Electr Eng (2011) 93:117–126
DOI 10.1007/s00202-010-0194-y

ORIGINAL PAPER

The impacts of capabilities and constraints of generating units on simultaneous scheduling of energy and primary reserve

Mostafa Rajabi Mashhadi · M. Hossein Javidi D. B. · M. Sadegh Ghazizadeh

Received: 16 January 2010 / Accepted: 13 December 2010 / Published online: 6 February 2011

Abstract Frequency control, as an ancillary service, is usually provided by generation reserves. Modern generating units have special technical capabilities; e.g., their governor operation mode can be selected to be either active or passive, their ramp rate can be selected to be either normal or fast, etc. On the other hand, generating units have some technical constraints; e.g. some generating units cannot participate in primary frequency control at their capacity limits. In this paper, operational capabilities and constraints of generating units are incorporated in a "simultaneous scheduling of energy and primary reserve" problem. Furthermore, a heuristic iterative method (based on genetic algorithm) is proposed to obtain the optimal scheduling. The impacts of capabilities and constraints on scheduling are investigated through simulation studies. Simulation results depicts that taking these capabilities and constraints of generating units into account, not only reduces the total operational cost of generating units, but also will end up with a feasible solution for the system, even in cases where the previously proposed methods fail.

Keywords Primary reserve · Simultaneous scheduling · Ramp rate · Ancillary services · Frequency control · Genetic algorithm

M. Rajabi Mashhadi (✉) · M. H. Javidi D. B.
Department of Electrical Engineering,
Ferdowsi University of Mashhad, Mashhad, Iran
e-mail: mo_ra18@stu-mail.um.ac.ir; mrajabim@yahoo.com

M. Rajabi Mashhadi
Khorasan Regional Electric Company, Mashhad, Iran

M. S. Ghazizadeh
Department of Electrical Engineering,
Power and Water University of Technology, Tehran, Iran

List of symbols

Variables

- g_{it} Scheduled generation of unit i during time period t.
- $\overline{g}_{it}$ Maximum generation of unit i during time period t under primary frequency control.
- Δf_t Frequency deviation during time period t for the worst contingency.
- Δf_{it}^{b} Frequency deviation during time period t when unit i is operated at its maximum $\overline{g}_{it}$.
- r_{it}^{pr} Scheduled primary reserve of generating unit i during time period t.

Binary variables (0/1)

- u_{it} A variable defining the operation status of generator i during time period t (equals 1 if the unit is on and zero if it is off).
- v_{it} A variable defining the operation status of governor of generating unit i during time period t (equals 1 if the governor is in active mode and zero if it is not.).
- w_{it} A variable specifying ramp rate mode (1 if the unit i is operated in fast ramp rate mode during time period t and zero if it is not.).
- y_{it} Equals 1 if unit i turns on during time period t and equals zero if it does not.
- z_{it} Equals 1 if unit i turns off during time period t and equals zero if it does not.

Parameters

- d_t Demand of the system during time period t.
- a_i Unit i linear generation cost parameter.
- b_i Unit i quadratic generation cost parameter.
- C_i^0 Unit i fixed generation cost.
- C_{it}^{su} Cost of unit i for start-up during time period t.

C_{it}^{sd}	Cost of unit i for shut-down during time period t.
$q0_{it}^{pr}$	Primary reserve rate during time period t in normal ramp rate state for unit i.
$q1_{it}^{pr}$	Primary reserve rate during time period t in fast ramp rate state for unit i.
Δf^{min}	Maximum allowed deviation in system frequency decrease.
g_i^{max}	Maximum generation output of unit i.
g_i^{min}	Minimum generation output of unit i.
g_i^{pr-max}	Maximum generation output of unit i during primary frequency control.
g_i^{pr-min}	Minimum generation output of unit i during primary frequency control.
$r_i^{normal-pr}$	Normal ramp-up limit of unit i under primary control.
$r_i^{fast-pr}$	Fast ramp-up limit of unit i under primary control.
R_i	Droop of unit i.

Other symbols are defined in the text as they appear.

1 Introduction

One of the most important tasks in operating a power system is frequency control. In restructured power systems, frequency control is considered as an ancillary service and is usually provided by system operator using the resources made available by market participants. Generation reserve, usually referred as "frequency control reserve", is the main resource for frequency control, and according to the response time and how it is deployed, is classified as primary, secondary, and tertiary [1,2]. Primary reserve, as the fastest one, is provided by on-line generating units through their local droop characteristic in response to system frequency deviations from nominal. Primary reserve has a response time of the order of seconds [3,4]. Secondary generation reserve, provided based on a centralized strategy, has a response time of about a minute. The task of secondary reserve is to regulate the area-control error under load-following conditions [5,6]. The tertiary reserve is aimed to return the area-control error to zero and to ensure that all operational constraints are satisfied. Tertiary reserve is centrally implemented. It is provided by generation or demand flexibility and has a response time of the order of minutes [7].

In electricity markets, energy and reserve may be scheduled simultaneously or sequentially. However, as scheduling of energy and reserves are strongly coupled, scheduling them simultaneously will be more advantageous [7–9] ending with a higher social welfare [9].

This paper is focused on simultaneous scheduling of generation (energy) and primary reserve. The reserve should suffice for compensating large and sudden outages, in the form of loss of one or more generating units, in an isolated power system.

O'Sullivan and O'Malley [10] have introduced an iterative economic dispatch in which frequency deviations beyond the allowable range triggers modifications of the scheduled energy and primary reserve. Papadogiannis and Hatziargyriou [11] have considered stability and network constraints in dispatch of primary reserve. The method is based on a decision tree solution algorithm. However, in both of the above mentioned approaches, generation (energy) is scheduled a priori and then the reserve is scheduled (sequential scheduling). A later approach for formulation of unit commitment, proposed by Restrepo and Galiana [7], considers both primary and tertiary reserve constraints simultaneously. In the same year, Galiana et al. [9] showed that simultaneous scheduling and pricing of energy and reserves increases social welfare. Illian [12] considered the effects of a change in characteristics of a generating unit in operation planning (provision of frequency reserves). Thalassinakis and Dialynas [13] proposed an improved speed governor that utilizes the short time overloading capability of generating units and can contribute in a faster frequency restoration. They also proposed an efficient computational method for the optimal spinning reserve allocation, based on composite security criterion. Grey et al. [14] proposed an approach for rescuing frequency runaway. In their approach, the primary reserve is dispatched economically and securely such that the limits of transmission lines are not violated after losing a large generating unit.

In previous works on scheduling of generation (energy) and primary reserve, a relation between primary reserve and post-contingency system frequency deviation has been assumed [7,9]; and only some special constraints (e.g., system frequency limits, generation ramp rate and capacity constraints associated with primary frequency control) are considered. Modern generating units, utilizing special technical features, have affected the domain of the scheduling problem. The capability to select operation modes for governor (active or passive modes) and ramp rate for generator (normal or fast ramp rates) are types of special features that have not been considered in previous works. Furthermore, some generating units cannot contribute in frequency control at their capacity limits. This constraint has received relatively little attention in previous studies.

In this paper, the effects of real technical capabilities for modern generating units are taken into account in simultaneous scheduling of energy and primary reserve. Furthermore, the allowed range for participating in primary frequency control is considered in scheduling primary reserve. To obtain the optimal scheduling for energy and reserve, a heuristic iterative method based on genetic algorithm is proposed. Simulation results confirm that our formulation ends up with a more appropriate scheduling as compared to previously proposed methods.

In Sect. 2, technical capabilities of modern generating units and primary frequency capacity limits are discussed. Problem formulation is done in Sect. 3. Section 4 presents the heuristic method that is applied to solve the problem. Simulation results are discussed in Sect. 5. Concluding remarks concerning our innovation and the proposed method are presented in Sect. 6.

2 Technical capabilities and constraints of generating units

The scheduling of energy and primary reserve has been investigated. However, some of special technical features as well as limitations in capacity of thermal units for primary frequency control have not been considered in these investigations. In this section, such capabilities and limitations are introduced and their effects on formulating simultaneous scheduling of energy and primary reserve are considered.

2.1 Capability of selecting governor operation mode

Generally, most generating units have the capability of participating in primary frequency control [15]. On the other hand, due to malfunctioning of governor, violation of allowed dead band, lack of natural gas in winter; many thermal generating units cannot participate in primary frequency control [16,17]. Therefore, such generating units cannot respond to frequency variation and will be run at constant load [15]. On the other hand, in some modern generating units, the governor operation mode can be selected by the operator. In such systems, the unit may be chosen to contribute in frequency control or not. If the operation mode is adjusted such that the unit responds to frequency deviations and hence contributes in frequency control, it is referred to as "active mode" and if the governor is set such that the generator does not respond to frequency deviations, it is referred to as "passive mode". For example, in a typical modern gas turbine unit, the active and passive modes can be selected via the influent frequency mode command. In these generating units, the governor operating mode can be switched without the necessity to shut down the unit. This capability is implemented by defining adjustable parameters, such as time delay and frequency dead band. In the case of a large imbalance, such as loss of a generating unit in the system, the system frequency will deviate substantially. If the frequency deviation goes beyond the dead band of the governor, in contribution to system frequency, the speed governors will be activated. If the frequency deviation lies inside the dead band of the governor, or if time delay is not too short (typically more than 15 s), then, the speed governor will not be activated.

Table 1 Time delay and dead band limits in active or passive modes in some typical gas turbines in Iran

Modes	Active mode	Passive mode
Time delay (s)	4	15
Dead band limits (Hz)	0.015	0.4

Table 1 shows some typical values for time delay and dead band limits of some typical gas turbines (data extracted from the Iranian Power industry). As it can be seen, these values of the passive mode are greater than those of the active mode.

For generating units scheduled to contribute in primary frequency control, the operator sets the appropriate mode for the governor. The selected governor operation mode may be represented by a decision variable v; 1 for the active mode and 0 for the passive mode. A pre-set value, not a decision variable, may represent the governor operation mode of those generating units which are permanently operated in one mode (passive or active).

2.2 The allowed range for participating in primary frequency control

Some generating units cannot participate in primary frequency control at operating points close to their nominal operation limits. In some generating units, the allowed range for participating in primary frequency control ($g_i^{\text{pr}-\max} - g_i^{\text{pr}-\min}$) is smaller than their nominal operation range ($g_i^{\max} - g_i^{\min}$). For example, in a combined cycle power plant, because of the possible loss of steam turbine when participating in primary frequency control, the allowed lower operation limit is considered to be greater than its nominal value ($g_i^{\min}$). Furthermore, because of limitations associated with steam turbine in a combined cycle power plant, the associated gas turbine(s) may not be operated near the upper nominal operation limit. This implies that, when participating in primary frequency control, a value smaller than $g_i^{\max}$ should be considered as the upper operation limit of the unit. This is also true for some steam and gas turbine units [17,18]. This constraint, depicted in Fig. 1, can be formulated by Eqs. 1 and 2.

$$\left.\begin{aligned} &(g_i^{\min}.\,(1-v_{it}) + g_i^{\text{pr}-\min}.\,v_{it}).\,u_{it} \le g_{it} \\ &(g_i^{\max}.\,(1-v_{it}) + g_i^{\text{pr}-\max}.\,v_{it}).\,u_{it} \ge g_{it} \end{aligned}\right\}, \quad \forall i,t \qquad (1)$$

$$\left.\begin{aligned} &0 \le r_{it}^{\text{pr}} \le v_{it}.\,g_i^{\text{pr}-\max} - g_{it} \\ &r_{it}^{\text{pr}} \le v_{it}.\,r_i^{\text{normal}-\text{pr}} \end{aligned}\right\}, \quad \forall i,t \qquad (2)$$

Table 2 shows typical values for primary frequency capacity limits bound in different types of generating units.

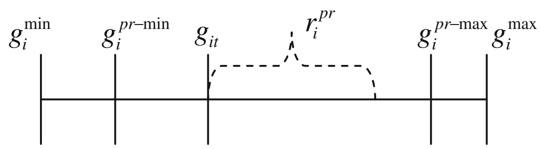

Fig. 1 Primary frequency capacity limits

Table 2 Typical primary frequency capacity limits (MW) for different types of generating units

Power plant	$g^{\min}$	$g^{\max}$	$g^{\text{pr}-\min}$	$g^{\text{pr}-\max}$
Gas turbine	30	120	30	100
Combined cycle	30	105	75	105
Steam unit	75	150	75	135

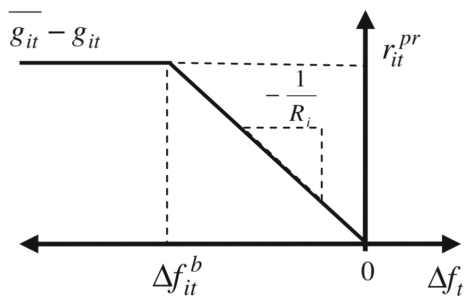

Fig. 2 Primary reserve characteristics of unit i [7]

The primary frequency capacity limits bound the amount of primary reserve capacity for participating in primary frequency control. Figure 2 illustrates the relation between primary reserve (r_{it}^{pr}) and frequency deviation Δf_t for a typical unit [7].

When a large imbalance—such as loss of a generating unit—occurs, the system frequency will decline resulting in a negative deviation from its nominal value and an increment in generating unit output. This increment in generating output is proportional to the frequency deviation and the frequency regulation constant (governor droop) of the unit [10,11]. For frequency deviations less than Δf_{it}^{b} (the breaking frequency), generation increases linearly according to the governor droop. On the other hand, for frequency deviation beyond the breaking frequency, the primary reserve will be bounded by ($\overline{g}_{it} - g_{it}$); where, $\overline{g}_{it}$ is equal to either maximum generation output limit during primary frequency control ($g_i^{\text{pr}-\max}$) or the unit frequency regulation limit ($g_{it} + r_i^{\text{normal}-\text{pr}} . u_{it} . v_{it}$), whichever is smaller. Variables r_{it}^{pr} and $\overline{g}_{it}$ can be formulated by (3) [7] and (4).

$$r_{it}^{\text{pr}} = \left\{ \begin{array}{ll} -\frac{1}{R_i} . \Delta f_t, & \text{if } \Delta f_{it}^{\text{b}} \leq \Delta f_t \leq 0 \\ \overline{g}_{it} - g_{it}, & \text{if } \Delta f_t \leq \Delta f_{it}^{\text{b}} \end{array} \right\}, \quad \forall i, t \tag{3}$$

$$\overline{g}_{it} = \min(u_{it} . v_{it} . g_i^{\text{pr}-\max}, g_{it} + u_{it} . v_{it} . r_i^{\text{normal}-\text{pr}}) \tag{4}$$

2.3 The capability of ramp rate selection

Some modern generating units can be operated with various ramp rates. In such units, during normal operation, the operator can select either normal or fast ramp rates. Figure 3 shows normal and fast ramp rates for a typical gas turbine unit.

We may define a binary variable (w) to represent the selected ramp rate. This decision variable w is assigned to 0 and 1 for normal and fast ramp rates, respectively. For such units, the primary reserve capacity limits as well as ($\overline{g}_{it}$) in (2)–(4) should be modified to (5)–(8). For generating units that their ramp rates cannot be adjusted, w is set to zero. Now, the primary reserve can be formulated using the following equations:

$$\left. \begin{array}{l} 0 \leq r_{it}^{\text{pr}} \leq u_{it} . v_{it} . g_i^{\text{pr}-\max} - g_{it} \\ r_{it}^{\text{pr}} \leq v_{it} . (r_i^{\text{normal}-\text{pr}} . (1 - w_{it}) + r_i^{\text{fast}-\text{pr}} . w_{it}) \end{array} \right\}, \quad \forall i, t \tag{5}$$

$$r_{it}^{\text{pr}} = \left\{ \begin{array}{ll} -1/R_i \cdot \Delta f_t, & \text{if } \Delta f1_{it}^{\text{b}} \leq \Delta f_t \leq 0 \\ (1 - w_{it}) \cdot (\overline{gn}_{it} - g_{it}) - (1/R_i \cdot \Delta f_t).w_{it}, & \text{if } \Delta f2_{it}^{\text{b}} \leq \Delta f_t \leq \Delta f1_{it}^{\text{b}} \\ (1 - w_{it}) \cdot \overline{gn}_{it} + w_{it} \cdot \overline{gf}_{it} - g_{it}, & \text{if } \Delta f_t \leq \Delta f2_{it}^{\text{b}} \end{array} \right\}, \quad \forall i, t \tag{6}$$

$$\overline{gn}_{it} = \min(u_{it}.v_{it}.g_i^{\text{pr}-\max}, g_{it} + r_i^{\text{normal}-\text{pr}}.u_{it}.v_{it}) \tag{7}$$

$$\overline{gf}_{it} = \min(u_{it}.v_{it}.g_i^{\text{pr}-\max}, g_{it} + r_i^{\text{fast}-\text{pr}}.u_{it}.v_{it}) \tag{8}$$

where, $\overline{gn}_{it}$ and $\overline{gf}_{it}$ represent the maximum generation output limits during primary frequency control for normal and fast ramp rates, respectively.

Figure 4 depicts the primary reserve characteristics for generating units that their ramp rate can be selected. As it can be seen, when the fast ramp rate is selected ($w_{it} = 1$), the maximum available primary reserve capacity will be increased. In contrary, the breaking frequency will be decreased from $\Delta f1_{it}^{\text{b}}$ to $\Delta f2_{it}^{\text{b}}$. This effect of ramp rate selection capability is investigated in Sect. 5.1 for an hourly simultaneous scheduling of energy and primary reserve problem.

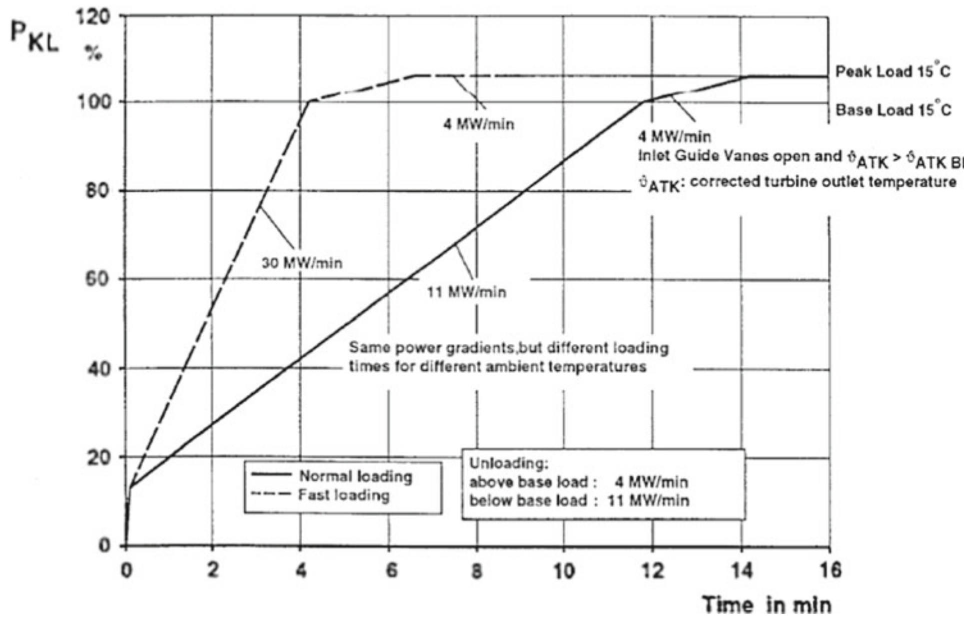

Fig. 3 Normal and fast loading ramp rates for a typical 159 MW gas turbine unit

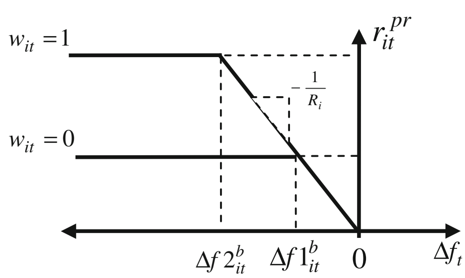

Fig. 4 Primary reserve characteristics of unit i for normal and fast ramp rates

3 Problem formulation

The aim of "simultaneous scheduling of energy and primary reserve" is to minimize the cost of energy and primary reserve over the scheduling horizon. This is expressed by (9), where the objective function includes operation and primary reserve costs. Operation costs include start-up, shut-down, and running costs. It is assumed that the running costs of generating units are quadratic, as shown by (10), and parameters associated with each unit are available to market operators [7].

$$Min\left[\sum_t\sum_i\{y_{it}.\,C_{it}^{\mathrm{su}}+z_{it}.\,C_{it}^{\mathrm{sd}}+C_{it}(g_{it},u_{it})\}\right.$$
$$\left.+\sum_t\sum_i\{C_{it}^{\mathrm{pr}}(r_{it}^{\mathrm{pr}})\}\right] \tag{9}$$

$$C_{it}(g_{it},u_{it})=u_{it}.\,C_i+a_i.\,g_{it}+\frac{1}{2}b_i.\,(g_{it})^2,\quad \forall i,t. \tag{10}$$

Generators may participate in primary reserve market by submitting their bids, in the form of Eq. 11; which implies that each generator can submit different offers for normal and fast ramp rates.

$$C_{it}^{\mathrm{pr}}(r_{it}^{\mathrm{pr}})=((1-w_{it}).\,q0_{it}^{\mathrm{pr}}+w_{it}.\,q1_{it}^{\mathrm{pr}}).\,r_{it}^{\mathrm{pr}}.\,u_{it}.\,v_{it},\forall i,t. \tag{11}$$

The constraints for this optimization problem may be classified in three main groups. The first group mainly includes typical operating constraints of a unit commitment problem. These constraints are generating unit capacity limits and pre-contingency power balances, as in (1) and (12), respectively [7].

$$\sum_i g_{it}=d_t,\quad \forall t. \tag{12}$$

As this investigation is focused on the impacts of modern generating unit capabilities on primary frequency control, to simplify the problem, a single-period scheduling problem is considered and the time-coupling constraints are not included. However, in a multi-period scheduling problem, time coupling constraints may not be ignored.

The second group of constraints includes adequacy of primary reserve and the allowed negative frequency deviation in severe contingencies. Loss of a generating unit, belonging to a given set s^kincluding all on line units, is considered as a contingency. Under post contingency situation, the demand and generation should be balanced and the remaining units, which are on line, should provide enough primary reserve for each contingency. This is considered as a constraint, realized as in (13) [7]. However, to avoid load shedding by under-frequency relays, the frequency deviation should be limited to the allowed negative frequency deviation, as in (14) [7].

$$\sum_{i \notin s^k} r_{it}^{\text{pr}} \geq \sum_{i \in s^k} g_{it}, \quad \forall k, t \tag{13}$$

$$\Delta f_t \geq \Delta f^{\min}, \quad \forall t \tag{14}$$

Special constraints, related to the capabilities of modern generating units in primary frequency control, such as selection of ramp rate and primary frequency capacity limits constitute the third group. Equation (8) defines the maximum generation output under primary frequency, considering the capability of ramp rate selection. The primary reserve, calculated through Eqs. (6) and (7), is limited by constraint of (5). Units participating in primary frequency control must satisfy Eq. (1) as the constraint for primary frequency control limits.

4 Solution method for the problem

The problem of hourly scheduling of energy and primary reserve is a Mixed-Integer Non Linear Programming (MINLP) problem. There are various numerical optimization techniques that can be applied to solve this problem. In [7], unit commitment with primary reserve problem has been solved through converting MINLP into a mixed integer linear programming (MILP), to be solved by means of commercially available mixed integer software, such as GAMS. Genetic algorithm has been commonly applied to solve similar optimization problems [19–21]. However, in such problems, the number of feasible solutions increases exponentially with the problem size. Therefore, heuristic search techniques may be employed to reduce computational time.

In this paper, to solve this MINLP problem, a heuristic iterative method based on genetic algorithm (GA) has been proposed. The flowchart of the proposed method is shown in Fig. 5. Although the method can also be developed for a multi-period scheduling, for simplicity, the flowchart only depicts the method for a single period (1 h) scheduling.

While initial population, in the method, is randomly generated, binary variables are encoded specially. In each step, population is checked for the solution feasibility and infeasible strings are eliminated. Therefore, new random populations are generated. This would ensure that only feasible strings are considered for solving the problem of simultaneous scheduling of energy and primary reserve. Major steps for the solution method are explained as below:

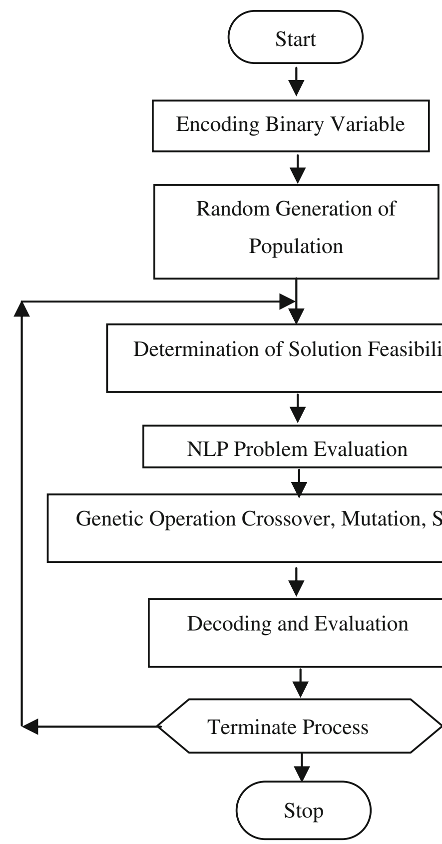

Fig. 5 Proposed method illustrative flowchart

Table 3 Possible states binary variables

States	u_{it}	v_{it}	w_{it}	Feasibility states
0	0	0	0	1
1	0	0	1	Non-feasible
2	0	1	0	Non-feasible
3	0	1	1	Non-feasible
4	1	0	0	2
5	1	0	1	Non-feasible
6	1	1	0	3
7	1	1	1	4

4.1 Encoding binary variables

In this step, the binary variables (u_{it}, v_{it} and w_{it}) are encoded. These binary variables generate eight different states in each hour for every generating unit. The only four possible ones of these states are shown in Table 3. Encoding of four possible states can be performed by using two bits for every generating unit (Table 4). Therefore, the initial population will be presented by strings with dimensions of twice the number of generating units. Figure 6 shows a typical string of the initial population.

4.2 Determination of solution feasibility

In this step, prior to scheduling of energy and primary reserve, feasible strings satisfying relations (15) and (17) are investigated. For the given schedule, constraints (15) and (17) guarantee balancing of generation and load and adequacy of possible maximum primary reserves ($r_{it}^{\max - \text{pr}}$), respectively.

Table 4 Encoding of four possible states

Feasible states	bit_1	bit_2	Unit states
1	0	0	Unit is off
2	0	1	Unit is on without participating in primary frequency control
3	1	0	Unit is on with participating in primary frequency control by normal ramp rate
4	1	1	Unit is on with participating in primary frequency control by fast ramp rate

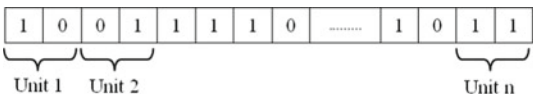

Fig. 6 Typical string schematic

The maximum of primary reserve for participating units in primary frequency control at maximum allowed frequency deviation ($\Delta f^{\min}$) is expressed by Eq. (16). These conditions assure that genetic algorithm works with feasible strings. In this way, as a number of unfeasible solutions are eliminated, the computation time will be decreased.

$$\sum_i u_{it}\,.\,g_i^{\min} \leq d_t \leq \sum_i u_{it}\,.\,g_i^{\max}, \quad \forall t \tag{15}$$

$$r_{it}^{\max-\mathrm{pr}} = \min\left\{\left(-\frac{1}{R_i}\,.\,\Delta f^{\min}\right), (g_i^{\mathrm{pr}-\max} - g_i^{\mathrm{pr}-\min}), (w_{it}\,.\,r_i^{\mathrm{normal}-\mathrm{pr}} + (1-w_{it})\,.\,r_i^{\mathrm{fast}-\mathrm{pr}})\right\} \tag{16}$$

$$\sum_{i \notin s^k} u_{it}\,.\,v_{it}\,.\,r_i^{\max-\mathrm{pr}} \geq u_{it}\,.\,g_i^{\min}, \quad \forall t, i \in s^k \tag{17}$$

4.3 NLP problem evaluation

In this step, having feasible strings in one population composed of binary variables, the scheduling problem is converted to a nonlinear linear programming (NLP) problem. Then, for cases that NLP has a solution, cost of the schedule is saved and unfeasible solutions are ignored.

5 Simulation results

To show the impacts of technical capabilities of modern generators technology on simultaneous scheduling of energy and primary reserve, simulations have been performed on two isolated power systems. The first system includes four generating units and the second system includes 17 generating units. Different cases have been investigated. Simulation results for these two cases are explained as below:

5.1 Power system including four generating units

Specifications of generating units as well as the offers of these units for primary reserve with normal and fast ramp rates in three different cases are presented in Tables 5 and 6, respectively. System frequency and maximum allowed frequency deviation have been assumed to be 60 and −0.6 Hz, respectively. The demand of the system has been assumed to be 170 MW. The droops of all units is assumed to be four percent. In all these cases, loss of one generator (N-1 criteria) at a time has been considered as the security criterion.

Table 5 Input data for power system including four-generating units

	Capacity limits				Ramp rates		Cost function	
No.	$g^{\max}$ (MW)	$g^{\min}$ (MW)	$g^{\mathrm{pr}-\max}$ (MW)	$g^{\mathrm{pr}-\min}$ (MW)	$r^{\mathrm{normal}-\mathrm{pr}}$ (MW)	$r^{\mathrm{fast}-\mathrm{pr}}$ (MW)	a (\$/MWh)	c (\$/h)
1	155	10	140	65	22	45	9.8	10
2	200	40	200	40	26	52	10.7	10
3	250	10	235	80	25	50	15.6	10
4	100	0	100	20	20	40	40	10

Table 6 Primary reserve rates for power system including four-generating units

Case	$q0$ (\$/MWh)				$q1$ (\$/MWh)			
	Unit1	Unit2	Unit3	Unit4	Unit1	Unit2	Unit3	Unit4
a	0.1	0.1	0.1	0.1	1	1	1	1
b	0.1	0.1	0.1	0.1	5	5	5	5
c	0.1	0.1	0.1	0.1	1	1	5	1

Table 7 Simulation results for the power system including four-generating units

State		1	2	3	4	5	6	7
Commitment status	u1	1	1	1	1	1	1	1
	u2	1	1	1	1	1	1	1
	u3	1	1	1	1	1	1	1
	u4	1	1	1	1	1	1	1
Operation mode of governors	v1	0	1	1	1	1	1	1
	v2	1	1	1	1	1	1	1
	v3	1	1	1	1	1	1	0
	v4	1	1	1	1	1	1	1
Ramp rate status	w1	0	0	0	1	0	1	1
	w2	0	0	1	1	0	1	1
	w3	1	0	0	1	0	1	0
	w4	0	0	0	1	0	1	1
Generation level (MW)	g1	93	71	93	125	71	116	75
	g2	67	67	67	105	67	114	64
	g3	10	32	10	20	68	114	11
	g4	0	0	0	0	44	56	20
Primary reserve (MW)	$r^{\mathrm{pr}}1$	0	22	22	30	22	39	39
	$r^{\mathrm{pr}}2$	26	26	48	50	26	50	50
	$r^{\mathrm{pr}}3$	47	25	25	50	25	50	0
	$r^{\mathrm{pr}}4$	20	20	20	25	20	25	25
Cost ($)		1876	1961	1879	2856	4283	6585	2546

Table 7 illustrates the solutions obtained by the heuristic method based on GA for 7 various states explained in subsections 5.1.1 and 5.1.2. In this table:

- the first row depicts considered states,
- rows 2 to 5 show commitment status of generating units (committed or not),
- rows 6 to 9 operation mode of governors for participating in primary frequency control (active or passive),
- rows 10 to 13 explain the ramp rate status of generating units (normal or fast),
- rows 14 to 17 show generation levels committed by each generator,
- rows 18 to 21 show primary reserve allocated to each generator and finally,
- row 22 shows the total cost associated with each state of scheduling.

Population size and the maximum generation for termination of GA are 20 and 100, respectively. Crossover and mutation probabilities are considered to be 0.8 and 0.15, respectively.

5.1.1 The role of ramp rate limit selection

In this section, the role of selecting ramp rate limits is investigated in the scheduling of energy and primary reserve. In this investigation, it is assumed that all generating units can participate in primary frequency control in their maximum operating range. In other words, the primary capacity limits are relaxed in this investigation. Scheduling of energy and primary reserve for three different cases of offers (a), (b) and (c) in Table 6 are shown in Table 7 as states 1, 2 and 3, respectively. It can be seen that while unit 3 participates in primary frequency control with fast ramp rate, unit 1 does not participate in primary frequency control in state 1.

If generators offer primary reserves with fast ramp rates in a very higher price such as case b in Table 6 (or in cases when they do not have the capability of participating in primary reserve with fast ramp rates), primary reserve of generators participating in primary frequency control by normal ramp rate are scheduled (state 2 in Table 7).

In this approach, if a generator offers its primary reserve with fast ramp rate in a price higher than prices offered by other units (such as unit 3 in case c in Table 6), it will not be scheduled. Therefore, generating units offering lower price will be scheduled a priory (such as state 3 in Table 7).

If generating units do not have the capability of fast ramp rates or do not offer this capability, scheduling may result in a solution with higher cost. This means that the cost of scheduling may become higher than the cases that generating units offer their reserve with fast ramp rate even in higher prices. As an example, the load is assumed to be 250 MW and generators offer the prices of primary reserve with normal and fast ramp rates in accordance with case (a) in Table 6.

Table 8 Generation levels and primary reserves (MW); 17-generating units case

Case: unit	a		b		c	
	g	r^{pr}	g	r^{pr}	g	r^{pr}
A	261	37	313	0	261	37
B	238	60	238	60	238	60
C	123	31	123	31	123	31
D	123	0	123	0	123	0
E	234	0	234	0	234	0
F	228	19	209	37	228	19
G	0	0	0	0	0	0
H	83	13	76	19	83	13
I	247	27	247	27	247	27
J	19	29	19	55	19	29
K	0	0	0	0	0	0
L	0	0	0	0	0	0
M	91	23	91	23	91	23
N	15	25	15	25	15	25
O	0	0	0	0	0	0
P	33	24	7	24	33	24
Q	5	12	5	12	5	12
Cost (£)	31842		31184		33462	

The prices for fast ramp rates are assumed to be 10 times higher than those with normal ramp rates. The simulation results confirm that if the capability of having fast ramp rates (state 4 in Table 7) is considered, the scheduling cost will be much lower (about 50%) than the scheduling cost for cases that this capability (state 5 in Table 7) is not considered. For a system load of 400 MW, if generators offer their reserve with the capability of fast ramp rates, the scheduling results to a feasible solution (state 6 in Table 7) while, in case of not considering this capability, the solution will not be feasible.

5.1.2 *Consideration of primary frequency capacity limits bound*

If we consider primary capacity limits in reserve, scheduling will change. Reserve scheduling and its cost for the data of case (a) in Table 6 are shown as state (7) in Table 7. Comparing states 1 and 7 in Table 7, it can be concluded that considering primary capacity limits not only affects the scheduling but also will seriously affect its cost. Therefore, it can be concluded that considering primary frequency limits seriously affects simultaneous scheduling of energy and primary reserve.

5.2 Power system including 17 generating units

In this case, the scheduling of energy and primary reserve scheme has been applied to an isolated system including 17 generating units over a single period. Data and the characteristics of generating units are taken from [10].

For this system, three alternatives of simultaneous scheduling of energy and primary reserve are considered.

(a) Generating units participate in frequency control with their capability of normal ramp rate only.
(b) Generating units participate in frequency control with their capability of normal or fast ramp rates.
(c) Generating units participate in frequency control with their capability of normal or fast ramp rates at primary frequency capacity limits.

In all the above cases, loss of one generator (N-1 criteria) at a time has been considered as the security criterion. Furthermore, in all these cases, the primary reserve limits in the case of normal ramp are set to equal 50% of the primary reserve limits with fast ramp rate. The fast ramp rates are assumed to be equal to those given in [10] ($r_i^{\mathrm{normal-pr}} = 0.5{*}r_i^{\mathrm{fast-pr}}$). The maximum limits of primary reserve capacity are set to equal 90% of the maximum generation output and the minimum limits of primary reserve capacity are set to equal twice of the minimum generation output ($g_i^{\mathrm{pr-max}} = 0.9{*}g_i^{\max}$ and $g_i^{\mathrm{pr-min}} = 2{*}g_i^{\min}$). All units have a regulation droop of 5% with a system nominal frequency of 50 Hz and a maximum allowed frequency deviation of 500 MHz. Load of the system has been assumed to be 1700 MW. It is also assumed that the unit incremental costs of primary reserves with normal and fast ramp rates are set to one tenth and equal of the linear generation cost components given in [10], respectively ($q0_{it}^{\mathrm{pr}} = 0.1 * a_i$ and $q1_{it}^{\mathrm{pr}} = a_i$).

Table 8 illustrates the results obtained using the proposed heuristic method for the above three mentioned alternatives.

The results confirm that the scheduling cost for cases that generators have the capability of fast ramp rates (case b) are less than cases which generators do not have this capability. In case b, generating units F, H and J participate in primary frequency control with the capability of fast ramp rate. Considering cases b and c (Table 8), it can be observed that considering primary capacity limits in scheduling formulation, not only affects the scheduling but also affects its cost. Therefore, it can be concluded that considering primary frequency limits affects simultaneous scheduling of energy and primary reserve.

6 Concluding remarks

In restructured power systems, frequency control has been considered as an ancillary service which is normally provided by system operator using sources made available by market participants. The main resources for controlling frequency are provided by generation reserves, usually called frequency control reserve. However, some generating units cannot participate in primary frequency control at normal operating ranges and are limited. On the other hand, modern generating units benefit having the capability of selecting their modes of operation such as participation modes in primary frequency control and normal or fast ramp rates. The effect of such capabilities and constraints on simultaneous scheduling of energy and reserve has not received enough attention in previous investigations.

In this paper, the constraints and capabilities associated with old and new generating technologies are explained and their effect on simultaneous scheduling of energy and primary reserve is investigated. In our study, only credible contingencies, and negative frequency deviations following each contingency have been considered.

To solve the problem, a heuristic iterative method based on genetic algorithm (GA) has been proposed. To avoid unfeasible solutions, a new strategy for coding binary variables, which eliminates unfeasible states from optimization process, is used. This strategy seriously reduces the computation time of scheduling. Simulation results confirm that considering the operational constraints and capabilities of generating units will not only result in a lower cost of supporting required reserves, but also will result in a feasible solution. The method can also be developed and generalized for considering tertiary reserve and multi-period scheduling.

References

1. Wood AJ, Wollenberg BF (1996) Power generation operation and control, 2nd edn. Wiley, New York
2. Rebours G, Kirschen DS, Trotignon M, Rossignol S (2007) A survey of frequency and voltage control ancillary—part I: technical features. IEEE Trans Power Syst 22:1106–1112
3. Koessler RJ, Feltes JW, Willis JR (1999) A methodology for management of spinning reserves requirements. IEEE Power Eng Soc Winter Meeting 1:584–589. doi:10.1109/PESW.1999.747520
4. Jalleli N, Ewart DN, Fink LH, Hoffmann AG (1992) Understanding automatic generation control. IEEE Trans Power Syst 7(3):1106–1112
5. Alomoush MI (2010) Load frequency control and automatic generation control using fractional-order controllers. Electr Eng. doi:10.1007/s00202-009-0145-7
6. Singh H, Papalexopoulos A (1999) Competitive procurement of ancillary services by an independent system operator. IEEE Trans Power Syst 14(2):498–504
7. Restrepo JF, Galiana FD (2005) Unit commitment with primary frequency regulation constraints. IEEE Trans Power Syst 20(4):1836–1843
8. Kirschen D, Strbac G (2004) Fundamentals of power system economics. Wiley, England
9. Galiana FD, Bouffard F, Arroyo JM, Restrepo JF (2005) Scheduling and pricing of coupled energy and primary, secondary, and tertiary reserves. Proc IEEE 93(11):1970–1984. doi:10.1109/JPROC.2005.857492
10. O'Sullivan JW, O'Malley MJ (1999) A new methodology for the provision of reserve in an isolated power system. IEEE Trans Power Syst 14(2):519–524
11. Papadogiannis KA, Hatziargyriou ND (2004) Optimal allocation of primary reserve services in energy market. IEEE Trans Power Syst 19(1):652–659
12. Illian HF (2006) Expanding the requirements for load frequency control. IEEE Power Eng Soc Gen Meeting, pp 1–7. doi:10.1109/PES.2006.1709245
13. Thalassinakis EJ, Dialynas EN (2007) A method for optimal spinning reserve allocation in isolated power systems incorporating an improved speed governor model. IEEE Trans Power Syst 22(4):1629–1637
14. Grey BA, Radman G, Sekar A (2007) Determination of spinning reserve deployment using an extended economic dispatch to include line flow limits and primary frequency regulation. IEEE 39th Southeastern Symposium on System Theory, pp 55–59
15. Kelefenz G (1986) Automatic control of steam power plants. transl. Vladimir F. Tomek-3(ed), Mannheim, Wien
16. Kehler JH (1999) Frequency regulation from steam turbine generators. IEEE Power Eng Soc Winter Meeting 1:775–776. doi:10.1109/PESW.1999.747554
17. Asgari MH, Tabatabaei MJ, Riahi R, Mazhabjafari A, Mirzaee M, Bagheri HR (2008) Establishment of regulation service market in Iran Restructured Power System. Canadian Conference on Electrical and Computer Engineering, pp 713–718. doi:10.1109/CCECE.2008.4564628
18. Bilenko VA, Melamed AD, Mikushevich EE, Nikol'skii DY (2009) Consideration of technological constraints and functional abnormalities in the algorithms of systems for automatically controlling the frequency and power of power units. Therm Eng 56(10):805–814
19. Swarup KS, Yamashiro S (2002) Unit commitment solution methodology using genetic algorithm. IEEE Trans Power Syst 17(1):87–91
20. Lee KY, El-Sharkawi MA (2008) Modern heuristic optimization techniques theory and application to power system. Wiley-IEEE Press, New York
21. Damousis IG, Bakirtzis AG, Dokopoulos PS (2004) A solution to the unit Commitment problem using integer-coded genetic algorithm. IEEE Trans Power Syst 19(2):1165–1172