resources (DSRs). The potential of DR in both day-ahead and real-time markets was investigated in [9] through DR aggregators. Intending to facilitate the integration of WPG, the authors in [10] proposed a DR program to co-operate between the electric power systems and the natural gas transmission system. In [11], a microgrid consisting of WPG, solar energy, and tidal power were considered to study stochastic energy management while handling the electricity price by Monte Carlo simulation (MCS). Flexible ramping products (FRPs) based on a distributionally-robust chance-constrained multi-interval optimal power flow

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Nomenclature

Indices and Sets

T	Set of the time period, indexed by t
N	Set of buses, indexed by n
S	Set of scenarios, indexed by s
G	Set of generation units, indexed by g
W	Set of wind power units, indexed by w
D	Set of strategic demands, indexed by d
DN	Set of competitive demands, indexed by dN
L	Set of transmission lines, indexed by l
Ψ_n^G	Set of generation units located at bus n
Ψ_n^W	Set of wind power units located at bus n
Ψ_n^{DN}	Set of competitive demands located at bus n
Ψ_n^D	Set of strategic demands located at bus n
$r(l)/s(l)$	Receiving/sending -end bus of line l

Parameters

$P_{w,t,s}$	wind power produced by the w_{th} wind power unit at time t and scenario s, (MW)
P_w^{max}	Maximum generated power by wind unit W
π_s	Probability occurrence of scenario s
C_g	Marginal cost of unit g
C_g^{RU}/C_g^{RD}	Upward/downward reserve capacity cost of unit g
C_g^U/C_g^D	Cost of increasing/ decreasing generation of unit g at the balancing stage
$R_g^{U,max}$	Upward reserve capacity by unit g
$R_g^{D,max}$	Downward reserve capacity by unit g
C_w	Marginal cost of wind power unit w
$C_{d,t}^{cap}$	Price cap for the day-ahead price bid
$C_d^{U\_cap}$	Balancing market price cap for load increase
$C_d^{D\_cap}$	Balancing market price cap for load curtailment
$C_{dN,t}$	Marginal utility of the dN_{th} competitive demand in the day-ahead market at time t
P_g^{max}	Maximum power output of unit g, MW
P_g^{min}	Minimum power output of unit g, MW
f_l^{max}	Transmission capacity of line l
$P_{dN,t}^{bid-max}$	Maximum bid power by demand dN
$P_{d,t}^{bid-max}$	Maximum bid power by demand d
$P_{d,t}^{min}$	Minimum cleared power for demand d
$P_{dN,t}^{min}$	Minimum cleared power for demand dN
$E_d^{Min-day}$	Minimum daily energy consumption for d
$E_d^{Max-day}$	maximum daily energy consumption for d
Δt	Interval duration of time t, h

Variables

$R_{d,t,s}$	Binary decision to prevent simultaneous increasing and curtailment of load of d_{th} strategic demand, at time t and scenario s
$P_{g,t}$	Power cleared to be produced by the g_{th} generation unit at time t
$R_{g,t}^U/R_{g,t}^D$	Upward/downward reserve capacity of unit g at time t Downward reserve capacity of unit g at time t
$P_{g,t,s}^U/P_{g,t,s}^D$	Upward/downward balancing power of unit g deploying from $R_{g,t}^U$ at time t and scenario s
$P_{w,t}$	Power cleared to be produced by the w_{th} wind power unit at time t
$P_{w,t,s}^{Curtail}$	Curtailed power of wind power unit w at time t and scenario s
$P_{dN,t}$	Power cleared to be consumed by the dN_{th} competitive demand at time t
$P_{d,t}$	Power cleared to be consumed by the d_{th} strategic demand at time t
$P_{d,t,s}^U/P_{d,t,s}^D$	Load increase/curtail by d_{th} strategic demand at time t and scenario s
$P_{d,t}^{bid}$	Power bid to be consumed by the d_{th} strategic demand at time t
$R_{d,t}^U/R_{d,t}^D$	Upward/downward reserve capacity of the d_{th} strategic demand at time t
$C_{d,t}$	Bid price of the d_{th} strategic demand in the DA market at time t
$C_{d,t}^U/C_{d,t}^D$	Bid price of the d_{th} strategic demand for load increase/ curtail in the balancing market at time t
$\delta_{n,t}^0$	Voltage angle in the DA at bus n, and time t
$\delta_{n,t,s}$	Voltage angle in the balancing stage at bus n, time t, and scenario s
$f_{l,t}^0$	Power flow through line l in the DA at time t
$f_{l,t,s}$	Power flow through line l in the balancing stage at time t, and scenario s
$\lambda_{n,t}^{DA}$	Locational marginal price at bus n and time t
$\gamma_{n,t,s}^{Bal}/\pi_s$	Balancing price at bus n, time t, and scenario s

considering the spatiotemporal correlation of wind power and demand uncertainties were studied in [12]. Authors in [13] developed an approach to study the impact of DR on generation adequacy while taking the uncertainties and behavior of customers into account. In [14], a list of price plans was provided to motivate various consumers to contribute to the DR program. In [15], the potential of DR was studied as a comprehensive set of DR programs, including tariff-based, incentive--based, and combinational DR programs where the power network has a high penetration of WPG systems. A new market framework was proposed in [16] to investigate demand aggregators' participation in four European electricity markets. In [17], a stochastic optimization model was proposed for a prosumer consisting of electric vehicle (EVs), thermostatically controlled load (TCLs), Shiftable load (SLs), PV power generation and inflexible load (IL) to define energy and tertiary reserve bids. The purpose was minimizing the cost of energy in DA and balancing markets, besides maximizing the revenue of selling reserve in the balancing stage. In [18], an optimal bidding strategy model with the demand response program was proposed for a load aggregator (LA) that helps the LA to make a more economical bidding strategy and reduce the risk of financial loss. In addition, independent system operators and regional transmission organizations benefit due to the decreased peak load of the system. In [19], a real-time trading framework for distribution networks was proposed where demands have a contract with an aggregator as a broker to deal with the distribution company. Then a bilevel formulation has been modeled to maximize the revenue of the distribution company at the upper level and maximize the profit of each aggregator at the lower level. The authors in [20] proposed an optimal bidding strategy for the aggregator while the responsiveness of residential customers was taken into account. Accordingly, different electrical appliances adjust their load through an energy management system, and the aggregator bids its optimal strategy in the day-ahead market by functional relation, which formulates the aggregator's decision-making process.In contrast with the large number of works in the literature considering the competitive behavior of consumers, there are limited studies that considered the strategic behavior of consumers. For example, in [21], the authors presented a Stackelberg game approach to activate the DR program in a residential area. In this approach, the consumers at the upper level (UL) were adjusting their load to maximize their receiving bonus, while the aggregator at the lower level (LL) was striving to maximize the utilization of wind power generation by offering a bonus to the consumers. However, the electricity market has not been included in the model. In [22], an optimization model was proposed for a DR aggregator, which was a strategic player in the real-time market to decide the optimal operation of a DR aggregator in the wholesale electricity market.

In [23], a bi-level optimization model was proposed for a flexible load aggregator, including distributed storage energy systems, EVs, and TLCs which were aggregated to trade in DA energy and reserve markets. In [24], the strategic behavior of a large consumer was presented in the day-ahead market without addressing the balancing market clearing. Reference [25] extended the work in [24] by including the balancing market, while still, the consumer could offer in the balancing market competitively. In addition, only a single-hour auction was considered in [25], which resulted in ignoring the load-shifting capability of the consumer. In [26], a bidding strategy was proposed for a PEV aggregator to participate in the day-ahead market. The paper considered both the uncertainty in electricity market bids and the constraints on the available demand flexibility.

In addition, in some literature, the strategic bidding strategy of battery energy storage system [27], an optimal bidding strategy for a strategic producer [28], and strategic bidding for wind power producers have been considered. However, to the best of our knowledge, strategic bidding of consumer demand, which participates in both day-ahead and balancing markets, has not been investigated so far. To address the existing gap, this paper which is the first of its kind proposes a comprehensive model to let the consumer demand take part in both day-ahead and balancing markets strategically. Table 1 shows the contribution of the proposed method compared to some of the literature reviews, which considered the participation of consumer demand in the electricity market. The last column of the table, which shows “Bidding only by consumer demand,” indicates that there are no other sources like battery energy storage that are integrated with consumer demand. This shows that consumer demand can participate in the electricity market stand alone. Overall, the main contributions of this work can be summarized as follows.

- Developing a two-stage bi-level stochastic optimization model that derives the optimal bidding strategy for a strategic consumer in both the day-ahead and balancing markets under uncertainty of RERs.
- Evaluating the actual market power of the strategic consumers by conducting the simulation for 24 hours of a whole day, from 1:00 a.m. to 24:00 p.m., which enables load-shifting for the strategic consumers.
- Adopting an exact linearization method to transform the resulted nonlinear mathematical program with equilibrium constraints (MPEC) problem into a mixed-integer linear programming (MILP) problem. This is performed by applying the strong duality theorem and replacing the bilinears term with the equivalent linear terms obtained from complementarity conditions, see Section III-D.
- Revealing the impact of strategic and competitive behavior of the consumer in the electricity market by implementing the proposed model on the IEEE RTS 24-Bus system and IEEE RTS 118-Bus system, and providing detailed discussion on the results. This shows the applicability of the proposed method.

The remainder of this paper is organized as follows. Section II describes the model. Section III presents the problem formulation. Section IV provides the simulation results and discussions. Section V concludes the paper.

2. Model Description and Assumptions

2.1. Problem Description

We propose a bidding strategy for a consumer with market power, which aims at minimizing the total expected electricity cost in both the day-ahead and balancing markets. Therefore, the strategic consumer bid day-ahead price, day-ahead power, up-reserve power, down reserve power, balancing price for load increase and balancing price for load decrease. The up and down reserve power capacity of the consumer is similar to conventional units, which aims to mitigate the uncertainties of the RERs in the network. In this paper, we adopt a two-stage bi-level stochastic programming problem that seeks to minimize consumer electricity costs at the upper-level subject to co-optimizing the energy and reserve at the lower level. The main assumptions for developing the proposed model are as follows.

- Only one large consumer is considered to bid strategically, and other consumers are assumed to bid competitively at their marginal price. In the same way, only the strategic consumer is able to consider up- and down-reserve power for load increase or load decrease, respectively.
- All generating units are supposed to be perfectly competitive and to offer at their marginal costs.
- To clear the market, a DC power flow is used.
- The only source of uncertainty is the WPG output which is modeled through a finite set of scenarios.
- A one-day period, equal to 24 hours, is considered for each consumer and generating unit.

3. Problem Formulation

This section presents the nomenclature, formulation of the bilevel model, equivalent MPEC by replacing Karush–Kuhn–Tucker (KKT) optimality conditions, and the resulted MILP (mixed-integer linear programming) model.

Table 1
Contribution of the proposed method compared to the other literature reviews.

Approach in	Strategic behaviour	Participating in DA	Participating in reserve and balancing	Multiple hours auction	Bidding only by consumer demand
Proposed study	✓	✓	✓	✓	✓
[17]	×	✓	✓	✓	✓
[18]	✓	×	×	✓	✓
[19]	×	✓	×	✓	✓
[20]	×	✓	×	✓	×
[21]	✓	×	×	✓	✓
[22]	✓	×	✓	✓	✓
[23]	✓	✓	✓	✓	×
[24]	✓	✓	×	×	✓
[25]	✓	✓	×	×	✓
[26]	✓	✓	×	✓	×

3.1. Bilevel Model

Identifying the optimal bidding strategy for a strategic consumer is formulated by the following bilevel model.

$$\underset{\Delta^{UL}\cup\Delta^{LL}}{Minimize}\sum_{d\in j}\sum_{t=1}^{T}\left(\lambda_{n(d),t}^{DA}P_{d,t}+\pi_s\sum_{s\in S}\left(\gamma_{n(d),t,s}^{Bal}\Big/\pi\right)\left(P_{d,t,s}^{U}-P_{d,t,s}^{D}\right)\right)\tag{1}$$

Subject to:

$$0\le P_{d,t}^{bid}\le P_{d,t}^{bid\_\max};\ \forall d,\forall t\tag{2}$$

$$0\le R_{d,t}^{U}\le\left(P_{d,t}^{bid\_\max}-P_{d,t}\right)R_{d,t};\ \forall d,\forall t\tag{3}$$

$$0\le R_{d,t}^{D}\le\left(P_{d,t}-P_{d,t}^{\min}\right)\left(1-R_{d,t}\right);\ \forall d,\forall t\tag{4}$$

$$0\le C_{d,t}\le C_{d,t}^{cap};\ \forall d,\forall t\tag{5}$$

$$0\le C_{d,t}^{U}\le C_{d}^{U\_cap};\ \forall d,\forall t\tag{6}$$

$$0\le C_{d,t}^{D}\le C_{d}^{D\_cap};\ \forall d,\forall t\tag{7}$$

$$R_{d,t}\in\{0,1\};\ \forall d,\forall t\tag{8}$$

where $\lambda_{n,t}^{DA},\ \gamma_{n(d),t,s}^{Bal},P_{d,t},P_{d,t,s}^{U},P_{d,t,s}^{D}\in arg$

$$\begin{aligned}&Minimize\sum_{t=1}^{T}\sum_{g\in G}\left(C_gP_{g,t}+C_g^{RU}R_{g,t}^{U}+C_g^{RD}R_{g,t}^{D}\right)+\sum_{t=1}^{T}\sum_{w\in W}\left(C_wP_{w,t}\right)+\sum_{t=1}^{T}\sum_{s\in S}\sum_{g\in G}\pi_s\left(C_g^{U}P_{g,t,s}^{U}-C_g^{D}P_{g,t,s}^{D}\right)+\\&\sum_{t=1}^{T}\sum_{s\in S}\sum_{w\in W}\pi_sC_w\left(P_{w,t,s}-P_{w,t}-P_{w,t,s}^{Curtail}\right)-\sum_{t=1}^{T}\sum_{dN\in DN}\left(C_{dN,t}P_{dN,t}\right)-\\&\sum_{t=1}^{T}\sum_{d\in D}\left(C_{d,t}P_{d,t}+\sum_{s\in S}\pi_s\left(C_{d,t}^{U}P_{d,t,s}^{U}-C_{d,t}^{D}P_{d,t,s}^{D}\right)\right)\end{aligned}\tag{9}$$

Subject to:

$$\sum_{g\in\Psi_n^G}P_{g,t}+\sum_{w\in\Psi_n^W}P_{w,t}-\sum_{l\in L|s(l)=n}f_{l,t}^{0}+\sum_{l\in L|r(l)=n}f_{l,t}^{0}=\sum_{d\in\Psi_n^D}P_{d,t}+\sum_{dN\in\Psi_n^{DN}}P_{dN,t}\ :\left(\lambda_{n,t}^{DA}\right);\forall n,\ \forall t\tag{10}$$

$$\sum_{g\in\Psi_n^G}\left(P_{g,t,s}^{U}-P_{g,t,s}^{D}\right)+\sum_{w\in\Psi_n^W}\left(P_{w,t,s}-P_{w,t}-P_{w,t,s}^{Curtail}\right)+\sum_{l\in L|s(l)=n}\left(f_{l,t}^{0}-f_{l,t,s}\right)-\sum_{l\in L|r(l)=n}\left(f_{l,t}^{0}-f_{l,t,s}\right)=\sum_{d\in\Psi_n^D}\left(P_{d,t,s}^{U}-P_{d,t,s}^{D}\right)\ :\left(\gamma_{n,t,s}^{Bal}\right);\forall n,\ \forall t,\ \forall s\tag{11}$$

$$f_{l,t}^{0}=B_{0,l}\left(\delta_{s(l),t}^{0}-\delta_{r(l),t}^{0}\right)\ :\ \left(\varphi_{l,t}\right);\ \forall l,\forall t\tag{12}$$

$$f_{l,t,s}=B_{0,l}\left(\delta_{s(l),t,s}-\delta_{r(l),t,s}\right)\ :\ \left(\omega_{l,t,s}\right);\forall l,\forall t,\forall s\tag{13}$$

$$-f_{ll}^{\max}\le f_{l,t}^{0}\le f_{ll}^{\max}:\left(\theta_{l,t}^{10},\theta_{l,t}^{up}\right);\forall l,\forall t\tag{14}$$

$$-f_{l}^{\max}\le f_{l,t,s}\le f_{l}^{\max}:\left(o_{l,t,s}^{lo},o_{l,t,s}^{up}\right);\forall l,\forall t,\forall s\tag{15}$$

$$-\pi\le\delta_{n,t}^{0}\le\pi\ :\left(\alpha_{n,t}^{lo},\alpha_{n,t}^{up}\right);\forall n\backslash n:ref,\forall t\tag{16}$$

$$\delta_{n,t}^{0}=0\ :\left(\zeta_{n,t}\right);n:ref,\forall t\tag{17}$$

$$-\pi\le\delta_{n,t,s}\le\pi\ :\left(\varepsilon_{n,t,s}^{lo},\varepsilon_{n,t,s}^{up}\right);\ \forall n\backslash n:ref,\forall t,\forall s\tag{18}$$

$$\delta_{n,t,s}=0\ :\left(\tau_{n,t,s}\right);n:ref,\forall t,\forall s\tag{19}$$

$$P_g^{\min}+R_{g,t}^{D}\le P_{g,t}\le P_g^{\max}-R_{g,t}^{U}:\left(\beta_{g,t}^{lo},\beta_{g,t}^{up}\right);\ \forall g,\forall t\tag{20}$$

$$0\le R_{g,t}^{U}\le R_g^{U,\max}\ :\left(\eta_{g,t}^{lo},\eta_{g,t}^{up}\right);\forall g,\forall t\tag{21}$$

$$0\le R_{g,t}^{D}\le R_g^{D,\max}\ :\left(\iota_{g,t}^{lo},\iota_{g,t}^{up}\right);\forall g,\forall t\tag{22}$$

$$0\le P_{g,t,s}^{U}\le R_{g,t}^{U}\ :\left(\kappa_{g,t,s}^{lo},\kappa_{g,t,s}^{up}\right);\ \forall g,\forall t,\forall s\tag{23}$$

$$0\le P_{g,t,s}^{D}\le R_{g,t}^{D}\ :\left(\mu_{g,t,s}^{lo},\mu_{g,t,s}^{up}\right);\forall g,\forall t,\forall s\tag{24}$$

$$0\le P_{w,t}\le P_w^{\max}\ :\left(\nu_{w,t}^{lo},\nu_{w,t}^{up}\right);\ \forall w,\forall t\tag{25}$$

$$0\le P_{w,t,s}^{Curtail}\le P_{w,t,s}\ :\left(\rho_{w,t,s}^{lo},\rho_{w,t,s}^{up}\right);\ \forall w,\forall t,\forall s\tag{26}$$

$$P_{dN,t}^{\min}\le P_{dN,t}\le\ P_{dN,t}^{bid-\max}:\left(\upsilon_{dN,t}^{lo},\upsilon_{dN,t}^{up}\right);\forall dN,\forall t\tag{27}$$

$$P_{d,t}^{\min}\le P_{d,t}\le\ P_{d,t}^{bid}:\left(\delta_{d,t}^{lo},\delta_{d,t}^{up}\right);\forall d,\forall t\tag{28}$$

$$0\le P_{d,t,s}^{U}\le R_{d,t}^{U}:\left(\sigma_{d,t,s}^{lo},\sigma_{d,t,s}^{up}\right);\ \forall d,\forall t,\forall s\tag{29}$$

$$0\le P_{d,t,s}^{D}\le R_{d,t}^{D}:\left(\phi_{d,t,s}^{lo},\phi_{d,t,s}^{up}\right);\ \forall d,\forall t,\forall s\tag{30}$$

$$E_d^{Min-day}\le\sum_{t=1}^{T}P_{d,t}+P_{d,t,s}^{U}-P_{d,t,s}^{D}\le E_d^{Max-day}:\left(\chi_{d,s}^{lo},\chi_{d,s}^{up}\right);\ \forall d,\forall s\Big\}.\tag{31}$$

The above bilevel model (1)-(31), includes upper-level (UL) problem (1)-(8) and lower-level (LL) problem (9)-(31). The dual variable corresponding to each constraint in (10)-(31) is indicated following a colon. The variables of the LL are in the set $\Delta^{LL}=\{P_{g,t},R_{g,t}^{U},R_{g,t}^{D},P_{g,t,s}^{U},P_{g,t,s}^{D},P_{w,t},P_{w,t,s}^{Curtail},$ $P_{dN,t},\ P_{d,t},\ P_{d,t,s}^{U},\ P_{d,t,s}^{D},\ \lambda_{n,t}^{DA},\ \gamma_{n,t,s}^{Bal},\ \phi_{l,}\ t,\ \omega_{l,}\ t,s,\theta_{l,t}^{up},\ \theta_{l,}\ t^{lo},\ o_{l,t,s}\ up,o_{l,t,s}\ {}^{lo},\alpha_{n,t}^{up},\alpha_{n,t}^{lo},\zeta_{n,t},\varepsilon_{n,t,s}^{up},\varepsilon_{n,t,s}^{lo},\ \tau_{n,t,s},\ \beta_{g,t}^{up},\beta_{g,t}^{lo},\ \eta_{g,t}^{up},\eta_{g,t}^{lo},\ \iota_{g,t}^{up},\iota_{g,t}^{lo},\ \kappa_{g,t,s}^{up},\ \kappa_{g,t,s}^{lo},\ \mu_{g,t,s}^{up},\ \mu_{g,t,s}^{lo},$ $\nu_{w,t}^{up},\nu_{w,t}^{lo},\ \rho_{w,t,s}^{up},\ \rho_{w,t,s}^{lo},\upsilon_{dN,t}^{up},\ \upsilon_{dN,t}^{lo},\ \delta_{d,t}^{up},\ \delta_{d,t}^{lo},\ \sigma_{d,t,s}^{lo},\ \sigma_{d,t,s}^{up},\ \phi_{d,t,s}^{lo},\ \phi_{d,t,s}^{up},\ \chi_{d,s}^{up},\chi_{d,s}^{lo}\}$. The variables of the UL include the variable in the set Δ^{LL}, besides the variables in the set $\Delta^{UL}=\{P_{d,t}^{bid},\ R_{d,t}^{U},\ R_{d,t}^{D},\ C_{d,t},\ C_{d,t}^{U},\ C_{d,t}^{D}\}$. The objective function of UL in (1) aims to minimize the total expected operational cost of the strategic consumer in both the day-ahead and balancing markets, while the objective function of LL in (9) represents the co-optimization of energy and reserve in the electricity market clearing process. The LL objective function includes the summation of the day-ahead energy and reserve dispatch cost as well as the anticipated balancing costs. Constraints (2)-(7) impose limits on the day-ahead power, up-reserve power, down reserve power, day-ahead price, balancing price for load increase, and balancing price for load decrease, respectively. Constraint (8) prevents simultaneous increase and curtailment of the load of the strategic consumer. Equations (10) and (11) show the power balance equations for the day-ahead and balancing stages, respectively. In (12) and (13), the transferred power for each line is indicated, and in (14) and (15), the capacity limits for each line is enforced in the day-ahead and balancing stages. In (16) and (18), the voltage angles of each bus are bounded, while in (17) and (19), the voltage angle of the reference bus is set to zero in the day-ahead and balancing stages, respectively. Constraints (20)-(24) impose limits on the cleared power, upward reserve, downward reserve, upward balancing power, and downward balancing power of each conventional generation unit, respectively. Constraints (25) and (26) limit the cleared and curtailed power of each wind power producer. In (27), the bounds for competitive loads are enforced. Constraints (28)-(30) impose limits on the cleared power, load increase, and load curtailment of each strategic load, respectively. It should be mentioned that the ramp rate consumption is not considered for the consumers in this study. The consumer is an aggregated load of must run loads and flexible loads. In order to study the performance of the presented approach, it has been applied to the IEEE RTS 24-Bus System [29]. Six wind farms have been added in different locations of the grid, including buses #3, #5, #7, #16, #21, and #23.

2.2. MPEC Model

The LL (9)-(31) is linear and thereby can be replaced by its KKT optimality constraints. Therefore, the original bilevel problem can be recast into a single-level MPEC as follows.

$$\underset{\Delta^{UL}\cup\Delta^{LL}}{Minimize} \sum_{d\in j}\sum_{t=1}^{T}\left(\lambda^{DA}_{n(d),t}P_{d,t} + \pi_s\sum_{s\in S}\left(\gamma^{Bal}_{n(d),t,s}\Big/\pi\right)\left(P^{U}_{d,t,s} - P^{D}_{d,t,s}\right)\right) \tag{32}$$

$$(2)-(8) \tag{33}$$

Subject to:

$$(A1)-(A71) \tag{34}$$

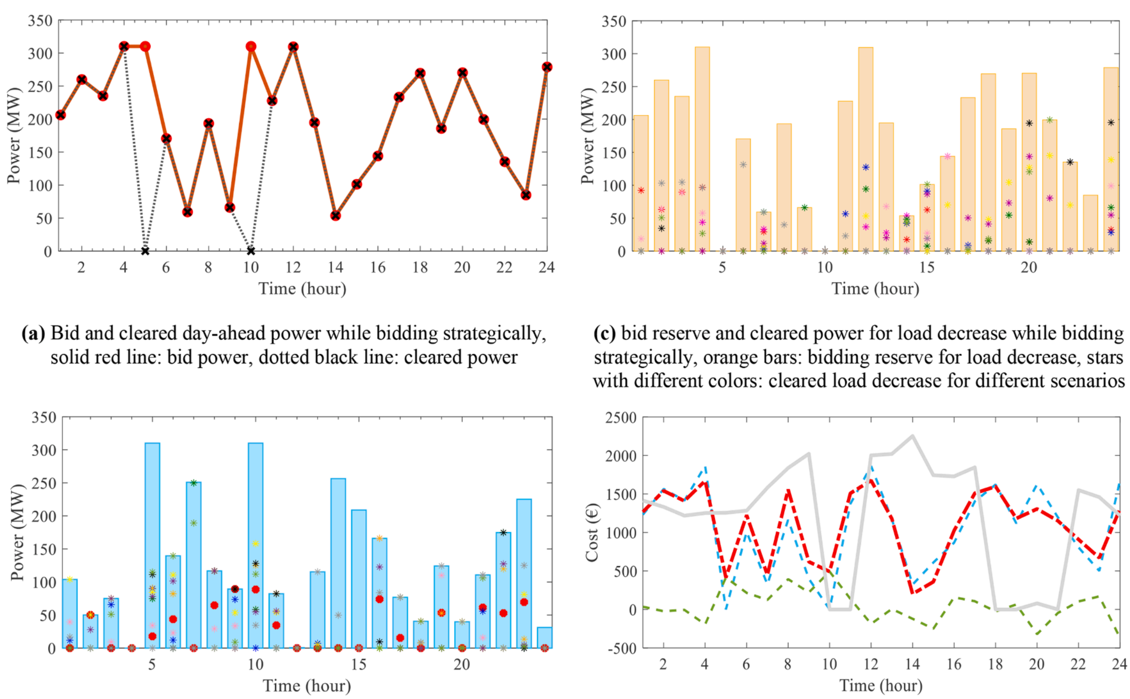
In addition, (34) correspond to the primal, dual, and Karush–Kuhn–Tucker (KKT) conditions of the LL problem (9)-(31). Interested readers may refer to Appendix A for detailed information on (34).

3.3. MILP Model

The MPEC (32)-(34) has the following nonlinearities:

- Bilinear terms $\lambda^{DA}_{n,t}P_{d,t}$ in the objective function (32).
- Bilinear terms $\gamma^{Bal}_{n(d),t,s}P^{U}_{d,t,s}$ in the objective function (32).
- Bilinear terms $\gamma^{Bal}_{n(d),t,s}P^{D}_{d,t,s}$ in the objective function (32).
- The complementarity constraints in (A.40)-(A.71).

Strong duality theorem (SDT) and some KKT constraints are adopted to replace the terms $\lambda^{DA}_{n,t}P_{d,t}$, $\gamma^{Bal}_{n(d),t,s}P^{U}_{d,t,s}$, and $\gamma^{Bal}_{n(d),t,s}P^{D}_{d,t,s}$ by their exact equivalent linear terms. Interested readers may refer to Appendix B for more details of linearization and converting the MPEC model to the MILP model.



(a) Bid and cleared day-ahead power while bidding strategically, solid red line: bid power, dotted black line: cleared power

(c) bid reserve and cleared power for load decrease while bidding strategically, orange bars: bidding reserve for load decrease, stars with different colors: cleared load decrease for different scenarios

(b) bid reserve and cleared power for load increase while bidding strategically, light blue bars: bid reserve for load increase, stars with different colors: cleared load increase for different scenarios

(d) Electricity consumption cost while bidding strategically and competitively; strategic bidding (dashed blue line: day-ahead cost, dashed green line: balancing cost, dot dashed red line: total cost), competitive bidding (grey line: total cost)

Fig. 1. Power and cost for consumer located at bus #18, **(a)** Bid and cleared day-ahead power while bidding strategically, solid red line: bid power, dotted black line: cleared powe. **(b)** bid reserve and cleared power for load increase while bidding strategically, light blue bars: bid reserve for load increase, stars with different colors: cleared load increase for different scenariosr. **(c)** bid reserve and cleared power for load decrease while bidding strategically, orange bars: bidding reserve for load decrease, stars with different colors: cleared load decrease for different scenarios. **(d)** Electricity consumption cost while bidding strategically and competitively; strategic bidding (dashed blue line: day-ahead cost, dashed green line: balancing cost, dot dashed red line: total cost), competitive bidding (grey line: total cost)

4. Simulation results

The performance of the proposed approach is thoroughly analyzed through two case studies, including IEEE RTS 24-Bus System [29] and IEEE RTS 118-Bus System. The simulations are conducted for 24 hours of a single day, from 1 a.m. to 24 p.m. The proposed model is implemented on an HP Z240 Tower Workstation with eight Intel Xeon E3-1230 v5 processors at 3.4 GHz and 16 GB of RAM using CPLEX 12.8 [30] under GAMS 25.1.2 [31].

4.1. IEEE RTS 24-Bus

In this case study, it is assumed that the consumer located at bus # 18, which has the biggest load in the network and constitutes 11.2 % of the total load, behaves strategically. The maximum load of the system is 2544.48 MW. Six wind farms, with 200 MW capacity for each of them, have been considered as RERs in different locations of the network, including 3, 5, 7, 16, 21, and 23 buses. The uncertainty of WPG is considered through 10 scenarios [32].

Fig. 1(a) illustrates the bid power and cleared day-ahead power of the consumer located at bus #18. Fig. 1(b) and Fig. 1(c) show the amount of reserve power for load increase and load curtailment as well as cleared balancing power of this consumer for different scenarios in the balancing market. Fig. 1(d) indicates the electricity consumption cost for this consumer when acting strategically and competitively. Adopting a strategic manner, this consumer can participate in the balancing market as well as the day-ahead market.

The total electricity consumption over 24 hours is shown for the consumer at bus #18 and the rest of the consumers altogether in Table 2 and Table 3, respectively. As it can be seen from these tables, adopting strategic bidding compared to competitive bidding, the total cost of the consumer at bus #18, which is acting strategically, has been reduced by €2873 (see Table 2), whereas the total cost of all other consumers (except load at bus #18), which are bidding competitively, shows a rise of about €4450 (see Table 3). According to Table 3, the total electricity cost has been reduced for some consumers who are geographically closer to bus #18, especially consumers # 13 and 14, while it shows a cost increase for the other consumers. Table 4 shows the total power curtailment of all WPG units. As it can be observed from this table, the total wind power curtailment of all WPG units has substantially decreased in each scenario. This can be due to the strategic behavior of the consumer in bus #18, which is shifting its load from hours with low WPG to hours with higher WPG.

Table 5 displays overall revenue in both the day-ahead and balancing markets for each wind generation unit. As it can be observed from Table 5, some WPG units, including # 1, 2, 3, and 4, have shown revenue increase, while the others, including #5, and 6, faced revenue decline. In addition, the total revenue for all WPG units shows an increase in revenue by €9095.05.

Table 6 shows the total revenue for conventional generators (in both the day-ahead and balancing markets), using strategic and competitive bidding of the consumer in bus #18. In both cases, it is assumed that other consumers are bidding competitively. In contrast with WPG units, the total benefit for conventional generators has decreased largely by about €11928. Finally, Table 7 indicates the impact of the strategic behavior of the consumer on social welfare. As can be seen from Table 7, the social welfare of the whole system shows an increase of 11984.6 while the consumer at bus #18 is a strategic player rather than a price taker.

Table 2
Electricity consumption cost for consumer at bus #18.

Consumer At bus #18	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Day-ahead	29094	25132	-3962
Balancing for load increase	0	4463.6	4463.6
Balancing for Load decrease	0	-3374.6	-3374,6
Total Cost	29094	26221	-2873

Table 3
Electricity consumption cost for price taker consumers.

Consumer #	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
1	14093	13947	-146
2	12695	12497	-198
3	20740	22048	1308
4	8632	9599	967
5	7951	9264	1313
6	15265	17886	2621
7	15262	16384	1122
8	21936	22342	406
9	21571	22600	1029
10	13133	13843	710
11	2772	2426	-346
12	6087	6535	448
13	6328	5392	-936
14	12909	10995	-1914
15	22197	20902	-1295
16	15826	15183	-643
Total Cost	217393	221843	+4450

Table 4
Total power curtailment of wind generation units.

Scenario #	Competitive Bidding (MW)	Strategic Bidding (MW)	Change (%)
1	3429.8	3055.5	-10.91
2	4386	4011.8	-8.53
3	3760.6	3386.4	-9.95
4	5554.7	5180.5	-6.74
5	4859.5	4485.2	-7.7
6	4896.3	4522	-7.64
7	3599.4	3225.1	-10.4
8	4063.2	3688.9	-9.21
9	4733.9	4359.6	-7.91
10	3449.2	3074.9	-10.85

Table 5
Total revenue for wind power generation units.

WPG unit #	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
1	19011	19179.91	1687.64
2	15111	20310.77	6908.93
3	21682	21136.77	907.13
4	15587	19381.81	3633.47
5	2177.2	842.167	-2658.31
6	19893	20777.62	-1383.82
Total	92534.0	101629.1	9095.05

Table 6
Total revenue for all conventional generation units.

	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Total revenue	138234.9	118732.2	-19052.7

Table 7
Social welfare of the system.

Bidding	Competitive Bidding	Strategic Bidding	Change
Social Welfare	15718.1	27702.7	11984.6

4.2. Sensitivity analysis

In this section, we will analyze how the market outcomes will change, given the amount of capacity that the strategic consumer considers to provide flexibility to the system. Accordingly, three minimum

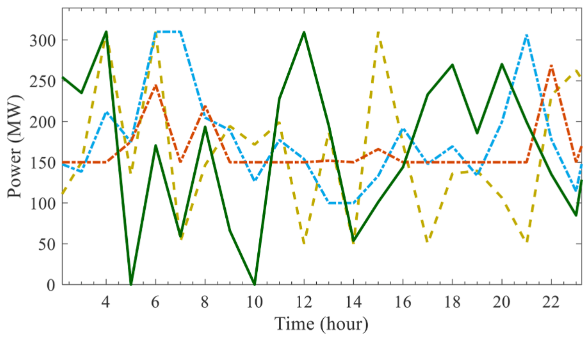


Fig. 2. Cleared Power for consumer located at bus #18; green line: cleared power when the minimum consumption per hour is 0; dashed yellow line: cleared power when the minimum consumption per hour is 50; dotted dashed blue line: cleared power when the minimum consumption per hour is 100; dotted dashed red line: cleared power when the minimum consumption per hour is 150

consumption levels of 50, 100, and 150 MW per hour have been considered for the strategic demand which is located at bus #18. Fig. 2 shows how the cleared demand will change for the strategic consumer over 24 hours when the minimum consumption levels have changed.

As it is shown in Fig. 2, the strategic consumer has the highest amount of flexibility when there is no limit for minimum consumption demand per hour for the strategic consumer. Accordingly, this consumer can adjust its load demand in a way that minimizes the electricity cost over 24 hours. In this case, the consumption demand is zero in some hours like 5 a.m. and 10 a.m. but is at the maximum load at some hours like 4 a.m. and 12 p.m. However, in real situations, this might not be possible, and the consumer needs to consume some demand at each hour. For this reason, three minimum consumption levels as 50, 100, and 150 MW have been considered here to analyze the behavior of the consumer when it is bidding strategically.

According to Fig. 2, where the minimum level of consumption is higher, the strategic consumer has less flexibility to change its load over the 24 hours because the amount of energy consumed over this period is constrained between two values which means the consumer should have a minimum and maximum amount of energy over the 24h hours period. This implies the consumers have less ability to manipulate the electricity price and probably have to pay more for its consumption. In the other way, when the minimum level of consumption is less, it means the consumer has more flexibility to provide and is able to adjust its load in a way to manipulate the electricity price more, and thereby is probable to pay less for the electricity cost over the period.

Table 8 provides the electricity consumption cost for the consumer at bus #18 in two conditions, i.e., when it is bidding strategically and when it is bidding as a price taker. The minimum and maximum amount of energy over 24 hours has been constrained between a minimum and maximum values. According to Table 8, when the consumption level is equal for both price taker and strategic condition, the electricity cost is noticeably lower (in all three minimum demand level including 50, 100, and 150 MW) when the consumer bids strategically compared to the price taker bid. For example, when the minimum demand consumption for the consumer is 50 MW per hour, the electricity cost is €3031.6 with strategic bidding.

Table 9
Electricity consumption cost for consumer at bus #59.

Consumer At bus #18	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Day-ahead	81695.83	67720	-35466.7
Balancing for load increase	0	9082.9	9082.9
Balancing for Load decrease	0	826.7	826.7
Total Cost	81695.83	75976.2	-5719.63

Table 10
Electricity consumption cost for all price taker consumers.

	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Electricity cost	372067.72	196079.39	-175988.33

Table 11
Total power curtailment of wind generation units.

Scenario #	Competitive Bidding (MW)	Strategic Bidding (MW)	Change (MW)
1	22846.36	22773.43	-72.934
2	22676.27	22604.73	-71.544
3	22614.84	22543.63	-71.207
4	24601.29	24530.5	-70.785
5	23305.29	23234.36	-70.929

Table 12
Total revenue for wind power generation units.

WPG unit #	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
1	11179.97	-11,897.6	-23077.57
2	3871.30	4,910.9	1039.60
3	39868.12	47,733.2	7865.08
4	23918.46	47,421.9	23503.44
5	-167.12	6,689.7	6856.82
6	23019.87	17,280.2	-5739.67
7	164.07	-1,146.7	-1310.77
8	-13474.96	3,667.1	17142.06
9	21331.41	27,783.2	6451.79
10	127.31	-2,810.8	-2938.11
Total	109838.43	139631.10	29792.67

Table 13
Total revenue for conventional generation units.

	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Total revenue (€)	97799.68	38115.11	-59684.56

Table 14
Social welfare of the system.

Bidding	Competitive Bidding	Strategic Bidding	Change
Social Welfare	246125.44	94309.38	-151816.06

In addition, Table 9 shows the electricity bill for the consumers with competitive bidding where they also experienced reduction of their electricity cost over the 24 hours period. Another result which seems

Table 8
Electricity consumption cost for consumer at bus #18.

Minimum consumption per hour by the consumer at bus #18 (MW)	Total consumption by competitive bidding over 24 hours (MW)	Total consumption by strategic bidding over 24 hours (MW)	Electricity consumption cost for competitive bidding (€)	Electricity consumption cost for strategic bidding (€)
50	1832.7	3829.7	11689.1	25954.6
100	2732.7	4428.2	17180.5	25990.6
150	3632.7	4073.3	22925.1	26036.0

Table 15
Social welfare of the system.

Bidding	Competitive Bidding	Strategic Bidding	Change
Social Welfare	20700.5	28655.8	+7955.3

very important in wind side, is significant reduction of curtailed energy by wind farm when the consumer is bidding strategically compared to the price taker bidding. Table 10, 11, and 12 show the amount of wind power curtailment for minimum demand of 50, 100, and 150 MW per hour for the consumer. In all three minimum demand levels, the curtailment energy has dropped substantially with the strategic bidding. However, the total revenue for the wind power units which is demonstrated in Table 13, has reduced which shows the electricity price decreases when the consumer is bidding strategically. Table 14 provides revenue for the conventional generation units which shows that they also experienced a big reduction in their revenue due to the producing less power (more wind power has been utilized) and also decreased electricity price.

Finally, the social welfare of the system is presented in Table 15 which implies considerable rise in the social welfare by €7955.3 (€20700.5 in competitive bidding and in €28655.8 in strategic bidding). Overall, having the flexibility to change its load over time and also the ability to bid strategically in the market gives the consumer the possibility to minimize their consumption cost and reduce the peak load in the network as well as reducing the wind power curtailment.

4.3. *IEEE RTS 118-Bus*

With the aim of further investigation of the proposed approach, it has

Table 16
Electricity consumption cost for consumer at bus #59.

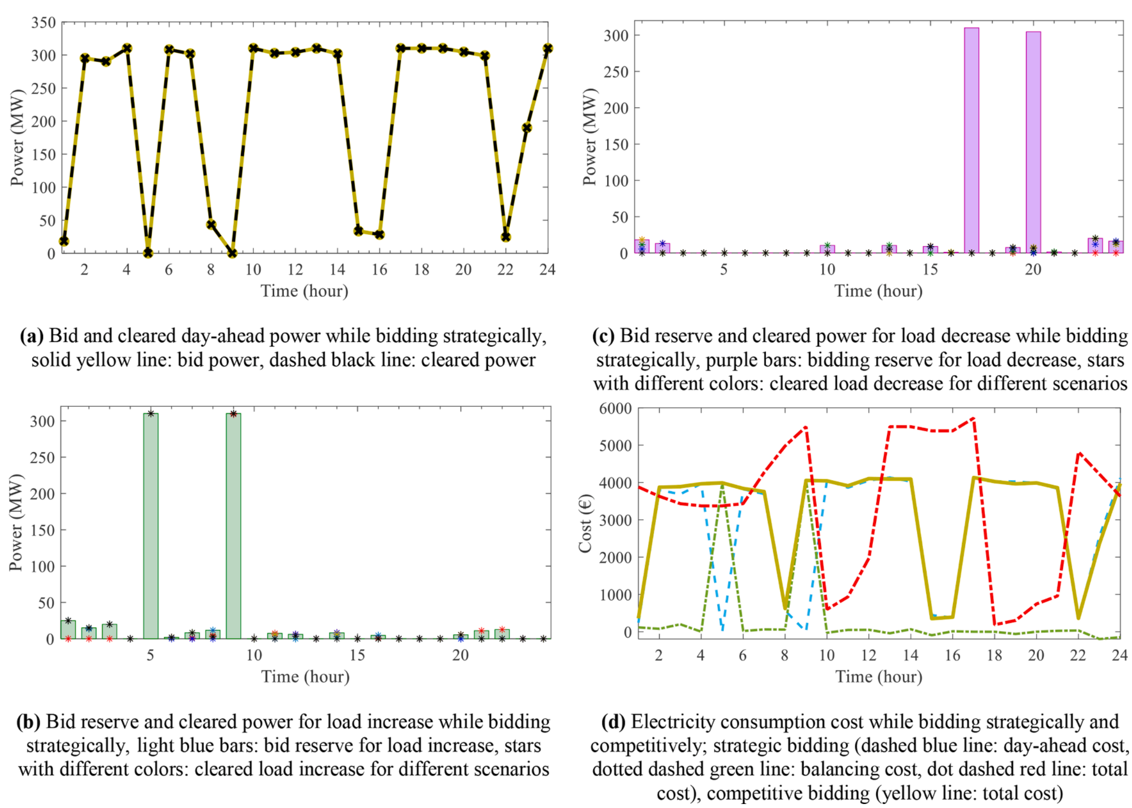
Consumer At bus #18	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Day-ahead	81695.83	67720	-35466.7
Balancing for load increase	0	9082.9	9082.9
Balancing for Load decrease	0	826.7	826.7
Total Cost	81695.83	75976.2	-5719.63

Table 17
Electricity consumption cost for all price taker consumers.

	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Electricity cost	372067.72	196079.39	-175988.33

been applied to the *IEEE RTS 118-Bus* system. In this case study, it is assumed that the consumer located at bus # 59, which has the biggest load in the network and constitutes around 6.5% of the total load, behaves strategically. The maximum load of the system is 6331.343 MW. Ten wind farms, with 200 MW capacity for each of them, have been considered as RERs in different locations of the network (the wind farms are located at the weak buses), including buses number 72, 103, 104, 105, 106, 107, 108, 109, 110, and 112. The uncertainty of WPG is considered through 5 scenarios [32].

Fig. 3(a) shows the bid power and cleared day-ahead power of the consumer located at bus #59. Fig. 3(b) illustrates the amount of reserve power considered for load increase as well as cleared balancing power of this consumer for different scenarios in the balancing market. In



(a) Bid and cleared day-ahead power while bidding strategically, solid yellow line: bid power, dashed black line: cleared power

(b) Bid reserve and cleared power for load increase while bidding strategically, light blue bars: bid reserve for load increase, stars with different colors: cleared load increase for different scenarios

(c) Bid reserve and cleared power for load decrease while bidding strategically, purple bars: bidding reserve for load decrease, stars with different colors: cleared load decrease for different scenarios

(d) Electricity consumption cost while bidding strategically and competitively; strategic bidding (dashed blue line: day-ahead cost, dotted dashed green line: balancing cost, dot dashed red line: total cost), competitive bidding (yellow line: total cost)

Fig. 3. Power and cost for consumer located at bus #59. **(a)** Bid and cleared day-ahead power while bidding strategically, solid yellow line: bid power, dashed black line: cleared power. **(b)** Bid reserve and cleared power for load increase while bidding strategically, light blue bars: bid reserve for load increase, stars with different colors: cleared load increase for different scenarios. **(c)** Bid reserve and cleared power for load decrease while bidding strategically, purple bars: bidding reserve for load decrease, stars with different colors: cleared load decrease for different scenarios. **(d)** Electricity consumption cost while bidding strategically and competitively; strategic bidding (dashed blue line: day-ahead cost, dotted dashed green line: balancing cost, dot dashed red line: total cost), competitive bidding (yellow line: total cost)

Table 18
Total energy curtailment of wind generation units.

Scenario #	Competitive Bidding (MWh)	Strategic Bidding (MWh)	Change (MWh)
1	22846.36	22773.43	-72.934
2	22676.27	22604.73	-71.544
3	22614.84	22543.63	-71.207
4	24601.29	24530.5	-70.785
5	23305.29	23234.36	-70.929

addition, Fig. 3(c) demonstrates the reserve power and cleared balancing power for load decrease and load curtailment. The electricity consumption cost for the consumer located at bus #59 for both strategic and competitive bidding is depicted in Fig. 3(d).

In Table 16 and Table 17, the total electricity consumption cost over 24 hours is given for the consumer capable of strategic bidding located at bus #59 and the rest of the consumers altogether, respectively. These tables indicate that the total cost of the consumer at bus #59, which is acting strategically, has been reduced by €5719.63 (see Table 9), compared to the competitive bidding condition. Furthermore, the total cost of all other consumers (except load at bus #59), which are bidding competitively, has decreased significantly by €175988.33 (see Table 10). Due to strategic bidding of the consumer at bus#59, the electricity cost has decreased for some consumers who are geographically closer to bus #59, which is because of the reduction of the day-ahead electricity price.

Table 18 gives the total power curtailment of all WPG units in the network. According to this table, the total wind power curtailment of all WPG units has noticeably reduced in each scenario, which is due to the strategic behavior of the consumer in bus #59 seeking to minimize its operational cost by shifting its load from hours with low WPG to hours with higher WPG. The total profit for each wind generation unit is revealed in Table 19, which shows revenue increase for some WPG units, including # 2, 3, 4, 5, 8, and 9 and revenue decrease for the other WPG units, e.g., #1, 6, 7, and 10. However, the overall revenue for all WPG units increased by €29792.67.

The total profit for conventional generators (in both the day-ahead and balancing markets), using strategic and competitive bidding of the consumer in bus #59, is given in Table 20. In contrast with WPG units, the total benefit for conventional generators has decreased dramatically by €59684.56, which shows some power from conventional generators is replaced by WPG units to supply the demands. Finally, Table 14 shows how the strategic behavior of a consumer affects social welfare. As can be seen from Table 21, the social welfare of the whole system decreased by 151816.06 when the consumer at bus #18 is a strategic player rather than a price taker consumer.

5. Conclusion

This paper presented optimal strategic bidding of a consumer in both the day-ahead and balancing markets. The IEEE RTS 24-Bus and IEEE RTS 118-Bus systems have been considered for verifying and revealing the potential of the proposed approach. The most important contributions of the proposed work were developing a two-stage bi-level stochastic optimization model that derives the optimal bidding strategy for a strategic consumer and also proposing an exact linearization method to transform the resulted nonlinear MPEC problem into a MILP problem. The impact of strategic and competitive bidding of one large consumer on the electricity consumption cost for demands, revenue for WPG units and conventional generators, wind power curtailment, and social welfare of the system has been investigated. Simulation results showed that when a consumer bids strategically in the network, it can affect the price in its favor. According to Tables 2 and 16, the electricity consumption cost of strategic bidding related to consumers located at bus# 18 and bus# 59 in 24- and 118-bus systems, respectively, has reduced significantly. This shows the consumer with strategic bidding can minimize the electricity cost in the market. However, the other consumers, who were bidding competitively, may incur an increase or decrease in total operational cost, depending on their bid price and power (see Table 3 and Table 17). In addition, the total power curtailment of WPG units in all possible scenarios has significantly decreased when there is a consumer demand who is bidding strategically instead of being price taker, which has resulted in higher total revenue for the WPG units (for example, total revenue for the WPG units was €101629.1 by strategic bidding versus € 92534 by competitive bidding of consumer located at bus#18 in 24-bus system). In contrast, the total revenue for all conventional generation units experienced a remarkable reduction, which was, for example, €118732.2 by strategic bidding versus €138234.9 by competitive bidding of consumer located at bus#18 in the 24-bus system. Finally, the social welfare of the system can increase or decrease depending on the cost for demands and revenue for WPG units and conventional generators. For example, social welfare has increased for the 24-bus system by 61.70 % but decreased for the 118-bus system by 76.25 %.

Future work will study the influence of higher penetration of RERs in the network while considering more than one strategic consumer. This will result in a highly complicated model, i.e., an equilibrium problem with equilibrium constraints (EPEC) instead of MPEC (for just one strategic consumer). The primary motivation is to find out new information for the most probable near-future scenario and its effects on the benefits of different players as well as the social welfare.

Table 19
Total revenue for wind power generation units.

WPG unit #	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
1	11179.97	-11,897.6	-23077.57
2	3871.30	4,910.9	1039.60
3	39868.12	47,733.2	7865.08
4	23918.46	47,421.9	23503.44
5	-167.12	6,689.7	6856.82
6	23019.87	17,280.2	-5739.67
7	164.07	-1,146.7	-1310.77
8	-13474.96	3,667.1	17142.06
9	21331.41	27,783.2	6451.79
10	127.31	-2,810.8	-2938.11
Total	109838.43	139631.10	29792.67

Table 20
Total revenue for conventional generation units.

	Competitive Bidding (€)	Strategic Bidding (€)	Change (€)
Total revenue (€)	97799.68	38115.11	-59684.56

Table 21
Social welfare of the system.

Bidding	Competitive Bidding	Strategic Bidding	Change
Social Welfare	246125.44	94309.38	-151816.06

CRediT authorship contribution statement

Mehdi Tavakkoli: Conceptualization, Methodology, Software, Writing – review & editing. **Sajjad Fattaheian-Dehkordi:** Software. **Mahdi Pourakbari-Kasmaei:** Formal analysis, Writing – review & editing. **Matti Liski:** Validation. **Matti Lehtonen:** Supervision.

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.

Appendix

Appendix A. Equation (34) comprises primal, dual, and KKT conditions of the LL problem (8)-(30), which are as follows.

$$\sum_{g\in\Psi_n^G} P_{g,t} + \sum_{w\in\Psi_n^W} P_{w,t} - \sum_{l\in L|s(l)=n} f_{l,t}^0 + \sum_{l\in L|r(l)=n} f_{l,t}^0 = \sum_{d\in\Psi_n^D} P_{d,t} + \sum_{dN\in\Psi_n^{DN}} P_{dN,t} \ : \left(\lambda_{n,t}^{DA}\right);\forall n,\ \forall t \tag{A.1}$$

$$\begin{aligned}&\sum_{g\in\Psi_n^G}\left(P_{g,t,s}^U - P_{g,t,s}^D\right) + \sum_{w\in\Psi_n^W}\left(P_{w,t,s} - P_{w,t} - P_{w,t,s}^{Curtail}\right) + \sum_{l\in L|s(l)=n}\left(f_{l,t}^0 - f_{l,t,s}\right) - \sum_{l\in L|r(l)=n}\left(f_{l,t}^0 - f_{l,t,s}\right) = \\ &\sum_{d\in\Psi_n^D}\left(P_{d,t,s}^U - P_{d,t,s}^D\right) \ : \left(\gamma_{n,t,s}^{Bal}\right);\forall n,\ \forall t,\ \forall s\end{aligned} \tag{A.2}$$

$$f_{l,t}^0 = B_{0,l}\left(\delta_{s(l),t}^0 - \delta_{r(l),t}^0\right) : \left(\varphi_{l,t}\right)\ ;\forall l, \forall t \tag{A.3}$$

$$f_{l,t,s} = B_{0,l}\left(\delta_{s(l),t,s} - \delta_{r(l),t,s}\right) \ : \left(\omega_{l,t,s}\right);\forall l, \forall t, \forall s \tag{A.4}$$

$$-f_{ll}^{\max} \le f_{l,t}^0 \le f_{ll}^{\max} : \left(\theta_{l,t}^{10}, \theta_{l,t}^{up}\right)\ ;\forall l, \forall t \tag{A.5}$$

$$-f_l^{\max} \le f_{l,t,s} \le f_l^{\max} : \left(o_{l,t,s}^{lo}, o_{l,t,s}^{up}\right)\ ;\forall l, \forall t, \forall s \tag{A.6}$$

$$-\pi \le \delta_{n,t}^0 \le \pi \ : \left(\alpha_{n,t}^{lo}, \alpha_{n,t}^{up}\right);\forall n\backslash n : ref, \forall t \tag{A.7}$$

$$\delta_{n,t}^0 = 0 \ : \left(\zeta_{n,t}\right)\ ; n : ref, \forall t \tag{A.8}$$

$$-\pi \le \delta_{n,t,s} \le \pi \ : \left(\varepsilon_{n,t,s}^{lo}, \varepsilon_{n,t,s}^{up}\right);\ \forall n\backslash n : ref, \forall t, \forall s \tag{A.9}$$

$$\delta_{n,t,s} = 0 \ : \left(\tau_{n,t,s}\right)\ ; n : ref, \forall t, \forall s \tag{A.10}$$

$$P_g^{\min} + R_{g,t}^D \le P_{g,t} \le P_g^{\max} - R_{g,t}^U : \left(\beta_{g,t}^{lo}, \beta_{g,t}^{up}\right);\ \forall g, \forall t \tag{A.11}$$

$$0 \le R_{g,t}^U \le R_g^{U,\max} \ : \left(\eta_{g,t}^{lo}, \eta_{g,t}^{up}\right);\forall g, \forall t \tag{A.12}$$

$$0 \le R_{g,t}^D \le R_g^{D,\max} \ : \left(\iota_{g,t}^{lo}, \iota_{g,t}^{up}\right);\forall g, \forall t \tag{A.13}$$

$$0 \le P_{g,t,s}^U \le R_{g,t}^U \ : \left(\kappa_{g,t,s}^{lo}, \kappa_{g,t,s}^{up}\right);\ \forall g, \forall t, \forall s \tag{A.14}$$

$$0 \le P_{g,t,s}^D \le R_{g,t}^D \ : \left(\mu_{g,t,s}^{lo}, \mu_{g,t,s}^{up}\right);\forall g, \forall t, \forall s \tag{A.15}$$

$$0 \le P_{w,t} \le P_w^{\max} \ : \left(\nu_{w,t}^{lo}, \nu_{w,t}^{up}\right);\ \forall w, \forall t \tag{A.16}$$

$$0 \le P_{w,t,s}^{Curtail} \le P_{w,t,s} \ : \left(\rho_{w,t,s}^{lo}, \rho_{w,t,s}^{up}\right);\ \forall w, \forall t, \forall s \tag{A.17}$$

$$P_{dN,t}^{\min} \le P_{dN,t} \le P_{dN,t}^{bid-\max} : \left(\upsilon_{dN,t}^{lo}, \upsilon_{dN,t}^{up}\right);\forall dN, \forall t \tag{A.18}$$

$$P_{d,t}^{\min} \le P_{d,t} \le P_{d,t}^{bid} : \left(\delta_{d,t}^{lo}, \delta_{d,t}^{up}\right);\forall d, \forall t \tag{A.19}$$

$$0 \le P_{d,t,s}^U \le R_{d,t}^U : \left(\sigma_{d,t,s}^{lo}, \sigma_{d,t,s}^{up}\right);\ \forall d, \forall t, \forall s \tag{A.20}$$

$$0 \le P_{d,t,s}^D \le R_{d,t}^D : \left(\phi_{d,t,s}^{lo}, \phi_{d,t,s}^{up}\right);\ \forall d, \forall t, \forall s \tag{A.21}$$

$$E_d^{Min-day} \le \sum_{t=1}^{T} P_{d,t} + P_{d,t,s}^U - P_{d,t,s}^D \le E_d^{Max-day} : \left(\chi_{d,s}^{lo}, \chi_{d,s}^{up}\right);\ \forall d, \forall s\Big\}. \tag{A.22}$$

$$\lambda_{n(g),t}^{DA} + \beta_{g,t}^{lo} - \beta_{g,t}^{up} = C_g\ ;\forall g,\ \forall t \tag{A.23}$$

$$\lambda_{n(w),t}^{DA} - \sum_s \gamma_{n(w),t,s}^{Bal} + \nu_{w,t}^{lo} - \nu_{w,t}^{up} = 0\ ;\forall w,\ \forall t \tag{A.24}$$

$$-\lambda_{n(dN),t}^{DA} + \upsilon_{dN,t}^{lo} - \upsilon_{dN,t}^{up} = -C_{dN,t}\ ;\forall dN,\ \forall t \tag{A.25}$$

$$-\lambda_{n(d),t}^{DA} + \delta_{d,t}^{lo} - \delta_{d,t}^{up} + \sum_{s}\chi_{d,s}^{lo} - \sum_{s}\chi_{d,s}^{up} = -C_{d,t}\,;\forall d,\ \forall t \quad (A.26)$$

$$-\beta_{g,t}^{up} + \eta_{g,t}^{lo} - \eta_{g,t}^{up} + \sum_{s}\kappa_{g,t,s}^{up} = C_{g}^{RU};\forall g,\ \forall t \quad (A.27)$$

$$-\beta_{g,t}^{lo} + \iota_{g,t}^{lo} - \iota_{g,t}^{up} + \sum_{s}\mu_{g,t,s}^{up} = C_{g}^{RD};\forall g,\ \forall t \quad (A.28)$$

$$\gamma_{n(g),t,s}^{Bal} + \kappa_{g,t,s}^{lo} - \kappa_{g,t,s}^{up} = \pi_s C_{g}^{U};\forall g,\ \forall t,\ \forall s \quad (A.29)$$

$$-\gamma_{n(g),t,s}^{Bal} + \mu_{g,t,s}^{lo} - \mu_{g,t,s}^{up} = -\pi_s C_{g}^{D};\forall g,\ \forall t,\ \forall s \quad (A.30)$$

$$-\gamma_{n(w),t,s}^{Bal} + \rho_{w,t,s}^{lo} - \rho_{w,t,s}^{up} = -\pi_s C_{w};\forall w,\ \forall t,\ \forall s \quad (A.31)$$

$$-\sum_{l|s(l)=n} B_{0,l}\varphi_{l,t} + \sum_{l|r(l)=n} B_{0,l}\varphi_{l,t} + \alpha_{n,t}^{lo} - \alpha_{n,t}^{up} = 0\,;\forall n\backslash n:ref,\forall t \quad (A.32)$$

$$-\sum_{l|s(l)=n} B_{0,l_l}\varphi_{l,t} + \sum_{l|r(l)=n} B_{0,l}\varphi_{l,t} + \zeta_{n,t} = 0\,;n:ref,\forall t \quad (A.33)$$

$$-\sum_{l|s(l)=n} B_{0,l}\omega_{l,t,s} + \sum_{l|r(l)=n} B_{0,l}\omega_{l,t,s} + \varepsilon_{n,t,s}^{lo} - \varepsilon_{n,t,s}^{up} = 0\,;\forall n\backslash n:ref,\forall t,\forall s \quad (A.34)$$

$$-\sum_{l|s(l)=n} B_{0,l}\omega_{l,t,s} + \sum_{l|r(l)=n} B_{0,l}\omega_{l,t,s} + \tau_{n,t,s} = 0\,;n:ref,\forall t,\forall s \quad (A.35)$$

$$-\lambda_{s(l),t}^{DA} + \lambda_{r(l),t}^{DA} + \sum_{s}\gamma_{s(l),t,s}^{Bal} - \sum_{s}\gamma_{r(l),t,s}^{Bal} + \varphi_{l,t} + \theta_{l,t}^{lo} - \theta_{l,t}^{up} = 0\,;\forall l,\ \forall t \quad (A.36)$$

$$-\gamma_{s(l),t,s}^{Bal} + \gamma_{r(l),t,s}^{Bal} + \omega_{l,t,s} + o_{l,t,s}^{lo} - o_{l,t,s}^{up} = 0\,;\forall l,\ \forall t,\ \forall s \quad (A.37)$$

$$-\gamma_{n(d),t,s}^{Bal} + \sigma_{d,t,s}^{lo} - \sigma_{d,t,s}^{up} + \chi_{d,s}^{lo} - \chi_{d,s}^{up} = -\pi_s C_{d,t}^{U};\forall d,\ \forall t,\ \forall s \quad (A.38)$$

$$\gamma_{n(d),t,s}^{Bal} + \phi_{d,t,s}^{lo} - \phi_{d,t,s}^{up} - \chi_{d,s}^{lo} + \chi_{d,s}^{up} = \pi_s C_{d,t}^{D};\forall d,\ \forall t,\ \forall s \quad (A.39)$$

$$0 \le \theta_{l,t}^{lo} \perp f_{l}^{\max} + f_{l,t}^{0} \ge 0\,;\ \forall l,\forall t \quad (A.40)$$

$$0 \le \theta_{l,t}^{up} \perp f_{l}^{\max} - f_{l,t}^{0} \ge 0;\ \forall l,\forall t \quad (A.41)$$

$$0 \le o_{l,t,s}^{lo} \perp f_{l}^{\max} + f_{l,t,s} \ge 0;\ \forall l,\forall t,\forall s \quad (A.42)$$

$$0 \le o_{l,t,s}^{up} \perp f_{l}^{\max} - f_{l,t,s} \ge 0;\ \forall l,\forall t,\forall s \quad (A.43)$$

$$0 \le \alpha_{n,t}^{lo} \perp \pi + \delta_{n,t}^{0} \ge 0\,;\ \forall n\backslash n:ref,\forall t \quad (A.44)$$

$$0 \le \alpha_{n,t}^{lup} \perp \pi - \delta_{n,t}^{0} \ge 0\,;\ \forall n\backslash n:ref,\forall t \quad (A.45)$$

$$0 \le \varepsilon_{n,t,s}^{lo} \perp \pi + \delta_{n,t,s} \ge 0\,;\ \forall n\backslash n:ref,\forall t,\forall s \quad (A.46)$$

$$0 \le \varepsilon_{n,t,s}^{up} \perp \pi - \delta_{n,t,s} \ge 0\,;\ \forall n\backslash n:ref,\forall t,\forall s \quad (A.47)$$

$$0 \le \beta_{g,t}^{lo} \perp P_{g,t} - P_{g}^{\min} - R_{g,t}^{D} \ge 0\,;\ \forall g,\forall t \quad (A.48)$$

$$0 \le \beta_{g,t}^{up} \perp P_{g}^{\max} - R_{g,t}^{U} - P_{g,t} \ge 0\,;\ \forall g,\forall t \quad (A.49)$$

$$0 \le \eta_{g,t}^{lo} \perp R_{g,t}^{U} \ge 0\,;\ \forall g,\forall t \quad (A.50)$$

$$0 \le \eta_{g,t}^{up} \perp R_{g}^{U,\max} - R_{g,t}^{U} \ge 0\,;\ \forall g,\forall t \quad (A.51)$$

$$0 \le \iota_{g,t}^{lo} \perp R_{g,t}^{D} \ge 0\,;\ \forall g,\forall t \quad (A.52)$$

$$0 \le \iota_{g,t}^{up} \perp R_{g}^{D,\max} - R_{g,t}^{D} \ge 0\,;\ \forall g,\forall t \quad (A.53)$$

$$0 \le \kappa_{g,t,s}^{lo} \perp P_{g,t,s}^{U} \ge 0\,;\ \forall g,\forall t,\forall s \quad (A.54)$$

$$0 \le \kappa_{g,t,s}^{up} \perp R_{g,t}^{U} - P_{g,t,s}^{U} \ge 0\,;\ \forall g,\forall t,\forall s \quad (A.55)$$

$$0 \le \mu_{g,t,s}^{lo} \perp P_{g,t,s}^{D} \ge 0\,;\forall g,\forall t,\forall s \quad (A.56)$$

$$0 \le \mu^{up}_{g,t,s} \perp R^D_{g,t} - P^D_{g,t,s} \ge 0\,; \forall g, \forall t, \forall s \tag{A.57}$$

$$0 \le \nu^{lo}_{w,t} \perp P_{w,t} \ge 0\,; \forall w\,, \forall t \tag{A.58}$$

$$0 \le \nu^{up}_{w,t} \perp P^{\max}_{w} - P_{w,t} \ge 0\,; \forall w\,, \forall t \tag{A.59}$$

$$0 \le \rho^{lo}_{w,t,s} \perp P^{Curtail}_{w,t,s} \ge 0\,; \forall w\,, \forall t, \forall s \tag{A.60}$$

$$0 \le \rho^{up}_{w,t,s} \perp P_{w,t,s} - P^{Curtail}_{w,t,s} \ge 0\,; \forall w\,, \forall t, \forall s \tag{A.61}$$

$$0 \le \upsilon^{lo}_{dN,t} \perp P_{dN,t} - P^{\min}_{dN,t} \ge 0\,; \forall dN\,, \forall t \tag{A.62}$$

$$0 \le \upsilon^{up}_{dN,t} \perp P^{bid-\max}_{dN,t} - P_{dN,t} \ge 0\,; \forall dN\,, \forall t \tag{A.63}$$

$$0 \le \delta^{lo}_{d,t} \perp P_{d,t} - P^{\min}_{d,t} \ge 0\,; \forall dN, \forall t \tag{A.64}$$

$$0 \le \delta^{up}_{d,t} \perp P^{bid}_{d,t} - P_{d,t} \ge 0\,; \forall d\,, \forall t \tag{A.65}$$

$$0 \le \sigma^{lo}_{d,t,s} \perp P^{U}_{d,t,s} \ge 0\,; \forall d\,, \forall t, \forall s \tag{A.66}$$

$$0 \le \sigma^{up}_{d,t,s} \perp R^{U}_{d,t} - P^{U}_{d,t,s} \ge 0\,; \forall d\,, \forall t, \forall s \tag{A.67}$$

$$0 \le \phi^{lo}_{d,t,s} \perp P^{D}_{d,t,s} \ \ge 0\,; \forall d\,, \forall t, \forall s \tag{A.68}$$

$$0 \le \phi^{up}_{d,t,s} \perp R^{D}_{d,t} - P^{D}_{d,t,s} \ \ge 0\,; \forall d\,, \forall t, \forall s \tag{A.69}$$

$$0 \le \chi^{lo}_{d,s} \perp - E^{Min-day}_{d} + \left(\sum_{t=1}^{T} P_{d,t} + P^{U}_{d,t,s} - P^{D}_{d,t,s} \right) \ge \ 0\,; \forall d\,, \forall s \tag{A.70}$$

$$0 \le \chi^{up}_{d,s} \perp E^{Max-day}_{d} - \left(\sum_{t=1}^{T} P_{d,t} + P^{U}_{d,t,s} - P^{D}_{d,t,s} \right) \ge \ 0\,; \forall d\,, \forall s \tag{A.71}$$

Appendix B. Converting MPEC model to the MILP model

First, strong duality equality is obtained.

$$\begin{aligned}
&\sum_{t=1}^{T} \sum_{g\in G} \left(C_g P_{g,t} + C^{RU}_g R^U_{g,t} + C^{RD}_g R^D_{g,t} \right) + \sum_{t=1}^{T} \sum_{w\in W} \left(C_w P_{w,t} \right) + \sum_{t=1}^{T} \sum_{s\in S} \sum_{g\in G} \pi_s \left(C^U_g P^U_{g,t,s} - C^D_g P^D_{g,t,s} \right) + \\
&\sum_{t=1}^{T} \sum_{s\in S} \sum_{w\in W} \pi_s C_w \left(P_{w,t,s} - P_{w,t} - P^{Curtail}_{w,t,s} \right) - \sum_{t=1}^{T} \sum_{d\in DN} \left(C_{dN,t} P_{dN,t} \right) - \\
&\sum_{t=1}^{T} \sum_{d\in D} \left(C_{d,t} P_{d,t} + \sum_{s\in S} \pi_s \left(C^U_{d,t} P^U_{d,t,s} - C^D_{d,t} P^D_{d,t,s} \right) \right) = - \sum_{w\in W} \sum_{t=1}^{T} \sum_{s\in S} P_{w,t,s} \gamma_{n(w),t,s} \\
&- \sum_{l\in L} \sum_{t=1}^{T} f^{\max}_l \left(\theta^{up}_{l,t} + \theta^{lo}_{l,t} \right) - \sum_{l\in L} \sum_{t=1}^{T} f^{\max}_l \left(\theta^{up}_{l,t} + \theta^{lo}_{l,t} \right) - \sum_{l\in L} \sum_{t=1}^{T} \sum_{s\in S} f^{\max}_l \left(o^{up}_{l,t,s} + o^{lo}_{l,t,s} \right) - \\
&\sum_{n\in N\backslash n:\, ref} \sum_{t=1}^{T} \pi \left(\alpha^{up}_{n,t} + \alpha^{lo}_{n,t} \right) - \sum_{n\in N\backslash n:\, ref} \sum_{t=1}^{T} \sum_{s\in S} \pi \left(\varepsilon^{up}_{n,t,s} + \varepsilon^{lo}_{n,t,s} \right) - \sum_{g\in G} \sum_{t=1}^{T} P^{\max}_g \beta^{up}_{g,t} + \\
&\sum_{g\in G} \sum_{t=1}^{T} P^{\min}_g \beta^{lo}_{g,t} - \sum_{g\in G} \sum_{t=1}^{T} R^{U,\max}_g \eta^{up}_{g,t} - \sum_{g\in G} \sum_{t=1}^{T} R^{D,\max}_g \iota^{up}_{g,t} - \sum_{w\in W} \sum_{t=1}^{T} P^{\max}_w \nu^{up}_{w,t} - \\
&\sum_{w\in W} \sum_{t=1}^{T} \sum_{s\in S} P_{w,t,s} \rho^{up}_{w,t,s} + \sum_{dN\in DN} \sum_{t=1}^{T} P^{\min}_{dN,t} \upsilon^{lo}_{dN,t} - \sum_{dN\in DN} \sum_{t=1}^{T} P^{bid-\max}_{dN,t} \upsilon^{up}_{dN,t} + \sum_{d\in D} \sum_{t=1}^{T} P^{\min}_{d,t} \delta^{lo}_{d,t} - \\
&\sum_{d\in D} \sum_{t=1}^{T} P^{bid}_{d,t} \delta^{up}_{d,t} - \sum_{d\in D} \sum_{t=1}^{T} \sum_{s=1} R^U_{d,t} \sigma^{up}_{d,t,s} - \sum_{d\in D} \sum_{t=1}^{T} \sum_{s=1} R^D_{d,t} \phi^{up}_{d,t,s} + \sum_{d\in D} \sum_{s=1} \chi^{lo}_{d,s} E^{Min-day}_d - \sum_{d\in D} \sum_{s=1} \chi^{up}_{d,s} E^{Max-day}_d
\end{aligned} \tag{B.1}$$

From constraint (A.26), we obtain:

$$C_{d,t} = \lambda^{DA}_{n(d),t} - \delta^{lo}_{d,t} + \delta^{up}_{d,t} - \sum_{s} \chi^{lo}_{d,s} + \sum_{s} \chi^{up}_{d,s}\,; \forall d,\ \forall t \tag{B.2}$$

Thus,

$$\sum_{d\in D}\sum_{t=1}^{T}C_{d,t}P_{d,t} = \sum_{d\in D}\sum_{t=1}^{T}\left(\lambda_{n(d),t}^{DA}-\delta_{d,t}^{lo}+\delta_{d,t}^{up}-\sum_{s}\chi_{d,s}^{lo}+\sum_{s}\chi_{d,s}^{up}\right)P_{d,t} \tag{B.3}$$

In the same way, from (A.64) and (A.65), we obtain:

$$\sum_{t=1}^{T}\sum_{d\in D}\delta_{d,t}^{lo}P_{d,t}=\sum_{t=1}^{T}\sum_{d\in D}\delta_{d,t}^{lo}P_{d,t}^{\min} \tag{B.4}$$

$$\sum_{t=1}^{T}\sum_{d\in D}\delta_{d,t}^{up}P_{d,t}=\sum_{t=1}^{T}\sum_{d\in D}\delta_{d,t}^{up}P_{d,t}^{bid} \tag{B.5}$$

Using (B.4) and (B.5), (B3) is simplified to (B.6).

$$\begin{aligned}\sum_{d\in D}\sum_{t=1}^{T}C_{d,t}P_{d,t} &= \sum_{d\in D}\sum_{t=1}^{T}\lambda_{n(d),t}^{DA}P_{d,t}-\sum_{t=1}^{T}\sum_{d\in D}\delta_{d,t}^{lo}P_{d,t}^{\min}+\sum_{d\in D}\sum_{t=1}^{T}\delta_{d,t}^{up}P_{d,t}^{bid}\\ &-\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{lo}P_{d,t}+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{up}P_{d,t}\end{aligned} \tag{B.6}$$

From constraint (A.38), (B.7) is obtained.

$$\pi_s C_{d,t}^{U}=\gamma_{n(d),t,s}^{Bal}-\sigma_{d,t,s}^{lo}+\sigma_{d,t,s}^{up}-\chi_{d,s}^{lo}+\chi_{d,s}^{up};\forall d,\ \forall t,\ \forall s \tag{B.7}$$

Thus,

$$\begin{aligned}\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\pi_s C_{d,t}^{U}P_{d,t,s}^{U} &= \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\gamma_{n(d),t,s}^{Bal}P_{d,t,s}^{U}-\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\sigma_{d,t,s}^{lo}P_{d,t,s}^{U}+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\sigma_{d,t,s}^{up}P_{d,t,s}^{U}\\ &-\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{lo}P_{d,t,s}^{U}+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{up}P_{d,t,s}^{U}\end{aligned} \tag{B.8}$$

In the same way, from (A.66) and (A.67), we obtain:

$$\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\sigma_{d,t,s}^{lo}P_{d,t,s}^{U} = 0 \tag{B.9}$$

$$\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\sigma_{d,t,s}^{up}P_{d,t,s}^{U} = \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\sigma_{d,t,s}^{up}R_{d,t}^{U} \tag{B.10}$$

Using (B.9) and (B.10), (B8) is simplified as (B11).

$$\begin{aligned}\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\pi_s C_{d,t}^{U}P_{d,t,s}^{U} &= \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\gamma_{n(d),t,s}^{Bal}P_{d,t,s}^{U}+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\sigma_{d,t,s}^{up}R_{d,t}^{U}-\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{lo}P_{d,t,s}^{U}\\ &+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{up}P_{d,t,s}^{U}\end{aligned} \tag{B.11}$$

From constraint (A.39), we obtain:

$$\pi_s C_{d,t}^{D}=\gamma_{n(d),t,s}^{Bal}+\phi_{d,t,s}^{lo}-\phi_{d,t,s}^{up}-\chi_{d,s}^{lo}+\chi_{d,s}^{up};\forall d,\ \forall t,\ \forall s \tag{B.12}$$

Thus,

$$\begin{aligned}\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\pi_s C_{d,t}^{D}P_{d,t,s}^{D} &= \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\gamma_{n(d),t,s}^{Bal}P_{d,t,s}^{D}+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\phi_{d,t,s}^{lo}P_{d,t,s}^{D}-\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\phi_{d,t,s}^{up}P_{d,t,s}^{D}\\ &-\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{lo}P_{d,t,s}^{D}+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{up}P_{d,t,s}^{D}\end{aligned} \tag{B.13}$$

In the same way, from (A.68) and (A.69), we obtain:

$$\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\phi_{d,t,s}^{lo}P_{d,t,s}^{D} = 0 \tag{B.14}$$

$$\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\phi_{d,t,s}^{up}P_{d,t,s}^{D} = \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\phi_{d,t,s}^{up}R_{d,t}^{D} \tag{B.15}$$

Constraint (B.14) and (B.15) are used to simplify (B.13) as follows.

$$\begin{aligned}&\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\pi_s C_{d,t}^{D} P_{d,t,s}^{D} = \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\gamma_{n(d),t,s}^{Bal} P_{d,t,s}^{D} - \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\phi_{d,t,s}^{up} R_{d,t}^{D} - \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{lo} P_{d,t,s}^{D}\\&+\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{up} P_{d,t,s}^{D}\end{aligned} \tag{B.16}$$

From constraints (A.70) and (A.71), we obtain (B.17) and (B.18), respectively:

$$\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{lo}\left(P_{d,t}+P_{d,t,s}^{U}-P_{d,t,s}^{D}\right) = \sum_{d\in D}\sum_{s\in S}\chi_{d,s}^{lo} E_{d}^{Min-day} \tag{B.17}$$

$$\sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\chi_{d,s}^{up}\left(P_{d,t}+P_{d,t,s}^{U}-P_{d,t,s}^{D}\right) = \sum_{d\in D}\sum_{s\in S}\chi_{d,s}^{up} E_{d}^{Max-day} \tag{B.18}$$

Finally, by replacing the bilinear terms in (B.6), (B.11), and (B.16), with their equivalents in (B.1), and using (B.17) and (B.18) for simplification, we obtain:

$$\begin{aligned}&\sum_{d\in D}\sum_{t=1}^{T}\lambda_{n(d),t}^{DA}P_{d,t} + \sum_{d\in D}\sum_{t=1}^{T}\sum_{s\in S}\gamma_{n(d),t,s}^{Bal}\left(P_{d,t,s}^{U}-P_{d,t,s}^{D}\right) = \sum_{t=1}^{T}\sum_{g\in G}\left(C_g P_{g,t} + C_g^{RU}R_{g,t}^{U} + C_g^{RD}R_{g,t}^{D}\right)+\\&\sum_{t=1}^{T}\sum_{w\in W}\left(C_w P_{w,t}\right) + \sum_{t=1}^{T}\sum_{s\in S}\sum_{g\in G}\pi_s\left(C_g^{U}P_{g,t,s}^{U} - C_g^{D}P_{g,t,s}^{D}\right) + \sum_{t=1}^{T}\sum_{s\in S}\sum_{w\in W}\pi_s C_w\left(P_{w,t,s}-P_{w,t}-P_{w,t,s}^{Curtail}\right)\\&-\sum_{t=1}^{T}\sum_{d\in DN}\left(C_{dN,t}P_{dN,t}\right) + \sum_{w\in W}\sum_{t=1}^{T}\sum_{s\in S}P_{w,t,s}\gamma_{n(w),t,s} + \sum_{l\in L}\sum_{t=1}^{T}f_l^{\max}\left(\theta_{l,t}^{up}+\theta_{l,t}^{lo}\right)+\\&\sum_{l\in L}\sum_{t=1}^{T}\sum_{s\in S}f_l^{\max}\left(o_{l,t,s}^{up}+o_{l,t,s}^{lo}\right) + \sum_{n\in N\backslash n:\,ref}\sum_{t=1}^{T}\pi\left(\alpha_{n,t}^{up}+\alpha_{n,t}^{lo}\right) + \sum_{n\in N\backslash n:\,ref}\sum_{t=1}^{T}\sum_{s\in S}\pi\left(\varepsilon_{n,t,s}^{up}+\varepsilon_{n,t,s}^{lo}\right)\\&+\sum_{g\in G}\sum_{t=1}^{T}P_g^{\max}\beta_{g,t}^{up} - \sum_{g\in G}\sum_{t=1}^{T}P_g^{\min}\beta_{g,t}^{lo} + \sum_{g\in G}\sum_{t=1}^{T}R_g^{U,\max}\eta_{g,t}^{up} + \sum_{g\in G}\sum_{t=1}^{T}R_g^{D,\max}\iota_{g,t}^{up}+\\&\sum_{w\in W}\sum_{t=1}^{T}P_w^{\max}\nu_{w,t}^{up} + \sum_{w\in W}\sum_{t=1}^{T}\sum_{s\in S}P_{w,t,s}\rho_{w,t,s}^{up} + \sum_{dN\in DN}\sum_{t=1}^{T}P_{dN,t}^{bid-\max}\upsilon_{dN,t}^{up} - \sum_{dN\in DN}\sum_{t=1}^{T}P_{dN,t}^{\min}\upsilon_{dN,t}^{lo}\end{aligned} \tag{B.19}$$

The above equation (B.19) allows calculating the objective function of the UL problem as a combination of linear terms only. It should be remarked that the $-\delta_{d,t}^{up}P_{d,t}^{bid}, \phi_{d,t,s}^{up}R_{d,t}^{D}, \sigma_{d,t,s}^{up}R_{d,t}^{U}$, which are nonlinear terms in the strong duality constraints (B.1), are canceled with the same terms in (B.6), (B.11), and (B.16). In addition, Fortuny-Amat transformation [33] is used to recast the nonlinear complementarity constraints (A.40)-(A.71) into exact linear constraints.

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