International Journal of Engineering

Journal Homepage: www.ije.ir

Stochastic Unit Commitment in the Presence of Demand Response Program under Uncertainties

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PAPER INFO

Paper history:
Received 03 August 2016
Received in revised form 06 May 2017
Accepted 07 July 2017

Keywords:
Ancillary Services
Demand Response
Stochastic Optimization
Uncertainty
Wind Power

A B S T R A C T

In this paper, impacts of various uncertainties such as random outages of generating units and transmission lines, forecasting errors of load demand and wind power, in the presence of Demand response (DR) programs on power generation scheduling are studied. The problem is modelled in the form of a two-stage stochastic unit commitment (UC) which by solving it, the optimal solutions of UC as well as DR are obtained. Generating units' constraint, DR and transmission network limits are included. Here, DR program is considered as ancillary services (AS) operating reserve which is provided by demand response providers (DRPs. In order to implement the existent uncertainties, Monte Carlo (MC) simulation method is applied. In this respect, scenarios representing the stochastic parameters are generated based on Monte Carlo simulation method which uses the normal distribution of the uncertain parameters. Backward technique is used to reduce the number of scenarios. Then, scenario tree is obtained by combining the reduced scenarios of wind power and demand. The stochastic optimization problem is then modelled as a mixed-integer linear program (MILP). The proposed model is applied to two test systems. Simulation results show that the DR improves the system reliability and also reduces the total operating cost of system under uncertainties.

doi*: 10.5829/ije.2017.30.08b.04*

NOMENCLATURE

i	Index for thermal units.	C_{it}^{SU}	Scheduled start-up cost of unit i at time t [$]
j	Index for demand.	C_{itw}^{A}	Adjustment cost due to the change in the start-up of unit i at time t and scenario w [$]
t	Index for time (hour)	$f_{tw}(n,r)$	Power flow through line (n,r) at time t and scenario w [MW]
m	Index for energy blocks offered by thermal units, running from 1 to $\boldsymbol{N_{Oit}}$ (number of blocks)	L_{jtw}^{C}	Power consumption for load j at time t and scenario w [MW]
s	Index for DRP bid segments, running from 1 to $\boldsymbol{N_{SL}}$	L_{jt}^{S}	Scheduled power for load j at time t [MW]
w	Index for scenarios, running from 1 to $\boldsymbol{N_w}$	L_{jtw}^{shed}	Involuntary load shedding for load j at time t and scenario w [MW]
r,n	Indices for system buses	P_{Gitm}	Scheduled power from the m-th block of energy offered by unit i at time t [MW]
Λ	Set of transmission lines	$P_{t}^{WP,S}$	Scheduled wind power at time t [MW]
M_L	Set of loads in the set of buses	p_{it}^{S}	Scheduled power of unit i at time t [MW]
M_G	Set of generating units into the set of buses	P_{itw}^{G}	Scheduled power of unit i at time t and scenario w [MW]
λ_{it}^{SU}	Start-up offer cost of unit i at time t [$]	R_{it}^{U}	Scheduled up-spinning reserve of unit i at time t [MW]
λ_{Gitm}	Marginal cost of the m-th block of energy offered by unit i at time t [$/MWh]	R_{it}^{D}	Scheduled down-spinning reserve of unit i at time t [MW]
λ_{Ljt}	Profit of load j at time t [$/MWh]	R_{it}^{NS}	Scheduled non-spinning reserve of unit i at time t [MW]
λ_{t}^{WP}	Marginal cost of the energy offer submitted by the wind producer at time t [$/MWh]	r_{itw}^{U}	Deployed up-spinning reserve of unit i at time t and scenario w [MW]

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Please cite this article as: J. Valinejad, Z. Oladi, T. Barforoushi, M. Parvania, Stochastic Unit Commitment in the Presence of Demand Response Program under Uncertainties, International Journal of Engineering (IJE), TRANSACTIONS B: Applications Vol. 30, No. 8, (August 2017) 1134-1143

$VOLL_{jt}$	Value of loss load for load j at time t [$/MWh]	r_{itw}^{D}	Deployed of unit i at time t and scenario w [MW]
V_t^S	Wind power spillage cost at time t [$/MWh]	r_{itw}^{NS}	Deployed non-spinning reserve of unit i at time t and scenario w [MW].
π_w	Probability of scenario w	r_{Gitwm}	Deployed reserve from the m-th block of energy offered by of unit i at time t and scenario w [MW]
$B(n,r)$	Susceptance of line n-r (p.u.)	S_{tw}	Wind spillage at time t and scenario w [MW]
$f^{max}(n,r)$	Maximum capacity of line $n-r$ [MW]	$\boldsymbol{U_{it}}$	Binary variable (equal to 1 if unit i is committed at time t , otherwise 0)
L_{jtw}	Realized consumption for load j at time t and scenario w [MW]	V_{itw}	Binary variable (equal to 1 if unit i is online at time t and scenario w, otherwise 0)
P_{tw}^{WP}	Realized wind power generation at time t and scenario w [MW]	W_{jtw}^{s}	Binary variable associated with discrete point s of load j at time t; equal 1 if the point s is deployed in scenario w and 0 otherwise
δ_{ntw}	Voltage angle at bus n at time t and scenario w [rad]	Z_{jt}^{s}	Binary variable associated with discrete point s of load j at time t; equal 1 if the point s is scheduled and 0 otherwise

1. INTRODUCTION

By dominant increase in the electricity consumption, applying renewable sources of energy for generating electricity is increased due to environmental impacts. Among them, wind energy has gained more attraction in comparison with other resources. Also, due to intermittent nature of wind resources, the wind power is not accurately predictable. Thus, Independent System Operator (ISO) determines a certain value of reserve in system to cover the uncertainty and preserve the reliability of system. Significant development of communication systems and then feasibility of on-line measurement of consumptions in the demand-side, together with entering of power system in the competitive market setting, makes the system operators to use the demand side for providing ancillary services. DR is defined as the participation of end users in the electricity market that is applied in response of cost changes [1]. In order for better implementation of the DR program, demand response provider (DRP) is introduced as a new entity to electricity market. DRP registers a consumer for participating in the DR program and proposes her or him to ISO. Thus, in the operational planning, the DR resources are allocated by the operators as reserve capacity. Also, the reserve capacity provided through DR not only can improve the system reliability during peak time, but also can be used as an alternative for costly conventional units [2].

Nowadays, competition and restructuring in the power systems lead to emergence of new problems and uncertainties. This makes great interest in system operators in using stochastic programming for solving problems. In literature [3, 4], operating reserve is evaluated using reliability criterion, where the unit commitment risk is determined according to the demand risk supply. In reference [5] the optimization process of spinning reserves and unit commitment are considered simultaneously. Simopoulos et al. presented a reliability constrained unit commitment, which considers both forced outage of units and uncertainty of the demand, to determine the spinning reserve. Simulated annealing algorithm was used for solving the problem. In reference [6], a two-stage stochastic unit commitment model has been presented to determine both the spinning and non-spinning reserves in the presence of a high penetration of wind power. Wind power uncertainty was considered in sets of scenarios. However, forced outages of generating units and transmission lines have been neglected.

In literature [7], demand-side reserve offers are studied in joint energy and reserve electricity markets where, the problem is modelled as a mixed-integer linear program (MILP). Generators and consumers submit offers and bids on five distinct products. Demand side reserve not only increases the consumer's benefits but also reduces market power. In the mentioned reference, the emphasis is on the impact and advantages of demand-side reserve offers. Later, the notion of demand-side reserve has been used by several researchers [8-10]. In reference [11] a stochastic security constrained unit commitment is presented, which considers uncertainty and fuel and emission constraints. The model presented by Lei et al. [11] was extended to include the system reliability cost [12]. Meanwhile, in both mentioned papers, Monte Carlo method has been used to generate scenarios which model the stochastic nature of parameters, such as forced outage of units and the uncertainty of the demand. LOLE and EENS were used as reliability criteria to determine required reserves. Parvania and Fotuhi-Firuzabad presented a two-stage stochastic unit commitment model considering DR programs in the wholesale electricity market. Also, the commitment state of generating units, the scheduled energy, spinning reserves and reserve provided by demands are determined over the planning horizon. DR was considered as an operating reserve, whose cost was modelled as a piecewise linear. Later, [13] was extended to a stochastic model which considers reliability [14]. An adaptive robust network-constrained AC unit commitment (AC-UC) model is presented in reference [15] where, a tri-level decomposition algorithm was introduced to solve the AC-UC problem and to find a robust commitment schedule. Probabilistic criteria are used to optimize the amount, location, and chronological procurement of the reserve in a given power system in literature [16] where, The presented approach factors the probability of individual contingencies in a cost/benefit analysis, which balances the pre-contingency operating costs against the post-contingency cost of interruptions. Shahidehpour et al. [17] presented a two-stage robust security constrained unit commitment (SCUC) model for managing the wind power uncertainty in the hourly power system scheduling. The presented method does not only pay attention to the feasible and economic operations within the flexible sets but also consider the risk in wind spillage or load curtailment out of them. An N-1 security constrained formulation was presented by Tejada-Arango et al. [18] to solve SCUC, where Line Outage Distribution Factors (LODF).

In none of the mentioned references, impacts of uncertainty of wind power, forecasted demand and random failures of generating units and transmission lines are considered simultaneously. In addition, DR program is considered as operating reserves in order to handle existing uncertainties and therefore improving system reliability and reducing the total cost. Thus, in this paper, a novel model is proposed to investigate impacts of DR programs on operating cost and reliability under uncertainties of demand, wind generation and failures of components. The unit commitment problem is modelled in the form of two-stage stochastic programming, considering the reliability criterion. To handle existing uncertainties, Monte Carlo simulation method is applied and sets of scenarios are generated. Therefore, consideration of stochastic contingencies and DR programs in wind power and thermal UC under uncertainties is the main contribution of this paper. The expected load not served is considered as reliability index for involuntary load shedding. The energy and reserves of generating units and reserves provided by DRP are determined by solving the stochastic MILP model using solver CPLEX 11.2.0 under GAMS.

2. MATHEMATICAL FORMULATION

In the following sub-sections, the mathematical formulation of the proposed framework is presented.

The proposed framework: Figure 1 shows the proposed framework which consists of three main parts. Scenario tree which models uncertainty of wind power, load demand and component failures, system data and DR programs are the main inputs of the framework. Here, the considered problem is modelled as a two stage stochastic program, which minimization of the total operating costs with related constraints are considered at the first stage. Also, at the first stage, here-and-now decision variables are considered. At the second stage, realization of existing uncertainties are considered and therefore wait-and –see decision variables are considered at this stage. Similar to the first stage, the objective function of the second stage is the expected value of operation cost. Details of the optimization problem (objective function and constraints) are explained in the following sections.

***Modelling of uncertainty*:** Discrete estimations of continuous stochastic processes which are a set of discrete scenarios with correspondent probabilities are used for modelling the uncertainty [19]. In this paper, Monte Carlo method is applied to simulate random outage of generating units and transmission lines [13]. Moreover, wind power uncertainties and forecasted demand error are modelled through generating scenarios. Moreover, computational tractability of stochastic optimization models based on scenarios is related to the number of scenarios, thus using a method for reducing the number of scenarios is essential. Backward reduction method is then used to reduce the number of scenarios [11]. Finally, for determining the scenario tree, the reduced uncertainty scenarios are combined with each other and the complete scenario is determined.

Modelling of DR: Having aggregated retail consumer responses by DRPs, a bid-quantity offer is submitted to the ISO, as shown in Figure 2. Equations (1)-(2) denote the value of scheduled DR where, m_j^S and π_j^S in Figure 1 are the reduced demand in the discrete point of s and its correspondent offered cost respectively.

$$\Delta_{jt}^{S} = m_{jt}^{S} - m_{jt}^{S-1} \qquad ;s = 1,2,...,N_{SL} \tag{1}$$

$$DR_{jt} = \sum \Delta_{jt}^{S} Z_{jt}^{S} \tag{2}$$

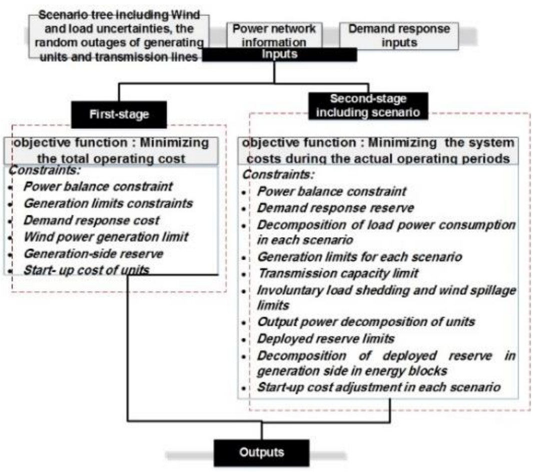

Figure 1. The proposed framework

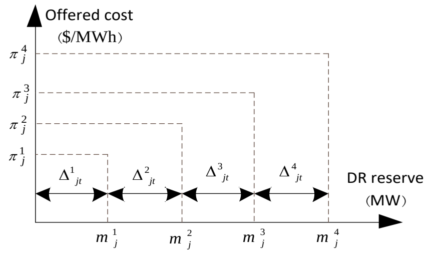

Figure 2. Package of DRP

Reliability Assessment: In stochastic method for reliability evaluation the expected load not served is used as reliability index which can be considered as a constraint [20]. However, this is not very applicable since evaluation of desired value of this index is complicated. The other method is introducing this index in the objective function, as indicated by (3) and (4) [14].

$$\mathrm{ELNS}_j = \sum_{w=1}^{N_w} \pi_w \sum_{t=1}^{N_t} \mathrm{L}_{\mathrm{jtw}}^{\mathrm{shed}} \tag{3}$$

$$\mathrm{Cost}_{ELNS_j} = \sum_{j=1}^{N_L} VOLL_{jt} \times ELNS_j \tag{4}$$

Objective function: Equation (5) represents the objective function, the total operating cost. The expected load not served is considered as a criterion for involuntary load shedding. The first and second lines of (5) represent payment regarding to start-ups, revenue of units, spinning and non-spinning reserves, DR and wind power, respectively. The second stage is included with the probability of π_W, which involves the system costs during the actual operating periods. The last line of (5) represents the costs of the second stage. These costs are related to actual costs of start-up, reserves, DR, wind spillage and reliability, respectively. $C_{it}^{R^U}$, $C_{it}^{R^D}$ and $C_{it}^{R^{NS}}$ are the costs of up spinning reserve, down spinning reserve and non-spinning reserve of unit i at time t, respectively.

$$\begin{aligned} Min\ EC &= \sum_{t=1}^{N_t} EC_t = \sum_{t=1}^{N_t} \left\{ \sum_{i=1}^{N_G} C_{it}^{SU} \right. \\ &+ \sum_{i=1}^{N_G}\sum_{m=1}^{N_{Oit}} \lambda_{Gitm} P_{Gitm} \\ &+ \sum_{i=1}^{N_G} \left(C_{it}^{RU} R_{it}^{R} + C_{it}^{RD} R_{it}^{D} + C_{it}^{RNS} R_{it}^{NS} \right) \\ &\left. + \sum_{j=1}^{N_L} CDR_{jt} + \lambda_t^{WP} P_t^{WPS} \right\} \\ &+ \sum_{W=1}^{\pi_W} \pi_W \left\{ \sum_{t=1}^{N_t} \left[\sum_{i=1}^{N_G} C_{itw}^{A} + \sum_{i=1}^{N_G}\sum_{m=1}^{N_{Oit}} \lambda_{Gitm} r_{Gitwm} \right. \right. \\ &\left. \left. - \sum_{j=1}^{N_L} \lambda_{Ljt} L_{jtw}^{C} + \sum_{j=1}^{N_L} \left(ECDR_{jtw} + V_t^{S} S_{tw} \right) \right] \right\} \\ &+ Cost_{ELNS_j} \end{aligned} \tag{5}$$

Constraints on the first-stage variables: Constraints of the first-stage variables to deal with the modeling of energy trading and the reserve in the electricity market are represented by equations (6)-(16). Power balance is represented by (6). Network constraints are not considered in this stage. Equations (7)-(9) constrain the total power produced by unit and power generation to be scheduled in each block of offered energy and the relationship between them, respectively. Equation (10) represents the cost of scheduled DR before realization of each scenario, where π_{jt}^S denotes the cost of reserve capacity. Power produced by wind power is constrained by (11). Constraints (12)-(14) represent reserve limits on generation side. Equations (15) and (16) constrain start-up cost of units.

$$\sum_{i=1}^{N_G} p_{it}^S + P_t^{WPS} = \sum_{j=1}^{N_L} L_{jt}^S \tag{6}$$

$$p_i^{\min} u_{it} \le p_{it}^S \le p_i^{\max} u_{it} \tag{7}$$

$$0 \le p_{Gitm} \le p_{Gitm}^{\max} \tag{8}$$

$$p_{it}^S = \sum_{m=1}^{N_{Oit}} P_{Gitm} \tag{9}$$

$$CDR_{jt} = \sum_{s=1}^{N_{SL}} \Delta_{jt}^S \pi_{jt}^S z_{jt}^S \tag{10}$$

$$p_t^{WP\min} \le p_t^{WPS} \le p_t^{WP\max} \tag{11}$$

$$0 \le R_{it}^U \le R_{it}^{U\max} u_{it} \tag{12}$$

$$0 \le R_{it}^D \le R_{it}^{D\max} u_{it} \tag{13}$$

$$0 \le R_{it}^{NS} \le R_{it}^{NS\max} (1 - u_{it}) \tag{14}$$

$$C_{it}^{SU} \ge \lambda_{it}^{SU} (u_{it} - u_{i,t-1}) \tag{15}$$

$$C_{it}^{SU} \ge 0 \tag{16}$$

Second-stage constraints: The second-stage constraints are the constraints of actual operating of system while uncertainties of wind power generation, system load forecast, forced outage of generating units and system transmission lines are realized.

Equations (17) and (18) represent power balance constraint at thermal and wind power buses, respectively. A two-state Markov model is applied to generate random outage of generating units and transmission lines [4]. In (18) the random variable ξ_{itw} is correspondent with the random outage of generating units where its arrays are binary and are 1 if the generating units are healthy and 0 otherwise. Power flow from the line n-r in each scenario is modeled by (19), where the random variable ξ_{ltw} is related to outage of transmission lines, and where its arrays are binary and are 1 if the transmission lines are healthy and 0 otherwise. The DR reserve provided by DR and its cost in each scenario are represented by (20) and (21) respectively; where πe_{jt}^{S} denotes the energy cost of the DR reserve. Equation (22) relates the realized load demand, the realized DR and power consumption in each period and scenario. Equations (23) and (24) represent generation limits for each scenario. Power flow of transmission lines are constrained by (25). Equations (26) and (27) constrain involuntary load shedding and wind spillage at each time and scenario. Equation (28) is introduced to decompose the power produced and allocated operating reserves of generating units, where P_{itw}^{G} is a slack variable. Constraints of deployed reserves are represented by (29)-(31) on generation-side. Also, (32) shows the deployed reserve of demand side. These constraints exist due to the fact that in each scenario of the second stage, value of scheduled reserves must be less than those in the first stage. Equation (33) is similar to (9) and denotes reserve decomposition through energy block using variables r_{Gitwm} at each time period. (34) and (35) denote that the reserve blocks are added to the energy blocks, however, down spinning reserve are subtracted from the energy blocks. Thus, the applied reserve cost of each unit at each time period and scenario is $\sum_{m=1}^{N_{Oit}} \lambda_{Gitm}.r_{Gitwm}$, as it was stated in the objective function.

$$\sum_{i:(i,n)\in M_G} \xi_{itw} \times P_{itw}^{G} - \sum_{j:(j,n)\in M_L} (L_{jtw}^{C} - L_{jtw}^{shed}) - \sum_{r:(n,r)\in\Lambda} f_{tw}(n,r) = 0 \tag{17}$$

$$\sum_{i:(i,n)\in M_G} \xi_{itw} \times P_{itw}^{G} - \sum_{j:(j,n)\in M_L} (L_{jtw}^{C} - L_{jtw}^{shed}) + P_{tw}^{WP} - S_{tw} - \sum_{r:(n,r)\in\Lambda} f_{tw}(n,r) = 0 \tag{18}$$

$$f_{tw}(n,r) = \xi_{ltw} \times B(n,r)(\delta_{ntw} - \delta_{rtw}) \tag{19}$$

$$dr_{jtw} = \sum_{s=1}^{N_{SL}} \Delta_{jt}^{S} w_{jtw}^{S} \tag{20}$$

$$ECDR_{jtw} = \sum_{s=1}^{N_{SL}} \Delta_{jt}^{S} \pi e_{jt}^{S} w_{jtw}^{S} \tag{21}$$

$$L_{jtw}^{C} = L_{jtw} - dr_{jtw} \tag{22}$$

$$P_{itw}^{G} \ge P_{i}^{\min} v_{itw} \tag{23}$$

$$P_{itw}^{G} \le P_{i}^{\max} v_{itw} \tag{24}$$

$$-f^{\max}(n,r) \le f_{tw}(n,r) \le f^{\max}(n,r) \tag{25}$$

$$0 \le L_{jtw}^{shed} \le L_{jtw}^{C} \tag{26}$$

$$0 \le S_{tw} \le P_{tw}^{WP} \tag{27}$$

$$P_{itw}^{G} = p_{it}^{S} + r_{itw}^{U} - r_{itw}^{D} + r_{itw}^{NS} \tag{28}$$

$$0 \le r_{itw}^{U} \le \varepsilon_{itw} \times R_{it}^{U} \tag{29}$$

$$0 \le r_{itw}^{D} \le \varepsilon_{itw} \times R_{it}^{D} \tag{30}$$

$$0 \le r_{itw}^{NS} \le \varepsilon_{itw} \times R_{it}^{NS} \tag{31}$$

$$0 \le dr_{jtw} \le DR_{jt} \tag{32}$$

$$r_{itw}^{U} + r_{itw}^{NS} - r_{itw}^{D} = \sum_{m=1}^{N_{Oit}} r_{Gitwm} \tag{33}$$

$$r_{Gitwm} \le p_{Gitwm}^{\max} - p_{Gitm} \tag{34}$$

$$r_{Gitwm} \ge -p_{Gitm} \tag{35}$$

C_{itw}^{SU} describes the setting up cost applied to the i-th unit during the real operating and time period of t and scenario of w. C_{itw}^{A} denotes the cost of changes in the setting up program of i-th unit during the time period of t and scenario of w. Constraints (28) to (38) couple electricity market decisions and of real operating of system which is implemented through reserve consumption.

$$C_{itw}^{A} = C_{itw}^{SU} - C_{it}^{SU} \tag{36}$$

$$C_{itw}^{SU} \ge \lambda_{it}^{SU} (v_{itw} - v_{i,t-1,w}) \tag{37}$$

$$C_{itw}^{SU} \ge 0 \tag{38}$$

3. CASE STUDIES

3. 1. Three Bus Sustem Single line of 3-bus system is depicted in Figure 3 and the required data consisting of the network data, start-up cost of units, cost of energy, reserve of generation-side and data regarding to the hourly system demand is derived from [1]. VOLL is assumed to be 1000 \$/MWh. Data related to the DRP, in three discrete points, is presented in Table 1.

To simulate uncertainty of wind power and load forecast error, we assume that the wind power and hourly demand are subject to a normal distribution N(μ,σ^2). Standard deviation (σ) of wind power and load forecasting are assumed 30% and 20%, respectively Three cases are considered for a 4-h scheduling horizon.

Case 1: without utilizing DR reserve
Case 2: with participating 5% of consumers
Case 3: with participating 10% of consumers

Table 2 shows results for case1. In this case, only thermal units compensate the uncertainty. The first priority of operator for power production is the unit i3. At hour 2, the wind power (3MW) is scheduled more than its forecasted. Moreover, forced outage of unit i3 occurs in some scenarios during actual operation. Thus, the operator compensates the forced outage and the wind power uncertainty by allocating the non-spinning reserves for unit i1 and i2. For compensating outage of transmission lines L2 and L3, unit i3 is scheduled as down spinning reserve. In the cases 2 and 3, 95% and 90% of load is considered as the maximum involuntary load shedding, respectively. Table 3 shows that at hour 2, the operator allocates less non-spinning reserve to unit i2 (18.41 MW) to cover the uncertainties. Since using of DR is economic, the operator schedules 4 MW reserve. At hour 1, the wind power is scheduled which is less than it's forecasted, the allocated down spinning reserve is equal to 4.85MW. In case 3, 10% of consumers provide system reserve.

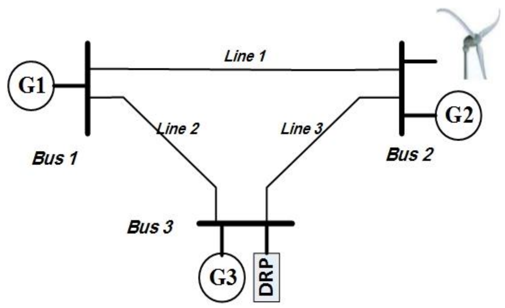

Figure 3. Single line diagram of 3-bus system

TABLE 1. DRP offers in 3-bus system

Section	1	2	3
DR reserve	33%of total responses	66% of total responses	100% of total responses
Capacity cost of reserve (\$/MWh)	2.5	3.5	4.5
Energy cost of reserve (\$/MW)	20	28	36

TABLE 2. results of case 1

	Unit	T(hour) 1	2	3	4
P_{it}^{S} (MW)	i1	0	0	0	0
	i2	0	0	0	0
	i3	27.5	50	50	36.6
R_{it}^{U} (MW)	i1	0	0	0	0
	i2	0	0	0	0
	i3	0	0	0	0
R_{it}^{D} (MW)	i1	0	0	0	0
	i2	0	0	0	0
	i3	5.8	5.1	0	4.9
R_{it}^{NS} (MW)	i1	23.1	32.4	39.1	31.6
	i2	0	22.4	29.2	0
	i3	0	0	0	0
$P_{t}^{WP,S}$ (MW)		2.5	30	60	3.4

TABLE 3. Results of case2

	Unit	T (hour) 1	2	3	4
P_{it}^{S}(MW)	i1	0	0	0	0
	i2	0	0	0	0
	i3	26.54	50	50	31.66
R_{it}^{U}(MW)	i1	0	0	0	0
	i2	0	0	0	0
	i3	3.66	0	0	0
R_{it}^{D}(MW)	i1	0	0	0	0
	i2	0	0	0	0
	i3	4.85	5.13	0	0
R_{it}^{NS}(MW)	i1	21.68	32.44	40.32	29.66
	i2	0	18.41	23.70	0
	i3	0	0	0	0
$P_{t}^{WP,S}$(MW)		3.46	30	60	8.34
DR_{jt} (MW)		1.5	4	5.5	2

Table 4 shows that at hour 2, the operator allocates less non-spinning reserve to unit i2 (14.4MW). Moreover, the non-spinning reserve provided by unit i1 is less than case 2, because the uncertainties is covered by scheduling the demand-side reserves (8MW) as well as reducing reserve provided by thermal units. Note that by increasing participation of demand-side, production of thermal units is decreased and wind power production is increased, because uncertainty of wind power makes the operator allocate the reserve to the demand side. Thus in case2 and case3, by increasing the demand-side participation, the operator prefers to schedule the wind power more and therefore all of DRP offers are accepted. In fact, more expensive unit has less role in providing the system reserve by allocating DR. Thus, the total cost is decreased. Table 5 summarizes results of cases 1 to 3. According to Table 5, the total operating cost is significantly decreased by increasing participation of consumers in DR program. Participation of consumers at the amount of 5% and 10% has decreased the total cost by 3.02% and 6.22%, respectively. This is due to the decrease in production of thermal units and allocating reserve to these units. In case2 and case3, cost of the expected load not served is also decreased by increasing participation of DR program. This causes decreasing involuntary load shedding. Therefore, even by increase in the cost of DR, the total cost of system is decreased. Consequently, using DR program not only reduces the total cost, but also increases the system reliability.

TABLE 4. Results of case3

	Unit	T (hour) 1	2	3	4
	i1	0	0	0	0
P_{it}^{S} (MW)	i2	0	0	0	0
	i3	25.8	50	50	34.1
	i1	0	0	0	0
R_{it}^{U} (MW)	i2	0	0	0	0
	i3	0	0	0	0
	i1	0	0	0	0
R_{it}^{D} (MW)	i2	0	0	0	0
	i3	4.1	0.41	0	2.46
	i1	20.1	32.4	40.06	27.6
R_{it}^{NS} (MW)	i2	0	14.41	20.41	0
	i3	0	0	0	0
$P_{t}^{WP,S}$ (MW)		4.2	30	60	5.9
DR_{jt} (MW)		3	8	11	4

TABLE 5. Costs of 3-bus system

	Case 1	Case 2	Case 3
Operation cost ($)	6351.11	6158.91	5955.76
Energy cost ($)	4429.19	4252.38	4069.11
Reserve cost of units ($)	980.55	899.42	789.17
DR cost ($)	0	174.35	367.88
Expected load not served cost ($)	941.37	832.76	729.60

Also, consumers benefit from DR program, because they buy more reliable electrical power and pay less money.

3. 2. MREC Network

The second case is the MAZANDARAN regional electric company (MREC network. Single-line diagram of MREC network is shown in Figure 4 consisting of 16 load buses [23-24]. The scheduling horizon is assumed to be 24 hours. Table 6 shows the average demand for the first hour. A 140 MW wind power plant is assumed to be installed at bus DARYASAR. The expected wind power productions in each hour are given in Table 7. Also, Table 7 shows the hourly demand coefficients which are used to calculate average hourly demand. There is one DRP at each load bus, which is registered by ISO. Offers of DRPs at each load bus are given in Table 8.

It is assumed that generating units submit 40% and 100% of the highest incremental cost of their energy production to the ISO as the operation cost, up, down-spinning and non-spinning reserves and energy, respectively.

TABLE 6. Demand of MREC network for first hour (MW)

Bus	Load	Bus	Load
HASANKIF	8.9	AMOL	98.2
GONBAD	61.9	DARYASAR	37.5
GORGAN	89.8	ROYAN	46.4
MINO DASHT	29.8	ALIABAD	31.5
KORDKUY	53.5	DANYAL	40.4
SARI	34.5	SAVAD KOH	9.5
DEHAK	57.1	BABOL	59.5
KAGHAZ SAZI	38.1	GHAEMSHAHR	62.6

TABLE 7. Forecasted wind power and hourly load coefficient

Time	wind power production MW	Hourly load coefficient	time	wind power production MW	Hourly load coefficient
1	43.8255	1.0000	13	75.3942	0.2638
2	81.2186	1.3690	14	96.5398	0.7768
3	54.6304	1.9618	15	60.6466	1.1241
4	60.0396	1.7357	16	36.2506	1.2906
5	69.5713	1.3450	17	3.0273	1.6228
6	85.6079	1.8262	18	7.4394	1.9461
7	80.0759	2.3545	19	5.078	2.1866
8	106.2962	0.9105	20	5.9349	2.4414
9	72.66	1.7280	21	4.2745	2.6242
10	63.7126	2.1237	22	52.2892	3.5928
11	113.676	2.3218	23	62.5426	4.2763
12	63.6823	2.3907	24	39.942	3.8400

TABLE 8. DRP offers for MREC

	1	2	3
DR reserve	33%of total responses	66% of total responses	100% of total responses
Capacity cost of reserve ($/MW)	3	4	5
Energy cost of reserve ($/MWh)	24	32	40

Available transmission capacity and capacity of units are shown in Figure 4. Also, susceptances of existing transformers of NEKA, NARIVARAN, HASANKIF and ALIABAD are 33, 20, 16.67 and 20 (p.u.), respectively, in the base of 100 MVA. Data for generating units are given in the Table 9. It is assumed that 10% of consumers participate in supplying operating reserve.

In order to simulate wind power and demand uncertainties, 1000 scenarios were generated. The standard deviation (σ) of the wind power uncertainty and load forecast was assumed 10% for wind and 5% for demand. Then, the number of scenarios was reduced to 5 and 10 for the wind and demand, respectively. Figures (5)- (8) depict scheduled power, down-spinning reserve, up spinning reserve and non-spinning reserve of units in the case which 10% of consumers participate in DR. The total energy produced by NEKA4, NEKA2 and ALIABAD2 are obtained equal to 17317, 5363 and 10303 MWh, respectively over the planning period. The total down-spinning reserves for these units are 2973.1, 348.7 and 17.4 MWh, respectively. In addition, the total up-spinning reserves are 37.8, 2.0, and 0.5 MWh, respectively. At hours 1 and 2, only unit 1 of NEKA4 has been scheduled for up-spinning reserve due to its lower operating cost. On the other hand, the unit having higher operating cost of NEKA2 has been scheduled for non-spinning reserve, equal to 22.78 MW. At hour 5, 10 MW has been scheduled for ALIABAD2 as no-spinning reserve. The total non-spinning reserve for NEKA4, NEKA2 and ALIABAD are 78, 22 and 10 MWh, respectively. Figure 9 depicts the sensitivity of consumers' participation in DR scheduling cost, the cost of expected load not served and total cost of power system. By increasing participation of DR program, the total operating cost is significantly decreased. The cost of expected load not served is decreased. This shows that use of ASDRP reduces the risk of involuntary load shedding. Thus, implementing DR program not only reduces the total operating cost, but also can increase the reliability of system and all the consumers can benefit because less money is paid and also the electricity is used with more reliability.

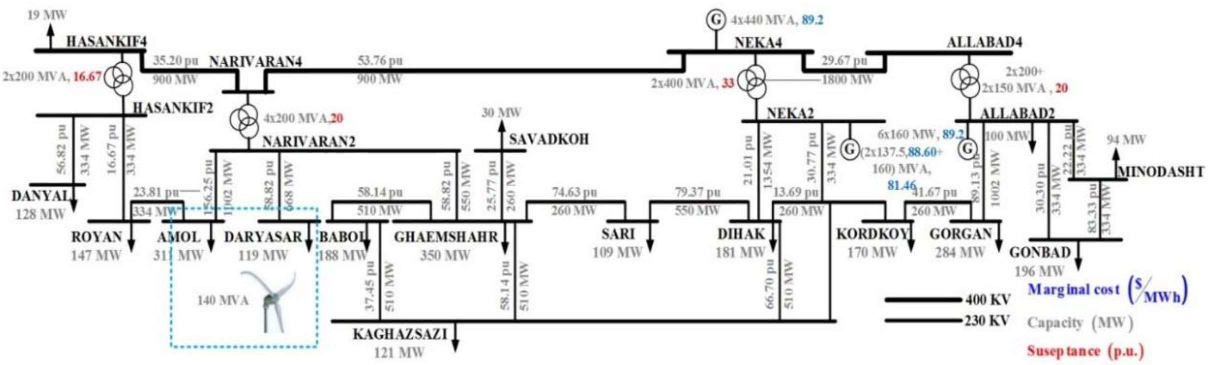

Figure 4. Single-line diagram of MREC transmission network

TABLE 9. Data for generating units of MREC

Bus	NEKA4	NEKA2	NEKA2	ALI ABAD2
Unit Capacity (MW)	4*440	2*137.5	160	2*480
Generation block (MW)	500/1000 / 1760	40/80/275	40/80/18 0	320/640/960
Marginal cost ($/MWh)	16.92/16. 98/ 17.02	40.72/40.79 / 40.87	23.35/ 22.73/ 23.09	37.72/37.79/ 37.87
MAX. Production	4*480	2*137.5	160	2*480
MIN. Production	4*100	2*10	10	2*10

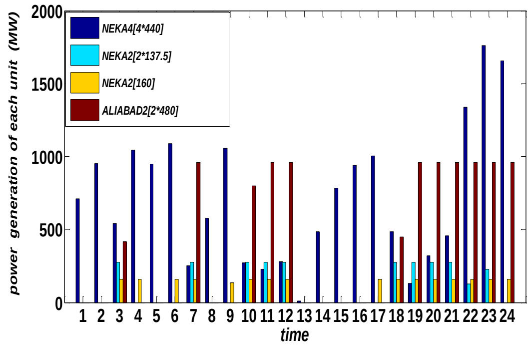

Figure 5. Output of units (DR=10%)

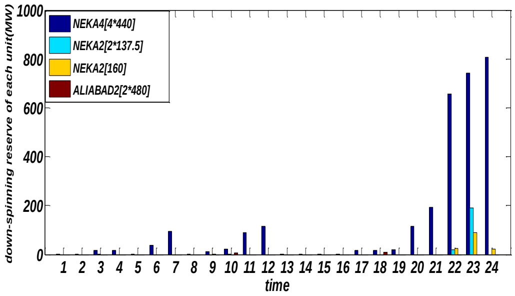

Figure 6. Down spinning reserve of units (DR=10%)

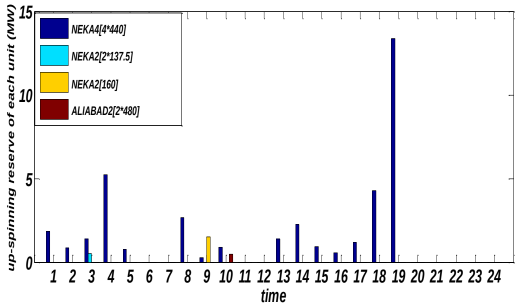

Figure 7. Up spinning reserve (DR=10%)

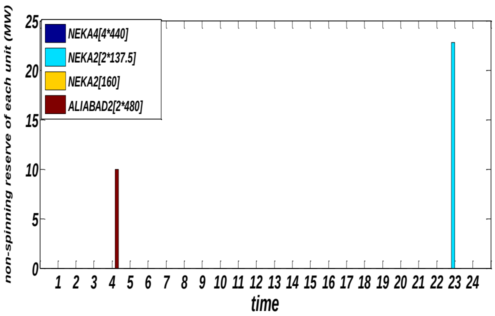

Figure 8. Non-spinning reserve (DR=10%)

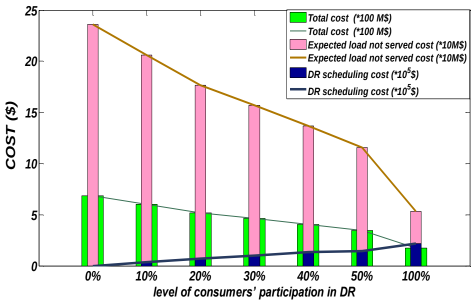

Figure 9. System costs in terms of consumers' participation in DR

4. CONCLUSION

A new model was proposed to examine impacts of uncertainties associated to component failures, load demand and wind power on the generation scheduling in the presence of DR programs. The proposed model determines the optimal schedule of energy and reserve of generation and demand-side, dealing with system reliability by considering simultaneous impact of demand uncertainties and wind power generation following by random outage of generating units and transmission lines in combination with DRP. The considered problem has been solved in the form of a two-stage stochastic optimization problem with both continuous and binary decision variables. Scenarios were generated using Monte Carlo simulation, while normal distribution was used. In order to reduce the number of scenarios backward technique was used. Simulation results show that implementing the ASDRP in power system under uncertainties can improve the system reliability, since by increasing the participation of consumers in DR programs; the cost of ELNS is significantly decreased. It means that with participation of consumers in the ASDRP, the reduction in involuntary load shedding is gained for all consumers. Furthermore, by increasing the level of consumers' participation and increasing the use of allocated DRP reserve, the cheaper generating units are committed. This leads to decreasing in the operating cost, because utilizing from demand-side leads to decreasing the costs of energy, reserve and involuntary load shedding.

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Stochastic Unit Commitment in the Presence of Demand Response Program under Uncertainties

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PAPER INFO

Paper history:
Received 03 August 2016
Received in revised form 06 May 2017
Accepted 07 July 2017

Keywords:
Ancillary Services
Demand Response
Stochastic Optimization
Uncertainty
Wind Power

چکیده

در این مقاله اثرات عدم قطعیت‌های مختلف نظیر خروج تصادفی واحدهای تولید و خطوط انتقال، خطای پیش بینی بار و تولید توان بادی در حضور برنامه‌های پاسخگویی تقاضا (DR) بر زمان‌بندی تولید مطالعه می‌شود. مسئله مورد نظر به صورت یک مسئله تصادفی دومرحله‌ای درمدار قرار گرفتن واحدهای تولید (UC) مدل می‌شود که با حل آن جوابهای بهینه UC و DR تعیین می‌شوند. محدودیتهای واحدهای تولید، برنامه DR و حدود شبکه انتقال در نظر گرفته می‌شوند. در این مقاله، برنامه DR بصورت خدمات جانبی ذخیره درنظر گرفته می‌شود که توسط فراهم‌کنندگان آن ارائه می‌گردد. به منظور پیاده‌سازی عدم قطعیتها، از شبیه سازی مونت کارلو (MC) استفاده می‌شود. به این منظور، سناریوهایی که نماینده عدم قطعیتها هستند بر اساس شبیه سازی مونت کارلو تولید می‌شوند که در آن از توزیع نرمال پارامترهای غیرقطعی استفاده می‌شود. ، برای کاهش سناریو از تکنیک پسرو استفاده می‌شود. سپس با ترکیب سناریوهای توان بادی و تقاضا درخت سناریو تشکیل می‌گردد. مسئله بهینه سازی تصادفی بصورت یک مسئله برنامه‌ریزی خطی صحیح آمیخته (MILP) مدل می‌شود. مدل پیشنهادی روی دو سیستم آزمون بکار گرفته می‌شود. نتایج شبیه سازی نشان می‌دهد که DR ضمن بهبود قابلیت اطمینان سیستم، هزینه کل بهره‌برداری را تحت شرایط عدم قطعیت کاهش می‌دهد.

doi*: 10.5829/ije.2017.30.08b.04*