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Scheduling of battery energy storages in the joint energy and reserve markets based on the static frequency of power system

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ABSTRACT

By using the battery energy storage (BES) as a fast, reliable, and controllable resource, the system operator can compensate for power mismatches via changing the generation and consumption in discharging and charging modes. However, BES could decrease the inertia of the grid and endanger the security of the system. Therefore, system operators require a scheduling model that takes into account both security and economic issues. This paper presents a linear model for the optimal scheduling of synchronous generators and BESs in the joint energy and reserve markets, based on the constraints of primary and secondary frequency services. In the proposed model, the technical limitations of synchronous generators and BESs, the frequency limitation of the grid, rate of change of frequency (RoCoF) of generators, and the RoCoF of the grid are considered as constraints of the optimization problem. Accordingly, the optimal scheduling of the resources is determined in a way that ensures the security criteria of the system are not violated after the contingency. The effectiveness of the proposed strategy is demonstrated by four case studies. Simulation results show that increasing the battery capacity by 4.68% of the total capacity of the system reduces the total frequency reserves, and total costs of the system by 13.21 and 2.96%, respectively. Consequently, system operators can reduce total operating costs and provide adequate security by deploying BESs.

1. Introduction

Over the past decade, the consumption of electrical energy is increased dramatically. Moreover, the limitation of fossil fuels such as coal, petroleum and natural gas, environmental pollution, and global warming have forced governments to provide many motivations for investing in renewable energy resources. However, increasing the penetration level of renewable energy resources in the distribution network leads to a new challenge for the system operators. Using renewable resources without the inertia constant and decreasing the inertia of power system can treat the frequency stability of power systems [1]. Therefore, power system operators try to maintain the frequency of system in a secure margin by proper scheduling of available resources and reserve service.

The battery energy storage (BES) as a schedulable and reliable resource could improve the flexibility of power system, significantly [1]. One of the main advantages of BES in comparison with other renewable energy resources is its fast response [2]. Therefore, after the occurrence of a contingency, BESs can compensate the power mismatch by adjusting the charging and discharging power. However, decreasing the inertia of power system could endanger the frequency stability of synchronous generators and the power system. Therefore, frequency stability is a critical issue that shall be considered in the scheduling of BESs in power systems [3].

1.1. Aim

The frequency of grid is the main parameter that reflects the balance of generation and consumption, and the security of power systems [4]. After an unpredicted event or occurrence of a contingency, the available generating units shall provide the immediate proper response to prevent the instability of system. Therefore, within a few seconds after the occurrence of a disturbance, the market operator uses primary frequency control (PFC) service to maintain the grid frequency within the allowable range in real-time [5]. In traditional power systems, PFC service is usually provided by synchronous generators, which are equipped by the governor. After stabilizing the frequency in the safe margin, the operator has enough time to return the frequency to its nominal value. In the secondary frequency control (SFC) service that

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Indices

b, Ω_b	index and set of buses
g, Ω_{G_b}	index and set of generators which are connected to bus b
s, Ω_{S_b}	index and set of storages which are connected to bus b
d, Ω_{D_b}	index and set of loads which are connected to bus b
t, T	index and set of time
i,int	index and set of intervals (pre=pre-contingency, pri=primary frequency, sec=secondary frequency)

Parameters

A	availability binary variable (1=available, 0=unavailable)
m	droop parameter of generator (Hz/MW)
H	inertia constant of generator (s)
P^r	rated power of generator (MW)
ρ^{DA}	day-ahead price ($/MW)
ρ^{UR}	up-regulation price ($/MW)
ρ^{DR}	down-regulation price ($/MW)
ρ^{RT}	real-time price ($/MW)
ρ^{D}	demand price ($/MW)
$voll$	value of lost load ($/MW)
P^D	demand of consumer (MW)
$P^{GEN,\min}/P^{GEN,\max}$	minimum/maximum power of generator (MW)
$P^{DCH,\min}/P^{DCH,\max}$	minimum/maximum power of storage in discharging mode (MW)
$P^{CH,\min}/P^{CH,\max}$	minimum/maximum power of storage in charging mode (MW)
$LSH^{\max}/LSH^{\max}$	minimum/maximum capacity of shed load (MW)
$E^{\min}/E^{\max}$	minimum/maximum level of energy of storage (MWh)
$f^{\min}/f^{\max}$	minimum/maximum frequency of grid (Hz)
$RoCoF^{\max}$	maximum RoCoF of generator (Hz/s)
$RoCoF^{\max}_{sys}$	maximum RoCoF of power system (Hz/s)
$ramp^{UP}/ramp^{DN}$	ramp up/down of generator (MW/h)
$ramp^{SU}/ramp^{SD}$	startup/Shutdown ramp of generator (MW/h)

Variables

P^{GEN}	output power of generator (MW)
P^{CH}	charging power of storage (MW)
P^{DCH}	discharging power of storage (MW)
LSH	shed load of demand (MW)
P^{REF}	set point of power (MW)
f	frequency of grid (Hz)
$P^{GEN,DA}$	generator's bid in day-ahead market ($/MW)
R^{UR}	generator's bid in up-regulation service ($/MW)
R^{DR}	generator's bid in down-regulation service ($/MW)
$P^{GEN,RT}$	generator's deployed power in real-time ($/MW)
$P^{DCH,DA}$	storage's bid in day-ahead market-discharging mode ($/MW)
R^{URDCH}	storage's bid in up-regulation service-discharging mode ($/MW)
R^{DRDCH}	storage's bid in down-regulation service-discharging mode ($/MW)
$P^{DCH,RT}$	storage's deployed power in real-time-discharging mode ($/MW)
$P^{CH,DA}$	storage's bid in day-ahead market-charging mode ($/MW)
R^{URCH}	storage's bid in up-regulation service-charging mode ($/MW)
R^{DRCH}	storage's bid in down-regulation service-charging mode ($/MW)
$P^{CH,RT}$	storage's deployed power in real-time-charging mode ($/MW)
E	energy level of storage
ν	charging binary variable (1=charging, 0=otherwise)
μ	discharging binary variable (1=discharging, 0=otherwise)
u	commitment status binary variable (1=committed, 0=otherwise)
α	startup binary variable (1=startup, 0=otherwise)
β	shutdown binary variable (1=shutdown, 0=otherwise)

happens within a few minutes after the occurrence of disturbance, the market operator tries to adjust the frequency of grid to its nominal value by rescheduling the power set points of synchronous generators [5].

The rapid development of renewable energy resources decreases the market share of synchronous generators. Therefore, the role of governor-equipped synchronous generators in PFC and inertia of power systems will be reduced in the near future that can threaten the stability of power systems. In this regard, BES resources can be deployed to generate or store electricity by rapidly injecting or absorbing power in real-time. BESs are static resources and do not have rotating parts and rotating frequency, consequently. Some researchers propose the virtual inertia concept to design the proper controller for non-synchronous resources' participation in PFC [6]. However, these resources have not real inertia constant and they could decrease the inertia of power system and endanger the security of grid. Therefore, the main challenge in utilizing renewable energy resources is developing a proper scheduling strategy that ensures the secure operation of grid.

1.2. Literature review

The frequency constraint unit commitment problem [7,8], scheduling of renewable energy resources [9,10], and their impacts on power system stability have been studied in different technical literature. In [7, 8], the system frequency response is added as a set of constraints to the security-constrained unit commitment (SCUC) problem. However, the characteristics and limitations of primary and secondary frequency controls are neglected in the proposed models. In [9,10] the security limitations of power system are ignored. In [11], a linear model is proposed to determine the frequency-regulating reserve, in the clearing problem of the joint energy and reserve markets. However, the power system behavior in PFC is not modeled in the model. A hierarchy model for scheduling synchronous generators in the joint energy and reserve markets is presented in [12,13]. The performance of the proposed model could be improved by considering the BES.

In [14], the interruptible load as a resource to provide primary frequency reserve is added to SCUC problem. One of the main challenges of the operator after PFC stage is recovering the frequency to its nominal value that is not considered in this work. In [15], a set of inertia-dependent constraints is added to the SCUC problem to model the inertia constant of generating units in the scheduling problem of the joint energy and reserve markets. The presented model of this work is nonlinear and the piecewise linear functions are used for the linearization that could reduce the accuracy of results. The contribution of load damping in the frequency response of power system is studied in [16]. The variable virtual inertia control strategy is proposed in [17] to analyze the impact of converter-interfaced renewable resources on the frequency response of the power system. However, the proposed models of [17,18] are proper for PFC, and SFC is not considered.

In [18], the model for scheduling wind power resources and BESs in the energy market and regulation ancillary service is presented. In the proposed framework, the battery cycle life is modeled in the optimal bidding strategy. Modeling the dynamic performance of BES could improve the achieved results. Authors in [19] provide a model for peak shaving and frequency regulation by BES based on uncertainties of consumption and regulation signals. The simulation results demonstrate that BESs' participation in the joint peak shaving and frequency regulation ancillary services leads to higher profit for the resources' owner. However, the impact of BESs on the inertia of the power system is neglected in this work. The proposed state-machine-based control framework of [20] enables the power system operator to use the BES as the backup of wind resources for participating in the frequency ancillary service. The proposed model is proper for controlling BES in PFC and SFC. However, the economic aspect is not modeled in the scheduling of resources. In [21], the overloading capability of BES in short-term operation is used to compensate for the wind power variations. It shall be noted that using this capability in the long term can reduce the BES's lifetime.

The proposed framework of [22] uses electrical vehicles and energy storage devices to provide the frequency regulation service. In this work, the frequency constraint is modeled as a reserve limitation that does not reflect the behavior of the system in the PFC and SFC. It shall be noted that the market operator can use both generation and demand-side resources for the frequency regulation service. To increase the inertia of the power system in the presence of renewable resources, the virtual inertia concept is used in [23] for the droop control of voltage source inverter (VSI) units. Additionally, the frequency-sensitive model is suggested for deploying demand response programs in primary and secondary frequency regulations. However, increasing or decreasing consumption could lead to dissatisfaction of consumers, which shall be considered. In the presented robust model of [24], the impact of renewable resource fluctuations on the frequency excursion of power system is evaluated. In [25], a two-stage model is presented to minimize the operation cost of micro-grids and restrict the frequency deviation during islanding events. The readjustment procedure of power set points in the SFC is not in this model. In the advanced power system, micro-grids can be connected and exchange energy together.

The frequency management in interconnected micro-grids is the challenge that has been evaluated in [26]. The proposed model provides an energy management framework to schedule primary and secondary reserves to prevent frequency excursion in interconnected micro-grids within the occurrence of a contingency. Considering the energy storage could increase the applicability of the proposed model in the smart grids. In [27], the impact of demand response programs and energy storage on the energy and reserve management of islanded multi-micro-grids is studied. In [28], the frequency and voltage constraints are considered in the coordinated scheduling of renewable energy resources and responsive loads. However, the reduction of power system inertia is the main issue that has not been considered in the proposed model. In [29], BES is used as a backup resource of fuel cells to provide the PFC. However, the fast response of fuel cells or BESs is an advantage in comparison with other energy resources, but in the PFC horizon, the inertia of the power system is a key factor that prevents sharp frequency deviations. In some papers, the BES units are used to improve the performance of the power system. In [30], the optimal strategy is determined based on the maximization of renewable energy production and BES, and minimization of the tie-line active power deviation. In [31,32], the impact of BES is used to minimize the difference in the active power flow between two ac tie-lines.

In [33], the frequency constraint unit commitment problem is solved in the presence of BES. In this work, the authors claim that the fast-response capability of BES could improve the frequency dynamic security. The proposed model neglects the dynamic response of the power system in the SFC. In [34], the fast response capability of compressed air energy storage is used to inject power after a disturbance and maintain the frequency of the power system in the allowable intervals. Considering the battery energy storage could promote the applicability of this model in smart grids. The concept of frequency security margin is introduced in [35] to evaluate the capability of the power system to maintain the frequency of grid within the predefined interval after the occurrence of a contingency. It shall be noted this model is very interesting for PFC studies and it can be developed for recovery the frequency of system after occurrence of a disturbance. In [36], effects of operation constraints of BESs such as the state of charge (SOC), inverter limitations, ramp rate on the participation level of these resources in PFC are evaluated.

As seen in the literature review, different models have been proposed to consider frequency control in the scheduling problem of BESs in the joint energy and reserve markets, but the tradeoff between their fast response and impact on the inertia of power system is still a challenge among the researchers.

1.3. Motivation

The main motivation of this work is to investigate the possibility of using the available capacity of BESs to supply the frequency reserve that is required to maintain the security of power systems to an acceptable level. Therefore, the impacts of BESs on the different frequency control levels such as PFC and SFC shall be studied. Moreover, a frequency-constrained scheduling strategy shall be developed based on the technical characteristics of BESs.

1.4. Procedure & contributions

During the occurrence of a contingency, the balance of generation and consumption will be disrupted and the frequency error signal will be generated based on the value of power mismatch. Power system operators try to commit fast response synchronous generators to compensate for the power mismatch and maintain the frequency within the allowable interval. Therefore, they use PFC ancillary service for the secure operation of the power system after the occurrence of a contingency. The interval of PFC is less than a few seconds after disturbance [13]. After stabilizing the frequency within the safe margin, the power system operator uses the SFC service to return the frequency of the grid to its nominal value. In SFC, the operator has enough time to reschedule the power set points of generators [13].

In traditional power systems, the governors of synchronous generators respond to the error signal by readjusting the fuel valve. The response of synchronous generator to an error signal depends on many parameters such as governor speed, design of the controller, the inertia of generator, etc. The development of renewable energy resources changes the structure of generation systems from rotational machines to inverter-based interfaces. As mentioned before, the main advantage of BES in comparison with the traditional resources is its flexibility. In over-frequency conditions, BES can reduce its generation (in discharging mode) or absorb the surplus of energy (in charging mode). Similarly, in under-frequency conditions, the generating/consuming power of BES can be increased/decreased in discharging/charging mode. However, the main problem in using BESs is the frequency stability. These resources are inertia less and have not rotating part. Therefore, they cannot provide the mechanical response to damp the oscillations of frequency.

In this work, a coordinated model is proposed for scheduling BESs and synchronous generators in the joint energy and reserve markets. To evaluate the security of system, the single contingency analysis (N-1) is used. In PFC, the frequency excursion signal is considered to readjust the output power of generators. In SFC, both frequency excursion signal and power setpoint are addressed to reschedule the available generating units. Moreover, BES resources are used as fast response units to adjust the generation and consumption of the grid after the occurrence of a contingency. The model is formulated based on minimization of the negative social welfare, and technical limitations of resources and network such as capacity, ramp rate, state of charge, frequency, rate of change of frequency (RoCoF) of individual generators and power systems are considered as constraints in the optimization problem. The model is linearized by the big M theory and formulated based on mixed-integer linear programming (MILP) methodology. The optimal

Table 1
Data of synchronous generators.

Bus (b)	Generator (g)	$P^{G,MIN}$ (MW)	$P^{G,MAX}$ (MW)	m (mHz/MW)	Ramp rate (MW/min)	H (MJ/MW)	$\rho^{UR}_{i=pri}$($/MW)	$\rho^{UR}_{i=sec}$($/Mh)	Coefficient of cost function ($/MWh^2, $/MWh, $/h)
1	1	16	20	150	3	2.8	17	30	0.44, 48.4, 633
	2	16	20	150	3	2.8	17	30	0.44, 48.4, 633
	3	15.2	76	39.74	2	3	18	9	0.01, 11, 145
	4	15.2	76	39.74	2	3	18	9	0.01, 11, 145
2	5	16	20	150	3	2.8	17	30	0.44, 48.4, 633
	6	16	20	150	3	2.8	17	30	0.44, 48.4, 633
	7	15.2	76	39.74	2	3	18	9	0.01, 11, 145
	8	15.2	76	39.74	2	3	18	9	0.01, 11, 145
7	9	25	100	30	7	2.8	15	18	0.07, 25.4, 615
	10	25	100	30	7	2.8	15	18	0.07, 25.4, 615
	11	25	100	30	7	2.8	15	18	0.07, 25.4, 615
13	12	69	197	15.23	3	2.8	15	20	0.02, 28.5, 739
	13	69	197	15.23	3	2.8	15	20	0.02, 28.5, 739
	14	69	197	15.23	3	2.8	15	20	0.02, 28.5, 739
15	15	2.4	12	250	1	2.8	25	15	0.08, 38.9, 56
	16	2.4	12	250	1	2.8	25	15	0.08, 38.9, 56
	17	2.4	12	250	1	2.8	25	15	0.08, 38.9, 56
	18	2.4	12	250	1	2.8	25	15	0.08, 38.9, 56
	19	2.4	12	250	1	2.8	25	15	0.08, 38.9, 56
	20	54.3	155	19.35	3	3	22	15	0.01, 9.3, 220
16	21	54.3	155	19.35	3	3	22	15	0.01, 9.3, 220
18	22	100	400	7.5	20	5	25	41	0, 13.5, 621
21	23	100	400	7.5	20	5	25	41	0, 13.5, 621
22	24	10	50	60	2	3.5	0	0	0, 0, 0
	25	10	50	60	2	3.5	0	0	0, 0, 0
	26	10	50	60	2	3.5	0	0	0, 0, 0
	27	10	50	60	2	3.5	0	0	0, 0, 0
	28	10	50	60	2	3.5	0	0	0, 0, 0
	29	10	50	60	2	3.5	0	0	0, 0, 0
23	30	54.3	155	19.35	3	3	22	15	0.01, 9.3, 220
	31	54.3	155	19.35	3	3	22	15	0.01, 9.3, 220
	32	54.3	155	19.35	3	3	22	15	0.01, 9.3, 220

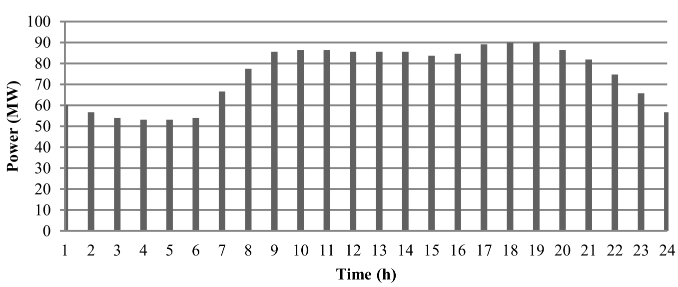

Fig. 1. Individual Load profile.

Table 2
Data of loads.

Bus (b)	1	2	3	4	5	6	7	8	9
ρ^D($/MWh)	5	6	5	9	3	7	4	5	5
% of system load	3.8	3.4	6.3	2.6	2.5	4.8	4.4	6.0	6.1
Bus (b)	10	13	14	15	16	18	19	20	
ρ^D($/MWh)	5	5	4	7	6	3	10	12	
% of system load	6.8	9.3	6.8	11.1	3.5	11.7	6.4	4.5	

scheduling of resources in the joint energy and reserve markets is determined in a way that maintains RoCoFs and the frequency of generators and grid within the allowable range after the occurrence of the single contingency events and restore the frequency to its nominal value based on the minimum operational cost. The main contributions of this work can be summarized as follow:

- Presenting a linear model for coordinated scheduling of BES and synchronous generators in the joint energy and reserve markets based on the limitations of PFC and SFC and modeling the frequency response of BES in the scheduling of resources.
- Coupling the security and energy management problem with considering the frequency, and RoCoFs of grid and individual generation in the presence of BESs to show impacts of BES in PFC and SFC.

1.5. Paper organization

The rest of this paper is organized as follows: Section 2 formulates the frequency control in primary and secondary intervals, RoCoF, the proposed objective function, and the related constraints. Numerical simulations are presented in Section 3 and the performance of the proposed model is evaluated via different scenarios. Finally, Section 4 concludes the paper.

2. Scheduling problem

A BES stores the energy from renewable sources and releases it when the customer needs it. BESs are very fast responding resources, and they can reach full power within milliseconds. Consequently, BES can be used for ancillary services such as providing operating reserves and frequency control to minimize the impact of contingencies. The BES needs the converter to inject/absorb power to/from the power grid. In power systems, voltage source, Z-source, and quasi-Z-source converters are the most common. Moreover, a low-pass filter (such as LC or LCL) is used to reduce the injected harmonics [37].

The frequency of power system is highly dependent on the balance of generation and consumption. Increasing the generation/consumption increases/decreases the frequency of system. The static performance of the generator within pre and post contingency intervals can be represented by (1)–(3) [14]:

Table 3
Data of energy storages.

Bus (b)	Storage (s)	P^{MIN} (MW)	P^{MAX} (MW)	E^{MIN} (MWh)	E^{MAX} (MWh)	$\rho^{DA}=\rho^{RT}$ ($/MW)	$\rho^{UR}_{i=pri}$($/MW)	$\rho^{UR}_{i=sec}$($/MW)	Initial energy (MWh)
1	1	1	10	1	10	23.4	14	19	3
	2	1	10	1	10	23.4	14	19	3
2	3	2	15	1	15	25.3	30	27	10
	4	1	10	1	10	23.4	14	19	3
	5	1	20	1	18	27.6	28	24	7
7	6	1	20	1	18	27.6	28	24	7
13	7	1	20	1	18	27.6	28	24	7
15	8	1	10	1	10	23.4	14	19	4
	9	1	10	1	10	23.4	14	19	3
22	10	1	10	1	10	23.4	14	19	3
23	11	2	15	1	15	25.3	30	27	10

Table 4
The operational cost for different case studies ($).

Case	Energy supply cost		Reserve		Energy notsupplied cost	Total cost
	Pre-contingency	Post-contingency	Primary	Secondary		
I	448,732.25	271,856.20	29,781.32	18,564.15	0	768,933.919
II	437,218.32	263,911.75	27,421.71	17,581.14	0	746,132.92
III	439,871.35	267,311.04	28,981.25	17,761.62	0	753,925.26
IV	430,411.23	260,451.32	26,721.11	17,311.18	0	734,894.84

Table 5
The operational cost of synchronous generators ($).

Case	Generation cost		Reserve cost	
	Pre-contingency	Post-contingency	Primary	Secondary
I	448,732.25	271,856.2	29,781.32	18,564.15
II	413,221.54	256,711.65	25,321.11	16,911.41
III	421,482.21	263,181.45	27,432.62	17,411.39
IV	409,541.49	254,291.46	23,711.34	15,182.37
Table 5. The operational cost of energy storages ($).				
Case	Generation cost		Reserve cost	
	Pre-contingency	Post-contingency	Primary	Secondary
I	0	0	0	0
II	23,996.78	7200.1	2100.6	669.73
III	18,389.14	4129.59	1548.63	350.23
IV	20,869.74	6159.86	3009.77	2128.81

Table 6
Total generation in pre and post contingency intervals (MW).

Case	Pre-contingency		Post-contingency	
	Synchronous generators	Energy storages	Synchronous generators	Energy storages
I	30,477.60	0	30,477.60	0
II	28,847.60	1630	29,646.10	831.50
III	29,217.60	1260	30,006.76	470.84
IV	29,047.59	1430	29,756.78	720.82

$$\sum_{b\in\Omega_B}\left(\sum_{g\in\Omega_{G_b}}\Delta P^{GEN}_{g,b,i,t}+\sum_{s\in\Omega_{S_b}}\left(\mu_{s,b,i,t}.\Delta P^{DCH}_{s,b,i,t}-\nu_{s,b,i,t}.\Delta P^{CH}_{s,b,i,t}\right)\right)=\sum_{b\in\Omega_B}\left(\sum_{d\in\Omega_{D_b}}\Delta P^{D}_{d,b,i,t}-\Delta LSH_{d,b,i,t}\right) \quad (1)$$

$$0\le\mu_{s,b,i,t}+\nu_{s,b,i,t}\le 1 \quad (2)$$

$$LSH_{d,b,pre,t}=0 \quad (3)$$

The first and second terms of the left-hand side of (1) represent changes of the output power of generating and storage units, respectively. The right-hand side demonstrates the variations of demand and amount of shed load. As seen in this equation, the unexpected outage of generating units imposes negative imbalance power that shall be compensated by available generators, storage units, or load shedding. In (2), the binary variablesνandμrepresent the charging and discharging modes of battery energy storage. It shall be noted that both $\nu$and$\mu$are equal to zero when the energy storage is not committed. Moreover, the load shedding in the pre-contingency interval is zero that is represented by (3).

The available generating units respond to the contingency based on the set point of power (that is sent by the power system operator) and frequency excursion that is formulated by (4) and (5) [23]:

$$\Delta P^{GEN}_{g,b,i,t}=\Delta P^{REF}_{g,b,i,t}-A_{g,b,i,t}.\frac{\Delta f_{i,t}}{m_{g,b}}.u_{g,b,i,t} \quad (4)$$

$$\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\Delta P^{GEN}_{g,b,i,t}=\sum_{b\in\Omega_B}\left(\sum_{g\in\Omega_{G_b}}\Delta P^{REF}_{g,b,i,t}-\Delta f_{i,t}.\sum_{g\in\Omega_{G_b}}\frac{A_{g,b,i,t}.u_{g,b,i,t}}{m_{g,b}}\right) \quad (5)$$

As seen in (4), to compensate the over/under frequency, the output power of generating units shall be decreased/increased. Variations of the output power of available individual generators and power system's synchronous generators in post contingency are represented by (4) and (5), respectively.

2.1. Primary frequency control

In the primary frequency control, there is not enough time to adjust the power set point. Therefore, within pre-contingency and primary intervals, the power set point is not changed. Additionally, it is supposed that the commitment status of available generating units is not changed in the primary frequency interval. According to (6)–(9), available generating units' responses to the contingency is proportional to frequency excursion and droop index [5]:

$$P^{GEN}_{g,b,pri,t}-P^{GEN}_{g,b,pre,t}=A_{g,b,pri,t}.u_{g,b,pri,t}.\left(\frac{f_{pre,t}-f_{pri,t}}{m_{g,b}}\right) \quad (6)$$

$$\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}P^{GEN}_{g,b,pri,t}-P^{GEN}_{g,b,pre,t}=\left(f_{pre,t}-f_{pri,t}\right).\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\left(\frac{A_{g,b,pri,t}.u_{g,b,pri,t}}{m_{g,b}}\right) \quad (7)$$

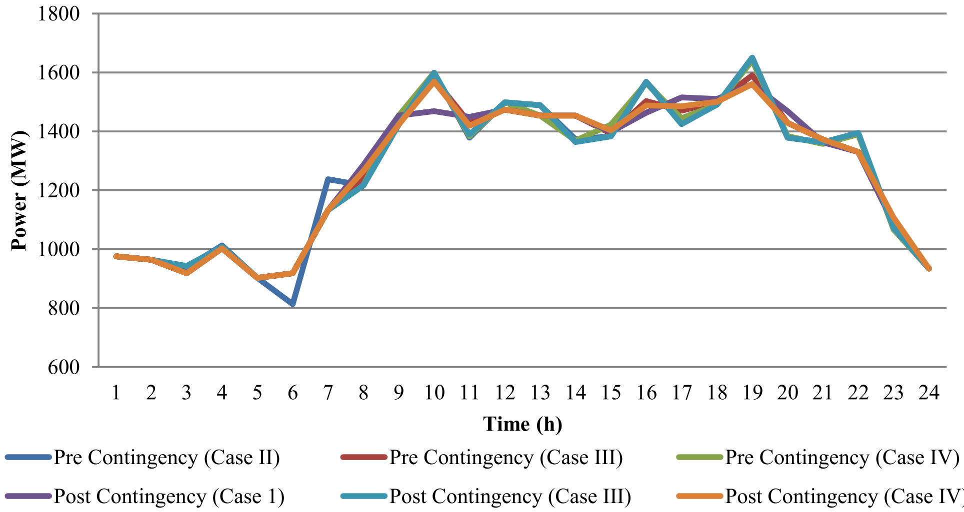

Fig. 2. Power generation of synchronous generators set in case studies II, III, IV.

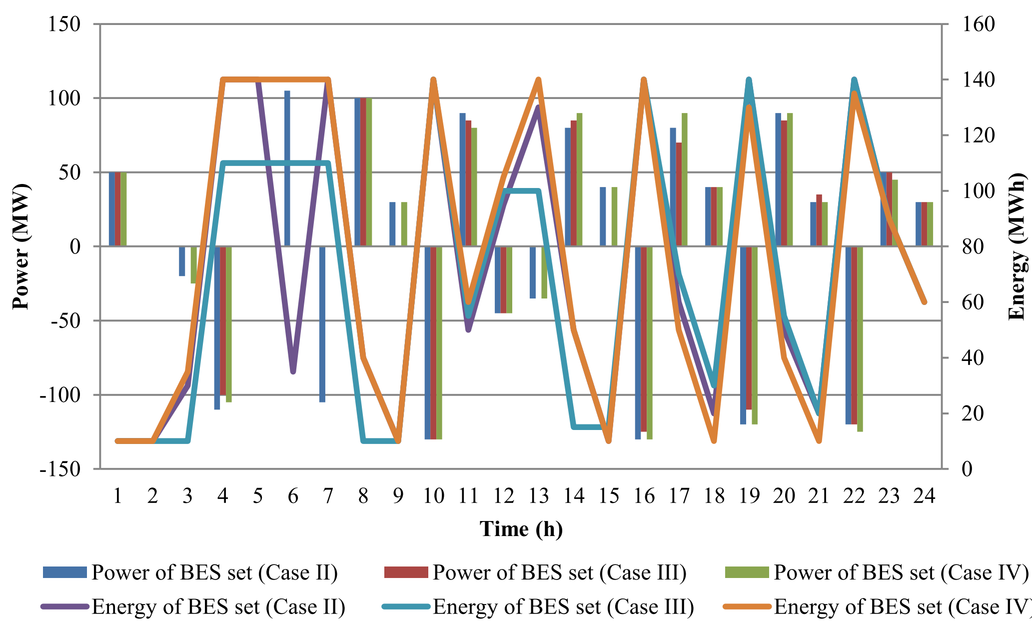

Fig. 3. Power and Energy level of BESs set in case studies II, III, IV (pre-contingency).

$$f_{pri,t} = f_{pre,t} - \frac{\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}} P^{GEN}_{g,b,pri,t} - P^{GEN}_{g,b,pre,t}}{\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\left(\frac{A_{g,b,pri,t}.u_{g,b,pri,t}}{m_{g,b}}\right)} \tag{8}$$

As seen in (6) and (7), by decreasing the frequency in the primary interval, the generating power of the available unit is increased, and vice-versa. The frequency of power system after the occurrence of a contingency and within the primary frequency interval can be calculated by (8) [5]. Additionally, (9)-(12) show that the commitment status of generators, charging/discharging modes of battery energy storage, power set points of generators cannot be changed in the primary frequency interval.

$$u_{g,b,pre,t} = u_{g,b,pri,t} \tag{9}$$

$$\mu_{s,b,pre,t} = \mu_{s,b,pri,t} \tag{10}$$

$$\nu_{s,b,pre,t} = \nu_{s,b,pri,t} \tag{11}$$

$$P^{REF}_{g,b,pre,t} = P^{REF}_{g,b,pri,t} = P^{GEN}_{g,b,pre,t} \tag{12}$$

According to (1), the performance of available generating units within the primary frequency interval can be rewritten as (13):

$$\begin{aligned}&\sum_{g\in\Omega_{G_b}}\left(A_{g,b,pri,t}.P^{GEN}_{g,b,pri,t} - \left(2A_{g,b,pri,t}-1\right).P^{GEN}_{g,b,pre,t}\right) - \sum_{d\in\Omega_{D_b}}\left(P_{d,b,pri,t} - P_{d,b,pre,t} + LSH_{d,b,pri,t}\right)+\\&\sum_{s\in\Omega_{S_b}}\left(A_{s,b,pri,t}.\left(P^{DCH}_{k,s,pri,t} - P^{CH}_{s,b,pri,t}\right) - \left(2A_{s,b,pri,t}-1\right).\left(P^{DCH}_{k,s,pre,t} - P^{CH}_{s,b,pre,t}\right)\right) = 0\end{aligned} \tag{13}$$

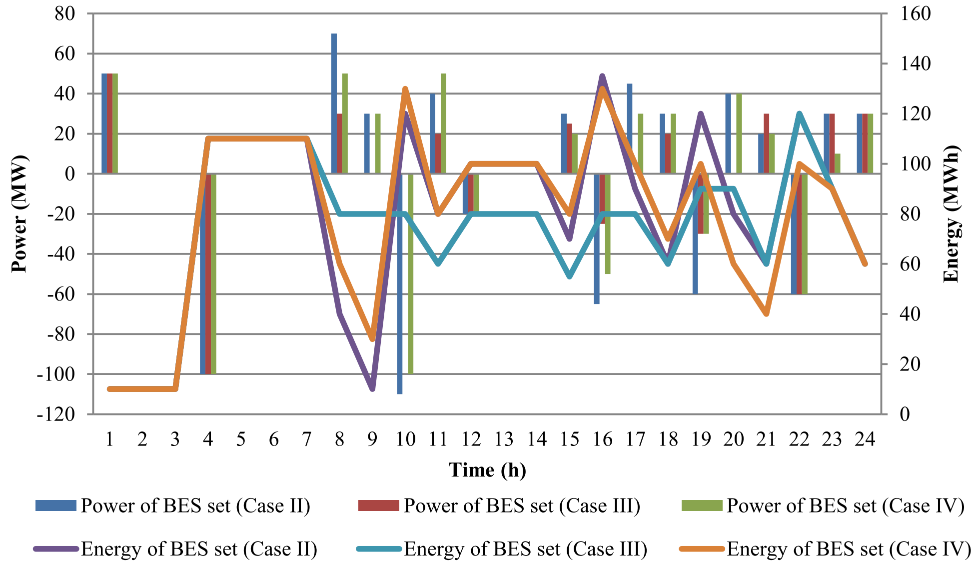

Fig. 4. Power and Energy level of BESs set in case studies II, III, IV (post-contingency).

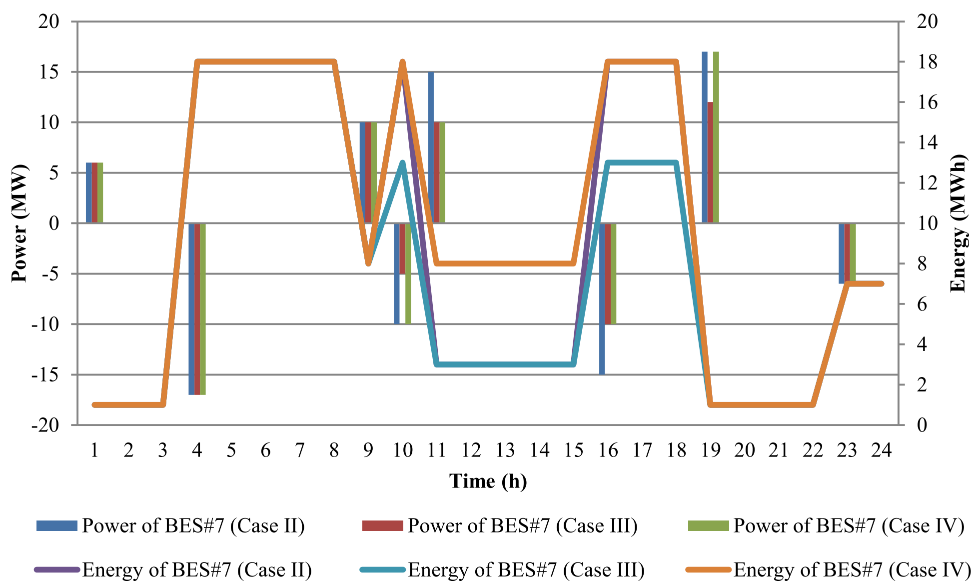

Fig. 5. Energy level of BES#7 in case studies II, III, IV (pre-contingency).

2.2. Secondary frequency control

In the secondary frequency control, the power system operator tries to return the frequency of system from f_{pri} to f_{sec} (that is usually equal to the nominal frequency of the grid). The secondary frequency control happens within a few minutes after the primary frequency [13]. Therefore, the power system operator has enough time to readjust the power set points. According to (4) and (5), the generating units' responses and the frequency of power system in the secondary frequency interval can be formulated by (14)-(15):

$$P^{GEN}_{g,b,\sec,t} - P^{GEN}_{g,b,pri,t} = P^{REF}_{g,b,\sec,t} - P^{REF}_{g,b,pri,t} + A_{g,b,\sec,t}.u_{g,b,\sec,t}.\left(\frac{f_{pri,t} - f_{\sec,t}}{m_{g,b}}\right) \tag{14}$$

$$f_{\sec,t} = f_{pri,t} - \frac{\sum_{b\in\Omega_b}\sum_{g\in\Omega_{G_b}} P^{GEN}_{g,b,\sec,t} - P^{GEN}_{g,b,pri,t} + P^{GEN}_{g,b,pre,t} - P^{REF}_{g,b,\sec,t}}{\sum_{b\in\Omega_b}\sum_{g\in\Omega_{G_b}} \frac{A_{g,b,\sec,t}.u_{g,b,\sec,t}}{m_{g,b}}} \tag{15}$$

In the secondary frequency control, it is supposed that no unexpected outage occurred in generating units (This work is based on the N-1 contingency analysis). The static performance of the generator within the post contingency interval is formulated by (16).

$$\sum_{g\in\Omega_{G_b}}\left(P^{GEN}_{g,b,\sec,t} - P^{GEN}_{g,b,pri,t}\right) - \sum_{d\in\Omega_{D_b}}\left(P^{D}_{d,b,\sec,t} - P^{D}_{d,b,pri,t} + LSH_{d,b,\sec,t} - LSH_{d,b,pri,t}\right) + \sum_{s\in\Omega_{S_b}}\left(P^{DCH}_{k,s,\sec,t} - P^{DCH}_{k,s,pri,t}\right) - \left(P^{CH}_{s,b,\sec,t} - P^{CH}_{s,b,pri,t}\right) = 0 \tag{16}$$

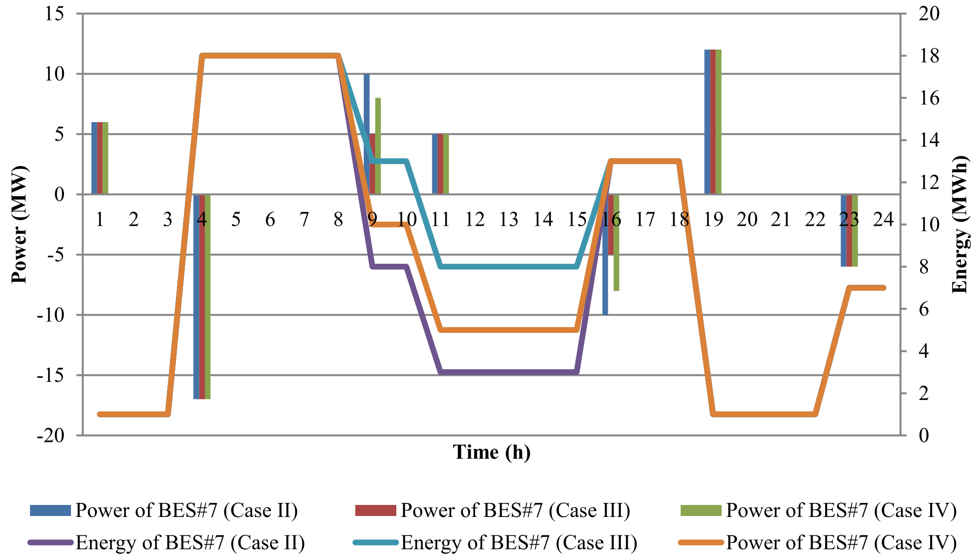

Fig. 6. Energy level of BES#7 in case studies II, III, IV (post-contingency).

2.3. Rate of change of frequency (RoCoF)

For the safe operation of the power system generator, the rate of change of frequency of grid and individual synchronous generators shall be within the permissible range. The swing Eq. (17) formulates the relation between RoCoF and variations of mechanical and electrical power of available generator [14]:

$$\frac{df_t}{dt} = \frac{f_{ref}}{2H_g.P^r_g}.\left(\Delta P^{MCH}_t - \Delta P^{ELE}_t\right) \tag{17}$$

The speed of changing the mechanical power is very lower than the electrical power. Therefore, the variation of mechanical power can be neglected (within the primary frequency interval, $\Delta P^{MCH} = 0$). According to (17), the maximum RoCoF has happened in the first cycles after the contingency that the shortage of electrical power of the power system is the maximum value. In other words, the maximum RoCoF happens within the primary frequency interval [5]. Eq. (18) shows the variation of electrical power of each synchronous generator.

$$\Delta P^{ELE}_{g,b,i,t} = \Delta P^{GEN}_{g,b,i,t} = \Delta P^{D}_{d,b,i,t} - \Delta LSH_{d,b,i,t} - \Delta P^{DCH}_{s,b,i,t} + \Delta P^{CH}_{s,b,i,t} \tag{18}$$

Therefore, the rate of variation of frequency for each individual available generator is represented by (19):

$$\frac{df_{g,b,i,t}}{dt} = -\frac{f_{ref}.A_{g,b,i,t}}{2H_{g,b}.P^r_{g,b}}.\Big(\Delta P^{D}_{d,b,i,t} - \Delta LSH_{d,b,i,t} - \left(2A_{s,b,i,t}-1\right).\left(\mu_{s,b,i,t}.\Delta P^{DCH}_{s,b,i,t} - \nu_{s,b,i,t}.\Delta P^{CH}_{s,b,i,t}\right)\Big) \tag{19}$$

Eq. (20) demonstrates the RoCoF of individual available generators:

$$RoCoF_{g,b,i,t} = -\frac{f_{ref}.A_{g,b,pri,t}}{2H_{g,b}.P^r_{g,b}}.\left(\begin{array}{l} P^{D}_{d,b,pri,t} - P^{D}_{d,b,pre,t} - LSH_{d,b,pri,t} \\ -\left(\begin{array}{l} A_{s,b,pri,t}.\left(\mu_{s,b,pri,t}.\left(P^{DCH}_{s,b,pri,t} - P^{DCH}_{s,b,pre,t}\right) - \nu_{s,b,pri,t}.\left(P^{CH}_{s,b,pri,t} - P^{CH}_{s,b,pre,t}\right)\right) \\ -\left(1 - A_{s,b,pri,t}\right).\left(\mu_{s,b,pre,t}.P^{DCH}_{s,b,pre,t} - \nu_{s,b,pre,t}.P^{CH}_{s,b,pre,t}\right) \end{array}\right) \end{array}\right) \tag{20}$$

The RoCoF of power system is calculated based on the amount of electrical power variation that is resulted from the unexpected outage of committed generating units. The RoCoF of system is calculated by (21):

$$RoCoF_{sys} = -\frac{f_{ref}.\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\left(1 - A_{g,b,pri,t}\right).u_{g,b,pre,t}.P^{GEN}_{g,b,pre,t} + \sum_{s\in\Omega_{S_b}}\left(1 - A_{s,b,pri,t}\right).\left(\mu_{s,b,pre,t}.P^{DCH}_{s,b,pre,t} - \nu_{s,b,pre,t}.P^{CH}_{s,b,pre,t}\right)}{2\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}} H_{g,b}.A_{g,b,pri,t}.P^r_{g,b}} \tag{21}$$

2.4. Objective function

In this work, the objective function is formulated based on minimizing the negative value of social welfare. The proposed objective function is formulated by (22).

$$\min \sum_{t\in T}\left(\begin{array}{l}\sum_{i\in \text{int}}\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\rho^{DA}_{g,b,i,t}.P^{GEN,DA}_{g,b,i,t}+\sum_{s\in\Omega_{S_b}}\rho^{DA}_{s,b,i,t}.(P^{DCH,DA}_{s,b,i,t}-P^{CH,DA}_{s,b,i,t})+\\ \sum_{i\in \text{int}}\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\rho^{UR}_{g,b,i,t}.R^{UR}_{g,b,i,t}+\sum_{s\in\Omega_{S_b}}\rho^{UR}_{s,b,i,t}.(R^{URDCH}_{s,b,i,t}-R^{URCH}_{s,b,i,t})+\\ \sum_{i\in \text{int}}\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\rho^{DR}_{g,b,i,t}.R^{DR}_{g,b,i,t}+\sum_{s\in\Omega_{S_b}}\rho^{DR}_{s,b,i,t}.\left(R^{DRDCH}_{s,b,i,t}-R^{DRCH}_{s,b,i,t}\right)+\\ \sum_{i\in \text{int}}\sum_{b\in\Omega_B}\sum_{g\in\Omega_{G_b}}\rho^{RT}_{g,b,i,t}.P^{GEN,RT}_{g,b,i,t}+\sum_{s\in\Omega_{S_b}}\rho^{RT}_{s,b,i,t}.(P^{DCH,RT}_{s,b,i,t}-P^{CH,RT}_{s,b,i,t})+\\ \sum_{i\in \text{int}}\sum_{b\in\Omega_B}\sum_{d\in\Omega_{D_b}}\left(voll_t.LSH_{d,b,i,t}-\rho^{D}_{d,b,i,t}.P^{D}_{d,b,i,t}\right)\end{array}\right) \tag{22}$$

The first, second, third, fourth, and fifth terms of (22) represent day-ahead, up and down regulation, real-time load shedding, and demand-supply costs, respectively. As seen in (23)–(25), the generating power of each unit is the sum of day-ahead and real-time values:

$$P^{GEN}_{g,b,i,t}=P^{GEN,DA}_{g,b,i,t}+P^{GEN,RT}_{g,b,i,t} \tag{23}$$

$$P^{DCH}_{s,b,i,t}=P^{DCH,DA}_{s,b,i,t}+P^{DCH,RT}_{s,b,i,t} \tag{24}$$

$$P^{CH}_{s,b,i,t}=P^{CH,DA}_{s,b,i,t}+P^{CH,RT}_{s,b,i,t} \tag{25}$$

2.5. Constraints

In this subsection, the operational constraints of generating unit are modeled:

Capacity constraint of generators: The power set point (26), the output power of committed available generators in the day-ahead planning horizon (27), up and down reserves (28) and (29), deployed power in real-time planning horizon (30) and total generation of synchronous generators (31) shall within the permissible interval:

$$A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\min}_{g,b}\le P^{REF}_{g,b,i,t}\le A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\max}_{g,b};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{26}$$

$$A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\min}_{g,b}\le P^{GEN,DA}_{g,b,i,t}\le A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\max}_{g,b};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{27}$$

$$A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\min}_{g,b}\le R^{UR}_{g,b,i,t}\le A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\max}_{g,b};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{28}$$

$$A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\min}_{g,b}\le R^{DR}_{g,b,i,t}\le A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\max}_{g,b};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{29}$$

$$-R^{DR}_{g,b,i,t}\le P^{GEN,RT}_{g,b,i,t}\le R^{UR}_{g,b,i,t};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{30}$$

$$A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\min}_{g,b}\le P^{GEN}_{g,b,i,t}\le A_{g,b,i,t}.u_{g,b,i,t}.P^{GEN,\max}_{g,b};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{31}$$

Capacity constraint of energy storages: Same as generators, the generating power of energy storages in the energy (32)-(37), and reserve (38)-(41) markets in charging and discharging modes, shall be within the allowable interval, as follows:

$$A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\min}_{s,b}\le P^{DCH,DA}_{s,b,i,t}\le A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{32}$$

$$-R^{DRDCH}_{s,b,i,t}\le P^{DCH,RT}_{g,b,i,t}\le R^{URDCH}_{s,b,i,t};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{33}$$

$$A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\min}_{s,b}\le P^{DCH}_{s,b,i,t}\le A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{34}$$

$$A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\min}_{s,b}\le P^{CH,DA}_{s,b,i,t}\le A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{35}$$

$$-R^{DRCH}_{s,b,i,t}\le P^{CH,RT}_{g,b,i,t}\le R^{URCH}_{s,b,i,t};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{36}$$

$$A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\min}_{s,b}\le P^{CH}_{s,b,i,t}\le A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{37}$$

$$A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\min}_{s,b}\le R^{URDCH}_{s,b,i,t}\le A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{38}$$

$$A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\min}_{s,b}\le R^{DRDCH}_{s,b,i,t}\le A_{s,b,i,t}.\mu_{s,b,i,t}.P^{DCH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{39}$$

$$A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\min}_{s,b}\le R^{URCH}_{s,b,i,t}\le A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{40}$$

$$A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\min}_{s,b}\le R^{DRCH}_{s,b,i,t}\le A_{s,b,i,t}.\nu_{s,b,i,t}.P^{CH,\max}_{s,b};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_b,\forall i\in \text{int},\forall t\in T \tag{41}$$

Capacity of load shedding: The capacity limitation of shed load is represented by (42)

$$LSH^{\min}_{d,b}\le LSH_{d,b,i,t}\le LSH^{\max}_{d,b};\ \ \forall d\in\Omega_{D_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{42}$$

Ramping constraint: The variation rate of output power of generators can be limited by the ramp-up (43) and ramp-down (44) constraints:

$$P^{GEN}_{g,b,i,t}-P^{GEN}_{g,b,i,t-1}\le ramp^{UP}_{g,b}.u_{g,b,i,t-1}+ramp^{SU}_{g,b}.\alpha_{g,b,i,t};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{43}$$

$$P^{GEN}_{g,b,i,t-1}-P^{GEN}_{g,b,i,t}\le ramp^{DN}_{g,b}.u_{g,b,i,t}+ramp^{SD}_{g,b}.\beta_{g,b,i,t};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{44}$$

where, $\alpha$and$\beta$are startup and shutdown binary variables. The relations betweenα,β, and u are represented by (45)-(46)

$$\alpha_{g,b,i,t}+\beta_{g,b,i,t}\le 1;\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{45}$$

$$\alpha_{g,b,i,t}+\beta_{g,b,i,t}=u_{g,b,i,t}-u_{g,b,i,t-1};\ \ \forall g\in\Omega_{G_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{46}$$

Energy constraint of battery storage: The total stored energy of the battery and its energy constraint can be modeled by (47) and (48), respectively. Additionally, constraint (49) ensures that the net value of charging and discharging power of storage within the planning period is zero.

$$E_{s,b,i,t}=A_{s,b,i,t}.E_{s,b,i,t-1}-P^{DCH}_{s,b,i,t}+P^{CH}_{s,b,i,t};\ \ \forall s\in\Omega_{S_b},\forall b\in\Omega_B,\forall i\in \text{int},\forall t\in T \tag{47}$$

$$A_{s,b,i,t}.E_{s,b,i,t}^{\min} \leq E_{s,b,i,t} \leq A_{s,b,i,t}.E_{s,b,i,t}^{\max}; \quad \forall s \in \Omega_{S_b}, \forall b \in \Omega_B, \forall i \in \text{int}, \forall t \in T \tag{48}$$

$$E_{s,b,i,0} = E_{s,b,i,T}; \quad \forall s \in \Omega_{S_b}, \forall b \in \Omega_B, \forall i \in \text{int}, \forall t \in T \tag{49}$$

Energy balance: In the pre-contingency interval, the generating power of generators and discharged power of battery storage shall be equal to the consumption of the grid and the required power for charging of batteries. Moreover, the power shortage of unavailable committed units is supplied by the load shedding, the deployed power of the generator, and batteries in the primary frequency interval. In the secondary frequency interval, variation of the generating power of generators and discharged power of battery storages shall be equal to variations of the consumption of grid and shed load. The balance constraints in the pre-contingency and primary and secondary frequency intervals are represented by (50), (51), and (52), respectively.

$$\sum_{\forall b\in\Omega_B}\sum_{\forall s\in\Omega_{S_b}} P_{g,b,pre,t}^{GEN} + \sum_{\forall b\in\Omega_B}\sum_{\forall s\in\Omega_{S_b}} \left(P_{s,b,pre,t}^{DCH} - P_{s,b,pre,t}^{CH}\right) = \sum_{\forall b\in\Omega_B}\sum_{\forall d\in\Omega_{D_b}} P_{d,b,pre,t}^{D} \tag{50}$$

$$\left(\begin{array}{l}\sum\limits_{\forall b\in\Omega_B}\sum\limits_{\forall g\in\Omega_{G_b}} A_{g,b,pri,t}\cdot\left(P_{g,b,pri,t}^{GEN} - P_{g,b,pre,t}^{GEN}\right) + \sum\limits_{\forall b\in\Omega_B}\sum\limits_{\forall d\in\Omega_{D_b}} LSH_{d,b,pri,t} \\ + \sum\limits_{\forall b\in\Omega_B}\sum\limits_{\forall s\in\Omega_{S_b}} A_{s,b,pri,t}\cdot\left(P_{s,b,pri,t}^{DCH} - P_{s,b,pre,t}^{DCH} - P_{s,b,pri,t}^{CH} + P_{s,b,pre,t}^{CH}\right)\end{array}\right) = \left(\begin{array}{l}\sum\limits_{\forall b\in\Omega_B}\sum\limits_{\forall g\in\Omega_{G_b}} \left(1 - A_{g,b,pri,t}\right).P_{g,b,pre,t}^{GEN} + \\ \sum\limits_{\forall b\in\Omega_B}\sum\limits_{\forall s\in\Omega_{S_b}} \left(1 - A_{s,b,pri,t}\right)\cdot\left(P_{s,b,pre,t}^{DCH,DA} - P_{s,b,pre,t}^{CH,DA}\right)\end{array}\right) \tag{51}$$

$$\sum_{\forall b\in\Omega_B}\sum_{\forall s\in\Omega_{S_b}} P_{g,b,\sec,t}^{GEN} - P_{g,b,pri,t}^{GEN} + \sum_{\forall b\in\Omega_B}\sum_{\forall s\in\Omega_{S_b}} \left(P_{s,b,\sec,t}^{DCH} - P_{s,b,pri,t}^{DCH} - P_{s,b,\sec,t}^{CH} + P_{s,b,pri,t}^{CH}\right) = \sum_{\forall b\in\Omega_B}\sum_{\forall d\in\Omega_{D_b}} P_{d,b,\sec,t}^{D} - P_{d,b,pri,t}^{D} - LSH_{d,b,\sec,t} + LSH_{d,b,pri,t} \tag{52}$$

Frequency constraint: In various intervals, the frequency of grid shall be within the allowable range that is specified by the system operator. Eq. (53) shows the frequency constraint.

$$f_i^{\min} \leq f_{i,t} \leq f_i^{\max}; \quad \forall i \in \text{int}, \forall t \in T \tag{53}$$

where for i=pri, $f_i^{\min}$ is the nadir frequency. It is important to note that the setting of the protection system strongly depends on the nadir frequency [38]. To calculate the nadir frequency, the dynamic response of the power system must be simulated. This leads to a nonlinear scheduling problem [39]. However, in [40] the linearization technique for the nadir constraint is presented. In this study, the static frequency response of the system is modeled. Therefore, it is assumed that nadir frequency and protection system settings will not change during the post-contingency intervals. In addition, the inertia of the total system is assumed to remain unchanged after the contingency [41]. As a result, the nadir frequency is considered a fixed parameter.

RoCoF constraint: For the safe operation of synchronous generators, RoCoF of available committed generators (in primary frequency interval) and the power system shall be within the permissible range. The constraints of RoCoF of individual generators and the power system are represented by (54) and (55), respectively.

$$-A_{g,b,pri,t}.RoCoF_{g,b}^{\max}.u_{g,b,pri,t} \leq RoCoF_{g,b,pri,t} \leq A_{g,b,pri,t}.RoCoF_{g,b}^{\max}.u_{g,b,pri,t}; \quad \forall g \in \Omega_{G_b}, \forall b \in \Omega_B, \forall t \in T \tag{54}$$

$$-RoCoF_{sys}^{\max} \leq RoCoF_{sys} \leq RoCoF_{sys}^{\max} \tag{55}$$

3. Simulation results

The presented model is simulated on IEEE RTS 24-bus test system. This test system has 32 synchronous generators and 17 loads. Data of synchronous generators and each load are presented in Table 1 and Fig. 1, respectively. Data of loads belong to week 2, Tuesday, winter, Weekday [42]. Table 2 provides the load price and its distribution in the test system [42]. The value of the lost load is \$2000/MWh for the entire scheduling horizon. The marginal cost of synchronous generators is calculated based on the quadratic cost function. The proposed procedure of [13] is used to construct offer blocks and the same values are considered for the deployed powers in the day-ahead and real-time horizons. Moreover, it is supposed that startup, shutdown, up and down ramp-rate values are equal, and during the power variation, the participation level of each synchronous generator is 0.05 p.u. of the rating power. Additionally, the maximum RoCoF of synchronous generators and power system is limited to 0.50 Hz/s. It shall be noted that in this work, 11 energy storages are considered that the related data are presented in Table 3. In this work, the constraints of network such as capacity and impedance of lines are neglected. Therefore, the simulation study is performed based on the worst condition that is the outage of the largest generator that is 400 MW. In this work, the CPLEX optimizer solver is used to solve the proposed model. It shall be noted that CPLEX employs the branch and cut approach to find the optimal solutions.

To evaluate the performance of the proposed model, four case studies are considered as follows:

- Case I: In this case study and during the primary and secondary frequency intervals, the frequency excursions are limited to $\pm 80mHz$and $\pm 60mHz$, respectively [13]. It shall be noted that BES units are not considered in this case study.
- Case II: In the second case study, the impact of BES is evaluated. The frequency excursion limitations are the same as the first case study.
- Case III: In the third case study, the impact of increasing the security of the network is evaluated. Therefore, the frequency excursions during the primary and secondary frequency intervals are limited to $\pm 60mHz$and$\pm 45mHz$.
- Case IV: In the fourth case study, the security constraints of the network are decreased. Therefore, the frequency excursions during the primary and secondary frequency intervals are limited to $\pm 100mHz$and $\pm 75mHz$.

The operational costs in different case studies are presented in Table 4. It shall be noted that in Case I the data of [13] is used. However, in [13] the multi-objective approach is applied to simultaneously consider the operational cost and frequency excursion in the objective function. The total operational cost of [13] is 787,591.895 \$. The frequency excursion and the RoCoF are incorporated into our proposed model as constraints of the optimization problem, and the total operational cost is 768,933.919 \$.

Comparing results of cases I and II demonstrates that considering BES decreases the operational cost within pre and post contingency intervals. However, the results are very sensitive to the case study and can be changed by decreasing the marginal cost of synchronous generators. Moreover, the reserve cost is decreased in the second case study and the reason is the higher availability of BESs in comparison with synchronous generators. Comparing the results of Cases II and III shows that increasing the security of the network (or lower permissible frequency excursions) leads to higher operational cost. However, the operational cost of Case III is still less than Case I. The results of case IV demonstrate that decreasing the security of the network decreases the operational costs in the pre and post contingency intervals.

In Tables 5 and 6, the breakdown of operational cost of synchronous generators and BESs are tabulated, respectively. As seen in these tables, considering BESs decreases the operational cost of synchronous generators. Comparing results of Cases II and III shows that decreasing frequency excursions in the primary and secondary intervals, leads to higher/lower operational costs for synchronous generators/BESs. By decreasing the permissible frequency excursions, the power system operator has to commit the generating units with higher inertia constant to maintain the frequency of the grid within the permissible intervals. It shall be noted that BESs are inertia-less units and their scheduling in pre-contingency interval could increase the frequency excursion after the occurrence of a contingency. Analysis of results of Cases III and IV demonstrate that the operational costs of generators and BESs are decreased and increased by decreasing the security of the network, respectively.

The optimal generating powers of synchronous generators and BESs are tabulated in Table 6. Results of Case II demonstrate that the generating powers of synchronous generators are decreased by using BESs. It shall be noted that BESs are fast-response units. Therefore, the power system operators can use these resources to diminish the impact of ramp-rate constraints of synchronous generators that increases the reserve cost as well as the total operational cost. However, BESs are very fast-response units and could decrease the operational cost of network, their negative impact on the inertia of power systems is inevitable. In other words, increasing the participation level of BESs could endanger the security of network. Case III shows that increasing the security of the grid leads to higher/lower participation levels for synchronous generators/BESs. Results of Case IV confirm that the generating power of BES is increased by increasing the frequency excursion range. Fig. 2 demonstrates the generating power of synchronous generators set in pre and post contingency intervals for different case studies.

Figs. 3 and 4 represent the energy levels of BESs set in the pre and post contingency intervals, respectively. It shall be noted that the positive and negative values of power represent discharging and charging powers, respectively. Additionally, the energy levels of BES#7 (as an example) in the pre and post-contingency intervals are shown in Figs. 5 and 6, respectively. It shall be noted that the increasing and decreasing energy levels demonstrate the charging and discharging of batteries. Comparing Figs. 3 and 4 shows that the power system operator decreases the generation of BESs in the post-contingency interval to maintain the inertia and security of the grid within the acceptable range. Therefore, the inertia of power systems and the security of networks are critical issues that shall be considered in the scheduling of BES resources.

4. Conclusions

In this work, a security-constrained model is proposed for scheduling synchronous generators and BESs in the joint energy and reserve markets. In the proposed objective function that is formulated based on minimizing the negative social welfare, and the security constraints such as frequency of the grid, RoCoF of generators, and power system in primary and secondary frequency intervals are considered. In this model, the optimal scheduling of generating units is specified in a way that minimizes the energy and reserve costs and maintains the frequency and RoCoF of the system and generators within the permissible ranges. BESs are very fast-response units and they could diminish the negative impact of the ramp-rate constraint of synchronous generators and improve the flexibility of the power system. Simulation results show that using BESs could decrease the reserve cost and the total operational cost of the power system. However, increasing the penetration level of BESs has a negative impact on the inertia of the power system. According to the presented results, the participation levels of BESs in the energy and reserve markets are decreased by increasing the security of the network (or decreasing the frequency excursion range). Therefore, in the scheduling of BES, the power system shall consider both positive and negative characteristics of BESs, which are improving the flexibility of grids and decreasing the inertia of the power system.

CRediT authorship contribution statement

Meysam Khojasteh: Data curation, Formal analysis, Investigation, Methodology, Software, Validation, Visualization, Writing – original draft, Writing – review & editing. **Pedro Faria:** Conceptualization, Methodology, Validation, Writing – review & editing. **Zita Vale:** Conceptualization, Funding acquisition, Methodology, Project administration, Resources, Supervision, Validation, Writing – review & editing.

Declaration of Competing Interest

None.

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