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Multi Objective Scheduling of Utility-scale Energy Storages and Demand Response Programs Portfolio for Grid Integration of Wind Power

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Abstract- *Increasing the penetration of variable wind generation in power systems has created some new challenges in the power system operation. In such a situation, the inclusion of flexible resources which have the potential of facilitating wind power integration is necessary. Demand response (DR) programs and emerging utility-scale energy storages (ESs) are known as two powerful flexible tools that can improve large-scale integration of intermittent wind power from technical and economic aspects. Under this perspective, this paper proposes a multi objective stochastic framework that schedules conventional generation units, bulk ESs, and DR resources simultaneously with the application to wind integration. The proposed formulation is a sophisticated problem which coordinates supply-side and demand-side resources in energy and up/down spinning reserve markets so that the cost, emission, and multi objective functions are minimized separately. In order to determine the most efficient DR program which can potentially coordinate with bulk ESs in the system with a significant amount of wind power, a comprehensive DR programs portfolio including time- and incentive-based programs is designed. Afterwards, strategy success index (SSI) is employed to prioritize DR programs from independent system operator (ISO) perspective. The IEEE-RTS is used to reveal the effectiveness of the proposed method.*

Keyword: Bulk energy storages, Demand response programs, Electricity market, Wind power generation.

NOMENCLATURE

Indices

b,b'	Index of system buses
i	Index of generating unit
j	Index of bulk energy storage units
l	Index of transmission line
m	Segment index for linearized fuel cost
$Tpeak$	Index of peak hours
s	Index of scenarios
t,t'	Index of hours
NM	Number of segments for the piecewise linearized emission and fuel cost curves of units
NS	Number of wind generation scenarios
NG	Number of generation units
NES	Number of bulk energy storage units
NT	Number of studied hours
NB	Number of network buses

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Parameters

d_t^0	Initial electricity demand at hour *t* (MW)
LD_b	Demand contribution of bus *b* (MW)
C_{itm}^{e}	Slope of segment *m* in linearized fuel cost curve of unit *i* at hour *t* ($/MWh)
$EC_{itm}^{SO_2/NO_x}$	Slope of segment m in linearized emission emission curve of unit *i* at hour *t* (lbs/MWh)
MPC_i	Minimum production cost of unit *i* ($)
$MPE_i^{SO_2/NO_x}$	Minimum produced emission of unit *i* (lbs/h)
ρ_t^0	Initial electricity price at hour *t* ($/MWh)
ω_s	Probability of scenario *s*
C_{it}^{UC}	Offered capacity cost of up-spinning reserve provision of unit *i* at hour *t* ($/MW)
C_{it}^{DC}	Offered capacity cost of down-spinning reserve provision of unit *i* at hour *t* ($/MW)
C_{it}^{NSR}	Offered capacity cost of non-spinning reserve provision of unit *i* at hour *t* ($/MW)
C_{it}^{UE}	Offered energy cost of up-spinning reserve provision of unit *i* at hour *t* ($/MWh)
C_{it}^{DE}	Offered energy cost of down-spinning reserve provision of unit *i* at hour *t* ($/MWh)

$C_{jt}^{ES,Energy}$	Offered energy cost of bulk energy storage *j* at hour *t* ($/MWh)
$C_{jt}^{ES,U}$	Offered capacity cost of up-spinning reserve provision of bulk ES *j* at hour *t* ($/MW)
$C_{jt}^{ES,D}$	Offered capacity cost of down-spinning reserve provision of bulk ES *j* at hour *t* ($/MW)
$C_{jt}^{ES,NSR}$	Offered capacity cost of non-spinning reserve provision of bulk ES *j* at hour *t* ($/MW)
C_{jt}^{UE}	Offered energy cost of up-spinning reserve provision of bulk ES *j* at hour *t* ($/MWh)
C_{jt}^{DE}	Offered energy cost of down-spinning reserve provision of bulk ES *j* at hour *t* ($/MWh)
$C^{spillage}$	Cost of wind power curtailment ($/MWh)
$VOLL_{bt}$	Value of lost load in bus *b* at hour *t* ($/MWh)
INC_t	Incentive payment at hour *t* ($/MWh)
IC_t	Initial contract level of customers at hour *t* (MWh)
PEN_t	Penalty payment at hour *t* ($/MWh)
W_{bt}^{*}	Forecasted value of wind generation in bus b at hour t ($/MWh)
η_{Ch} / η_{DeCh}	Charge/discharge efficiency of bulk ES
$E_{tt'}$	Price elasticity of demand
$P_i^{\min} / P_i^{\max}$	Minimum/ maximum output limit of generation unit *i* (MW)
RU_i / RD_i	Ramp up/down of generation unit *i* (MW/h)
SC_i	Start-up cost of generation unit *i* ($)
MUT_i / MDT_i	Minimum up/down time of generation unit *i* (h)
$P_j^{ChES,\max} / P_j^{DeES,\max}$	Maximum charging/discharging power of bulk ES *j* (MW)
$SOE_j^{ES,\min} / SOE_j^{ES,\max}$	Minimum/Maximum energy limit of bulk ES *j* (MWh)
α_j	Percent of initial energy level of bulk ES *j*
$SOE_{j,initial}^{ES}$	Initial state of the charge of bulk ES *j* at the beginning of scheduling horizon
X_l	Reactance of line *l*
$F_l^{\max}$	Maximum capacity of transmission line *l* (MW)
τ	Spinning reserve market lead time (h)

Variables

$\delta_{bt}^0 / \delta_{bt\omega}$	Voltage angle in bus *b* at hour *t* (rad)
$F_{lt}^0 / F_{lt\omega}$	Power flow through line *l* at hour *t* (MW)
U_{it}	Binary status indicator of generation unit *i* at hour *t*
$I_{jt}^{DeBatt} / I_{jt}^{ChBatt}$	Binary indicator of net discharge/charge status of bulk BES *j*
LS_{bts}	Involuntary load shedding in bus *b* at hour *t* of scenario *s* (MWh)
WS_{bts}	Wind power spillage in bus *b* at hour *t* of scenario *s* (MWh)
P_{itm}^{e}	Generation of segment *m* in linearized fuel cost curve (MW)
d_t	Modified demand of hour t after simultaneous IBDR and TBRDR programs (MW)
ρ_t	Optimal DR tariffs at hour *t* in TBRDRPs ($/MWh)
$C_t^{Incentive/Penalty}$	Incentive or penalty payments as a result of IBDRPs ($)
P_{it}	Total scheduled power of unit *i* at hour *t* (MW)
SUC_{it}	Start-up cost of generation unit *i* at hour *t* ($)
$P_{it}^{usr} / P_{it}^{dsr}$	Scheduled up- and down-spinning reserve capacity of unit *i* at hour *t* (MW)
P_{it}^{nsr}	Scheduled non-spinning reserve capacity of unit *i* at hour *t* (MW)
$P_{jt}^{ChES} / P_{jt}^{DeES}$	Scheduled charge/discharge power of bulk ES *j* at hour *t* (MW)
$P_{jt}^{usr} / P_{jt}^{dsr}$	Scheduled up- and down-spinning reserve capacity of bulk ES *j* at hour *t* (MW)
P_{jt}^{nsr}	Scheduled non-spinning reserve capacity of bulk ES *j* at hour *t* (MW)
$sr_{its}^{U} / sr_{its}^{D}$	Deployed up- and down spinning reserve of unit *i* at hour *t* of scenario *s* (MWh)
$sr_{jts}^{ES,U} / sr_{jts}^{ES,D}$	Deployed up- and down spinning reserve of bulk ES *j* at hour *t* of scenario *s* (MWh)
SOE_{jt}^{ES}	Energy stored in bulk ES *j* at hour *t* (MWh)

1. INTRODUCTION

The ongoing deployments of variable renewable energy sources (VRESs), particularly wind power, entail new challenges in power system operation due to their inherent intermittent nature. Traditionally, this variability has been compensated for through conventional power plants. However, covering the uncertainties of VRESs may cause significant wear-and-tear impacts on the fleet of conventional power plants and can even decrease their expected lifetimes and substantially increase the system operation costs [1-2]. Therefore, wind–thermal generation scheduling problem plays a key role in implementing clean power producers in competitive environments [3].

With the above-mentioned challenges introduced by VRESs, the need for flexible resources in power systems is higher than ever. Under this perspective, emerging utility-scale energy storages (ESs) can play an important role to better manage the intermittency as a result of high penetration of VRESs. In fact, bulk ESs have fast ramping capability and, hence, may become more efficient than the conventional generation units in terms of providing additional required flexibility.

On the other hand, the recent deployment of smart grid technologies potentially enables the possibility of managing customer's demand and, therefore, helps power systems operate in a more efficient way [4]. Nowadays, demand response (DR) is known as a powerful tool to increase operational flexibility which can facilitate the integration of VRESs [5-6]. It is noteworthy that there is a wide spectrum of DR programs that are implemented by independent system operators (ISOs) with the aim of encouraging customers to alter their typical energy usage according to the ISO purposes.

It should be noticed that, in the presence of such bulk ESs in energy and reserve markets, the former supply and demand-side scheduling of power systems must be changed. In this situation, it is important from the ISO perspective to select and implement an appropriate DR program in order to achieve an optimal coordinated dispatch in power grids with high penetration of VRESs in order to minimize total operation cost and air pollutant emissions simultaneously.

1.1. Literature review

A wide range of previous studies has addressed the wind-thermal generation scheduling problem. For instance, a model was proposed to determine operating reserves in the simultaneous market clearing of energy and reserve by stochastic programming in Ref. [7]. It is noteworthy that this paper scheduled the supply-side resource without considering the effect of demand-side resources. Demand-side resources were also have been modeled as peak clipping and demand shifting units with the aim of wind integration [8-9]. However, the mentioned studies have used deterministic approaches, while wind power has a stochastic nature. In Ref. [10], DR resources were incorporated into the unit commitment problem in the presence of wind power in order to achieve smoother load profile and decrease the need for additional ramp caused by wind generation. It is notable that DR resources are considered dispatchable units besides other conventional units in the market environment. The stochastic nature of wind power and pollutant emission issues was not addressed in Ref. [10]. A more precise model was presented in Ref. [11] that considered load reduction and load recovery using price elasticity concept. In fact, the authors in Ref. [11] attempted to provide a flexible load profile to reduce the need for the ramp services of conventional units with the aim of wind integration. However, the uncertainty of wind power and also the impacts of implementing various DR programs were neglected.

Another set of papers has gone a step further by using stochastic programming approaches [12, 13]. In Ref. [12], a two-stage stochastic programing was introduced considering generation units and responsive loads in energy and reserve markets to compensate for the uncertainty of wind power. Furthermore, the effects of various voluntary DR programs on facilitating the grid integration of wind power were investigated using a stochastic scheduling framework in Ref. [13]. Although the uncertainty of wind power was incorporated into the model using stochastic programming approach and the effects of various DR programs were considered, the DR tariffs and incentives were considered to have fixed values that were not optimal. In addition, the bulk ESs were not considered.

Recently, there is a general consensus that bulk ESs can enroll in co-optimized energy and reserve markets as active market participants, especially at the high penetration of VRESs due to their technical features [14-15]. On this basis, there have been many studies that investigate the role of ESs in power grid operation. For instance, the role of utility-scale compressed air energy storages (CAESs) in co-optimized energy and reserve markets was evaluated in Ref. [15]. The paper also presented a novel approach to determine the required amount of regulation services in the systems with a significant amount of wind power. However, the model was formulated using a deterministic approach in the mentioned work. In addition, a stochastic real-time unit commitment was proposed to deal with the uncertainty of VRESs considering an ideal and generic model for ESs in Ref. [16]. The role of DR programs was neglected in the mentioned paper. Plug-in electric vehicles are also a flexible option that can be categorized into both demand-side options and energy storages [17]. The mentioned energy storage options can mitigate the wind variability, since they can alleviate the differences between the electricity supply and demand in the power systems with high penetration of wind power [18].

1.2. Contributions

Although previous papers in the literature have studied the impacts of bulk ESs or DR programs in the operation of power systems with a considerable share of VRESs, coordinated operation scheduling of the mentioned resources has not been investigated so far. It is worth noting that simultaneous scheduling of bulk ESs and DR programs portfolio is a key issue for ISOs in the future power systems with a high amount of non-dispatchable renewable energy resources. In other words, with introducing utility-scale ESs that have no uncertainty in their response, there may be the possibility that the enabled quantity of DR decrease severely. On this basis, the ISO should select and implement an efficient DR program from DR portfolio that not only encourages the customers more and more to participate in power system transactions, but also fulfills the requirements of the power system operator. Therefore, the main contributions of this paper are highlighted as follows:

- Optimal tariffs and incentives/penalties of different DR programs are obtained based on the power system's operational conditions.
- Coordinated operation of bulk ESs and a set of DR programs are investigated in the power grid with high penetration of wind power.
- The economic and environmental objectives from ISO point of view are considered separately and simultaneously using a multi objective stochastic framework.
- Prioritizing DR programs include time-based rate DR programs (TBRDRPs) and incentive-based DR programs (IBDRPs).

1.3. Paper organization

The rest of this paper is organized as follows. Section 2 presents the role of DR and bulk ESs in the grid integration of VRESs. Moreover, the formulation of DR programs and bulk ESs is given in this section. The proposed two-stage stochastic network-constrained unit commitment formulation is presented in Section 3. Numerical studies are discussed in Section 4 and the conclusions are reported in Section 5.

2. DR PROGRAMS AND BULK ESS

Demand-side management programs, especially DR and emerging utility-scale ESs, are known as key options for providing additional required flexibility as a consequence of huge penetration of VRESs. For instance, as claimed in Ref. [19], DR is sufficient to meet nearly all the fluctuations of VRESs. Moreover, the detailed descriptions of DR as a possible way for handling the intermittency of VRESs were investigated in Ref. [20].

Emerging bulk ESs are also known as a solution for facilitating VRESs integration into power grid due to their capability to be both demand and generation in over- and under-supply situations from VRESs. In this context, the state of the art of three different kinds of ESs technologies including pump hydro storages, batteries, and fuel cells was reviewed in Ref. [21]. Furthermore, the state of the art of ES that can be used for mitigating wind uncertainty was discussed from different aspects in Ref. [22].

Below, the mathematical formulation and relevant descriptions of DR programs as well as a typical bulk ES is presented in detail.

2.1. Basic model of DR programs

Generally, DR refers to the change in the typical consumption pattern of customers in response to the change in electricity tariffs or the specified given incentives for achieving economic and reliability goals. On this basis, DR programs are categorized into two main groups: TBRDRPs and IBDRPs. In TBRDRPs, customers are encouraged to change their consumption according to the electricity tariffs that are notified by ISO, while in IBDRPs, a specified given incentive persuades customers to change their usual consumption. It is noteworthy that there is also a penalty scheme in a certain number of IBDRPs depending on the program type and condition. The classification of DR programs is shown in Fig. 1. More details are discussed in [23-25].

Here, customer's sensitivity to the change in electricity tariffs is considered through the concept of price elasticity of demand, as in [23]. The price elasticity of demand in the t-th period versus the *t'-th* period can be defined as can be seen in Eqs. (1) and (2) [23].

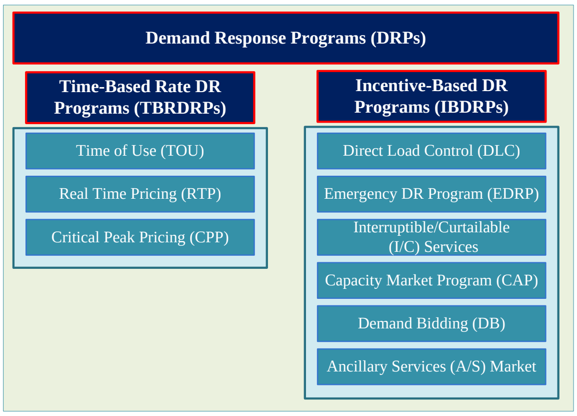

Fig. 1. Classification of DR programs

$$E_{tt'} = \frac{\partial d_t}{\partial \rho_{t'}} \cdot \frac{\rho_{t'}^0}{d_t^0} \qquad t' = 1, 2, 3, ..., 24 \tag{1}$$

where

$$\begin{cases} E_{tt'} \le 0 & if \quad t = t' \\ E_{tt'} \ge 0 & if \quad t \ne t' \end{cases} \quad and$$
$$\frac{\partial d_t}{\partial \rho_{t'}} = constont \quad for\, t, t' = 1, 2, ..., 24 \tag{2}$$

If $B(d_t)$ is assumed to be the value of electricity from customers' viewpoint for using d_t during hour *t*, the customer net benefit can be calculated as can be seen in Eq. (3):

$$NB = B(d_t) - d_t.\rho_t + INC_t.\left(d_t^0 - d_t\right) - PEN_t \cdot \left\{IC_t - \left[d_t^0 - d_t\right]\right\} \tag{3}$$

It is notable that the second and third terms on the right of the equality in the above equation are related to the cost of electricity consumption and revenue from incentive at hour *t*, respectively. Also, the forth term is associated to the penalties for the customers that participate in DR, but do not reduce their load according to their initial contract level (i.e. IC_t) in the needed time. It should be noted that the calculation of $B(d_t)$ is beyond the scope of the current paper and more details were provided in Ref. [25]. To maximize the customer's net benefit, the derivative of Eq. (3) should be equal to zero:

$$\frac{\partial NB}{\partial d_t} = \frac{\partial B(d_t)}{\partial d_t} - \rho_t - INC_t - PEN_t = 0 \tag{4}$$

As a consequence:

$$\frac{\partial B(d_t)}{\partial d_t} = \rho_t + INC_t + PEN_t \tag{5}$$

Usually, it is presumed that the customer's net benefit is a quadratic function of customer consumption as follows Refs. [23-25]:

$$B(d_t) = B_t^0 + \rho_t^0 \left[d_t - d_t^0 \right] \left\{ 1 + \frac{d_t - d_t^0}{2E_{tt}\, d_t^0} \right\} \tag{6}$$

By differentiating Eq. (6) and replacing the results in Eq. (5), the "single period model" of responsive loads is obtained as shown in Eq. (7):

$$d_t = d_t^0 \left\{ 1 + \frac{E_{tt} \left[\rho_t - \rho_t^0 + INC_t + PEN_t \right]}{\rho_t^0} \right\} \tag{7}$$

Since a change in the electricity price at hour t' may cause the load variation at hour *t*, by expanding Eq. (7), we will have the "multi period model" of responsive loads including TBRDRPs as well as IBDRPs, as can be seen in Eq. (8). More detailed explanations can be found in [23-25].

$$d_t = d_t^0 + \sum_{\substack{t'=1 \\ t' \neq t}}^{24} E_{tt'} \frac{d_t^0}{\rho_{t'}^0} \left[\rho_{t'} - \rho_{t'}^0 + INC_{t'} + PEN_{t'} \right] \tag{8}$$

By combining Eqs. (7) and (8), the "composite period economic model" of responsive loads can be obtained as follows [23-25]:

$$d_t = d_t^0 \left\{ 1 + E_{tt} \frac{\left[\rho_t - \rho_t^0 + INC_t + PEN_t \right]}{\rho_t^0} + \sum_{\substack{t'=1 \\ t' \neq t}}^{24} E_{tt'} \frac{\left[\rho_{t'} - \rho_{t'}^0 + INC_{t'} + PEN_{t'} \right]}{\rho_{t'}^0} \right\} \tag{9}$$

2.2. Calculating optimal DR tariffs and incentives

When DR programs are optimally combined by other operational problems, the main aim of the coordinated decision making problem is to determine the optimal incentives or optimal tariffs in the DR programs. This subject is addressed in this section for a typical TBRDRP as well as IBDRP. For the sake of simplicity and without loss of generality, time of use (TOU) and emergency DR program (EDRP) are selected here as TBRDRP and IBDRP, respectively. It is noteworthy that the same procedure can be performed for other DR programs.

- **Optimal TOU program**

By dividing the hourly load profile into three time periods including low load, off-peak, and peak time periods, the TOU program model will be obtained using Eq. (9), as shown in Eq. (10) [26].

$$d_t = d_t^0 \left\{ 1 + \sum_{t' \in LTP} E_{tt'} \cdot \frac{[\rho^{LTP} - \rho_{t'}^0]}{\rho_{t'}^0} + \sum_{t' \in OTP} E_{tt'} \cdot \frac{[\rho^{OTP} - \rho_{t'}^0]}{\rho_{t'}^0} + \sum_{t' \in PTP} E_{tt'} \cdot \frac{[\rho^{PTP} - \rho_{t'}^0]}{\rho_{t'}^0} \right\} \tag{10}$$

Eq. (10) indicates the optimum amount of customer consumption in a 24-h period while participating in the TOU program. In order to have an appropriate TOU pricing scheme, inequalities (11-13) must be considered to specify the reasonable range of price in three time periods [26].

$$\rho^{LTP} \leq \rho_t^0 \tag{11}$$

$$\rho^{PTP} \geq \rho_t^0 \tag{12}$$

$$\rho^{LTP} \leq \rho^{OTP} \leq \rho^{PTP} \tag{13}$$

The maximum response potential of customers is also modelled through Eq. (14). This equation determines the maximum possible amount of load level that can be decreased in peak periods and recovered in other periods at each hour.

$$-DR^{\max} \cdot d_t^0 \leq \Delta d_t \leq DR^{\max} \cdot d_t^0 \tag{14}$$

In order to guarantee the comfort level of customers, Eq. (15) lets the total energy consumption over the scheduling horizon remain unchanged. However, if the customers have load reduction potential, the equation should be modified based on their load reduction capability.

$$\sum_{t=1}^{NT} \Delta d_t = 0 \tag{15}$$

- **Optimal EDRP program**

Unlike TBRDRPs, the implementation of EDRP imposes some costs on ISOs. This cost is related to the incentive payments to customers for their load reduction at specific hours and is formulated as shown below at each hour:

$$C_t^{EDRP} = INC_t \times \left(d_t^0 - d_t \right) \tag{16}$$

Through the similar procedure explained in subsection

2.1 in detail, the final EDRP model will be achieved:

$$d_t = d_t^0 \left\{ 1 + \sum_{t'=1}^{24} E_{tt'} . \frac{INC_{t'}}{\rho_{t'}^0} \right\} \tag{17}$$

By substituting the above equation in Eq. (16), the cost of customer's participation in EDRP from the ISO perspective can be formulated as Eq. (18) [27].

$$C_t^{EDRP} = d_t^0 \left\{ \sum_{t'=1}^{24} E_{tt'} . \frac{INC_{t'}^{\ 2}}{\rho_{t'}^0} \right\} \tag{18}$$

From Eq. (18), it can be concluded that C_t^{EDRP} is a quadratic function of incentive as shown in Fig. 2. The function can be accurately approximated by a piecewise linear model as represented in Eq. (19) [27].

$$C_t^{EDRP} = \sum_{n=1}^{SegNo} v_{nt} AS_{nt} \tag{19}$$

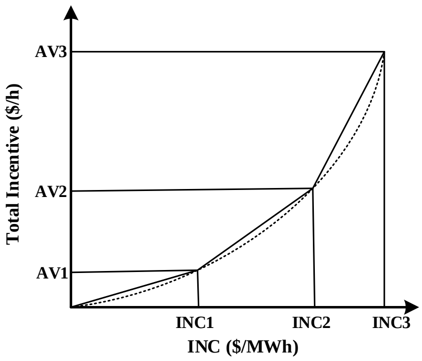

Fig. 2. Piecewise linear total incentive for a typical hour [27].

2.3. Utility-scale ESs formulation

This paper considers a generic model for bulk ESs based on the assumption that the bulk ES is an active market player in the electricity market. In this regard, the bulk ES can participate in day-ahead energy, spinning reserve, and non-spinning reserve markets besides other conventional units. The model of bulk ES is presented by Eqs. (20)-(28).

$$0 \le P_{jt}^{ChES} + P_{jt}^{dsr} \le P_j^{ChES,\max} I_{jt}^{ChES} \tag{20}$$

$$0 \le P_{jt}^{DeES} + P_{jt}^{usr} \le P_j^{DeES,\max} I_{jt}^{DeES} \tag{21}$$

$$0 \le P_{jt}^{DeES} + P_{jt}^{usr} + P_{jt}^{nsr} \le P_j^{DeES,\max} \tag{22}$$

$$I_{jt}^{DeES} + I_{jt}^{ChES} \le 1 \tag{23}$$

$$0 \le sr_{jt\omega}^{ESU} \le P_{jt}^{usr} \tag{24}$$

$$0 \le sr_{jt\omega}^{ESD} \le P_{jt}^{dsr} \tag{25}$$

$$SOE_{jt}^{ES} = SOE_{j(t-1)}^{ES} + \eta_{Ch} \left(P_{jt}^{ChES} + P_{jt}^{dsr} \right) - \eta_{DeCh} \left(P_{jt}^{DeES} + P_{jt}^{usr} + P_{jt}^{nsr} \right) \tag{26}$$

$$SOE_j^{ES,\min} \le SOE_{jt}^{ES} \le SOE_j^{ES,\max} \tag{27}$$

$$SOE_{j,initial}^{ES} = \alpha_j SOE_j^{ES,\max} \tag{28}$$

The limits on the capacity of ES while getting charged and discharged are considered in Eqs. (20) and (21), respectively. Note that Eqs. (20) and (21) have two terms including day-ahead energy and up/down spinning reserve capacity markets and also Eq. (22) deals with the non-spinning reserve capacity provided by the bulk ES. Moreover, Eq. (23) prevents simultaneous charge and discharge operations of ES. Eqs. (24) and (25) restrict the actual deployed real-time reserves for corrective actions in the worst case according to the scheduled reserve capacity in the day-ahead market. The amount of stored energy within the reservoir of bulk ES j at hour t as a function of energy stored until hour t-1, participation in energy, and up/down spinning reserve markets is represented by Eq. (26). The maximum and minimum levels of storages at hour t are also considered through Eq. (27). Finally, Eq. (28) shows the initial stored energy level of the bulk ES as a function of its maximum reservoir capacity.

3. PROBLEM FORMULATION

In this section, a two-stage stochastic programming approach is used to model the simultaneous operation scheduling of supply- and demand-side resources for mitigating wind power uncertainty. The conventional generation units and utility-scale ESs are considered the supply-side resources, while DR programs enable the demand-side ones. The schematic view of the proposed model is shown in Fig. 3. The first-stage problem corresponds to the market clearing regardless of any scenario realization, while the second-stage is associated to the actual operation of power system considering wind power scenario realizations.

The main objective of the proposed formulation is to determine an optimal wind-thermal generation scheduling in the presence of two flexible resources, namely DR programs and utility-scale ESs, with the application to facilitating wind power integration. In fact, the proposed model is a sophisticated decision making problem with an objective function including the total operation costs as well as the emission level of generating units that should be minimized while satisfying a number of equality and inequality constraints.

3.1. Objective function

The objective function has two main terms as can be seen in Eq. (29):

$$Min \quad \left(W_C \cdot F^{\cos t} + W_E \cdot F^{emission} \right) \tag{29}$$

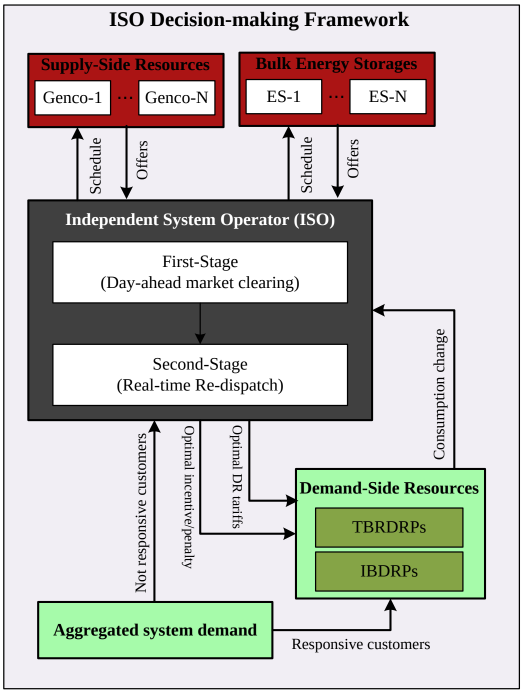

Fig. 3. Simultaneous scheduling of supply- and demand-side resources

In Eq. (29), weighting factors W_C and W_E represent the significance of cost and emission from the ISO point of view in the decision making problem. Therefore, different weighting can be considered to assign different shares of cost and emission in the objective function. Moreover, the operating cost and emission levels of generation units are formulated as shown in Eq. (30) and Eq. (31), respectively.

In Eq. (30), the first line is related to the costs of providing energy and spinning/non-spinning capacity reserve through conventional generation units in the day-ahead market. The second line of Eq. (30) represents the same costs for bulk ESs. The third line contains two terms which express the cost paid to customers as the incentive for their load reduction at peak hours and the income of ISO from penalizing the consumers they do not respond to when needed, respectively. These costs have been transformed into their linear forms as depicted through Eq. (19). It is noteworthy that, since the implementation of TBRDRPs changes the consumption pattern, the generation cost is affected as well. The second part of Eq. (30) which involves the wind power scenario realizations includes the costs as a result of activated reserves by generation units, bulk ESs, load shedding, and wind power spillage.

It is noteworthy that emissions produced by generation units are usually expressed based on their power production [28]. Here, two most popular generating unit emissions, namely SO_2 and NO_x, are considered through a linear emission function in order to preserve the mixed integer linear programming (MILP) nature of the model, as in [28].

$$\begin{aligned}
F^{cost} =& \\
&\sum_{t=1}^{NT}\sum_{i=1}^{NG}\left(SUC_{it} + MPC_i U_{it} + \sum_{m=1}^{NM}(P_{itm}^{e}\cdot C_{itm}^{e}) + C_{it}^{UC}P_{it}^{usr} + C_{it}^{DC}P_{it}^{dsr} + C_{it}^{NSR}P_{it}^{nsr}\right) \\
&+\sum_{t=1}^{NT}\sum_{j=1}^{NES}\left(C_{jt}^{ES,Energy}P_{jt}^{DeES} + C_{jt}^{ES,U}P_{jt}^{usr} + C_{jt}^{ES,D}P_{jt}^{dsr} + C_{jt}^{ES,NSR}P_{jt}^{nsr}\right) \\
&+\sum_{t\in Tpeak} C_t^{Incentive} - \sum_{t\in Tpeak} C_t^{Penalty} \\
&+\sum_{s=1}^{NS}\omega_s\left[\sum_{t=1}^{NT}\sum_{i=1}^{NG}\left(C_{it}^{UE}sr_{its}^{U} - C_{it}^{DE}sr_{its}^{D}\right)\right. \\
&\quad +\sum_{t=1}^{NT}\sum_{j=1}^{NES}\left(C_{jt}^{UE}sr_{jts}^{ES,U} - C_{jt}^{DE}sr_{jts}^{ES,D}\right) \\
&\quad \left. +\sum_{t=1}^{NT}\sum_{b=1}^{NB}\left(VOLL_{bt}LS_{bts}\right) + \sum_{t=1}^{NT}\sum_{b=1}^{NB}\left(C^{spillage}WS_{bts}\right)\right]
\end{aligned} \tag{30}$$

$$F^{emission} = \sum_{t=1}^{NT}\sum_{i=1}^{NG}\left(MPE_i^{SO_2/NO_x}U_{it} + \sum_{m=1}^{NM}(P_{itm}^{e}\cdot EC_{itm}^{SO_2/NO_x})\right) \tag{31}$$

3.2. First-stage constraints

- DC power flow

$$\sum_{i\in G_b}P_{it} + \sum_{j\in ES_b}\left(P_{jt}^{DeES} - P_{jt}^{ChES}\right) + W_{bt}^{*} - \left(LD_b\, d_t\right) = \sum_{l\in L_b}F_{lt}^{0} \tag{32}$$

$$F_{lt}^{0} = \left(\delta_{bt}^{0} - \delta_{b't}^{0}\right)/X_l \tag{33}$$

- Transmission line flow limits

$$-F_l^{\max} \le F_{lt}^{0} \le F_l^{\max} \tag{34}$$

- Generation units start-up cost constraint

$$SUC_{it} = SC_i\,(U_{it} - U_{i(t-1)}) \tag{35}$$

- Power generation constraints

$$P_{it} = \sum_{m=1}^{NM}P_{itm}^{e} \tag{36}$$

$$0 \le P_{itm}^{e} \le P_{im}^{\max} \tag{37}$$

$$P_i^{\min}U_{it} \le P_{it} \le P_i^{\max}U_{it} \tag{38}$$

$$P_{it} + P_{it}^{usr} + P_{it}^{nsr} \le P_i^{\max} \tag{39}$$

$$P_{it} + P_{it}^{usr} \le P_i^{\max}U_{it} \tag{40}$$

$$P_{it} - P_{it}^{dsr} \ge P_i^{\min}U_{it} \tag{41}$$

- Up-, down-, and non-spinning reserve limits

$$0 \le P_{it}^{usr} + P_{it}^{nsr} \le RU_i\ \tau \tag{42}$$

$$0 \le P_{it}^{dsr} \le RD_i\ \tau \tag{43}$$

$$0 \le P_{it}^{nsr} \le \left(1 - U_{it}\right)RU_i\ \tau \tag{44}$$

- Minimum up and down time constraints

$$\sum_{t'=t+2}^{t+MUT_i}\left(1 - U_{it'}\right) + MUT_i\left(U_{it} - U_{i,t-1}\right) \le MUT_i \tag{45}$$

$$\sum_{t'=t+2}^{t+MDT_i}U_{it'} + MDT_i\left(U_{i,t-1} - U_{it}\right) \le MDT_i \tag{46}$$

- Ramp up and down rate limits

$$P_{it} - P_{i,t-1} \le RU_i\, U_{it} + P_i^{\min}\left(1 - U_{i,t-1}\right) \tag{47}$$

$$P_{i,t-1} - P_{it} \le RD_i\, U_{i,t-1} + P_i^{\min}\left(1 - U_{it}\right) \tag{48}$$

3.2. Second-stage constraints

- DC power flow equation in scenarios

$$\begin{aligned}&\sum_{i \in G_b}\left(sr_{its}^{GU} - sr_{its}^{GD}\right) + \sum_{j \in ES_b}\left(sr_{jts}^{ESU} - sr_{jts}^{ESD}\right) + LS_{bts} \\ &+\left(w_{bts} - W_{bt}^{*} - WS_{bts}\right) = \sum_{l \in L_b} F_{lts} - F_{lt}^{0}\end{aligned} \tag{49}$$

$$F_{lts} = \left(\delta_{bts} - \delta_{b'ts}\right) / X_l \tag{50}$$

- Transmission line flow limits in scenarios

$$-F_l^{\max} \le F_{lts} \le F_l^{\max} \tag{51}$$

- Deployed up- and down-spinning reserve limits

$$0 \le sr_{its}^{GU} \le P_{it}^{usr} \tag{52}$$

$$0 \le sr_{its}^{GD} \le P_{it}^{dsr} \tag{53}$$

- Involuntary load shedding limit

$$0 \le LS_{bts} \le LD_b\, d_t \tag{54}$$

- Wind spillage limit

$$0 \le WS_{bts} \le w_{bts} \tag{55}$$

3.3. Prioritizing DR programs portfolio

The entry of bulk ESs into energy and reserve markets will change the wind-thermal generation scheduling. In this situation, it is very important for the ISO to select and implement an appropriate DR program which has more coordination with ESs and other conventional power plants. In this regard, in order to compare the effectiveness of different DR strategies in the presence of utility-scale ESs for wind power integration, geometric average utility function (GAUF) as in Ref. [27] is applied. Under this perspective, strategy index (SI) and strategy success index (SSI) are used as can be seen in Eqs. (56)-(57) [27].

$$SI = \sum_{t=1}^{24}\left(St_1(t)\right)^{w_1} \times \left(St_2(t)\right)^{w_2} \times \cdots \left(St_k(t)\right)^{w_k} \tag{56}$$

$$SSI = \frac{\sum_{t=1}^{M} SI(t)}{\sum_{t=1}^{M} SI(\max)} \tag{57}$$

In Eq. (56), $St_k(t)$ indicates the performance value of the k-th attribute for each alternative in the t-th period. Also, M represents the studied time horizon which is one day here. In Eq. (56), W_k shows the weight of the k-th attribute. The SSI which is represented by Eq. (57) is in fact the normalized value of the SI factor. In short, higher SSI shows the better performance of a DR program. On this basis, the ISO can prioritize different DR programs due to its preferences which can include economic or environmental objectives.

4. SIMULATION RESULTS AND DISCUSSION

Several numerical studies have been conducted on the modified IEEE 24-bus RTS. In this respect, it is assumed that six hydro units are excluded. Also, two 400 MW wind farms (nearly 20% of total installed generation capacity) and two 20MW bulk ES units are located in buses 2 and 22, respectively. The required data of the mentioned test system including generation units and network parameters are taken from [29].

The hourly load corresponds to a weekend day in winter as given in Ref. [29], while the peak of the day is assumed 2850 MW. The generation units offer energy based on four linear segments between their minimum and maximum generation limits, as stated in Ref. [16]. The emission function slopes and the initial emission of generating units are the same as those for the corresponding unit fuel cost curves, all multiplied by the conversion factors of 0.2 and 0.5 for SO2 and NOx emission, respectively [28].

Moreover, it is presumed that generation units offer capacity cost for up-, down-, and non-spinning reserves at the rates of 40%, 40%, and 20% of their highest incremental cost of producing energy, respectively. Moreover, the cost of deployed reserves at the re-dispatch stage is considered to be at the rate of the highest incremental cost of energy production as well. The spinning reserve market's lead time is assumed to be 10 min.

The ES is assumed to have 1:1 charge to discharge ratio and 4:1 reservoir energy capacity to discharge ratio with the charging/discharging efficiency of 80%. Moreover, the bulk ES energy and up- and down-spinning reserve offers are considered 12.5 $/MWh, 5 $/MWh, and 5 $/MWh, respectively. Also, the offered cost of ES for providing non-spinning reserve is assumed to be 2.5 $/MWh. The state of charge of ESs is assumed to be between 10% and 90% according to the suggestion by some manufacturers and the initial state of the charge of both ESs is considered 20%. The load curve is divided into three periods: low-load period (1:00-8:00), off-peak period (9:00-16:00), and peak period (17:00-24:00). Moreover, the participation level of customers in DR programs is considered 20%. It is notable that the initial electricity price is assumed to be 12.5 $/MWh which is the mean value of electricity prices before DR implementation in 24-h scheduling horizon. In addition, the values of self and cross price elasticity of demand are extracted directly from [23].

Table 1. Optimal DR programs portfolio statement

Group no.	Scenario no.	Programs	Electricity price ($/MWh)	Incentive value at peak ($/MWh)	Penalty value at peak ($/MWh)
Base	-	Initial load	12.5 flat rate	0	0
1	1	TOU	9.7, 12.5, 14.3 at low-load, off-peak, and peak periods, respectively	0	0
	2	RTP	8.3,8.3,8.3,8.3,8.3,8.3,8.3,8.3,10.7,13.1,13.8,14,13.8,13.2,13.4,13.3,14.8,16.5,16.5,15.8,15.2, 14.7,13.6,12 at 1-24h	0	0
	3	CPP	21.7 at 18 and 19 h; otherwise, 11.53	0	0
2	4	DLC	12.5 flat rate	2.35	0
	5	EDRP	12.5 flat rate	3.125	0
	6	I/C	12.5 flat rate	3.125	0.875
3	7	TOU+DLC	9.7, 12.5, 14.3 at low-load, off-peak, and peak periods, respectively	2.35	0
	8	TOU+EDRP	9.7, 12.5, 14.3 at low-load, off-peak, and peak periods, respectively	3.125	0
	9	TOU+I/C	9.7, 12.5, 14.3 at low-load, off-peak, and peak periods, respectively	3.125	0.875

The DR portfolio contains three groups of DR programs. Group #1 is the TBRDRPs including TOU, real-time pricing (RTP) and critical peak pricing (CPP). Group #2 is the IBDRPs which include direct load control (DLC), EDRP, and interruptible/curtailable (I/C) programs. Group #3 is the combination of TBRDRPs and IBDRPs. In order to evaluate the economic and environmental potentials of different DR programs in coordination with bulk ESs for facilitating wind power integration, three case studies are conducted. In this respect, case 1 and case 2 deal with economic- and environmental-driven scheduling, respectively. Moreover, a trade-off between economic and environmental objectives is studied in case 3. The proposed model is solved using the MILP solver CPLEX 12.5.0 under GAMS software. The optimal DR rates are calculated for each program, as can be seen in Table 1. It is noteworthy that these are the most popular and widely used DR programs in the power market [30].

4.1. Case 1: Economic-based scheduling

In order to evaluate the effectiveness of different DR strategies in the presence of bulk ESs for wind-thermal generation scheduling problem from the economic perspective, a cost-based optimization is done here. To this end, in the first case, W_C and W_E are assumed to be 1 and 0, respectively. Tables 2-4 represent different terms of operation cost in the 24-h scheduling horizon for different DR program groups in detail. It can be obviously concluded from Tables 2-4 that the total operation cost is decreased considerably in comparison with the base case. According to the obtained results, I/C program is the most effective DR program in the field of operation cost reduction due to the fact that this program applies a punishment mechanism besides incentivizing customers.

Table 2. Terms of operation cost in Group #1 in case 1($)

Cost term	Group #1: TBRDRPs			
	Scenario No.			
	Base	1	2	3
Generation unit production	510837	494307	481919	516314
Up/down reserve capacity	51998	49280	47865	54173
ES energy	386	2009	1803	300
ES capacity reserve	3635	3552	3309	3760
Incentive	0	0	0	0
Penalty	0	0	0	0
Wind spillage	2257	1990	1871	2120
Deployed-reserve	-20099	-17534	-14934	-40041
Total	549014	533604	521833	536626

Table 3. Terms of operation cost in Group #2 in case 1($)

Cost term	Group #2: IBRDRPs			
	Scenario No.			
	Base	4	5	6
Generation unit production	510837	474485	466096	458321
Up/down reserve capacity	51998	47988	47320	46793
ES energy	386	2086	1722	1836
ES capacity reserve	3635	3303	3133	3086
Incentive	0	5374	7146	9147
Penalty	0	0	0	-3058
Wind spillage	2257	2780	3200	3428
Deployed-reserve	-20099	-17176	-17121	-18256
Total	549014	518840	511496	501297

On this basis, the customers that do not decrease their consumption based on the contract amount should be penalized. Afterwards, DR strategies of Group #3 can bring remarkable economic benefits, since these DR programs motivate the customers to change their typical consumption using both tariff schemes and incentive mechanisms.

Table 4. Terms of operation cost in Group #3 in case 1($)

Cost term	Group #3: TBRDRPs+IBRDRPs			
	Scenario No.			
	Base	7	8	9
Generation unit production	510837	469658	462428	455047
Up/down reserve capacity	51998	47141	46888	46047
ES energy	386	2206	2252	1836
ES capacity reserve	3635	3424	3435	3392
Incentive	0	9490	11262	13264
Penalty	0	0	0	-2119
Wind spillage	2257	2770	2910	3536
Deployed-reserve	-20099	-18699	-18706	-18225
Total	549014	515990	510469	502778

From wind power integration point of view, the RTP and TOU programs have positive impacts on the facilitation of wind integration. For instance, the optimal RTP and TOU pricing schemes can reduce wind spillage by 17% and 12%, respectively. It should be noticed that nearly in all the scenarios, DR implementation changes the scheduling of the bulk ESs in energy and reserve markets so that the participation of bulk ESs in energy market is increased. It is notable that the expected costs for deploying reserves are negative due to the fact that the down reserves account for the negative cost in the objective function. In other words, it is the cost which has been avoided. Moreover, the penalty costs get negative values according to the fact that this term is considered the revenue in the objective function from ISO view point. In Fig. 4, the impacts of implementing different types of DR programs on the system load profile are investigated. Almost all types of the programs try to decrease the load level in the peak period while increasing the load level at low-load hours and, consequently, providing a flatter load profile. This issue will not only remove the strain on the conventional generation units, but also support the integration of wind power into the power system.

4.2. Case 2: Environmental-based scheduling

In order to evaluate the coordinated operation of bulk ESs and DR programs portfolio at high penetration of wind power from the environmental perspective, in the second case, W_C and W_E coefficients are assumed to be 0 and 1, respectively. It should be emphasized that the amount of pollutant emissions in case 1 without implementing DR is equal to 193879 lbs. The environmental-based decision making decreases the value of pollutant emissions to 160578 lbs. In order to investigate the effectiveness of different DR programs in the case of emission reduction, Table 5 provides a comprehensive comparison in detail.

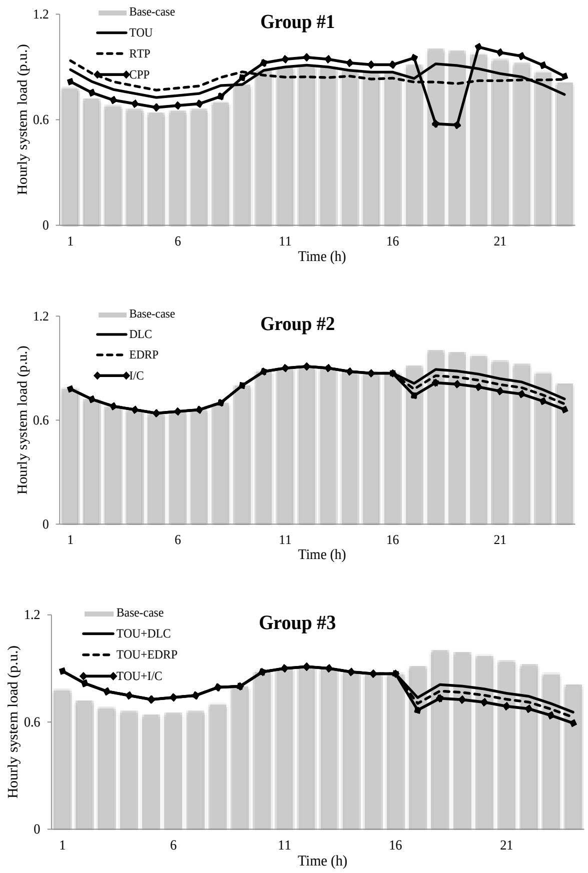

Fig. 4. Effect of various DR programs on load curve in case 1.

Table 5. Total emission comparison of different scenarios in case 2

Group no.	Scenario no.	Emission (lbs)	Emission reduction (%)
Base-case	-	160578	0
1	1	160374	0.13
	2	158388	1.36
	3	160384	0.12
2	4	145705	9.26
	5	141256	12.03
	6	135567	15.57
3	7	146837	8.56
	8	142243	11.42
	9	137121	14.61

As can be seen in Table 5, a remarkable emission reduction is achieved as a consequence of implementing DR in most scenarios. The minimum level of decreasing emission (0.12%) is related to scenario no. 3, namely CPP. Moreover, the most effective DR program from the environmental viewpoint is devoted to scenario no. 6, which is I/C program. It can be concluded that DR programs related to Group #2 and Group #3 have better performance in the field of mitigating pollutant emissions. In order to represent the impressions of ISO set target including economic and environmental objectives in the scheduling of bulk ESs, the total stored energy of bulk ESs in the base case (without considering

DR programs) are compared in case 1 and case 2, as can be seen in Fig. 5.

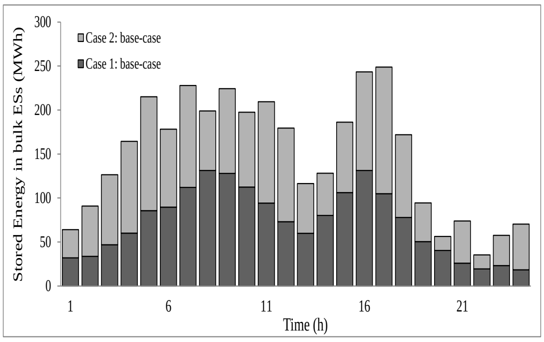

Fig. 5. Total level of stored energy in the ESs in case 1 and case 2

As can be observed, the total energy level of bulk ESs in case 1 (i.e. cost-based scheduling) is less than the total energy level of bulk ESs in case 2 (i.e. emission-based scheduling). Therefore, the ISO prefers to dispatch ESs for economic objectives in comparison with the environmental applications in electricity market.

4.3. Case 3: Economic-environmental based scheduling

In the third case, a trade-off is established between economic and environmental objectives. To this end, W_C and W_E coefficients are assumed to be 0.5 and 0.5, respectively. The optimal values of operation cost and emissions are reported for different scenarios in Table 6. According to Table 6, the operation cost as well as pollutant emissions is reduced as a result of DR implementation. In Group #1, the minimum values of operation cost (526128$) and emission (167559 lbs) are related to scenario no. 2 (i.e. RTP). The same procedure can be applied for the programs of Group #2 and Group #3.

Table 6. Comparison of different scenarios in case 3

Group no.	Scenario no.	Operation Cost ($)	Emission (lbs)
Base-case	-	557490	180570
1	1	540838	172279
	2	526128	167559
	3	555406	179730
2	4	525963	166327
	5	516537	159892
	6	507130	155177
3	7	524345	159517
	8	517184	153634
	9	510090	151066

Since the determination of the most efficient DR program is crucial from the ISO viewpoint, as mentioned earlier, in this paper, SSI coefficient is used to compare the performance of DR programs portfolio in facilitating wind power integration. On this basis, the predefined DR programs portfolio is prioritized in different case studies, as can be seen in Table 7.

Table 7. Prioritizing of DR programs portfolio in different case studies

Case 1 Economic-based		Case 2 Environmental-based		Case 3 Economic-environmental based	
Priorities (1-10)		Priorities (1-10)		Priorities (1-10)	
Scenario no.	SSI (%)	Scenario no.	SSI (%)	Scenario no.	SSI (%)
6	100	6	100	6	100
9	99.70	9	98.87	9	99.28
8	98.20	5	95.97	5	96.98
5	98.00	8	95.31	8	96.74
7	97.15	4	93.04	4	94.81
4	96.62	7	92.32	7	94.71
2	96.06	2	85.59	2	90.68
1	93.94	1	84.53	1	89.11
3	93.42	3	84.52	3	88.86
Base-case	91.31	Base-case	84.42	Base-case	87.80

It is noteworthy that the operating cost and emission are considered the attributes. In addition, different scenarios of Table 1 are considered the alternatives. As can be seen in Table 7, the highest priority is achieved by implementing scenario no. 6, which is related to the implementation of I/C program. It seems reasonable due to the fact that I/C is an obligatory DR program implemented by ISO so that a punishment mechanism that penalizes the customers if they do not respond in the required time is applied. Therefore, it seems that the customers are forced to participate in DR program and, as a result, the maximum benefit is attained from the ISO perspective. Furthermore, it can be concluded that the implementation of only TBRDRPs is not a favourable option for ISO in the systems with a significant amount of wind generation. It is also seen that implementing a combination of TBRDRPs and IBDRPs can be desirable for the ISO most of the times. In order to represent the coordinated operation of bulk ESs and DR programs, the energy level of ESs in electricity market environment under the implementation of the most effective DR program (i.e. scenario no. 6) is shown for case 3 as given in Fig. 6. According to Fig. 6, the energy level of bulk ESs is high in low-load period due to the fact that the electricity price is low in this period. Therefore, the ESs do not participate in energy and reserve markets.

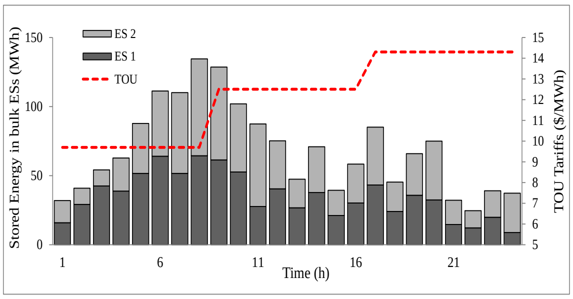

Fig. 6. Level of stored energy in the ESs in scenario no. 9 and case 3

In addition, the level of stored energy in ESs reaches its minimum value, since the electricity price is high in the mentioned period and, hence, the ESs are preferred to participate in the market and sell their stored energy. It is noteworthy that the ESs begin to charge, particularly from hour 22 onward when the electricity tariff is high. This issue is the consequence of the constraint expressed through Eq. (17). Based on Eq. (17), the level of stored energy of bulk ESs should be equal to 20% of their maximum energy capacity at the early hour of the day (i.e. hour 1).

5. CONCLUSIONS

In this paper, a two-stage stochastic programming approach was proposed to schedule the conventional units, bulk ESs, and DR programs with the application to wind power integration such that the total operation cost as well as emission was minimized. Numerical results indicated that implementing optimal TBRDRPs and IBDRPs could reduce both the operation cost and emission. In addition, the obtained results revealed that the TBRDRPs were better options in the field of mitigating wind power spillage although the mentioned programs were not suitable for economic purposes in comparison with other DR programs. According to the simulation results, the maximum SSI index was associated with the I/C program for both economic- and environmental-based scheduling. Furthermore, it can be concluded that the implementation of optimal DR programs could change the scheduling of ESs in energy and reserve markets such that the bulk ESs could be charged in low-loads and off-peak periods and inject power back into the grid, particularly at peak hours as energy or reserve services.

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