Wind Power Offering Strategy in Day-Ahead Markets: Employing Demand Response in a Two-Stage Plan

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***Abstract*—This paper deals with wind power offering strategies in day-ahead markets. A new plan is proposed in which a wind power producer participates in the day-ahead market while employing demand response (DR) to smooth its power variations. In this context, a new DR scheme is presented through which the wind power producer is able to achieve DR by establishing various DR agreements with DR aggregators. The proposed offering plan involves two stages: the first stage clears on the day-ahead market. The wind power producer decides on day-ahead offers as well as DR agreements with the aggregator. The second stage takes place on the balancing market. In a successive approach, the wind power producer determines its energy trading for each period until the whole day is covered. Additionally, proper DR agreements for each period are confirmed here. The proposed plan is formulated in a stochastic programming approach, where its validity is assessed on a case of the Nordic market.**

***Index Terms*—Day-ahead market, demand response (DR) scheme, DR options, fixed DR, flexible DR, stochastic programming, two-stage wind offering plan.**

I. Introduction

WIND energy has been a rapidly growing renewable resource in the past few years. This development is facilitated via various subsidies and supportive policies to achieve individual goals worldwide. The European Union and Australia have an identical target of achieving 20% of renewable energy by 2020. U.S. states have distinct goals. For instance, California is targeting 33% renewable by 2020.

The power production uncertainty is a significant challenge for wind power producers. Three main practical solutions are provided to cope with this issue: *increasing the wind power forecasting accuracy*, *optimal wind trading strategies in short-term markets* and *a joint operation of wind power producers and easily controllable resources*. This paper however focuses on the last two solutions.

Optimal trading strategies in short-term markets are addressed in some investigations. Authors in [1] and [2] determine the energy level contracted in a short-term market in order to minimize imbalance costs. Paper [3] proposes a short-term trading strategy, which involves various trading floors, namely day-ahead, adjustment and balancing markets. Authors in [4] recommend the coalition of wind power producers to alleviate the wind uncertainty. Authors in [5] evaluate the offering strategy by price-maker wind power producers.

With regards to joint operation strategies, [6] illustrates the coordination of wind and pumped-storage units. A joint planning and operation strategy of wind power producers and hydro power plants is provided in [7] and [8]. Facilitating wind power production with battery storage systems is described in [9]. Finally, the coordination of wind power producers and thermal plants is addressed in [10]. Demand response (DR) is another source, which can be used in a joint operation with wind power producers. However, relevant studies in literature mostly provide the coordination of DR and wind power producers to improve network and market operations [11]–[13].

This paper investigates a *two-stage offering plan* in which a wind power producer uses *demand response* (DR) as a joint operation resource. In the first stage, the wind power producer places its offer on the day-ahead market and simultaneously determines the contribution of DR agreements. These decisions are made while the following two points are taken into account: 1) wind power forecast for the coming day is not perfect and involves a significant level of uncertainty; 2) day-ahead prices and imbalance charges/payments are also uncertain parameters. A stochastic profit function is formulated where the decisions are taken based on the plausible realizations of the above stochastic parameters. To this end, for each uncertain parameter, a set of scenarios are generated by applying ARIMA models to the historical data. The risk is also carried out using conditional value-at-risk.

The second stage is dedicated to correction actions made on the balancing (regulating) market. A consecutive approach is proposed where the wind power producer settles its power trading in the balancing market for each period. At the same time, the wind power producer approves its required DR agreements with the DR aggregator. These decisions are taken while imbalance prices (charges/payments) and wind power are known for the current period but they are still uncertain for the following intervals. Again a stochastic profit function is formulated in this stage, which runs for each period. This process is repeated until all periods of the day are cleared.

In order to model DR in the proposed offering plan, a new scheme is presented through which a wind power producer can arrange various DR agreements with a DR aggregator. The wind power producer can set a *fixed DR contract*, which is traded in a

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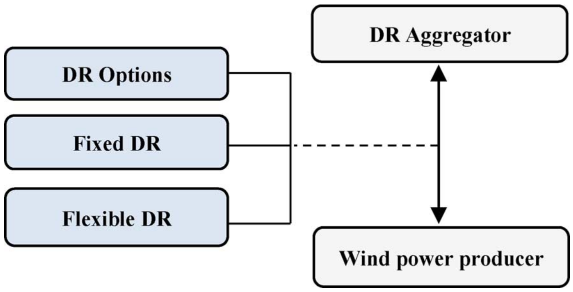

Fig. 1. Proposed DR scheme.

certain volume and price for a given period. In addition, a *flexible DR* is formulated, where it gives the wind power producer a chance to modify the usage pattern of the contracted DR during real-time usage. Furthermore, by adapting the financial option concept [14], new *DR options* are proposed here.

The proposed DR scheme is new as there is no such work in literature addressing a similar model. The majority of DR studies investigate the basic concept [15], [16], technical aspects [17] and DR formulations [18], [19]. Only authors in [20] and [21] study a mechanism through which DR is traded as a commodity. However, their method considers a pool-based DR exchange rather than bilateral contracts.

Overall, the contributions of the paper are as follows.

1) A two-stage offering plan in the day-ahead market is proposed in which wind power producers can benefit from DR in a joint operation.
2) A new DR scheme is proposed where DR can be traded as a public good between wind power producers and DR aggregators. For this purpose, various DR agreements with distinct features are proposed.

The rest of the paper is structured as follows. Section II discusses the given DR scheme with a detailed description of each DR agreement. The proposed plan is explained in Section III. Section IV provides a case study with numerical results. The last section concludes the paper.

II. Comprehensive DR Scheme

The proposed DR scheme arranges mutually attractive deals between a wind power producer and a DR aggregator. It is assumed that the DR aggregator is willing to bilaterally trade DR with wind power producers. Indeed, the aggregator makes contracts with customers and implements technical DR programs to trade it with wind power producers (DR purchasers). A similar real case exists, where EnerNOC [22] plays an arbitrator role between customers and DR purchasers.

The proposed DR scheme is depicted in Fig. 1. As can be seen, DR is traded through three main contracts: *DR options, fixed DR contracts and flexible DR agreements*. Note that the double ended arrow indicates that the DR flow can be either from the aggregator to the wind producer or in the opposite direction. That is, the DR aggregator is also able to buy energy from the wind power producer through DR agreements, where in this situation it encourages customers to consume more energy. This usually happens during off-peak periods.

A. DR Options

A wind power producer can arrange DR options with DR aggregators. According to this contract the wind power producer has a right but not an obligation to purchase DR. This means that the wind power producer signs this contract at the beginning of the decision time horizon, i.e., Stage 1. However, exercising the contract at the energy delivery time (Stage 2) depends on whether it is profitable or not. Each DR option is determined with a specific offer including a certain volume and price for a given period. Thus, when the DR option is set in stage 1, the decision on whether signing this contract or not is made with perfect knowledge about the contract details. This decision is called *here-and-now* in stochastic programming, which is modelled as independent of scenarios [6]. In stage 2, the producer decides on exercising the DR options signed in stage 1. If the contract is executed in stage 2, the wind power producer pays its cost to the DR aggregator. Otherwise, the producer has to pay the predefined penalty. Note that this decision is also independent of scenarios since it is made while the wind power producer perfectly knows its production and the market price in the real-time dispatch.

Similar to financial options, two DR options are introduced. Type one is called European DR options (EDRO), which is set in a way that the DR agreement is exercised at the expiration time. The expiration time is defined when the contract is arranged. In type 2 however, the DR option can be exercised at any time before the expiration time (American DR option).

DR options in each stage are formulated as follows.

Stage 1: this stage indicates whether the DR option is signed or not. This is shown by the binary variable $Sgn_{eo}(t)$ in the cost functions of European DR Option eo in (1a) and $Sgn_{ao}(t)$ in American DR option ao in (1b):

$$C_{eo}^{EDRO,S1}(t) = P_{eo}(t) \times \lambda_{eo}(t) \times Sgn_{eo}(t) \times d_t \quad \forall eo = 1,2,\ldots N_{eo} \tag{1a}$$

$$C_{ao}^{ADRO,S1}(t) = P_{ao}(t) \times \lambda_{ao}(t) \times Sgn_{ao}(t) \times d_t \quad \forall ao = 1,2,\ldots N_{ao}. \tag{1b}$$

Subscripts eo and ao denote European and American DR options, respectively. $P_{eo}(t)$ ($P_{ao}(t)$) and $\lambda_{eo}(t)$ ($\lambda_{ao}(t)$) are the power traded in European DR option eo (American DR option ao) and its price during time t. d_t shows the duration of time period t (Note that since market dispatch intervals are identical, d_t is the same for all periods). Finally, N_{eo} (N_{ao}) represents the number of European DR options (American DR options).

Stage 2: this stage belongs to the delivery time in which it is decided that whether the signed DR option in stage 1 is exercised in stage 2 or not. The exercising status of the DR option is shown by a binary variable $\in \{0,1\}$, where 1 indicates that the contract is applied and zero means that the wind power producer disregards the signed DR option. Indeed this binary variable is shown by $v_{eo}(t)$ in EDRO (2a) and $v_{ao}(t)$ in ADRO (2b):

$$C_{eo}^{EDRO,S2}(t) = Sgn_{eo}(t) \times \left\{ \begin{array}{c} P_{eo}(t) \times \lambda_{eo}(t) \times v_{eo}(t) \times d_t + \\ (1 - v_{eo}(t)) \times f_{eo}^{pen}(t) \end{array} \right\} \quad \forall eo = 1,2,\ldots,N_{eo} \tag{2a}$$

$$C_{ao}^{ADRO,S2}(t) = Sgn_{ao}(t) \times \left\{ \begin{array}{c} P_{ao}(t) \times \lambda_{ao}(t) \times v_{ao}(t) \times d_t + \\ (1 - v_{ao}(t)) \times f_{ao}^{pen}(t) \end{array} \right\} \quad \forall ao = 1, 2, \ldots, N_{ao}. \tag{2b}$$

$f_{eo}^{pen}(t)$ ($f_{ao}^{pen}(t)$) is the penalty of not exercising the EDRO (ADRO) during time interval t.

Note that American DR options can be exercised at any time before the expiration time. This constraint is provided in (3). This expression shows the period horizon ($t \in T_{ao}$) in which the American DR option ao can be exercised:

$$\sum_{t \in T_{ao}} v_{ao}(t) \leq 1; \quad \forall ao = 1, 2, \ldots, N_{ao}. \tag{3}$$

B. Fixed DR Contracts

A fixed contract is an agreement between a buyer and a seller of an asset to be traded at a future time [14]. Considering this concept, a fixed DR contract is proposed here, through which a wind power producer buys this contract from a DR aggregator. It is assumed that the wind power producer directly negotiates with the DR aggregator for a mutually attractive deal. Fixed DR contracts are offered in various blocks in which each block involves a certain amount of DR and price for a given period:

$$C_{f,b}^{FDR}(t) = P_{f,b}^{DR}(t) \times \lambda_{f,b}^{DR}(t) \times d_t \quad f = 1, \ldots, N_{FDR};\ b = 1, \ldots, N_{BDR} \tag{4}$$

$$P_{f,b}^{DR,MIN}(t) \leq P_{f,b}^{DR}(t) \leq P_{f,b}^{DR,MAX}(t). \tag{5}$$

Expressions (4) and (5) show the cost of the fixed DR and the margin size of each contract's block, respectively. $P_{f,b}^{DR}(t)$ and $\lambda_{f,b}^{DR}(t)$ are the power and the price of the bth block of fixed DR f. The number of contracts is given by N_{FDR} and the number of contract blocks is represented by N_{BDR}.

C. Flexible DR Agreement

Flexible DR agreements give the wind power producer a chance to better cope with the uncertainty of its power production as well as market price violations. When both parties (wind power producer and DR aggregator) set this contract (Stage 1), they negotiate the size, the price and the duration of the agreement. However, during the delivery time (Stage 2) the wind power producer is flexible to manage the usage distribution of the contracted DR volume in the given period. That is, the wind power producer has the right to distribute the DR usage over the contract period to cope with its uncertainty.

The cost of the flexible DR agreement is provided in (6). $P_{\text{flex}}^{DR}(t)$ and $\lambda_{\text{flex}}^{DR}(t)$ are the power and the price of flexible DR $flex$. UP_{flex}^{DR} is a binary variable indicating whether the flexible DR $flex$ is used in period t. N_{flex} is the number of flexible DR contracts. The size of flexible DR is imposed in (7). Equation (8) is valid in stage 2, where it states that the flexible DR volume over the contract period ($t \rightarrow SP : EP$) must be equal to the agreed volume (E_{flex}^{Agrd}) which is negotiated in stage 1. SP and EP represent the start and the end of the contract period, respectively:

$$C_{flex}^{FlexDR}(t) = P_{flex}^{DR}(t) \times \lambda_{flex}^{DR}(t) \times UP_{flex}^{DR}(t) \times d_t \quad flex = 1, \ldots, N_{flex} \tag{6}$$

$$P_{flex}^{DR,MIN}(t) \leq P_{flex}^{DR}(t) \leq P_{flex}^{DR,MAX}(t) \tag{7}$$

$$\sum_{t=SP}^{EP} P_{flex}^{DR}(t) \times d_t = E_{flex}^{Agrd}. \tag{8}$$

III. Proposed Trading Plan

The proposed offering plan is applied on the Nordic market, which is a well-established day-ahead market. This market involves three floors, called the spot market, *Elbas* as an adjustment market and the regulating market [1]. *Elbas* is not very active [1] and hence it is not modeled here.

The spot market closes at 12:00 pm the preceding day of the energy delivery. Then, offers and bids from players are stacked and the market price is derived. The revenue obtained from the day-ahead market is formulated in (9):

$$R^{DA}(t, w) = P^{DA}(t) \times \lambda^{DA}(t, w) \times d_t. \tag{9}$$

$P^{DA}(t)$ is the offered power in the day-ahead market during period t. $\lambda^{DA}(t, w)$ represents the price of the day-ahead market in scenario $w \in \Omega$ during time period t.

The regulating (balancing) market is used to balance between production and consumption. The balancing market can be either "short" or "long". In the short state, there is lack of energy while the long market has excess production [8]. Note that long and short markets are respectively known as positive and negative system imbalances in most studies [3], and thereafter we use these terms in the paper. In positive systems, regulation down is activated and generators with excess (deficit) generation are paid (charged) at a positive price $\lambda^{imb,pos}$ (negative price $\lambda^{imb,neg}$). On the other hand, in negative system imbalances, regulation up is applied and payments (charges) for excess (deficit) generation are settled at $\lambda^{imb,pos}$ ($\lambda^{imb,neg}$). For each regulation type, the relationships of $\lambda^{imb,pos}$ and $\lambda^{imb,neg}$ with the day-ahead market price (λ^{DA}) are given in [3] as follows:

$$\begin{array}{cc} & \begin{array}{cc} \boldsymbol{\lambda^{imb,pos}} & \boldsymbol{\lambda^{imb,neg}} \end{array} \\ \begin{array}{r} \textbf{\textit{Down}} \\ \textbf{\textit{Up}} \end{array} & \begin{bmatrix} \lambda^{imb,pos} \leq \lambda^{DA} & \lambda^{DA} \\ \lambda^{DA} & \lambda^{imb,neg} \geq \lambda^{DA} \end{bmatrix}. \end{array}$$

An estimation of imbalance payments and charges for the Nordic is provided in [8]:

$$\lambda^{imb,pos} = 0.95 \times \lambda^{DA} \tag{10}$$

$$\lambda^{imb,neg} = 1.05 \times \lambda^{DA}. \tag{11}$$

This paper further extends the given model in a way that the uncertainty of the regulating market is taken into account:

$$\lambda^{imb,pos} = S^{pos}(w) \times \lambda^{DA} \tag{12}$$

$$\lambda^{imb,neg} = S^{neg}(w) \times \lambda^{DA} \tag{13}$$

where $S^{pos}(w) \leq 1$ and $S^{neg}(w) \geq 1$ are the scenario-based factors of positive and negative imbalance prices, respectively. Depending on whether the wind power producer has excess or deficit production in the balancing market, it earns revenue or incurs cost. The revenue (payment) or cost (charge) of the balancing market ($RC^{Imb}(t, w)$) is then formulated as follows [3]:

$$RC^{\text{Imb}}(t, w) = P^{pos}(t, w) \times S^{pos}(t, w) \times \lambda^{DA}(t, w) \times d_t - P^{neg}(t, w) \times S^{neg}(t, w) \times \lambda^{DA}(t, w) \times d_t \tag{14}$$

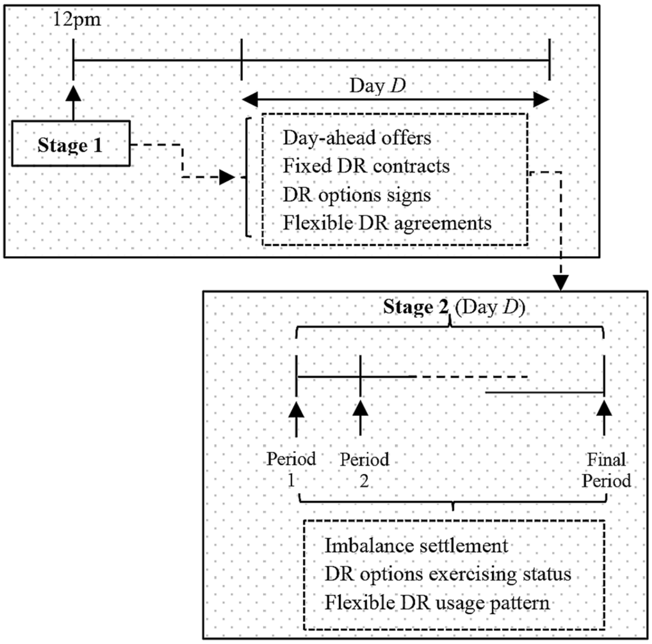

Fig. 2. Proposed wind power offering strategy.

where $P^{pos}(t,w)$ and $P^{neg}(t,w)$ are the positive and negative imbalance power volumes in scenario $w \in \Omega$ and time period t.

The proposed offering strategy is illustrated in Fig. 2. It is assumed that the wind power producer is a price-taker in the market. A further assumption is that the wind power producer is treated as similar to conventional power plants [23], where it is responsible for its bidding strategy and power production variation. Note that this producer acts as a balance responsible player in the Nordic market, where it is responsible for its imbalance charges/payments. In addition, similar to [8] this paper aims to determine the optimal offering quantities instead of presenting bidding curves which is investigated in [3].

A. Stage 1: Day-Ahead Clearing

This stage clears on the day-ahead market. The wind power producer decides on day-ahead offers for the entire next day. In addition, the volume of fixed DR contracts is negotiated. Furthermore, the wind power producer determines the periods in which European DR options are signed. Proper American DR options are also signed and the time horizon in which each one can be exercised is determined. Finally, the required flexible DR agreements are appointed.

The above decisions are made while wind power production as well as day-ahead and imbalance prices (charges/payments) are uncertain. A stochastic profit function is formulated in which the uncertain characteristics of these parameters are taken into account using a set of scenarios. In addition, the risk faced with this uncertainty is modeled though CVaR as an appropriate risk measure.

The profit function is given in (15). This function is calculated for the whole day ($t \rightarrow 1 : FP$). It consists of the following terms. The expected revenue obtained from selling power through the day-ahead market, the expected revenue/cost of the balancing market, the costs of all DR contracts and the weighted CVaR. Note that $\pi(w)$ is the probability of scenario w. ξ and η_w are auxiliary variables for calculating CVaR [3], and β is the confidence level, which is 0.95. Note also that the risk level ($\rho = [0 - \infty)$) represents the trade-off between the expected profit and the risk. A risk-averse wind power producer willing to minimize the risk chooses a large value of the risk. On the other hand, a risk-neutral wind power producer prefers higher profits and consequently selects a risk factor close to 0.

The profit function is subject to the following constraints. The size of fixed DR and flexible DR contracts are enforced by (16) and (17), respectively. Furthermore, the positive and negative imbalance offers are limited by (18) and (19) respectively. $P^{W}(t,w)$ is wind power production in scenario w and time t. P^{InstW} is the installed capacity of the wind power producer. The power balance is given in (20). In this equation, $P^{Imb}(t,w)$ and $P^{TDR}(t)$ represents the imbalance power and total DR volume, where they are represented in (21) and (22), respectively. Finally, expressions (23) and (24) represent CVaR constraints [3], which are derived to linearize this risk measure. Note that Profit(w) in (23) indicates the obtained profit in scenario w [see (25)]:

$$
\begin{aligned}
MAX\ PF &= \sum_{w\in\Omega} \pi(w) \times \sum_{t=1}^{FP} \left[R^{DA}(t,w) + RC^{\mathrm{Imb}}(t,w)\right] \\
&\quad - \sum_{ao=1}^{N_{ao}} \sum_{t\in T_{ao}} C_{ao}^{ADRO,S1}(t) - \sum_{t=1}^{FP} \sum_{eo=1}^{N_{eo}} C_{eo}^{EDRO,S1}(t) \\
&\quad - \sum_{t=1}^{FP} \sum_{f=1}^{N_{FDR}} \sum_{b=1}^{N_{BDR}} C_{f,b}^{FDR}(t) - \sum_{t=1}^{FP} \sum_{flex=1}^{N_{Flex}} C_{flex}^{FlexDR}(t) \\
&\quad + \rho \times \left(\xi - \frac{1}{1-\beta} \sum_{w\in\Omega} \eta_w \times \pi_w\right)
\end{aligned} \tag{15}
$$

subject to

$$P_{f,b}^{DR,MIN}(t) \le P_{f,b}^{DR}(t) \le P_{f,b}^{DR,MAX}(t) \tag{16}$$

$$P_{flex}^{DR,MIN}(t) \le P_{flex}^{DR}(t) \le P_{flex}^{DR,MAX}(t) \tag{17}$$

$$0 \le P^{pos}(t,w) \le P^{W}(t,w) + P^{TDR}(t) \tag{18}$$

$$0 \le P^{neg}(t,w) \le P^{InstW} + P^{TDR}(t) \tag{19}$$

$$P^{DA}(t) + P^{Imb}(t,w) = P^{W}(t,w) + P^{TDR}(t) \tag{20}$$

$$P^{Imb}(t,w) = P^{pos}(t,w) - P^{neg}(t,w) \tag{21}$$

$$
\begin{aligned}
P^{TDR}(t) &= \sum_{f=1}^{N_{FDR}} \sum_{b=1}^{N_{BDR}} P_{f,b}^{DR}(t) \\
&\quad + \sum_{flex=1}^{N_{Flex}} P_{flex}^{DR}(t) \times UP_{flex}^{DR}(t) \\
&\quad + \sum_{ao=1}^{N_{ao}} P_{ao}(t) \times Sgn_{ao}(t) \\
&\quad + \sum_{eo=1}^{N_{eo}} P_{eo}(t) \times Sgn_{eo}(t)
\end{aligned} \tag{22}
$$

$$-\mathrm{Profit}(w) + \xi - \eta(w) \le 0; \forall w \in \Omega \tag{23}$$

$$\eta(w) \ge 0; \forall w \in \Omega \tag{24}$$

$$
\begin{aligned}
\mathrm{Profit}(w) &= \sum_{t=1}^{FP} \left[R^{DA}(t,w) + RC^{\mathrm{Imb}}(t,w)\right] \\
&\quad - \sum_{ao=1}^{N_{ao}} \sum_{t\in T_{ao}} C_{ao}^{ADRO,S1}(t)
\end{aligned}
$$

$$
\begin{aligned}
&-\sum_{t=1}^{FP}\sum_{eo=1}^{N_{eo}} C_{eo}^{EDRO,S1}(t)\\
&-\sum_{t=1}^{FP}\sum_{f=1}^{N_{FDR}}\sum_{b=1}^{N_{BDR}} C_{f,b}^{FDR}(t)\\
&-\sum_{t=1}^{FP}\sum_{flex=1}^{N_{Flex}} C_{flex}^{FlexDR}(t). \qquad (25)
\end{aligned}
$$

B. Stage 2: Regulating (Balancing) Market

Stage 2 deals with balancing settlements and final DR approvals. This stage runs a successive approach, which is repeated until all periods are covered. For each period a profit function is formulated through which the following decisions are made. The wind power producer decides on its energy trading in the balancing market for the current period. At the same time the producer determines its optimal share of DR agreements for the relevant period. Indeed, each DR agreement that has been set in the previous stage is finalized here. The wind power producer decides on the optimal usage of flexible DR. The constraint used here is that the total flexible DR usage should not exceed the agreed volume in stage 1 [see (8)]. Furthermore, the wind power producer decides on exercising the signed DR options in stage 1. In this way, the producer considers that European DR options are exercised only at the expiration time, while American DR options can be used at any time before the deadline. Note that the volume of the contracted fixed DR is predetermined in stage 1 and cannot be changed in this stage.

The above decisions are taken while the day-ahead awards (offers) are known. In addition, the imbalance price and wind power production for the current period are known, but they are still uncertain for the following periods.

The profit function which is formulated for each period is shown in (26). It consists of three terms: the profit obtained from the current period ($t = CP$) [see (27)], the expected profit over the following intervals until the final period ($t \to (CP+1) : FP$) [see (28)] and CVaR. Note that the main terms (27) and (28) involve the (expected) revenue/cost of the balancing market as well as the costs of DR agreements. Note also that the binary variable $v_{f,b}(t) \in \{0,1\}$ states whether the bth block of fixed DR f is set in stage 1. A similar variable is also used for the flexible DR status ($v_{flex}(t)$):

$$PF = \mathrm{Prof(t)}\,|_{t=CP} + \mathrm{EProf}(t)\,|_{t=CP+1}^{FP} + \rho.\mathrm{CVaR} \qquad (26)$$

where

$$
\begin{aligned}
&\mathrm{Prof}(t)\,|_{t=CP}\\
&\quad = RC^{\mathrm{Imb}}(CP)\\
&\qquad -\sum_{ao=1}^{N_{ao}} C_{ao}^{ADRO,S2}(CP) - \sum_{eo=1}^{N_{eo}} C_{eo}^{EDRO,S2}(CP)\\
&\qquad -\sum_{f=1}^{N_{FDR}}\sum_{b=1}^{N_{BDR}} C_{f,b}^{FDR}(CP)\times v_{f,b}(CP)\\
&\qquad -\sum_{flex=1}^{N_{Flex}} C_{flex}^{FlexDR}(CP)\times v_{flex}(CP) \qquad (27)
\end{aligned}
$$

$$
\begin{aligned}
&\mathrm{EProf}(t)\,|_{t=CP+1}^{FP}\\
&\quad = \sum_{w\in\Omega}\pi(w)\times\sum_{t=CP+1}^{FP}\left[RC^{\mathrm{Imb}}(t,w)\right]\\
&\qquad -\sum_{ao=1}^{N_{ao}}\sum_{\substack{t\in T_{ao}\\ t\geq CP+1}} C_{ao}^{ADRO,S2}(t)\\
&\qquad -\sum_{t=CP+1}^{FP}\sum_{eo=1}^{N_{eo}} C_{eo}^{EDRO,S2}(t)\\
&\qquad -\sum_{t=CP+1}^{FP}\sum_{f=1}^{N_{FDR}}\sum_{b=1}^{N_{BDR}} C_{f,b}^{FDR}(t)\times v_{f,b}(t)\\
&\qquad -\sum_{t=CP+1}^{FP}\sum_{flex=1}^{N_{Flex}} C_{flex}^{FlexDR}(t)\times v_{flex}(t). \qquad (28)
\end{aligned}
$$

The profit function is subject to the following constraints.

- Constraints (17)–(25). Note that in these constraints, the day-ahead awards are known. In addition, only those DR agreements set in stage 1 are taken into account here.
- Flexible DR energy constraint:

$$\sum_{t=0}^{CP-1} P_{flex}^{DR}(t) + \sum_{t=CP}^{FP} P_{flex}^{DR}(t) = E_{flex}^{Agrd}. \qquad (29)$$

- American DR option constraint (3).

IV. Case Study

A. Data Preparation and Assumptions

The proposed plan is evaluated on a realistic case of the Nordic market. Hourly market prices are available [24]. Hence, each period in this paper is considered as one hour. Nevertheless, note that the proposed method is also applicable on shorter time horizons.

Similar to leading studies in this area [1], [3], price and wind power scenarios are characterized using ARIMA models. A time series of the spot prices of the Nordic market, spanning January 2012 is used to generate price scenarios [24]. Overall, 20 day-ahead price scenarios are generated in stage 1. In addition, four positive and negative imbalance factors are randomly generated. For positive factors, scenarios range between 0.95 and 1 ($0.95 \leq S^{pos}(w) \leq 1$), while for negative factors they are between 1 and 1.05 ($1 \leq S^{neg}(w) \leq 1.05$).

The wind power producer Hemmet, located in Denmark, is chosen [25]. The installed capacity of this farm is 27 MW (Vestas Turbines). Wind speed scenarios are generated using the ARMA model where the available data in 2012 is used as input time series. 14 wind speed scenarios are generated in stage 1. These scenarios are then transformed to power scenarios using the Vestas Wind curve [26].

Overall, the total number of generated scenarios is 1120, which is calculated by the product of the numbers for day-ahead prices (20 scenarios), imbalance charges/payments (4 scenario-based factors) and wind power production (14 scenarios). This is derived using the method presented in [27]. To this end, the number of scenarios is increased until the objective function is stabilized. In this way a tradeoff between the tractability

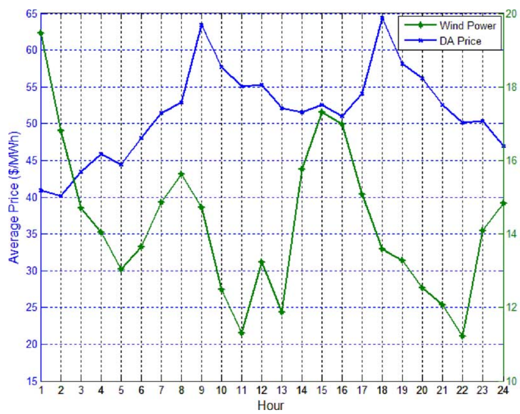

Fig. 3. Average wind power and spot price.

of the problem and the accuracy of the results is taken into account.

Fig. 3 shows the expected day-ahead price and wind power production. The day-ahead price involves two peak periods, just before Noon and during the evening. Wind power peaks however occur around midnight and the afternoon.

In stage 2, the day-ahead prices are known. However, wind power production and imbalance prices are still unknown. Wind power scenarios of stage 2 are obtained through reducing the number of scenarios generated in stage 1 to 7 scenarios. Indeed, those scenarios having higher deviations from the expected wind power depicted in Fig. 3 are removed. This is reasonable as the wind uncertainty in stage 2 is lower than that of stage 1. Imbalance price scenarios in stage 2 are considered the same as scenarios in stage 1.

DR information is as follows. Since DR contract data are not available, their details are assumed in this paper. However, in order to reasonably model these contracts, two main points are taken into account: first, the prices considered for DR contracts are chosen in a way that they are close to the average of market prices, shown in Fig. 3. Secondly, the DR contracts are assigned in such a way that when the wind power producer is in its high production periods and market prices are low, it most likely sells a part of its energy through DR contracts. On the other hand, when the market price is high, the wind power producer is assumed to be mostly a DR buyer in order to compensate its deviations during this time. Six fixed DR agreements are considered. The first contract covers 1 am to 5 am, where the wind power producer sells energy to the aggregator. The producer buys fixed DR in the next two contracts (6 am–12 pm). In fixed DR contract 4, the producer again sells energy to the DR aggregator (1 pm–4 pm). In the remaining contracts the wind power producer is a fixed DR buyer. Six flexible DR agreements are also modeled. Time horizon for each contract is the same as fixed DR contracts. It is assumed that the wind power producer is able to sell/buy up to 8-MWh flexible DR in each period. Finally, two American and two European DR options are used, where the wind power producer buys these options from the aggregator. The periods in which these options are used are 9 am–12 pm and 5 pm–8 pm. Note that the penalty of not exercising each option is assumed to be equal to 10% of the contract cost. The

TABLE I
DR CONTRACTS DETAILS

	Fixed DR	Flexible DR	European DR options	American DR options
Energy (MWh)	Buy up to 10 Sell up to 5	Buy/sell up to 8	Buy up to 6	Buy up to 2
price range ($/MWh)	41-58	44-59	55-62	62-63

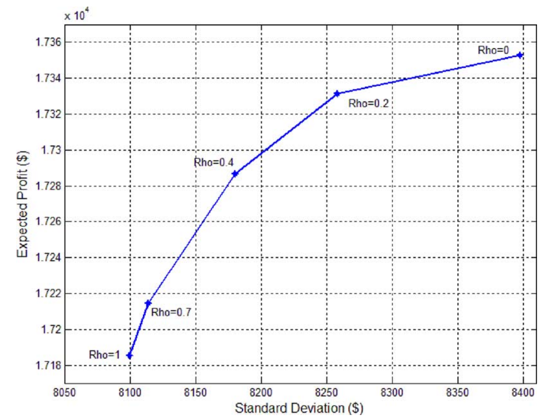

Fig. 4. Expected profit versus the standard deviation.

maximum available DR and DR price ranges are provided in Table I.

B. Numerical Results and Discussions

1) Decisions in Stage 1: The given problem is mixed-integer linear programming, which is solved for various risk levels using CPLEX 11.1.1 under GAMS [28].

The expected profit vs. the standard deviation is displayed in Fig. 4. It is obvious that while the risk-neutral wind power producer gains more profit with the cost of a higher profit deviation, risk-averse producers prefer a lower profit deviation and consequently obtain a lower profit.

Fig. 5 provides day-ahead offers for various risk levels. The risk-neutral wind power producers sell as much as possible in the day-ahead market. This sale however decreases as the risk level grows. That is, risk-averse producers refuse to sell the majority of their power in the day-ahead market, where they prefer to sell more energy in the balancing market. This is more obvious for $\rho = 1$, where the wind power producer's sale in the day ahead market is almost zero in most periods. In addition, it can be seen that the offer patterns are very similar in all risk levels. They follow the peak periods of wind production and day-ahead prices. More specifically, the risk-neutral producer has more noticeable offers during market price peaks.

Table II shows the contracted fixed DR agreements for different levels of the risk. The risk-neutral wind power producer ($\rho = 0$) sets fixed DR contracts (FC) 2 to 6. However, for the risk level of 0.2 and higher, the wind power producer sets FC 2 and FC 4 only. This declining trend is reasonable since the producer is a DR buyer in FC 5 and FC 6, and therefore, as the risk level increases, it avoids taking more risk by buying energy from these contracts and selling it to the volatile day-ahead market.

Table III represents the periods in which European DR Options (EDRO) are signed in stage 1. The risk-neutral wind power

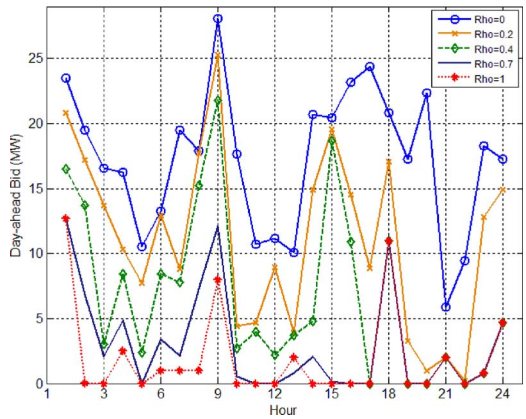

Fig. 5. Offers in the day-ahead market.

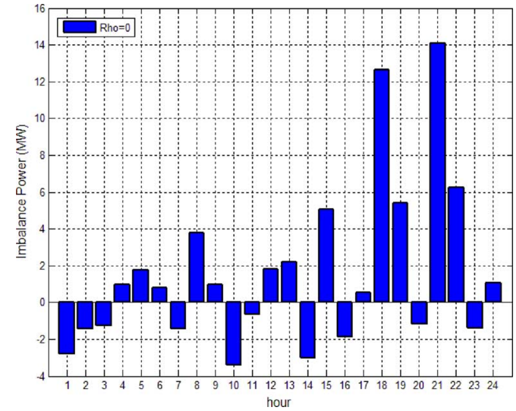

Fig. 6. Imbalance power for $\rho = 0$.

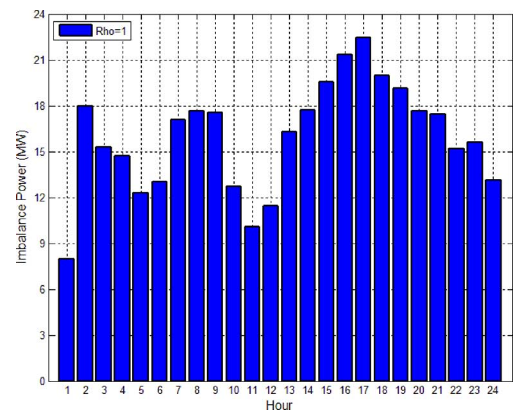

Fig. 7. Imbalance power for $\rho = 1$.

TABLE II
FIXED DR CONTRACTS

ρ	Set Contracts
0	FC2,FC4,FC5,FC6
0.2	FC2,FC4
0.4	FC2,FC4
0.7	FC2,FC4
1	FC2,FC4

TABLE III
SIGNED EUROPEAN DR OPTIONS IN STAGE 1

ρ	EDRO1	EDRO2
0	9am-12pm	6pm-8pm
0.2	9am-12pm	6pm
0.4	9am	6pm
0.7	-	6pm
1	-	6pm

TABLE IV
CONTRACTED FLEXIBLE DR IN STAGE 1(MWh)

ρ	Flex1	Flex2	Flex3	Flex4	Flex5	Flex6
0	2.5	3	8	6	8	2
0.2	2.5	3	8	6	8	2
0.4	2.5	3	8	6	8	2
0.7	2.5	3	8	4.8	8	2
1	2.5	0	8	6	8	2

producer uses both EDRO 1 and 2 in all periods. However, risk-averse producers refuse to sign EDROs in many periods, where ultimately the most risk-averse producer ($\rho = 1$) only signs EDRO 2 at 6 pm. With regards to American DR options (ADRO), the results indicate that both ADRO 1 and 2 are signed in this stage.

The volume of flexible DR agreements is illustrated in Table IV. Results show that all agreements are used by $\rho = 0.4$. However, for higher risk levels, this share decreases where for $\rho = 1$, flexible DR 2 is not applied. This decrement indeed follows the same rule as fixed DR and DR options.

2) Decisions in Stage 2: This section delivers the results of stage 2 for the risk-neutral ($\rho = 0$) and the risk-averse ($\rho = 1$) wind producers.

Figs. 6 and 7 depict the offers in the balancing market for $\rho = 0$ and $\rho = 1$, respectively. The sale by the risk-neutral wind power producer is very low in most periods. There are even some periods in which the producer buys energy from the balancing market. This trend is opposite for the risk-averse producer, where a high amount of power is sold in each period. This outcome confirms the tendency obtained in the day-ahead market shown in Fig. 5. That is, while the risk-neutral wind power producer is willing to sell more energy in the day-ahead market, the risk-averse producer prefers low risks and consequently submits more energy to the balancing market, where more precise predictions of power production as well as real-time prices are available.

Fig. 8 provides the total sold power of both wind power producers. The volume is identical for almost all periods. However, it can be seen that the risk-neutral wind power producer has a higher sale share during the peak periods of the price and wind power production (See Figs. 3 and 8), where this is more evident at 9 am, 3 pm and 5–10 pm. This result indicates that risk-neutral wind power producers have a higher tendency to buy DR than do risk-averse producers.

DR outcomes are as follows. All signed European DR in the first stage are exercised in stage 2 by both risk-neutral and risk-averse wind power producers. This is also the result for American DR options. Note that in this stage, ADRO 1 and 2 are exercised at 9 am and 6 pm, respectively. This indeed coincides with peak price periods shown in Fig. 3.

The usage distributions of all flexible DR agreements, except flexible DR 4, are the same as stage 1 for both risk levels. The

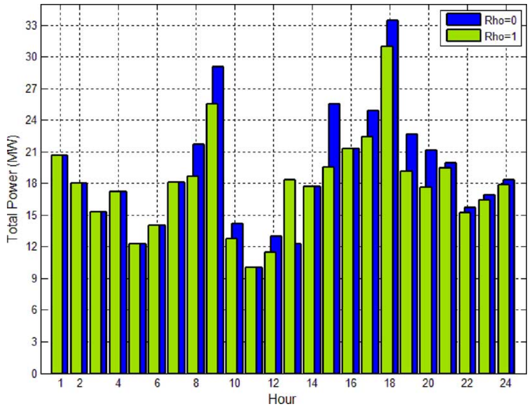

Fig. 8. Total power sold in the market for $\rho = 0$ and $\rho = 1$.

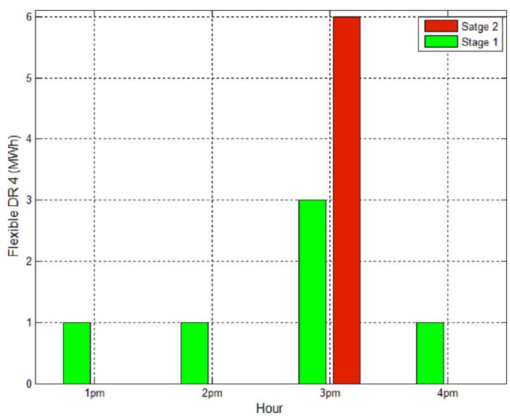

Fig. 9. Usage distribution of flexible DR 4 in stage 1 and 2—$\rho = 0$.

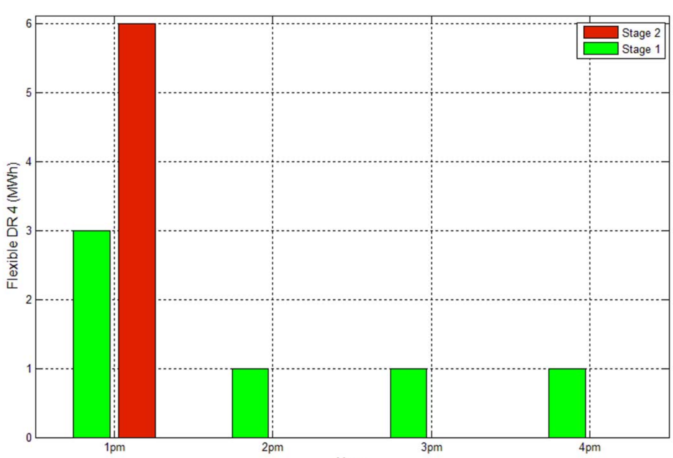

Fig. 10. Usage distribution of flexible DR 4 in stage 1 and 2—$\rho = 1$.

distributions of flexible DR 4 (Flex4) in stages 1 and 2 for the risk-neutral and the risk-averse wind power producers are delivered in Figs. 9 and 10, respectively. In both cases, the wind power producer changes the usage configurations in stage 2. It can be seen that in this stage the whole flexible DR 4 is used in one period. This is at 3 pm for $\rho = 0$ and 1 pm for $\rho = 1$. These results confirm a significant difference in sale shares of the risk-neutral and risk-averse wind power producers at relevant hours in Fig. 8. It can be seen that while the risk-neutral producer has a much higher sale at 3 pm, this happens at 1 pm for the risk-averse producer.

V. Conclusions

This paper presents a new wind offering plan in the day-ahead market. This plan includes two stages in which a wind power producer employs DR to alleviate its production uncertainty as well as market price violations. The first stage takes place on the day-ahead market, where the producer determines its offer in this market and simultaneously arranges various DR contracts with DR aggregators. The second stage is a successive process which is held right before each dispatch period. In this stage the wind power producer participates in the balancing market. The offer in this market is obtained while at the same time proper DR agreements are finalized. To include DR, a new scheme is proposed in which the wind power producer can set various DR agreements, called fixed DR, flexible DR, American DR options and European DR options with DR aggregators.

The proposed plan is evaluated on a case of the Nordic Market. A stochastic mixed-integer profit function is proposed for each stage which is solved using GAMS. The main findings are as follows. 1) The proposed two-stage plan allows wind power producers to better participate in both day-ahead and balancing markets. 2) While risk-neutral wind power producers prefer to sell most of their energy in the day-ahead market, risk-averse producers have a higher share in the balancing market. 3) In the proposed plan, a wind power producer can arrange various DR contracts in stage 1 and then manage them in stage 2 to better cope with its uncertainty.

Finally, we should emphasize that this paper models the bilateral DR contracts rather than a pool-based exchange. Indeed, the pool-based exchange is still not applicable in many markets since there are various barriers making DR providers reluctant to directly participate in the market. However, setting bilateral contracts with DR purchasers is more practical as there are real cases in Australia, Canada and the USA [22]. Note that by the enough growth of the DR market, it is expected that both bilateral and pool-based DR markets become active. To this end, the level of the risk taken by the wind power producer is the matter of concern. That is, if the producer is risk-neutral, it prefers to trade more in the pool-based market. However, as it becomes more risk averse, the share of bilateral contracts increases.

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