Coordinated Scheduling of Demand Response Aggregators and Customers in an Uncertain Environment

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***Abstract*—In this paper, a methodology to offer new potential of DR in real-time is presented. Since customers likely have extra possibilities for demand response (DR) participation in real-time, in addition to their scheduled potential in day-ahead, this method helps to provide balance in real-time market via DR aggregators. It can be vital once the stochastic variables of the network such as wind power generators (WPG) do not follow the forecasted production in real-time and have some distortions. Stochastic two-stage programming is applied to manage DR options, including load curtailment (LC), load shifting (LS), and load recovery (LR) in both day-ahead and real-time market. DR options in real-time are scheduled based on possible scenarios that reflect the behavior of wind power generation and are generated through Monte-Carlo simulation method. The merits of the method are demonstrated in a 6-bus case study, which shows a reduction in total operation cost.**

***Index Terms*—DR aggregators, optimal demand response, real-time market, two-stage linear programming, uncertainty handling.**

I. Nomenclature

A. Indices (sets) and abbreviations

DRK	Set of DR offers for day-ahead decision.
$DRKs$	Set of DR offers for real-time decision.
g (NG)	Index (set) of generating units.
gen	Generator units.
k (NK)	Index (set) of DR offers.
l (NL)	Index (set) of transmission lines.
LC	Load curtailment option.
LS	Load shifting option.
LR	Load recovery option.
n (NN)	Index (set) of nodes.
s (NS)	Index (set) of scenarios.
$scen$	Superscripts for wind scenarios.
$shed$	Superscripts for load shedding.
$spill$	Superscripts for wind spillage.
t (NT)	Index (set) of hours.
TC, TS, TR	Set of times for load curtailment, shift and recovery options.
$\hat{X} \in LC, LS, LR$	Superscripts for LC and LS and LR.

B. Parameters

C_{tg}^{gen}	Production cost of generator units.
$C_{tg}^{up}, C_{tg}^{down}$	Up/down reserve cost of generator units.
$C_{g}^{strt.up}, C_{g}^{sht.dwn}$	Generator start-up/shut-down cost.
Cs_{tns}^{spill}	Wind spillage cost per scenario.
$Cs_{tgs}^{up}, Cs_{tgs}^{down}$	Up/down reserve cost per scenario.
Cs_{tns}^{voll}	Value of loss of load per scenario.
$DR_{tnk}^{Cost,\hat{X}}$	Cost of offer k from DR option $\hat{X}$ in day-ahead market.
$DRs_{tnk}^{Cost,\hat{X}}$	Cost of offer k from DR option $\hat{X}$ in real-time market.
$DRK_{tnk}^{Min,\hat{X}}$	Minimum offer k from DR option $\hat{X}$ in day-ahead market.
$DRKs_{tnk}^{Min,\hat{X}}$	Minimum offer k from DR option $\hat{X}$ in real-time market.
$DRK_{tnk}^{Max,\hat{X}}$	Maximum offer k from DR option $\hat{X}$ in day-ahead market.
$DRKs_{tnk}^{Max,\hat{X}}$	Maximum offer k from DR option $\hat{X}$ in real-time market.
$LCD_{nk}^{\hat{X},\min}, LCD_{nk}^{\hat{X},\max}$	Min/max time for offer k from DR option $\hat{X}$.
LD_{tn}	Forecasted load.
$MC_{nk}^{\hat{X}}$	Maximum number of calling DR option $\hat{X}$ per day.
$MCs_{nk}^{\hat{X}}$	Maximum number of calling DR option $\hat{X}$ per day.

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$pf_l^{\max}, pf_l^{\min}$	Maximum/minimum transmission line capacity.
$P_g^{\max}, P_g^{\min}$	Maximum and minimum capacity of generating units.
$R_g^{\max,up}, R_g^{\max,down}$	Maximum up/down reserve.
Rmp_g^{up}, Rmp_g^{dwon}	Maximum ramp-up/-down.
X_{nl}	Transmission lines inductance.

C. Binary variables

u, y, z	Binary variables for on/off, start-up and shut-down status in day-ahead market.
us, ys, zs	Binary variables for on/off, start-up and shut-down status in real-time market.

D. Variables

$CDR^{\hat{X}}$	Total cost of DR scheduling for DR option $\hat{X}$ in day-ahead market.
$CDRs^{\hat{X}}$	Total cost of DR scheduling for DR option $\hat{X}$ in real-time market.
$DRK^{\hat{X}}$	DR scheduling for DR option $\hat{X}$ in day-ahead market.
$DRKs^{\hat{X}}$	DR scheduling for DR option $\hat{X}$ in real-time market.
P	Thermal power generation.
pf, pfs	Power line flows day-ahead/balancing.
$R_{tg}^{up}, R_{tg}^{down}$	Up/down reserve of units.
$Rs_{tgs}^{up}, Rs_{tgs}^{down}$	Up/down reserve of units for scenarios.
W	Wind power generation.
θ	Voltage angle.
Ls_{tns}^{shed}	Force load shedding
W_{tns}^{spill}	Wind spillage

II. Introduction

A. Motivation

With the expansion of demand response (DR) utilization all over the world, the importance of making the best strategy to take the whole advantages of demand-side management is highly encouraged [1].

There are lots of potentials and programs for DR, either in communication facilities like AutoDR, transactive controllers [2] or in different strategies like emergency demand response program (EDRP) and time of use (ToU) [3]–[5], which should be applied to schedule and optimize the DR usage.

Meanwhile, customers recently play a key role in the market and this issue should be considered by regulators and policy makers. In other words, the customers have been turned from passive players into active ones [6]. Accordingly, a new player has been introduced in the market in order to be placed as an interface between the ISO and the customers [7].

DR aggregators can actively communicate with customers to take the highest advantages of DR. In most of articles like [8]–[11], authors have considered only DR aggregators as active players. Moreover, different markets and resources have been applied to implement DR programs, ranging from the balancing market to the bilateral contracts. In [12], [13], bilateral contracts have been considered among the DR aggregator and the customer, considering day-ahead and balancing markets.

B. Contribution

In this paper, we consider both DR aggregators and customers as active players in the market. DR aggregators schedule the DR options including load curtailment (LC), load shifting (LS) and load recovery (LR) and offer the DR prices to customers for the participation in the day-ahead market. Meanwhile, customers may want to reduce or shift more loads in the real-time provided that an incentive is proposed by DR aggregators. For example, in the real-time market, customers are able to turn some more lights off or postpone the electric vehicle and washing machine usages, which all were supposed to be used according to the day-ahead scheduling. This strategy is highly desired when some unpredicted events take place in the real-time and the DR aggregator can cope with the uncertainties. For example, when the wind power generation in real-time is different from the forecasted one or the market price does not live up the expectations, customers are able to help avoiding power unbalances or economic losses. In this paper, wind power generation is considered as a stochastic variable and based on scenario generation using Monte-Carlo Simulation Method (MCS) the possible amount of wind generation in real-time has been taken into account. Based on these scenarios, new possible DR offers are decided in the real-time market with the new DR capabilities that customers offer.

A two-stage stochastic programming is applied to model the proposed strategy, where in the first stage the day-ahead DR aggregator is scheduled and in the second stage the customers and DR aggregators are scheduled for adding DR in real-time based on the offered incentives and possible scenarios for wind generation. The remaining parts of the paper are as follows. Section III introduces the DR offers and the way of DR aggregator price bidding. Likewise, scenario generation method and uncertainty handling are presented. Section IV presents the formulation of the proposed mixed integer linear (MIP) two-stage stochastic modeling and the constraints. Numerical results and the case study are provided in Section V. Section VI makes some concluding remarks.

III. Problem Statement

In this section, the mechanism of stochastic handling for wind power production is outlined. Moreover, the framework of the DR aggregator is explained.

A. Stochastic modeling

Since it is supposed the network includes renewable energy sources like wind farms, the stochastic nature of wind power production should be modeled in a scenario-based method to show the possible events in the real-time.

Wind speed is an uncertain variable which is translated into power in the wind power generator (WPG). Wind speed outline in one area can be adapted roughly to a Rayleigh distribution [14]:

$$f(v) = \left(\frac{2v}{c^2}\right) e^{-\left(\frac{v}{c}\right)^2} \tag{1}$$

Here c is the scale index and v is the wind speed in (m/s). To form the probability distribution function (PDF), some parameters should be calculated from historical data.

In this paper, scale index is attained from the subsequent acceptable estimation extracted from reference [15]:

$$c \approx 1.128 v_{mean} \tag{2}$$

where v_{mean} is the hourly average predicted wind speed taken from a time series. Likewise, the equation for converting wind speed to electric power through the WPG is as follows [16]:

$$p_w = \begin{cases} 0 & v < v_{ci} \cup v_{co} \le v \\ P_r . \dfrac{(v - v_{ci})}{(v_r - v_{ci})} & v_{ci} \le v \le v_r \\ P_r & v_r \le v \le v_{co} \end{cases} \tag{3}$$

where v_{ci} , v_{co} , v_r and P_r are cut-in, cut-out, rated wind speeds and rated output power of the WT, respectively.

B. Scenario generation

In this paper, several scenarios for power generation of the wind turbines are generated based on MCS. Using the constructed Rayleigh function, several scenarios which show the behavior of WPG in real-time are generated. The procedure of scenario generation is outlined in Fig. 1.

According to Fig. 1, an uniform random variable is generated and assigned to the mentioned PDF. Afterwards, a wind speed with a probability is selected followed by the amount of wind power generation. Accordingly, the desired scenarios can be obtained.

C. Market structure

Based on Fig. 2, the ISO runs a pre-emptive market that describes an interaction among day-ahead market and balancing market [17].

This market framework can cope with the uncertainty of renewable generation since enough flexible capacity is made available for balancing through day-ahead energy reserve dispatch. The structure can be seen in Fig. 2. In fact, day-ahead energy dispatch decisions account for the balancing operation through different scenarios, which contain possible events in real-time [17].

ISO receives generating companies (GENCOs) offers for energy and up/down reserve. The ISO also receives the DR offers from DR aggregators, and when the ISO clears the market, hourly DR scheduling will be sent to DR aggregators.

A two-stage stochastic model is applied for short-term scheduling. The first-stage decisions are those made for day-ahead market, including energy and reserve of GENCOs as well as DR scheduling for aggregators in each scheduling hour. The second-stage decisions are those related to the realization of scenarios, including the deployment of the reserve, wind spillage, and real-time DR decisions.

D. Demand Response Options

The DR aggregator can be designed for a specific class of customers [18]; however, in this paper, we consider a comprehensive DR aggregator scheme that considers all customers and causes further reduction in a number of DR correspondence with the consumers.

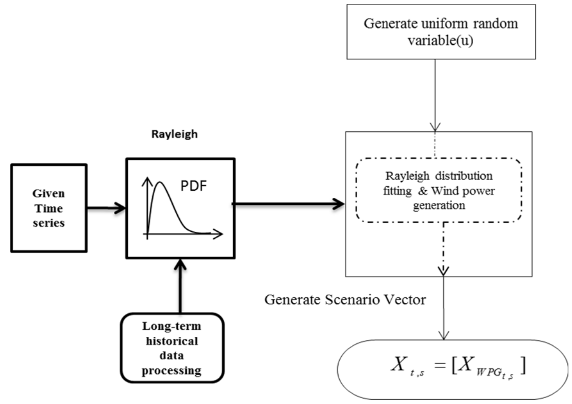


Figure 1. The framework of scenario generation for WPG.

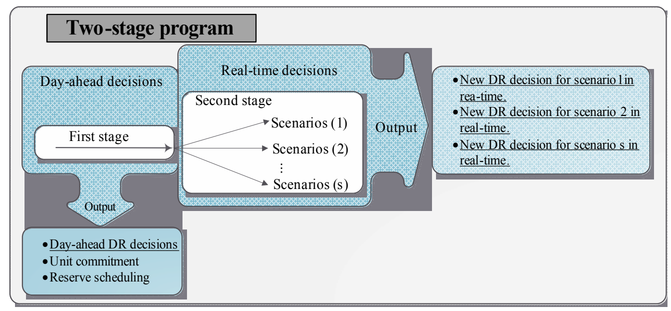


Figure 2. Proposed model framework.

Three load reduction strategies including load curtailment (LC), load shifting (LS), and load recovery (LR) are utilized as DR options to participate in the day-ahead market and in real-time decisions.

1) Day-ahead DR decisions

For the day-ahead DR decisions, three load reduction strategies are considered. In the LC option, customers reduce their consumption based on the program without shifting to other hours. For example, a residential customer can turn off the TV, or a commercial one can reduce its unnecessary consumptions [8], [18]. The LC contracts include a number of offers k ; each offer has a specific price according to an agreement among the ISO and DR aggregators $DR_{tnk}^{Cost,LC}$.

$$CDR_{tn}^{\hat{X}} = \sum_{k \in KD} DRK_{tnk}^{\hat{X}} DR_{tnk}^{Cost,\hat{X}} , \forall t \in TC , \forall n \tag{4}$$

$$DRK_{tnk}^{Min,\hat{X}} u_{tnk}^{\hat{X}} \le DRK_{tnk}^{\hat{X}} \le DRK_{tnk}^{Max,\hat{X}} u_{tnk}^{\hat{X}} , \forall t \in TC , \forall n , \forall k \tag{5}$$

$$u_{tnk}^{\hat{X}} - u_{t-1nk}^{\hat{X}} = y_{tnk}^{\hat{X}} - z_{tnk}^{\hat{X}} \tag{6}$$

$$y_{tnk}^{\hat{X}} + z_{tnk}^{\hat{X}} \le 1 \tag{7}$$

$$\sum_{t}^{t+LCD_{nk}^{\max,\hat{X}}-1} z_{tnk}^{\hat{X}} \ge y_{tnk}^{\hat{X}} \tag{8}$$

$$\sum_{t}^{t+LCD_{nk}^{\min}-1} u_{tnk}^{\hat{X}} \ge LCD_{nk}^{\hat{X},\min} (u_{tnk}^{\hat{X}} - u_{t-1nk}^{\hat{X}}) \tag{9}$$

$$\sum_{t} y_{tnk}^{\hat{X}} \le MC_{nk}^{\hat{X}} \tag{10}$$

$$DRK_{tnk}^{LR} \le DRK_{tnk}^{\max,LR} u_{tnk}^{LR} , \forall t \in TR, \forall n, \forall k \tag{11}$$

$$u_{tnk}^{LR} + u_{tnk}^{LS} \le 1 \tag{12}$$

$$\sum_{t \in TR} DRK_{tnk}^{LR} = \sum_{t \in TS} DRK_{tnk}^{LS} , \forall n, \forall k \tag{13}$$

The LC contract also has a maximum and minimum quantity of load curtailment for each LC offer, given in (5), where u_{tnk}^{LC} is a binary variable to show if the LC offer is scheduled (equal to 4). The exact volume of load curtailment quantity DRK_{tnk}^{LC} of offer k at time t for the LC option is scheduled for DR aggregator bus n and the total cost for LC will be obtained by (4). Equation (6) indicates when the offer t will be started $y_{tnk}^{LC}=1$ and when it will be terminated $z_{tnk}^{LC}=1$. Equation (7) is for preventing any coincidence in starting and terminating. Minimum and maximum durations of load reduction are given in (8)–(9) and the maximum number of load curtailment in a day is given in (10). For LS, all equations of LC will be repeated and three other equations are needed for shifting and recovery of curtailed loads, which are introduced in (11)–(13). According to (11), the volume of LR offer k at time t, DRK_{tnk}^{LR} has a limitation and should be lower than a specific amount defined in the contract. Moreover, as (13) shows, the total volume of LS in a day should be equal to the total volume of LS. Meanwhile, LR and LS should not be taking place at the same time, which is determined in (12).

2) *Real-time DR decisions*

For real-time DR decision, according to the possible events that are determined in the scenarios, new decisions for DR in order to apply in real-time will be made. DR aggregators provide this opportunity for customers to participate even in the real-time market in order to use any possible potential of customers' consumption to shift or curtail, which was not clarified in a day before. Therefore, customers utilize this opportunity to propose any new possible potential for participation in DR within real-time. Having performed this strategy leads to not only profit for customers to sell higher price DR in real-time, but also provides less expensive power balance for the ISO followed by the profit for DR aggregators. The equations of real-time DR are as follows:

$$CDRs_{tns}^{\hat{X}} = \sum_{k \in KD} DRKs_{tnks}^{\hat{X}} DR_{tnk}^{Cost,\hat{X}}, \forall t \in TC, \forall n \tag{14}$$

$$DRKs_{tnks}^{Min,\hat{X}} us_{tnks}^{\hat{X}} \le DRKs_{tnks}^{\hat{X}} \le DRKs_{tnks}^{Max,\hat{X}} us_{tnks}^{\hat{X}}, \forall t \in TC, \forall n, \forall k \tag{15}$$

$$us_{tnks}^{\hat{X}} - us_{t-1nks}^{\hat{X}} = ys_{tnks}^{\hat{X}} - zs_{tnks}^{\hat{X}} \tag{16}$$

$$ys_{tnks}^{\hat{X}} + zs_{tnk}^{\hat{X}} \le 1 \tag{17}$$

$$\sum_{t}^{t+LCD_{nk}^{\max,\hat{X}}-1} zs_{tnks}^{\hat{X}} \ge ys_{tnks}^{\hat{X}} \tag{18}$$

$$\sum_{t}^{t+LCD_{nk}^{\min}-1} us_{tnks}^{\hat{X}} \ge LCDs_{nk}^{\hat{X},\min} (us_{tnks}^{\hat{X}} - us_{t-1nks}^{\hat{X}}) \tag{19}$$

$$\sum_{t} y_{tnks}^{\hat{X}} \le MCs_{nks}^{\hat{X}} \tag{20}$$

$$DRK_{tnks}^{LR} \le DRKs_{tnk}^{\max,LR} us_{tnks}^{LR}, \forall t \in TR, \forall n, \forall k \tag{21}$$

$$us_{tnks}^{LR} + us_{tnks}^{LS} \le 1 \tag{22}$$

$$\sum_{t \in TR} DRKs_{tnks}^{LR} = \sum_{t \in TS} DRKs_{tnks}^{LS}, \forall n, \forall k \tag{23}$$

Equations (14)–(23) represents the real-time contract scheme and options for DR among DR aggregators and customers. The framework of DR options is similar to day-ahead market, though the DR threshold and price in real-time would be different.

3) *DR price bidding scheme*

In fact, the DR cost is non-linear since the price and DR quantity are both variable. However, to prevent trapping in a local optimum point in solving non-linear problems following by high degree of errors in the results, a method to achieve a linear problem is applied.

To this end, we apply price-quota curve approach, which is precise enough in linearization and the customers react to different prices in a stepwise way. Therefore, the price of each step is constant and the quantity is a decision variable in a special range for each step.

The stepwise function is shown in Fig. 3. Accordingly, the higher incentive the aggregator offers, the higher volume of load reduction will be selected by customers. It is noticed that the DR price bidding in day-ahead market by the DR aggregator is usually less than the DR price bidding in the real-time market, because in real-time market the customers expect higher price for their DR offers and the market price would be higher as well.

IV. Stochastic Two-Stage Programming

According to Fig. 2, the objective function is the minimization of total operation cost through stochastic two-stage MILP programming. The objective function is given in (24) and the constraints are given in (25)–(36).

In (24), there are two types of decision variables including day-ahead variables and real-time variables. The day-ahead ones are $P_{tg}^{gen}, SUC_{tg}^{gen}, R_{tg}^{up}, R_{tg}^{down}, CDR_{tn}^{LC}, CDR_{tn}^{LS}$ and the real-time decision variables consist of $Rs_{tgs}^{up}, Rs_{tgs}^{down}, W_{tns}^{spill}, CDRs_{tns}^{LC}, CDRs_{tns}^{LS}, Ls_{tns}^{shed}$.

$$\begin{aligned} Minimize \sum_{t \in NT} \Bigg\{ & \sum_{g \in NG} (C_{tg}^{gen} P_{tg}^{gen} + SUC_{tg}^{gen} + C_{tg}^{up} R_{tg}^{up} + C_{tg}^{down} R_{tg}^{down}) \\ & + \sum_{n \in NN} (CDR_{tn}^{LC} + CDR_{tn}^{LS}) \\ & + \sum_{s \in S} \pi_s \Bigg[\sum_{g \in NG} (Cs_{tgs}^{up} Rs_{tgs}^{up} + Cs_{tgs}^{down} Rs_{tgs}^{down}) \\ & + \sum_{n \in NN} (Cs_{tns}^{spill} W_{tns}^{spill} + Cs_{tns}^{voll} Ls_{tns}^{shed}) + \sum_{n \in NN} (CDRs_{tns}^{LC} + CDRs_{tns}^{LS}) \Bigg] \Bigg\} \end{aligned} \tag{24}$$

$$P_{tg}^{gen} + R_{tg}^{up} \le P_g^{\max} u_{tg}^{gen}, \forall t, \forall g \tag{25}$$

$$P_{tg}^{gen} - R_{tg}^{down} \ge P_g^{\min} u_{tg}^{gen}, \forall t, \forall g \tag{26}$$

$$\sum_{g \in NG} p_{tg}^{gen} + W_{tn}^{sch} + \sum_{k \in KD} (DRK_{tnk}^{LC} + DRK_{tnk}^{LS} - DRK_{tnk}^{LR}) = LD_{tn} + \sum_{l \in NL} pf_{tl}, \forall t, \forall n \tag{27}$$

$$0 \le R_{tg}^{up} \le R_g^{\max,up}, \forall t, \forall g \tag{28}$$

$$0 \le R_{tg}^{down} \le R_g^{\max,down}, \forall t, \forall g \tag{29}$$

$$P_{t-1g}^{gen} - P_{tg}^{gen} \le Rmp_g^{up}, \forall t, \forall g \tag{30}$$

$$P_{tg}^{gen} - P_{t-1g}^{gen} \le Rmp_g^{down}, \forall t, \forall g \tag{31}$$

$$SUC_{tg}^{gen} \ge C_g^{strt.up} (u_{tg}^{gen} - u_{t-1g}^{gen}), \forall t, \forall g \tag{32}$$

$$SUC_{tg}^{gen} \ge C_g^{sht.dwn} (u_{t-1g}^{gen} - u_{tg}^{gen}), \forall t, \forall g \tag{33}$$

$$pf_{tl} = \sum_{n \in NN} \frac{1}{X_{nl}} (\theta_{nl}^1 - \theta_{nl}^0), \forall t, \forall l \tag{34}$$

$$pf_l^{\min} \le pf_{tl} \le pf_l^{\max}, \forall t, \forall l \tag{35}$$

$$0 \le W_{tn}^{sch} \le W_{tn}^{\exp}, \forall t, \forall n \tag{36}$$

The first and the second line of equation (24) correspond to the first stage (day-ahead) decisions, which include generation costs of units, start-up and shut-down costs, units' capacity cost of up- and down- reserves, as well as the total cost of DR options (LS and LC). The third and fourth line of (24) are linked to the second-stage (real-time) decisions [17], which include real-time total DR cost for all scenarios, energy cost, up- and down- reserves, as well as wind spillage cost in all scenarios.

First-stage constraints are given in (25)–(36). Equations (25)–(26) are maximum/minimum capacity limitation of the units. The day-ahead balance equation is given in (27). Units' up-/down- reserve limitations are given in (28)–(29). Units' ramp-up and down constraints are given in (30)–(31). Equations (32)–(33) represent the constraints that define the units' start-up/shut-down costs. The DC power flow equation is presented in (34), and transmission line capacity is given in (35). Equation (36) defines that the amount of scheduled wind power should be less than the expected volume, which is the forecasted amount of wind power. Meanwhile, (4)–(13) are applied for computing DR costs in day-ahead market and (14)–(23) are utilized to obtain the DR cost in the real-time market.

The second-stage constraints are given in (37)–(42). Equation (37) is the balancing condition for the real-time market. DC power flow equations for real-time are given in (38)–(39). Wind-spillage should be lower than wind power of each scenario, which is shown in (40). Limitations of up-/down-reserve for each scenario are given in (41)–(42).

$$\sum_{g\in NG}(Rs^{up}_{tgs} - Rs^{down}_{tgs}) + W^{scen}_{tns} - W^{sch}_{tn} - W^{spill}_{tns} + \sum_{k\in KD}(DRKs^{LC}_{tnks} + DRKs^{LS}_{tnks} - DRKs^{LR}_{tnks}) = -\sum_{l\in NL}(pfs_{tls} - pf_{tl}), \forall t, \forall n, \forall s \quad (37)$$

$$pfs_{tls} = \sum_{n\in NN}\frac{1}{X_{nl}}(\theta^{1}_{nls} - \theta^{0}_{nls}), \forall t, \forall l, \forall s \quad (38)$$

$$pf^{\min}_{l} \le pfs_{tls} \le pf^{\max}_{l}, \forall t, \forall l \quad (39)$$

$$0 \le W^{spill}_{tns} \le W^{scen}_{tns} \quad (40)$$

$$0 \le Rs^{up}_{tgs} \le R^{up}_{tg} \quad (41)$$

$$0 \le Rs^{down}_{tgs} \le R^{down}_{tg} \quad (42)$$

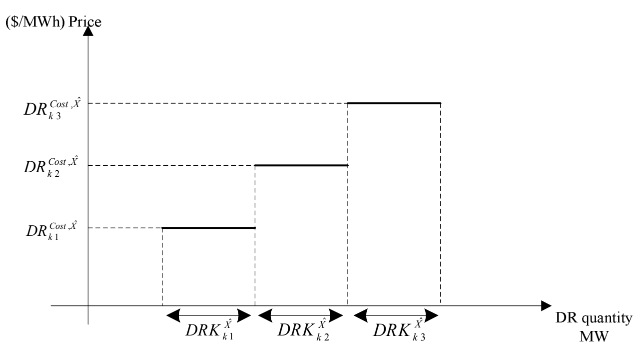


Figure 3. DR price bidding for day-ahead and real-time market.

V. Numerical Studies

A 6-bus system is applied to evaluate the proposed model in this paper. The system, which is shown in Fig. 4, includes three conventional generation units and a wind farm with the maximum capacity of 20 MW.

Units and line data for the case study are given in Tables I and II, respectively. In Table III, DR prices for different options including LC, LS and different offers (5 offers, k1 to k5) in the day-ahead and real-time markets are presented. Likewise, three DR aggregators are considered.

Tables IV and V introduce the range of DR options in different hours for the day-ahead and real-time markets, respectively. $DRK^{\max,LR}_{tnk}$ for LR option is considered 2 MW in day-ahead DR scheduling and 1.5MW in real-time DR scheduling.

The problem is solved by the solver CPLEX in GAMS [19] using a computer with 6 GB RAM and 2.6 GHz core i5 processor. The computation time is less than 1 second.

In this paper, the differences among scenarios after running DR options are illustrated as case 2. Case 1 includes the same method without running DR options in real-time for the scenarios; DR options run just in day-ahead.

Through the proposed method to generate scenarios for the WPGs, ten scenarios are generated. In Fig. 5, all ten scenarios along with the forecasted wind power production are shown. As can be seen, wind power production in scenario 2 is low during the day in a way that the maximum production for scenario 2 is 5 MW out of 20 MW. Instead, scenario 3 has a maximum wind power production in a way that the maximum production is 19 MW for this scenario. The range of power production in scenarios 4 and 5 is between scenarios 2 and 3. Other scenarios are relatively similar to each other.

In Fig. 6 the impacts of running real-time DR scheduling on loads are presented and divided in two parts.

In part a), the results of real-time DR scheduling for scenarios 2 to 5, that have larger variation, are brought to compare with the day-ahead DR scheduling in case 1 and case 2. The load profile after running the proposed method in case 2 for the day-ahead market is illustrated in part a) along with the results for the load after running DR in the day-ahead market for case 1 without running DR options in scenarios and real-time market.

In part b), the results of real-time DR scheduling for the remaining scenarios that have relatively similar patterns and less variation are presented. For scenario 2, the load reduction is higher in peak hours, since it has less wind power production compared with the forecasted one. Therefore, to compensate this shortage of production, DR options are applied to reduce the load, though the loads are recovered in off-peak hours. As a result, the highest load reduction occurs for scenario 2.

Table I. Units' Data

#	Bus	Generation cost	Minimum capacity	Maximum capacity	Start-up cost	Shut-down cost	Ramp rate	Min on-time	Min off-time	Reserve-up limit	Reserve down limit	Reserve up cost	Reserve down cost
G1	1	13,5	100	220	100	50	100	4	4	110	110	15	10
G2	2	40	10	100	200	100	60	3	2	50	50	45	35
G3	6	17,7	10	40	0	0	30	1	1	15	15	20	15

On the other hand, less load reduction occurs for scenario 3, since it has the highest wind power production among these scenarios. For scenarios in part b, the load pattern after DR is relatively the same, since the wind production pattern is similar for all those scenarios.

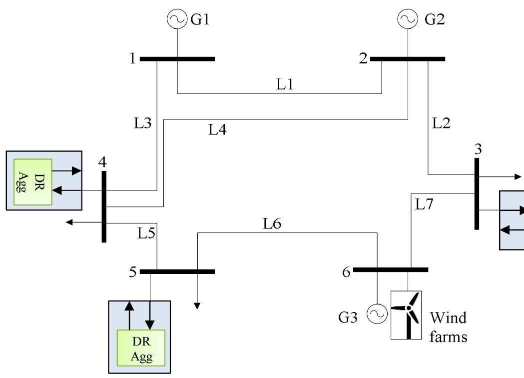


Figure 4. One-line diagram of the 6-bus network.

TABLE II. TRANSMISSION LINE DATA

Line	X	Capacity
L1	0,17	200
L2	0,037	100
L3	0,258	100
L4	0,197	100
L5	0,037	100
L6	0,14	100
L7	0,018	100

TABLE III. DR PRICES FOR 5 OFFERS AND TWO OPTIONS

market		K1 (€/MWh)	K2 (€/MWh)	K3 (€/MWh)	K4 (€/MWh)	K5 (€/MWh)
Day-ahead	LC price	10	11	12	13	14
	LS Price	10	11	12	13	14
Real-time	LC Price	11	12	13	14	15
	LS Price	11	12	13	14	15

TABLE IV. DR CONTRACT LIMITATION FOR THE QUANTITY OF ALL 5 OFFERS IN DR AGGREGATOR 1, 2, AND 3 IN DAY-AHEAD DR SCHEDULING

	DR aggregator #1 LC, LS (MW)		DR aggregator #2,3 LC, LS(MW)	
Hour	*Min*	*Max*	*Min*	*Max*
10	0.48	0.534	1	1.068
11	0.5	0.554	1.05	1.108
12	0.51	0.56	1.07	1.12
13	0.5	0.554	1.05	1.108
14	0.51	0.56	1.07	1.12
15	0.51	0.56	1.07	1.12
16	0.49	0.544	1.03	1.088
17	0.49 (LC=0)	0.544 (LC=0)	1.03 (LC=0)	1.088 (LC=0)
18	0.49 (LC=0)	0.544 (LC=0)	1.03 (LC=0)	1.088 (LC=0)

TABLE V. DR CONTRACT LIMITATION FOR THE QUANTITY OF ALL 5 OFFERS IN DR AGGREGATOR 1, 2, AND 3 IN REAL-TIME DR SCHEDULING

	DR aggregator #1 LC, LS (MW)		DR aggregator #2,3 LC, LS(MW)	
Hour	*Min*	*Max*	*Min*	*Max*
10	0.49	0.524	1.01	1.058
11	0.51	0.544	1.06	1.098
12	0.52	0.55	1.08	1.11
13	0.51	0.544	1.06	1.098
14	0.52	0.55	1.08	1.11
15	0.52	0.55	1.08	1.11
16	0.5	0.534	1.04	1.078
17	0.5 (LC=0)	0.534 (LC=0)	1.04 (LC=0)	1.078 (LC=0)
18	0.5 (LC=0)	0.534 (LC=0)	1.04 (LC=0)	1.078 (LC=0)

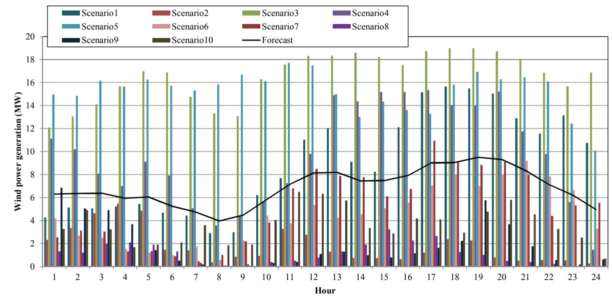
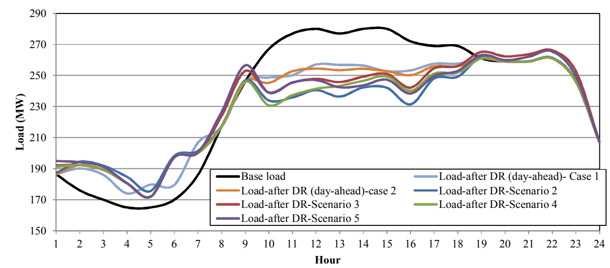
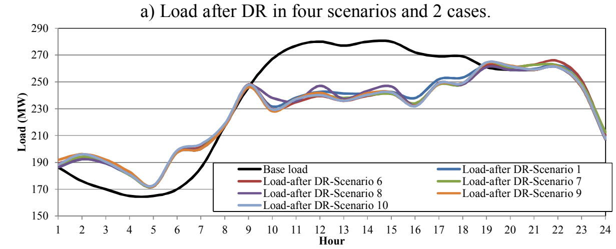


Figure 5. Forecasted wind power generation and ten scenarios extracted via the model.



a) Load after DR in four scenarios and 2 cases.



b) Load after DR in six other scenarios

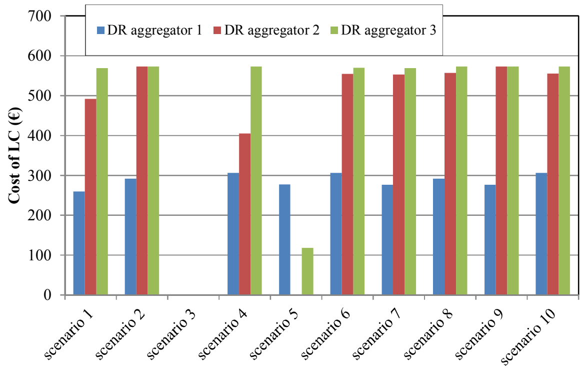
Figure 6. Base load and loads after DR in different states and scenarios: a) two cases and scenarios 2-5, and b) scenarios 1, 6-10.

A comparison among the DR aggregators cost for running DR options in all scenarios is performed in Fig. 7. In part a) of Fig. 7, there is no LC for scenario 3, since in these scenarios the highest wind power generation is foreseen. Therefore, there is no need to reduce the load, and all loads are served. Scenario 5 is nearly similar to scenario 3; hence, there is no DR cost for DR aggregator 2 and for two other DR aggregators it is too low; 100€ for DR aggregator 3 and 250€ for DR aggregator 1. Nevertheless, the DR costs for other scenarios and DR aggregator for running the LC are nearly the same. DR cost, generally, for DR aggregator 1 is lower than for the two other DR aggregators, since the amount of load under control of DR aggregator 1 is lower. In part b) of Fig. 7, LS cost is considered. In all scenarios, LS is applied; yet, LS cost is mostly less than the LC cost. Generally, the LS cost is around 300€, although the LS cost for DR aggregator 3 is around 400€ in scenario 5 and the LS cost is 150€ for DR aggregator 1. Moreover, as can be seen in part c), total DR cost, the summation of LS and LC costs is lowest for scenarios 3 and 5, which have the highest possible wind power productions. The price for other scenarios are approximately the same, with 900€ for DR aggregators 2 and 3, and 500€ for DR aggregator 1.

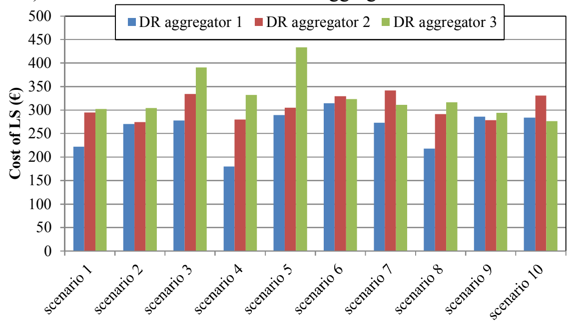
Finally, the different costs in all cases are provided in Table VI.

TABLE VI. DIFFERENT COSTS IN ALL CASES

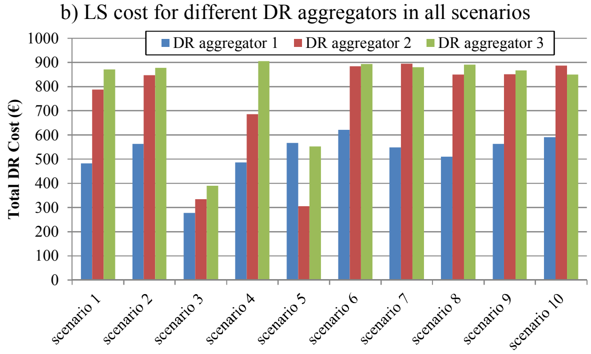
Cases	Total cost (€)	DR cost (€)
Case 1	90158.04	2142.35
Case 2	86054.1	2336.683



a) Total DR cost for different DR aggregators in all scenarios



b) LS cost for different DR aggregators in all scenarios



c) LC cost for different DR aggregators in all scenarios

Figure 7. DR cost in different DR aggregators and different scenarios: a) total cost, b) LS cost, and c) LC cost.

Based on Table VI, the proposed method has less total operation cost compared with case 1 where there is no DR scheduling for scenarios in real-time; nevertheless the day-ahead DR scheduling for case 2 is higher. The reason behind why the need for reserve of units in different scenarios is reduced is because of applying the new methodology for DR in real-time, which is less costly than units' reserve.

VI. CONCLUSIONS

A two-stage stochastic programming has been applied to model the real-time scheduling of DR options, including LC, LR and LS. Ten scenarios have been generated through the MCS method to show the different possible amount of WPG at each hour. Through this methodology, in addition to day-ahead DR scheduling by coordinating DR aggregators and customers, DR options in real-time were scheduled for DR aggregators based on each scenario, which showed shortage or enough wind power production. Hence, the more wind power was produced in each scenario, the less DR was applied for that scenario. Moreover, this method had less total operation cost.

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