Integrating demand response market into energy/reserve market: A bilevel approach

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***Abstract*—The concept of demand response (DR) market, which recently introduced, is a comprehensive approach to schedule DR. DR market is a separate market in which DR is treated as a virtual resource to be exchanged between DR buyers and sellers. The major advantage of the DR market in comparison to other DR proposals is that it allocates benefits and payments across all participants, fairly. However, there are still obstacles to its integration into the existing power markets. This paper tries to address technical and economical issues towards integrating DR market into energy/reserve markets. For this purpose, a bilevel approach is proposed for clearing joint energy/reserve and DR markets whose upper-level problem determines system requirements for reserve using *N-1* contingency criteria, and whose lower-level problem clears the DR market. The resulting nonlinear bilevel programming problem is translated into an equivalent single-level mixed-integer linear programming problem by replacing the lower-level problem by its Karush–Kuhn–Tucker optimality conditions and converting a number of nonlinearities to linear equivalents using some well-known techniques. Finally, a simple case study is used to verify the efficiency of the proposed approach.**

***Keywords*- Demand response market, reserve markets, bilevel programming, mixed-integer linear programming**.

NOTATION

The notation used throughout the paper is provided below. Some of the following constants and variables incorporate subscribe k if referring to the contingency state k.

A. Indices and Numbers

n Index of system buses, running from 1 to N_B.
i Index of generating units, running from 1 to N_U.
j Index of loads, running from 1 to N_L.
m Index of energy blocks offered by generating units, running from 1 to N_{Oi}.
k Index of contingency states, running from 0 to N_S.
g Index of costumer groups, running from 1 to N_G.
b Index of DR buyers, running from 1 to N_{DB}.
l Index of aggregators, running from 1 to N_A.

B. Continuous Variables

$p_{Gi}(m)$ Power output scheduled from the *m*-th block of energy offered by unit *i* [MW]. Limited to $p_{Gi}^{\max}(m)$.
r_i^U Up-spinning reserve scheduled for unit *i* [MW]. Limited to $R_i^{U,max}$.
r_i^D Down-spinning reserve scheduled for unit *i* [MW]. Limited to $R_i^{D,max}$.
r_i^{NS} Non-spinning reserve scheduled for unit *i* [MW]. Limited to $R_i^{NS,max}$.
rd_g^U Upward reserve scheduled for costumer group *g* [MW].
rd_g^D Downward reserve scheduled for costumer group *g* [MW].
$L_{j,k}^{Sh}$ Load shedding imposed on consumer *j* in contingency *k* [MW].
P_i^G Power output of unit *i* [MW].
$f(n,r)$ Power flow through line *(n,r)* [MW].
$s_{b,g}^U$ Upward DR supplied to buyer *b* from costumer group *g* [MW].
$s_{b,g}^D$ Downward DR supplied to buyer *b* from costumer group *g* [MW].
q_l^U Upward DR provided by aggregator *l* [MW]. Limited to $q_l^{U,\max}$.
q_l^D Downward DR provided by aggregator *l* [MW]. Limited to $q_l^{D,\max}$.

C. Dual variables

The dual variables below are associated with the following constraints:

γ_g^U Upward DR supply-demand for TSO and costumer group *g*.
γ_g^D Downward DR supply-demand for TSO and costumer group *g*.
$\lambda_{b,g}^U$ Upward DR supply-demand for Retailer/distributor *b* and costumer group *g*.
$\lambda_{b,g}^D$ Downward DR supply-demand for Retailer/distributor *b* and costumer group *g*.
$\underline{\mu}_l^U / \overline{\mu}_l^U$ Upper/lower bound on upward DR provided by aggregator *l*.
$\underline{\mu}_l^D / \overline{\mu}_l^D$ Upper/lower bound on downward DR provided by aggregator *l*.

C. Binary Variables

u_i 0/1 variable that is equal to 1 if unit *i* is scheduled to be committed.
$x_{g,d}^U$ 0/1 variable that is used to discretize rd_g^U.

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$\underline{w}_l^U$ 0/1 variable that is used to linearize complementary constraint associated to lower bound on q_l^U .

D. Constants

λ_i^{SU} Start-up offer cost of unit *i* [$].

$\lambda_{Gi}(m)$ Marginal cost of the *m*-th block of energy offered by unit *i* [$/MWh].

C_i^{RU} Offer cost of up-spinning reserve of unit *i* [$/MWh].

C_i^{RD} Offer cost of down-spinning reserve of unit *i* [$/MWh].

C_i^{RNS} Offer cost of non-spinning reserve of unit *i* [$/MWh].

π_k Probability of contingency state *k*.

λ_{Lj} Utility of consumer *j* [$/MWh].

v_j Value of load shed for consumer *j* [$/MWh].

L_j Demand of consumer *j* [MW].

$f^{\max}(n,r)$ Maximum capacity of line *(n,r)* [MW].

$P_i^{\min}$ Minimum power output of unit *i* [MW].

$P_i^{\max}$ Capacity of unit *i* [MW].

$\alpha_{b,g}^U, \beta_{b,g}^U$ Coefficients of upward DR demand function of buyer *b* from costumer group *g* [$/MWh^2],[$/MWh].

$\alpha_{b,g}^D, \beta_{b,g}^D$ Coefficients of downward DR demand function of buyer *b* from costumer group *g* [$/MWh^2],[$/MWh].

a_l^U, b_l^U Coefficients of upward DR supply function of aggregator *l* [$/MWh^2],[$/MWh].

a_l^D, b_l^D Coefficients of downward DR supply function of aggregator *l* [$/MWh^2],[$/MWh].

θ_l Willingness of aggregator *l* to provide DR.

E. Sets

Λ Set of transmission lines.

M_U Mapping of the sets of generating units into the set of buses.

M_L Mapping of the set of loads into the set of buses.

M_C Mapping of the sets of costumer groups into the set of loads.

I. INTRODUCTION

In power systems, operating reserve is very important to maintain an acceptable level of security. The generator random outages, unpredictable behavior of the demand and etc. necessitates the scheduling of reserve to reduce the risk of blackouts. In a deregulated electricity industry, the transmission system operator (TSO) is responsible for secure and efficient operation of power system.

In many existing electricity markets, separate markets are designed for scheduling the energy and reserve [1]. In such cases, the reserve market is run, usually in a sequential manner, after clearing the energy market. This type of sequential model introduces market inefficiencies. To avoid such inefficiencies, researchers have proposed the joint scheduling of energy and reserve [2-5]. Besides the energy offers, generating companies submit reserve offers from which the TSO allocates the required amounts.

In addition to the supply-side, demand response (DR) can be considered as a source of operational reserve by allowing fast upward/downward changes in the demand. The use of DR for providing reserves has been studied in [6-10]. In [6], the authors proposed a joint energy/reserve market model that includes demand-side reserve offers. The effects of demand-side participation in a market with probabilistic reserve were investigated in [7]. The authors of [8] investigated the load recovery impacts of demand response providers (DRPs) in joint energy/reserve market. Incorporating the DR into the security-constrained unit commitment (SCUC) is investigated in [11-14]. In these researches, it was shown that the DR can reduce the system operating cost, fuel consumptions, carbon footprints, and transmission congestion by reshaping the hourly load profile. The impacts of the DR on integration of renewable energy resource are also investigated in [15]-[18] via incorporation of the DR into the energy and reserve markets. The authors in [15] proposed an incentive-based DR program that facilitates the grid integration of wind power by reshaping the system load. In [16], the authors investigated the effects of DR in a future German power system, showing that using DR, the wind-uncertainty costs are reduced to less than € 2/MWh. Falsafi *et al.* [17] proposed a stochastic model for scheduling energy and reserves provided by both the generating units and DRPs with the aim of covering uncertainty of wind power. Economic evaluation of the DR according to its potential for mitigating the wind power forecast error in the power system operation is proposed in [18].

The authors of [19] believe that as most existing approaches for DR scheduling consider only one or some participants' point of view, they may be unfair towards other participants. For example, all the above mentioned approaches deal with the DR scheduling from TSO's point of view without considering other DR beneficiaries (i.e. retailers and distributors). Maximizing an individual player's DR benefits may conflict with another individual's benefits [20]. Nguyen *et al.* [21] proposed a comprehensive approach for DR scheduling. They designed a separate market for trading DR, known as demand response exchange (DRX) market, in which DR is treated as a virtual resource to be exchanged between the DR buyers (TSO, retailers and distributors) and sellers (DRPs). Electricity consumers via aggregators can participate in the DRX market as DR sellers. The aggregators are independent agents that combine multiple consumers into a single unit to negotiate purchase from the retailers. The main advantage of using DRX market for DR scheduling is fair allocation of the DR payments and benefits across all market participants [22]. A Walrasian [23] market clearing for the DRX market has been proposed in [24]. The inter-temporal impact of load recovery on DR scheduling via DRX market has been modeled in [25].

The main purpose of this paper is to integrate the DR market into the energy/reserve market. While the DR market is a comprehensive approach for DR scheduling, there are still obstacles to its integration into the existing power markets. The DR market proposed in [21] is in the form of financial market without considering any technical/physical constraints of the power system. Therefore, in its previously proposed form, it cannot work effectively along with the existing energy/reserve markets, which are essentially physical markets. On the other hand, in [21], it has been assumed that the TSO, as a DR buyer in the DR market, offer for purchasing DR through a simple demand function, while the TSO's demand for DR is not a predefined value and depends on load and technical/physical conditions of the power systems. Therefore, DR cannot be traded and scheduled in a separate market without considering other participants of the power system and the interactions among them. Authors in [26] proposed a new framework for clearing DR market considering technical/economical aspects of power system, which runs after clearing energy/reserve market. However, since the model in [26] runs after clearing the energy/reserve market, it may not lead to global optimum solutions. In this paper, to cope with the above mentioned limitations, a bilevel approach for clearing the energy/reserve and DR markets is proposed. The upper-level problem represents the joint energy/reserve market with demand-side reserve offers. The DR market clearing is modeled as the lower-level problem. Using the proposed bi-level programming, the TSO's demand for the DR is determined at the upper-level problem considering technical and economical aspects of the power market. At the lower-level, DR is cleared based on the TSO's demand and other DR buyers' offer.

The proposed bilevel problem is translated into a single level mixed-integer linear programming (MIP) problem based on the Karush–Kuhn–Tucker (KKT) optimality conditions [27] and some linearization rules. The resulting MIP formulation allows obtaining a global optimal solution using commercially available softwares, such as CPLEX [28].

The reminder of this paper is organized as follows. Section 2 describes the proposed bilevel model and involves the model formulation. The solution method for the bilevel model is discussed in Section 3. In Section 4, the application of the proposed model to an illustrative example is reported. Finally, Section 5 provides some relevant conclusions.

II. MODEL

A. *Market Assumptions*

Joint clearing of energy/reserve and DR markets is the main purpose of this paper. For didactic purposes, single-period scheduling is considered, as this model is simpler to describe and analyze (such as [6]). The *N-1* contingency criteria used for determination of system reserve requirements [5]. The generating units can supply energy as well as up-, down-, and non-spinning reserves. It is assumed that the generating units offer their marginal cost of energy through *m*-block price-quota curve, while a single flat rate is considered for their reserve offering [6]-[8].

Demand-side can offer into the DR market for providing upward and downward reserves through quadratic supply functions [21]. The TSO's demand for the DR is determined in the upper-level problem. Determination of the DR demand for other DR buyers, i.e. retailers and distributors, is out of the scope of this paper. It is assumed that retailers and distributors offer for purchasing the DR through quadratic gross benefit functions. Furthermore, it is assumed that retailers and distributors, as DR buyers, reveal their DR benefit functions, honestly. Therefore, 'obligatory contribution' constraint, as proposed in [21], is not considered in this paper.

B. *Bilevel Model*

Mathematical formulation of the proposed bilevel model for clearing the energy/reserve and DR markets is presented in this section. The main purpose of the proposed model is to integrate the DR market into the energy/reserve market, considering the technical/physical constraint of the power system. The upper-level problem represents the joint energy and reserve market clearing mechanism performed by the TSO with the aim of minimizing the cost of energy and reserve. The level of system requirement for operating reserve is determined in the upper-level using the *N-1* contingency criteria. The demand-side reserve offers are also included in this level. The lower-level problem represents the clearing of the DR market, performed by DR market operator, seeking for minimizing DR costs as well as maximizing benefits of the DR beneficiaries. The TSO's demand for the DR is determined in the upper-level problem. Then, in the lower-level problem, the price of DR is determined. The proposed bilevel model is stated in the following:

$$\text{Minimize } \pi_0\{\sum_{i=1}^{N_U}[\lambda_i^{SU}u_i+\sum_{m=1}^{N_{Oi}}\lambda_{Gi}(m)p_{Gi}(m)]$$
$$+\sum_{i=1}^{N_U}(C_i^{RU}r_i^U+C_i^{RD}r_i^D+C_i^{RNS}r_i^{NS})+\sum_{g=1}^{N_G}(\gamma_g^U rd_g^U+\gamma_g^D rd_g^D)\}$$
$$+\sum_{k=1}^{N_S}\pi_k\{\sum_{i=1}^{N_U}[\lambda_i^{SU}u_{i,k}+\sum_{m=1}^{N_{Oi}}\lambda_{Gi}(m)p_{Gi,k}(m)]-\sum_{j=1}^{N_L}\lambda_{Lj}L_{j,k}+\sum_{j=1}^{N_L}\nu_j L_{j,k}^{Sh}\} \quad (1)$$

subject to

$$\sum_{i:(i,n)\in M_U}P_i^G-\sum_{j:(j,n)\in M_L}L_j-\sum_{r:(n,r)\in\Lambda}f(n,r)=0\ ,\ \forall n \quad (2)$$

$$\sum_{i:(i,n)\in M_U}P_{i,k}^G-\sum_{j:(j,n)\in M_L}(L_{j,k}-L_{j,k}^{Sh})-\sum_{r:(n,r)\in\Lambda}f_k(n,r)=0\ ,\forall n,k \quad (3)$$

$$-f^{\max}(n,r)\le f(n,r)\le f^{\max}(n,r)\ ,\ \forall(n,r)\in\Lambda \quad (4)$$

$$-f^{\max}(n,r)\le f_k(n,r)\le f^{\max}(n,r)\ ,\ \forall(n,r)\in\Lambda,\forall k \quad (5)$$

$$P_i^{\min}u_i\le P_i^G\le P_i^{\max}u_i\ ,\ \forall i \quad (6)$$

$$0\le p_{Gi}(m)\le p_{Gi}^{\max}(m)\ ,\ \forall m,i \quad (7)$$

$$P_i^G=\sum_{m=1}^{N_{Oi}}p_{Gi}(m)\ ,\ \forall i \quad (8)$$

$$P_i^{\min}u_{i,k}\le P_{i,k}^G\le P_i^{\max}u_{i,k}\ ,\ \forall i,k \quad (9)$$

$$0\le p_{Gi,k}(m)\le p_{Gi}^{\max}(m)\ ,\ \forall m,i,k \quad (10)$$

$$P_{i,k}^G=\sum_{m=1}^{N_{Oi}}p_{Gi,k}(m)\ ,\ \forall i,k \quad (11)$$

$$0\le r_i^U\le R_i^{U,max}u_i\ ,\ \forall i \quad (12)$$

$$0\le r_i^D\le R_i^{D,max}u_i\ ,\ \forall i \quad (13)$$

$$0\le r_i^{NS}\le R_i^{NS,max}(1-u_i)\ ,\ \forall i \quad (14)$$

$$0\le r_{i,k}^U\le r_i^U\ ,\ \forall i,k \quad (15)$$

$$0 \le r_{i,k}^{D} \le r_{i}^{D} \ , \ \forall i,k \tag{16}$$

$$0 \le r_{i,k}^{NS} \le r_{i}^{NS} \ , \ \forall i,k \tag{17}$$

$$0 \le rd_{g,k}^{U} \le rd_{g}^{U} \ , \ \forall g,k \tag{18}$$

$$0 \le rd_{g,k}^{D} \le rd_{g}^{D} \ , \ \forall g,k \tag{19}$$

$$0 \le L_{j,k}^{Sh} \le L_{j,k} \ , \ \forall j,k \tag{20}$$

$$L_{j,k} = L_{j} - \sum_{g:(g,j)\in M_C} (rd_{g,k}^{U} - rd_{g,k}^{D}), \ \forall j,k \tag{21}$$

$$P_{i,k}^{G} = P_{i}^{G} + r_{i,k}^{U} + r_{i,k}^{NS} - r_{i,k}^{D} \ , \ \forall i,k \tag{22}$$

where

$\gamma_g^U, \forall g; \gamma_g^D, \forall g \in \arg:$ Maximize

$$\begin{aligned} &\sum_{b=1}^{N_{DB}}\sum_{g=1}^{N_G}[(-\alpha_{b,g}^{U} {s_{b,g}^{U}}^2 + \beta_{b,g}^{U} s_{b,g}^{U}) + (-\alpha_{b,g}^{D} {s_{b,g}^{D}}^2 + \beta_{b,g}^{D} s_{b,g}^{D})] \\ &-\sum_{l=1}^{N_A}[(a_l^U {q_l^U}^2 + b_l^U(1-\theta_l)q_l^U) + (a_l^D {q_l^D}^2 + b_l^D(1-\theta_l)q_l^D)] \end{aligned} \tag{23}$$

$$rd_g^U = \sum_{l=1}^{N_A} q_l^U \widehat{c}_l^g \qquad : \gamma_g^U, \ \forall g \tag{24}$$

$$rd_g^D = \sum_{l=1}^{N_A} q_l^D \widehat{c}_l^g \qquad : \gamma_g^D, \ \forall g \tag{25}$$

$$s_{b,g}^U = \sum_{l=1}^{N_A} q_l^U c_l^{b,g} \qquad : \lambda_{b,g}^U, \ \forall b,g \tag{26}$$

$$s_{b,g}^D = \sum_{l=1}^{N_A} q_l^D c_l^{b,g} \qquad : \lambda_{b,g}^D, \ \forall b,g \tag{27}$$

$$0 \le q_l^U \le q_l^{U,\max} \qquad : \overline{\mu}_l^U, \underline{\mu}_l^U, \ \forall l \tag{28}$$

$$0 \le q_l^D \le q_l^{D,\max} \qquad : \overline{\mu}_l^D, \underline{\mu}_l^D, \ \forall l \tag{29}$$

The bilevel problem comprises an upper-level problem (1)-(22) and the lower-level problem (23)-(29). The upper-level problem represents the stochastic energy/reserve market clearing while the lower-level problem refers to the DR market clearing. It should be noted that γ_g^U and γ_g^D in (1) are upward and downward DR prices calculated as the dual variables of (24) and (25), respectively.

The upper-level objective function (1) consists of the sum of three terms: a) the expected social welfare during the pre-contingency state (with the probability of π_0) including the expected costs of offer-based energy production and start-up of generating units, and scheduling reserve services provided by supply- and demand-side, b) the expected cost associated with the deployment of reserves in post-contingency states (with the probability of π_k), which may include the costs of start-up and rescheduling the generating units, re-dispatching the consumption and the load not served. This objective function is subject to the following constraints [5]. Pre-contingency power balance and line flow limits are presented by (2) and (4), respectively. Post-contingency power balance and line flow limits are presented by (3) and (5), respectively. The approximation of the energy offer cost function of generating units by blocks in pre- and post- contingency are presented by (7)-(8) and (10)-(11), respectively. Equations (6) and (9) satisfy the production limits of the generating units in pre- and post-contingency states, respectively. Up-, down-, and non-spinning reserve limits are stated by (12), (13) and (14), respectively. The deployed reserves constraints for the generating units are implied by (15)-(17). Equations (18) and (19) represents that the deployed reserves from demand-side in each contingency state must be lower than the amount of scheduling reserves (i.e. rd_g^U and rd_g^D). The upper and lower bounds on the amount of load shedding are implied by (20). The post-contingency consumption of load j is calculated using (21). Finally, equation (22) states the post-contingency production of the generating units.

The objective function of the lower-level problem (23) is sum of the benefit function of the DR buyers excluding the TSO minus total DR cost. It is assumed that buyer b who maybe a retailer or distributor offers a quadratic gross benefit function for each of his/her associated customer group g [21]. Similarly, a non-decreasing quadratic cost function assumed for each aggregator participating into the DR market. The coefficient θ_l in the DR cost function represents the aggregator's willingness to provide the DR. Constraints (24) and (25) states the upward and downward DR demand-supply balance for the TSO, respectively. The demand-supply balance constraints for retailers and distributors are presented in (26) and (27). Binary coefficients $\widehat{c}_l^g$ and $c_l^{b,g}$ represent a relational status of aggregator l to the group g of the TSO and the DR buyer b, respectively. Equations (28) and (29) enforce upper and lower bounds on the upward and downward DR which can be provided by aggregator l, respectively.

III. Equivalent Single-Level Mixed-Integer Linear Programming Problem

In this paper, the assumed benefit function for the DR buyers and the DR cost function of the aggregators in (23) are strictly concave and convex functions, respectively. Consequently, the lower-level problem (23)-(29) belongs to a well-known class of convex optimization with linear equality and inequality constraints. Since the lower-level problem is continuous and convex, the bilevel programming problem (1)-(29) can be transformed into an equivalent single-level through the KKT optimality conditions of the lower-level problem. The KKT optimality conditions of the lower-level problem are as follows.

$$2a_l^U q_l^U + b_l^U(1-\theta_l) + \sum_{g=1}^{N_G} \gamma_g^U \widehat{c}_l^g + \sum_{b=1}^{N_{DB}}\sum_{g=1}^{N_G} \lambda_{b,g}^U c_l^{b,g} + \underline{\mu}_l^U - \overline{\mu}_l^U = 0, \forall l \tag{30}$$

$$2a_l^D q_l^D + b_l^D(1-\theta_l) + \sum_{g=1}^{N_G} \gamma_g^D \widehat{c}_l^g + \sum_{b=1}^{N_{DB}}\sum_{g=1}^{N_G} \lambda_{b,g}^D c_l^{b,g} + \underline{\mu}_l^D - \overline{\mu}_l^D = 0, \forall l \tag{31}$$

$$-2\alpha_{b,g}^U s_{b,g}^U + \beta_{b,g}^U - \lambda_{b,g}^U = 0 \ , \ \forall b,g \tag{32}$$

$$-2\alpha_{b,g}^D s_{b,g}^D + \beta_{b,g}^D - \lambda_{b,g}^D = 0 \ , \ \forall b,g \tag{33}$$

$$\sum_{l=1}^{NA} q_l^U \hat{c}_l^g - rd_g^U = 0 \quad , \forall g \qquad (34)$$

$$\sum_{l=1}^{NA} q_l^D \hat{c}_l^g - rd_g^D = 0 \quad , \forall g \qquad (35)$$

$$\sum_{l=1}^{NA} q_l^U c_l^{b,g} - s_{b,g}^U = 0 \quad , \forall b, g \qquad (36)$$

$$\sum_{l=1}^{NA} q_l^D c_l^{b,g} - s_{b,g}^D = 0 \quad , \forall b, g \qquad (37)$$

$$0 \le q_l^U \perp \underline{\mu}_l^U \ge 0 \quad , \forall l \qquad (38)$$

$$0 \le (q_l^{U,\max} - q_l^U) \perp \overline{\mu}_l^U \ge 0 \quad , \forall l \qquad (39)$$

$$0 \le q_l^D \perp \underline{\mu}_l^D \ge 0 \quad , \forall l \qquad (40)$$

$$0 \le (q_l^{D,\max} - q_l^D) \perp \overline{\mu}_l^D \ge 0 \quad , \forall l \qquad (41)$$

By substituting the lower-level problem with its corresponding KKT optimality conditions (30)-(41) and adding them as constraint into the upper-level problem (1)-(22), the bi-level problem is transformed to a single-level mixed-integer nonlinear programming (MINLP) problem. The sources of nonlinearity are: a) the product of the upper-level problem variables rd_g^U and rd_g^D with the lower-level problem variables γ_g^U and γ_g^D in (1), b) the complementarity constraints (38)-(41). Since MINLP problems are difficult to solve, in this paper, some linearization techniques are employed to convert the MINLP problem into MIP, as follows:

- Binary expansion [28] is used to linearize the products of continuous decision variables in the objective function (1). Using the concept of binary expansion for $\gamma_g^U rd_g^U$, the variable rd_g^U is approximated by a set of discrete values $\{Rd_{g,d}^U, d = 1,...,D_1\}$, in which $D_1 = 2^{K_1}$ for non-negative integer k_1. The discrete approximation of rd_g^U is as

$$rd_g^U = \Delta_g^U \sum_{d=1}^{K_1} 2^d x_{g,d}^U \ , \forall g \qquad (42)$$

where $\Delta_g^U = \overline{rd}_g^U / D_1$, in which $\overline{rd}_g^U$ is an upper bound on rd_g^U, and $x_{g,d}^U$ is a binary variable.

Multiplying both sides of (42) by γ_g^U, we obtain

$$\gamma_g^U rd_g^U = \Delta_g^U \sum_{d=1}^{K_1} 2^d x_{g,d}^U \gamma_g^U \ , \forall g \qquad (43)$$

Now, the product of the continuous and binary variable in (42), i.e. $x_{g,d}^U \gamma_g^U$, can be replaced by the linear expression as follows:

$$0 \le \gamma_g^U - z_{g,d}^U \le G(1 - x_{g,d}^U) \ , \forall g, d \qquad (44)$$

$$0 \le z_{g,d}^U \le G x_{g,d}^U \quad , \forall g, d \qquad (45)$$

Where, $z_{g,d}^U = x_{g,d}^U \gamma_g^U$, and G is a large enough scalar for the constraints (44) and (45) to be relaxed when $x_{g,d}^U = 0$ and $x_{g,d}^U = 1$, respectively. The Linearization of $\gamma_g^D rd_g^D$ is similar to the abovementioned method.

- The complementarity condition in (38) can be replaced by

$$q_l^U \ge 0 \ , \ \forall l \qquad (46)$$

$$\underline{\mu}_l^U \ge 0 \quad , \forall l \qquad (47)$$

$$q_l^U \le \underline{w}_l^U M^P \ , \ \forall l \qquad (48)$$

$$\underline{\mu}_l^U \ge \underline{w}_l^U (1 - M^P) \quad , \forall l \qquad (49)$$

where $\overline{w}_l^U$ is an auxiliary binary variable, and M^P is a large enough constant [29]. Other complementarity conditions (39)-(41) can be linearized in a similar way.

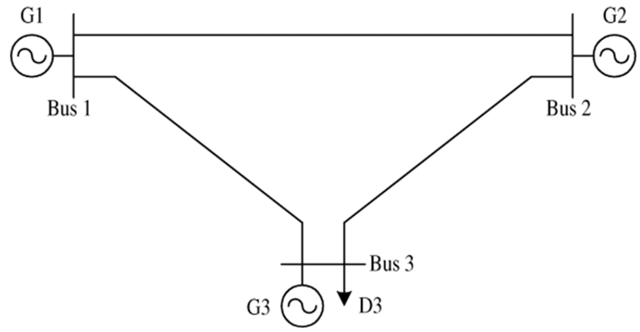

Figure 1. Test system

TABLE I. COEFFIECIENTS OF DR BUYERS' BENEFIT FUNCTION

	$\alpha_{b,g}^U$ (\$/MWh^2)	$\beta_{b,g}^U$ (\$/MWh)
Retailer	0.5	18
Distributor	0.6	20

IV. ILLUSTRATIVE EXAMPLE

To illustrate applicability of the proposed bilevel approach, it is implemented on a simple case study shown in Fig. 1. There is one TSO, one retailer and one distributor in the system. An aggregator is located on bus 3 who offers for providing up-spinning reserve. The coefficients of the aggregator's cost function for DR are 0.25 \$/MWh^2 and 8 \$/MWh. DR buyers, i.e. retailer and distributor, submit their purchasing bid via quadratic gross benefit function (the corresponding coefficients are provided in Table I).

TABLE II. GENERATOR DATA

Unit i	1	2	3
$P_i^{\max}$ (MW)	10	10	10
$P_i^{\min}$ (MW)	100	100	50
$\lambda_{Gi}(1)$ (\$/MWh)	30	40	20
λ_i^{SU} (\$/MWh)	100	100	100
C_i^{RU} (\$/MWh)	5	7	8
C_i^{RD} (\$/MWh)	5	7	8
λ_i^{-1} (h)	500	500	250

The power system shown in Fig. 1 consists of three generating units and transmission lines. The generator data which extracted from [31] are provided in Table II. Each generating unit offers a single block of energy. The bounds on the amount of the offered reserves are assumed to be the largest possible. The mean times to failure (λ_i^{-1}) of each of the generating units are listed in the last row of Table II. The three lines have null resistances and 0.13 p.u. reactances. The capacities and the mean time to failure of all lines are the same and equal to 55 MW and 10000 h, respectively. The demand on bus 3 and its value of lost load are assumed 110 MW and 10000 \$/MWh, respectively.

In order to limit the number of constrains which influence the optimum solution, non-spinning reserve is not considered in this study [6]. For the given data, the proposed bilevel model is solved using CPLEX 10.1.1 under GAMS [28]. The simulations are carried out for the following cases:

- Case I: Energy/reserve market without DR
- Case II: Energy/reserve market incorporating DR (TSO-based partial approach [5])
- Case III: Joint energy/reserve and DR markets

Table III reports the market clearing results for the abovementioned cases, including scheduled power and reserves for the generating units, scheduled DR, and expected load not served (ELNS). As can be seen, in Case I, the ELNS is 10 MWh, while this value is substituted by 5 MW of DR in Case II. This substitution decreases the cost of lost load and reserve. The reserve requirement in case II is decreased by 16.7% in comparison to Case I. In Case III, the scheduled DR is increased by more than 100% compared to that in the partial approach of Case II. Moreover, the scheduled reserve in case III is decreased by 35% and 22% in comparison to Case I and II, respectively. These results show that the proposed bilevel approach for DR scheduling leads to more utilization from the demand-side in the energy/reserve market and consequently reduces the cost of energy and reserve.

The advantage of the proposed model in decrement of the energy/reserve cost and increment of the participants' benefit can be seen in Table IV. The objective function of the energy/reserve market, gross benefit of DR buyers, costumer revenue and total market surplus for Case II and Case III are compared in Table IV. In Case I, the optimal value for the objective function (1) is obtained 3633.63 \$. In the TSO-based partial approach, i.e. Case II, only the TSO pay for the scheduled DR. In other words, in this case, the two other DR beneficiaries, i.e. retailer and distributor, are free riders, in the sense that they enjoy the benefits of DR but pay nothing at all. This is the major disadvantage of the partial approaches for DR scheduling (which is addressed in the proposed bilevel model). In the proposed model, the DR cost is allocated across all the DR beneficiaries. The total market surplus, i.e. DR buyers' benefit minus costumer revenue, in Case III is increased up to 17% in comparison to Case II.

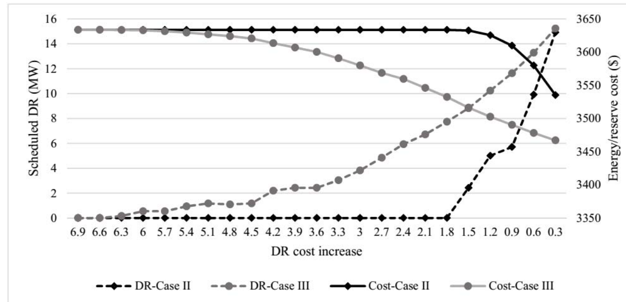

Figure 2. Effect of DR cost on scheduled DR and energy/reserve cost

TABLE III. MARKET CLEARING RESULTS: POWER (MW), RESERVES (MW), DR (MW), AND ELNS (MWH)

Case	P_1^G	P_2^G	P_3^G	r_1^U	r_2^U	r_1^D	r_2^D	q_3^U	ELNS
I	50	10	50	10	50	5	0	-	10
II	50	10	50	5	45	5	0	5	0
III	50	10	50	0	38.8	5	0	11.2	0

TABLE IV. MARKET AND PARTICIPANTS OUTCOM

		Case II	Case III
Energy/Reserve market	Objective Function (\$)	3615.18	3495.16
DR Market	TSO Benefit (\$)	71.97	140.30
	Retailer Benefit (\$)	78.51	138.68
	Distributor Benefit (\$)	86.09	148.55
	Costumer Revenue (\$)	53.52	151.78
Energy/Reserve market with DR participation	Total market surplus (\$)	236.57	275.76

The effect of DR cost on the amount of the scheduled DR and the energy/reserve cost is investigated and compared for Case II and Case III. For this purpose, the DR cost coefficients are multiplied by a factor ranging from 0.3 to 7. Then, the proposed bilevel model and the partial approach are run for each of the resulted DR cost functions. The results of this investigation are illustrated in Fig. 2. As seen in this figure, in Case III, the DR is scheduled for a wider range of DR cost in comparison to Case II. The reason is that the DR cost is shared among all DR beneficiaries in Case III. Moreover, the amount of the scheduled DR and the effect of DR in decrement of the system costs are larger in the bilevel approach.

V. CONCLUSIONS

This paper proposed a bilevel model for clearing energy/reserve and DR markets. The main purpose of this study is to integrate the recently introduced DR market into the power markets. In the proposed bilevel model, the upper-level problem presents stochastic energy/reserve market clearing. The *N-1* contingency criteria used in this level to determine the system requirement for reserves. The lower-level problem clears the DR market. By replacing the lower-level problem by its KKT optimality conditions and converting a number of nonlinearities to linear equivalents using some well-known techniques, the resulting nonlinear bilevel programming problem is translated into an equivalent single-level mixed-integer linear programming problem. The proposed bilevel model is tested by its implementation on a simple case study. It was shown that by using the proposed model, participation of the demand-side in the energy/reserve market can be increased.

Our focus in this paper was on determination of the TSO's demand for the DR. Hence, the DR demand for other DR beneficiaries, i.e. retailers and distributors, are supposed to be known functions. However, to better investigate the interactions between the DR market and other existing markets, detailed models for retailers and distributors should be incorporated into the model as well. This issue will be considered in our future research.

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