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Electric Power Systems Research 78 (2008) 527–538
ELECTRIC POWER SYSTEMS RESEARCH
www.elsevier.com/locate/epsr

A method for reserve clearing in disaggregated model considering lost opportunity cost

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Received 12 October 2006; received in revised form 17 March 2007; accepted 25 April 2007
Available online 5 June 2007

Abstract

In this paper, a new formulation for clearing reserve market in a deregulated environment with separated energy and reserve market is introduced. In the proposed method, reserve market is cleared such that the costs associated with capacity reservation, producing energy in real-time, opportunity cost of those units which are accepted in the energy market and backed down from the accepted values to participate in the reserve market are minimized. This optimization problem is formulated and solved using linear programming method. Finally, the proposed method is applied to a six units test system to examine the applicability and effectiveness of the proposed method.

Keywords: Ancillary services; Deregulation; Opportunity cost; Reserve market

1. Introduction

One of the most important issues in the last decade in power system area is deregulation and restructuring. Deregulation and restructuring have recently taken place in most countries in the world, and is increasing more and more. In the new environment, a vertically integrated utility (VIU) is divided into its three main components of Generation companies (Genco), Transmission companies (Transco), and Distribution companies (Disco). Increasing efficiency using creation of competition is one of the most important objectives of deregulation, as competition can facilitate efficiency, price transparency and also supply-demand satisfaction.

Ancillary services are necessary to support transmission of power while maintaining system reliability and ensuring the required degree of quality and safety [1]. There are different types of ancillary services, such as spinning reserve (SR), non-spinning reserve, voltage and reactive support, black start, and, etc. [2]. Currently, there are two forms of market auctions, which are implemented in a deregulated environment for procuring of energy and ancillary services. In some countries, energy and ancillary services are aggregated and in others are not. In an aggregated framework, such as NYISO [3], PJM [4], ISO-NE [5] and new California market [6], the energy and ancillary service markets are cleared simultaneously. In a disaggregated framework, on the other hand, energy and ancillary service markets are cleared sequentially. In the latter case, energy market clearing does not incorporate any security considerations. That is, once the energy market is settled by the market operator (MO), the system operator (SO) procures ancillary services such that the reliability and security requirements (criteria) are met. In some power markets, such as Spanish electricity market, the system operator and the market operator are separate entities [7], while in others, such as Texas, both functions are performed by a unique entity [8]. In general, disaggregated framework can be categorized into sequential and simultaneous forms [9]. In the sequential form, a series of auctions is carried out by SO. In this form, an auction for the best quality service is carried out first followed by decreasing quality services auctions [10]. In the simultaneous form, all types of ancillary services are simultaneously cleared. This approach is also known as rational buyer in which various ancillary services scheduled simultaneously such that the requirement of each category is met [2].

In [11–13], an approach for procuring operating reserve has been presented using insurance theory. In [14], the generating

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doi:10.1016/j.epsr.2007.04.007

units have been scheduled such that a given risk index is met. The optimal value of the risk index is determined using cost-benefit analysis. The concept in [14] has been applied to a traditional power system. In [15], using correlation between capacity and reliability, a scheme for procuring and pricing operating reserve in a deregulated environment has been proposed. In [16], the customers in a bilateral model have given the opportunity to purchase spinning reserve according to their needs using a well-being framework. A pool-based market clearing algorithm, which is based on the deterministic/probabilistic criterion for application in electricity market, has been introduced in [17]. In this context, the energy and reserve are simultaneously solved and units are committed such that loss of load probability (*LOLP*) or expected energy not supplied (*EENS*) is smaller than a predetermined value. A security constrained economic dispatch for optimal reserve allocation and pricing has been formulated in [18]. In [18], a system has been divided into different control areas where it is assumed that the amount of reserve required in each area is predetermined. Then, the optimal spot price of operating reserve has been calculated using the Lagrange multipliers. An integrated energy and spinning reserve market model has been presented in [19], in which market dispatch is carried out so that the total payment including both energy and spinning reserve and expected energy not served (EENS) is minimized. Reserve allocation in deregulated environments has been done in [20] using risk minimization approach. In [21], an approach for spinning reserve allocation considering reliability and cost in the deregulated environments has been proposed.

Disaggregated framework has advantage and disadvantages versus the aggregated one. Lower complexity and transparency of clearing results are advantages of a disaggregated framework. Aggregated market clearing treats as a "black box" in which justifying and explaining of schedules and prices are very hard [9]. Nevertheless, achieving higher social welfare is one of the great advantages of aggregated clearing method. The other weakness of disaggregated method is lack of existence of feasible solution to meet the reserve requirements.

In this paper, a method for clearing reserve (10 min operating reserve) market in a disaggregated framework is presented. This method, preserves the good features of disaggregated framework while tries to improve its performance via overcoming the above limitations. Using the proposed method, not only the total cost is less than the disaggregated method, but also there is a feasible solution for reserve market.

The rest of this paper is organized as follows. In Section 2, problem formulation is presented. The simulation results are given in Section 3. In Section 4, concluding remarks and discussions, concerning the proposed method are presented.

2. Problem formulation

In this section, the formulation of the proposed technique is described. For this, first the general assumptions about the market model are presented. The opportunity cost will then be modeled and finally the proposed market clearing technique is described.

2.1. Market model

The market structure is assumed to be a disaggregated pool model. In this market, the energy and reserve are cleared separately by a single entity, such as Texas or can be cleared by the separated entities, such as the Spanish power market. In the separated framework, market operator (MO) and system operator (SO) are respectively responsible for energy and reserve clearing market. Generators submit their offer curves for energy and reserve to the market. These curves must be monotonically increasing functions of prices. Then, according to the submitted energy curve, the energy market is cleared. After clearing the energy market, the reserve market is cleared such that the reserve cost is minimized. A bid based model is used in this paper and the proposed method is applicable for cost curve coefficient model.

The number of generating companies is assumed to be N. Each generating company submits individual bidding blocks both for energy and reserve as follows:

$$[E_i^j, \mathrm{BE}_i^j], \quad j = 1, 2, \ldots, n_{\mathrm{e}i}$$
$$[R_i^k, \mathrm{BR}_i^k], \quad k = 1, 2, \ldots, n_{\mathrm{r}i}$$

where E_i^j is the energy quantity offered by the ith generating company for the jth band, BE_i^j the energy price offered by the ith generating company for the jth band, R_i^k the capacity reservation quantity offered by the ith generating company for the kth band, BR_i^k the capacity reserve price offered by the ith generating company for the kth band, $n_{\mathrm{e}i}$ the number of energy bid bands offered by the ith generating company, $n_{\mathrm{r}i}$ is the number of reserve bid bands offered by the ith generating company.

If the payment mechanism in the energy market is pay-as-bid, then the energy payment to the ith generating unit can be expressed as:

$$\mathrm{EP}_i(P_i) = \sum_{j=1}^{c} E_i^j \cdot \mathrm{BE}_i^j + \left(P_i - \sum_{j=1}^{c} E_i^j \right) \mathrm{BE}_i{}^{c+1} \tag{1}$$

$$\sum_{j=1}^{c} E_i^j \le P_i \le \sum_{j=1}^{c+1} E_i^j \tag{2}$$

where EP_i is the energy payment to the ith generating company with the accepted energy equal to P_i in the energy market.

If the payment mechanism in the energy market is uniform, then all accepted generating companies in the energy market receive market clearing price (MCP) as:

$$\mathrm{EP}_i(P_i) = \mathrm{MCP} \cdot P_i \tag{3}$$

After clearing the energy market, the reserve market is cleared such that the reserve cost is minimized. In [22,23], four alternative energy/reserve market designs and payment mechanisms to the generating unit reserve providers are proposed for implementing in the ISO-NE. These payment mechanisms are: payment for availability, payment for opportunity cost, payment for availability and opportunity cost, and payment for availability or opportunity cost.

In the proposed method, the payment for the generating units that are accepted in the reserve market contains two parts. The first part is capacity reservation, which is for the reserved capacity. The second part is the payment for delivering power in real-time. Delivering power in real-time is related to the contingency probability factor (CPF). The CPF is strongly related to the reliability of generating units [24]. In this paper, it is assumed that this factor is specified. Therefore, ISO announces the CPF for GENCOs to consider this factor in their energy and reserve bidding for maximizing their profits before closing the market. Therefore, the reserve payment (RP) to the ith generating company with R_i accepted capacity in the reserve market and with CPF equal to ρ can be written as:

$$\mathrm{RP}_i(R_i,\rho)=\sum_{k=1}^{d}R_i^k\cdot\mathrm{BR}_i^k+\left(R_i-\sum_{k=1}^{d}R_i^k\right)\cdot\mathrm{BR}_i^{d+1}+\rho\left[\sum_{l=1}^{e}E_i^l\cdot\mathrm{BE}_i^l+\left(R_i-\sum_{l=1}^{e}E_i^l\right)\cdot\mathrm{BE}_i^{e+1}\right]\quad(4)$$

Subject to the following constraints:

$$\begin{aligned}&\sum_{k=1}^{d}R_i^k\le R_i\le\sum_{k=1}^{d+1}R_i^k\quad\text{and}\quad d\le n_{\mathrm{ri}}-1\\&\sum_{l=1}^{e}E_i^l\le R_i\le\sum_{l=1}^{e+1}E_i^l\quad\text{and}\quad e\le n_{\mathrm{ei}}-1\end{aligned}\quad(5)$$

As stated before, in a disaggregated framework, the reserve market is cleared just after clearing the energy market in such a way that the total cost of reserve is minimized. This clearing procedure may have two potential problems:

1. The original energy schedule may not lead to the commitment of sufficient capacity to meet the reserve requirement. In this situation, the maximum available reserve in the reserve market is less than the required reserve. This case occurs when units with high ramp rates are accepted in the energy market and do not have enough capacity for participating in the reserve market.
2. Since the energy and reserve markets are cleared separately, from the total cost (energy market cost plus reserve market cost) point of view, these solutions do not lead to the global optimum.

In the proposed method, the above limitations are dealt with using some complementary considerations in reserve market clearing. In this manner, some units are backed down from their accepted values in the energy market and are participated in the reserve market. In this case, the backed down units are eligible to receive opportunity cost.

2.2. Opportunity cost modeling

As discussed in the previous section, in order to satisfy the reliability criterion and to maximize the social welfare, some accepted units in the energy market may be forced to back down. In this case, opportunity cost is paid to these units. In this context, if the payment mechanism in the energy market is MCP, then opportunity cost for the ith generating company can be calculated as:

$$\mathrm{OC}_i(P_i-\bar{P}_i)=\mathrm{Max}(0,(\mathrm{MCP}-\mathrm{BE}_i)\cdot(P_i-\bar{P}_i))\quad(6)$$

where OC_i is the opportunity cost of the ith generating company; MCP the market clearing price (the highest accepted price in the energy market); P_i the accepted value of the ith generating unit in the energy market after clearing the energy market by MO; $\bar{P}_i$ is the accepted value of the ith generating unit in the energy market after clearing the reserve market by SO.

In the above formulation, multi-block bids are not considered. However, the formulation can be simply extended for multi-block. If the payment mechanism in the energy market is pay-as-bid, then the opportunity cost for the ith generating company can be calculated as follows:

$$\mathrm{OC}_i(P_i-\bar{P}_i)=\mathrm{BM}_i(P_i-\bar{P}_i)\quad(7)$$

where BM_i is the benefit margin of the ith generating company, in some power markets, such as Iran Power Market (IPM), generating companies send their benefit margins to the market operator.

In this paper, for those generators which are eligible for receiving opportunity cost, the opportunity cost is assumed to be equal to the capacity reservation bid. Opportunity cost is paid to units that are backed down from the accepted values in the energy market and are participated in the reserve market with a capacity equal to their reduction in the energy market. Therefore, the payment for these units is the same as the units that are accepted in the reserve market, and is modeled as follows:

$$\begin{aligned}&\mathrm{OC}_i(P_i-\bar{P}_i,\rho)\\&=\sum_{m=1}^{a}R_i^m\cdot\mathrm{BR}_i^m+\left(P_i-\bar{P}_i-\sum_{m=1}^{a}R_i^m\right)\mathrm{BR}_i^{a+1}\\&\quad+\rho\left\{\sum_{n=1}^{b}E_i^n\cdot\mathrm{BE}_i^n+\left(P_i-\bar{P}_i-\sum_{n=1}^{b}E_i^n\right)\mathrm{BE}_i^{b+1}\right\}\end{aligned}\quad(8)$$

Subject to

$$\begin{aligned}&\sum_{m=1}^{a}R_i^m\le P_i-\bar{P}_i\le\sum_{m=1}^{a+1}R_i^m\quad a\le n_{\mathrm{ri}}-1\\&\sum_{n=1}^{b}E_i^m\le P_i-\bar{P}_i\le\sum_{n=1}^{b+1}E_i^m\quad b\le n_{\mathrm{ei}}-1\\&\bar{P}_i\le P_i\end{aligned}\quad(9)$$

Having formulated the opportunity cost, the details of the proposed market clearing algorithm may now be presented.

2.3. Proposed market clearing technique

Our main objective in the proposed method is to overcome the previously discussed limitations of the reserve clearing method in the disaggregated framework, while preserving its benefits.

The improvements are achieved by clearing the reserve market such that the summation of the following costs is minimized:

1. Capacity reservation payment;
2. Energy payment for those units that were not accepted in the energy market, and are ready to participate in the reserve market. As the load and generation must be balanced in all times instants, the backed down capacities should be compensated by other units;
3. Opportunity cost payment for those units that have to back down from the accepted value in the energy market and are participated in the reserve market to satisfy reliability and social welfare criteria.

Therefore, the market clearing procedure in the proposed method is implemented through the following steps:

- Step1: Clear energy market such that

$$\mathrm{Min}\sum_{i=1}^{N}\mathrm{EP}_i(P_i) \tag{10}$$

Subject to:

$$\sum_{i=1}^{N}P_i = \mathrm{Load}, \quad P_i^{\mathrm{Min}} \le P_i \le P_i^{\mathrm{Max}} \tag{11}$$

where:

$$\mathrm{EP}_i(P_i) = \sum_{j=1}^{c}E_i^j\cdot\mathrm{BE}_i^j + \left(P_i - \sum_{j=1}^{c}E_i^j\right)\cdot\mathrm{BE}_i^{c+1}, \quad \sum_{j=1}^{c}E_i^j \le P_i \le \sum_{j=1}^{c+1}E_i^j \tag{12}$$

- Step 2: The residual capacity (ResCap) and available reserve (AR) corresponding to each unit are calculated after clearing the energy market using the following equations:

$$\mathrm{Residual\ capacity}_i(\mathrm{ResCap}_i) = P_i^{\mathrm{Max}} - P_i \tag{13a}$$

$$\mathrm{Available\ reserve}_i(\mathrm{AR}_i) = \mathrm{Min}[\mathrm{ResCap}_i, 10\times\mathrm{RR}_i] \tag{13b}$$

where RR_i is the ramp rate of the ith generating unit in MW/min

- Step 3: Clear the reserve market such that

$$\mathrm{Min}\sum_{i=1}^{N}\mathrm{RP}_i(R_i,\rho) + \sum_{i=1}^{N}\mathrm{EP}_i(P_i') + \sum_{i=1}^{N}\mathrm{OC}_i(P_i-\bar{P}_i,\rho) - \sum_{i=1}^{N}\mathrm{REP}_i(P_i,\bar{P}_i) \tag{14}$$

Subject to:

$$\sum_{i=1}^{N}R_i + \sum_{i=1}^{N}(P_i-\bar{P}_i) = \mathrm{Required\ reserve} \tag{15a}$$

$$\sum_{i=1}^{N}P_i' = \sum_{i=1}^{N}(P_i-\bar{P}_i) \tag{15b}$$

$$P_i + R_i + P_i' \le P_i^{\mathrm{Max}} \tag{15c}$$

$$R_i + (P_i-\bar{P}_i) \le 10\times\mathrm{RR}_i \tag{15d}$$

where P_i' is the amount of energy that is accepted by SO in the reserve clearing process, from the ith unit excess to the amount accepted by MO, R_i the fraction of the ith generating unit capacity that is accepted in the reserve market, $\mathrm{EP}_i(P_i')$ is the energy payment to the ith accepted generating unit with P_i' MW higher than the accepted amount in the energy market clearing. $\mathrm{EP}_i(P_i')$ can be written as:

$$\mathrm{EP}_i(P_i') = \sum_{j=1}^{h}E_i^j\cdot\mathrm{BE}_i^j + \left(P_i + P_i' - \sum_{j=1}^{h}E_i^j\right)\cdot\mathrm{BE}_i^{h+1} - \mathrm{EP}_i(P_i), \quad \sum_{j=1}^{h}E_i^j \le P_i + P_i' \le \sum_{j=1}^{h+1}E_i^j, \quad P_i' \le \mathrm{ResCap}_i \tag{16}$$

As mentioned before, in the reserve market clearing, there are two reasons for reconsidering the units that were not accepted in the energy market. The first is that the original energy schedule does not lead to the commitment of sufficient capacity so as to meet the required reserve. This situation occurs when units with high ramp rates (such as hydro units) have a low marginal cost. In this case, these units are already accepted in the energy market and no longer have the capacity for contributing in the reserve market. From Eqs. (14) and

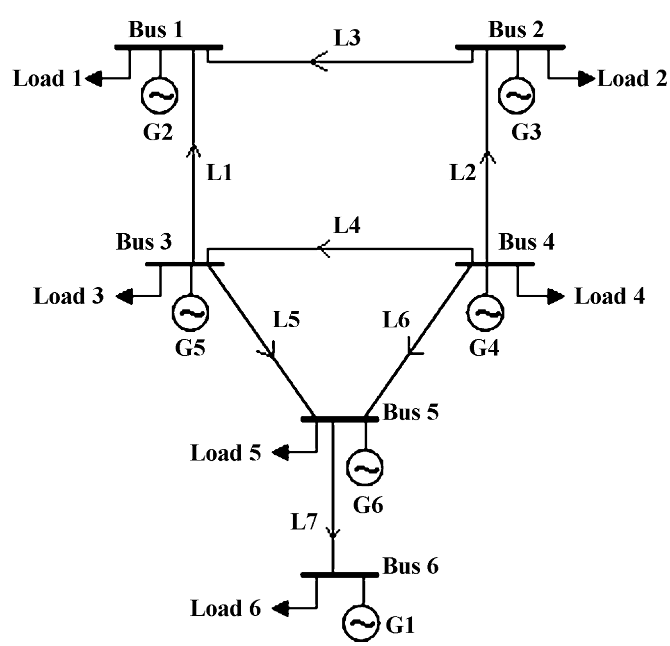

Fig. 1. Single line diagram of test system.

Table 1
Six unit test system data

Unit	Energy offer						Reserve offer		RR (MW/min)	MW limit
	Band 1		Band 2		Band 3		Band 1			
	MW	Price ($)	MW	Price ($)	MW	Price ($)	MW	Price ($)		
1	5	13	7	23	5	27	17	7.5	1	17
2	80	14	60	26	60	28	200	10	2	200
3	70	11	15	22	15	25	100	8.5	1	100
4	400	12	60	21	60	24	520	2	2	520
5	200	10	40	11	40	12	280	1	4	280
6	50	17	30	27	30	29	110	10	1	110

Table 2
Energy market clearing result with and without considering transmission constraints

System load (MW)	Unit no.	Without transmission constraints				With transmission constraints			
		P_i	$ResCap_i$	AR_i	Energy cost ($)	P_i	$ResCap_i$	AR_i	Energy cost ($)
500	1	0	17	10	5490	0	17	10	5490
	2	0	200	20		0	200	20	
	3	70	30	10		70	30	10	
	4	190	330	20		190	330	20	
	5	240	40	40		240	40	40	
	6	0	110	10		0	110	10	
600	1	0	17	10	6690	0	17	10	6690
	2	0	200	20		0	200	20	
	3	70	30	10		70	30	10	
	4	290	230	20		290	230	20	
	5	240	40	40		240	40	40	
	6	0	110	10		0	110	10	
700	1	0	17	10	7890	5	12	10	7996
	2	0	200	20		28	172	20	
	3	70	30	10		70	30	10	
	4	390	130	20		348	172	20	
	5	240	40	40		240	40	40	
	6	0	110	10		9	101	10	
800	1	5	12	10	9185	5	12	10	9374
	2	45	155	20		62	138	20	
	3	70	30	10		70	30	10	
	4	400	120	20		352	168	20	
	5	280	0	0		280	0	0	
	6	0	110	10		31	79	10	
900	1	5	12	10	10840	8	9	9	10901
	2	80	120	20		80	120	20	
	3	70	30	10		86	14	10	
	4	415	105	20		396	124	20	
	5	280	0	0		280	0	0	
	6	50	60	10		50	60	10	
1000	1	12	5	5	13068	12	5	5	13337
	2	80	120	20		120	80	20	
	3	85	15	10		100	0	0	
	4	493	27	20		420	100	20	
	5	280	0	0		280	0	0	
	6	50	60	10		68	42	10	

(15a) it is clear that if the available reserve in the reserve market is less than the required reserve, then some units are backed down and participated in the reserve market to satisfy the reliability criterion. The backed down units are hence eligible to receive opportunity cost. Due to the consistent balance between load and generation, the backed down portion of the accepted capacity in the energy market should be compensated by other units (Eq. (15b)). The second reason concerns the social welfare. From the social welfare point of view, since the reallocation strategy tends to minimize the cost, the total energy and reserve costs can also be potentially reduced.

$(P_i - \bar{P}_i)$: The backed down capacity of the ith generating unit for participating in the reserve market.

$\mathrm{REP}_i(P_i, \bar{P}_i)$: Reduction of energy payment associated to the ith generating unit. If the ith generating unit has to back down from its accepted value in the energy market, then this unit is eligible for receiving opportunity cost. In this case, the energy payment to this unit is reduced as follows:

$$\begin{aligned} &\mathrm{REP}_i(P_i, \bar{P}_i) = \mathrm{EP}_i(P_i) - \mathrm{EP}_i(P_i - \bar{P}_i) \\ &\bar{P}_i \leq P_i \end{aligned} \tag{17}$$

- Step 4: The total cost can be calculated as follows:

$$\begin{aligned} \mathrm{TC} = &\sum_{i=1}^{N} \mathrm{EP}_i(P_i) + \sum_{i=1}^{N} \mathrm{RP}_i(R_i, \rho) + \sum_{i=1}^{N} \mathrm{EP}_i(P'_i) \\ &+ \sum_{i=1}^{N} \mathrm{OC}_i(P_i - \bar{P}_i, \rho) - \sum_{i=1}^{N} \mathrm{REP}_i(P_i, \bar{P}_i) \end{aligned} \tag{18}$$

where TC is the total cost.

Note that, usually the reserve requirements (Eq. (15a)) are determined using deterministic criteria or "rule-of-thumb"

Table 3
Clearing reserve market using merit order with $\rho = 0.35$

System load	Required reserve (MW)	Unit no.	Without transmission constraints			With transmission constraints		
			R_i	Reserve cost ($)	Total cost ($)	R_i	Reserve cost ($)	Total cost ($)
500	50	1	0	270	5760	0	270	5760
		2	0			0		
		3	0			0		
		4	10			10		
		5	40			40		
		6	0			0		
600	60	1	0	332	7022	5	492	7182
		2	0			15		
		3	0			0		
		4	20			0		
		5	40			40		
		6	0			0		
700	70	1	5	498	8388	7	763	8759
		2	5			20		
		3	0			3.8		
		4	20			0		
		5	40			30.8		
		6	0			8.4		
800	80	1	Feasible solution is not possible			Feasible solution is not possible		
		2						
		3						
		4						
		5						
		6						
900	90	1	Feasible solution is not possible			Feasible solution is not possible		
		2						
		3						
		4						
		5						
		6						
1000	100	1	Feasible solution is not possible			Feasible solution is not possible		
		2						
		3						
		4						
		5						
		6						

methods. The most common deterministic criterion dictates a reserve margin equal to the size of the largest unit or to some percentage of the peak load [25]. For example in Spanish and Ontario power system, reserve is determined equal to some fraction of the peak load and to the largest on line generator, respectively [17]. Due to their simplicity of concept and ease of applying, the deterministic criteria methods have widely used in practice. The basic weakness of the deterministic criteria is that they do not consider the stochastic nature of system behavior and component failures [26]. In the probabilistic techniques, the stochastic nature of system components is incorporated and a comprehensive evaluation of system risk is provided [27].

In the following section, the applicability and effectiveness of the proposed method is studied through simulations.

3. Simulation results

A six unit system proposed in [28] is modified and used to illustrate the performance of the proposed technique. The single line diagram of this example is shown in Fig. 1. The line capacities are assumed to be 70 MVA. This system has 6 generators with capacities ranging from 17 to 520 MW. The total system generation is 1227 MW, and the system peak load is assumed to be 1000 MW. The loads of buses 1–6 are, respectively, assumed to be 23, 11, 23, 21, 17 and 5 percents of the system load. The required reserve in each bus is determined using deterministic criteria and it is equal to 10 percent of bus load. The data of this system including energy bidding blocks, reserve bidding blocks, ramp rate capability, and maximum capacity of units are listed in Table 1. For simulating the proposed method, it is assumed that the system load varies from 500 to 1000 MW. Two cases are

Table 4
Clearing energy and reserve market using aggregated method with $\rho = 0.35$

System load	Required reserve (MW)	Unit no.	Without transmission constraints			With transmission constraints		
			P_i	R_i	Total cost ($)	P_i	R_i	Total cost ($)
500	50	1	0	0	5760	0	0	5760
		2	0	0		0	0	
		3	70	0		70	0	
		4	190	10		190	10	
		5	240	40		240	40	
		6	0	0		0	0	
600	60	1	0	0	7022	5	0	7056.8
		2	0	0		14.4	0	
		3	70	0		70	0	
		4	290	20		270.4	20	
		5	240	40		240	40	
		6	0	0		0.2	0	
700	70	1	0	5	8377	5	7	8559.3
		2	10	5		51.8	0	
		3	70	0		70	0	
		4	380	20		318.8	20	
		5	240	40		240	40	
		6	0	0		14.4	3	
800	80	1	2	10	9991.5	5	7	10095
		2	80	0		80	0	
		3	70	0		70	9.2	
		4	400	20		367.2	20	
		5	240	40		240	40	
		6	8	10		37.8	3.8	
900	90	1	5	10	12123	7.2	9.8	12349
		2	80	10		94.3	20	
		3	75	10		90	10	
		4	450	20		399	18.9	
		5	240	40		258.7	21.3	
		6	50	0		50.8	10	
1000	100	1	7	10	14757	7	10	15096
		2	113	20		153	20	
		3	90	10		90	10	
		4	500	20		420	20	
		5	240	40		250	30	
		6	50	0		80	10	

studied. In case 1, transmission capacity constraints are ignored. In case 2, the effect of transmission constraints on the scheduling of generating units using the proposed method are considered.

3.1. Case 1: without considering transmission constraints

In this case the energy market clearing, residual capacity, available reserve of each unit, and also energy costs for the given range of load were calculated. The calculated values are listed in Table 2. After clearing energy market by the market operator, the system operator clears the reserve market. Table 3 shows the results of merit order (sequential) method for reserve market clearing. From Table 2 it is seen that as the load is increased, the available reserve is decreased. Since the available reserve for the load levels higher than 700 MW is less than the required reserve, therefore achieving a feasible solution for the reserve market for these load levels is not possible. After clearing the energy market for 800 MW, the maximum available reserve is 70 MW, which is less than the required reserve (80 MW). In this case the maximum capacity of generator 5, which has the highest ramp rate, is accepted in the energy market.

Table 4 shows the energy and reserve market clearing results using the aggregated method. Using this method, not only the total cost is less than the disaggregated method, but there is also a feasible solution for the reserve market within the assumed load range.

Tables 5 and 6 show the reserve clearing results using the proposed method. As it can be seen, the reserve market has a feasible solution for all the load range when the proposed method is applied. This is one of the privileges of the proposed method. As stated earlier, the lack of a feasible solution is one of the weak points of the disaggregated framework. The proposed method overcomes this problem. Suppose that the system load level is 800 MW. If the network constraints are not consid-

Table 5
Clearing reserve market using the proposed method with $\rho = 0.35$

System load	Required reserve (MW)	Unit no.	Without transmission constraints				With transmission constraints			
			P'_i	R_i	$P_i - \bar{P}_i$	Total cost ($)	P'_i	R_i	$P_i - \bar{P}_i$	Total cost ($)
500	50	1	0	0	0	5760	0	0	0	5760
		2	0	0	0		0	0	0	
		3	0	0	0		0	0	0	
		4	0	10	0		0	10	0	
		5	0	40	0		0	40	0	
		6	0	0	0		0	0	0	
600	60	1	0	0	0	7022	5	0	0	7056.8
		2	0	0	0		14.4	0	0	
		3	0	0	0		0	0	0	
		4	0	20	0		0	0.4	19.6	
		5	0	40	0		0	40	0	
		6	0	0	0		0.2	0	0	
700	70	1	0	5	0	8377	0	7	0	8565.3
		2	10	5	0		23.8	0	0	
		3	0	0	0		0	0	0	
		4	0	10	10		0	0	20	
		5	0	40	0		0	30.8	9.2	
		6	0	0	0		5.4	3	0	
800	80	1	0	7	3	9991.5	0	7	0	10095
		2	35	0	0		18	0	0	
		3	0	0	0		0	9.2	0	
		4	0	20	0		15.2	20	0	
		5	0	0	40		0	0	40	
		6	8	10	0		6.8	3.8	0	
900	90	1	0	10	0	12123	0	9	0.8	12349
		2	0	10	0		14.3	20	0	
		3	5	10	0		4	10	0	
		4	35	20	0		3	18.9	0	
		5	0	0	40		0	0	21.3	
		6	0	0	0		0.8	10	0	
1000	100	1	0	5	5	14757	0	5	5	15096
		2	33	20	0		33	20	0	
		3	5	10	0		0	0	10	
		4	7	20	0		0	20	0	
		5	0	0	40		0	0	30	
		6	0	0	0		12	10	0	

ered, then using the proposed method, from Table 5 generators 1 and 5 should, respectively, back down 3 and 40 MW from their accepted values in the energy market, in order to participate in the reserve market. Therefore, the total 43 MW reduction in the energy should be compensated by other units in an economic manner. From Table 5 it is clear that this reduction will be compensated by generator 2 and 6 with the amounts of 35 and 8 MW, respectively. Hence, the share of generator 1, 2, 5 and 6 in the energy market are respectively modified to 2, 80, 240 and 8 MW, respectively. The rest of reserve requirement (80–43 = 37 MW) is provided by units 1, 4 and 6 as indicated in Table 5. It is clear that by participating the backed down units in the reserve market, the reliability requirement can be met, while the reliability criterion was not satisfied using the merit order method.

Table 6 shows each of the costs in the reserve market clearing using the proposed method. The total cost (energy market cost plus reserve market cost) can be calculated by the summation of energy cost (from Table 2), RP_i, EP_i, OC_i , and $-REP_i$ (from Table 6). From the social welfare point of view, it is clear that the proposed method leads to the minimum cost compared with the disaggregated method. If the transmission constraints are not considered, the total cost of the proposed method is the same as the aggregated method.

3.2. Case 2: with considering transmission constraints

3.2.1. Example 1: two area test system

In order to illustrate the effect of transmission capacity constraint on the optimal scheduling of generating units, we first start with a simplified two area case. For this, the original six bus system is converted into two areas A and B, with units 1–4 belonging to area A and units 5–6 belonging to area B. The total load demand and reserve requirement are assumed to be 700 and 70 MW, respectively. Moreover, the load is equally divided

Table 6
RP_i, EP_i, OC_i and REP_i corresponding to each unit

System load	Required reserve (MW)	Unit no.	Without transmission constraints				With transmission constraints			
			RP_i (\$)	EP_i (\$)	OC_i (\$)	REP_i (\$)	RP_i (\$)	EP_i (\$)	OC_i (\$)	REP_i (\$)
500	50	1	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0
		4	62	0	0	0	62	0	0	0
		5	208	0	0	0	208	0	0	0
		6	0	0	0	0	0	0	0	0
600	60	1	0	0	0	0	0	65	0	0
		2	0	0	0	0	0	201.6	0	0
		3	0	0	0	0	0	0	0	0
		4	124	0	0	0	2.48	0	121.52	235.2
		5	208	0	0	0	208	0	0	0
		6	0	0	0	0	0	3.4	0	0
700	70	1	60.25	0	0	0	108.85	0	0	0
		2	74.5	140	0	0	0	333.2	0	0
		3	0	0	0	0	0	0	0	0
		4	62	0	62	120	0	0	124	240
		5	208	0	0	0	160.16	0	44.62	101.2
		6	0	0	0	0	47.85	91.8	0	0
800	80	1	108.85	0	36.15	39	108.85	0	0	0
		2	0	490	0	0	0	252	0	0
		3	0	0	0	0	149.04	0	0	0
		4	187	0	0	0	124	182.4	0	0
		5	0	0	208	480	0	0	208	480
		6	159.5	136	0	0	60.61	115.6	0	0
900	90	1	159.7	0	0	0	146.95	0	12.44	18.4
		2	191	0	0	0	382	371.8	0	0
		3	162	110	0	0	172.5	100	0	0
		4	197.5	735	0	0	173.565	36	0	0
		5	0	0	208	480	0	0	110.76	255.6
		6	0	0	0	0	194.5	21.6	0	0
1000	100	1	84.75	0	77.75	115	84.75	0	77.75	115
		2	382	858	0	0	396	884	0	0
		3	172.5	125	0	0	0	0	172.5	250
		4	208	168	0	0	187	0	0	0
		5	0	0	208	480	0	0	156	360
		6	0	0	0	0	201.5	324	0	0

Table 7
Energy market clearing results, energy and reserve market clearing results using the aggregated method, and energy and reserve market clearing results of two area system using the proposed method

System load (MW)	Unit no.	P_i	ResCap_i	AR_i	Energy cost ($)	Line flow (MW)
Energy market clearing results of two area system						
700	1	0	17	10	0	70
	2	0	200	20	0	
	3	70	30	10	770	
	4	350	170	20	4200	
	5	280	0	0	2920	
	6	0	110	10	0	

System load	Unit no.	P_i	R_i	Line flow (MW)	Total cost ($)
Energy and reserve market clearing results of two area system using aggregated method with $\rho = 0.35$					
700	1	0	5	70	8549
	2	0	0		
	3	65	5		
	4	355	20		
	5	240	40		
	6	40	0		

System load	Unit no.	P'_i	R_i	$P_i - \bar{P}_i$	Line flow (MW)	Total cost ($)
Energy and reserve market clearing results of two area system using the proposed method with $\rho = 0.35$						
700	1	0	5	0	70	8549
	2	0	0	0		
	3	0	0	5		
	4	5	20	0		
	5	0	0	40		
	6	40	0	0		

between area A and area B, and the transmission capacity is assumed 70 MVA.

For this simplified case, the energy market clearing results, residual capacity, available reserve, and energy cost are given in Table 7. From Table 7, the maximum available reserve (AR) in areas A and B is 60 and 10 MW, respectively. Even with a sufficient available reserve of the system, due to tie line congestion, the available reserve in area A may not contribute to the area B. Therefore, there is no feasible solution for the reserve market using the disaggregated method.

Market clearing results of this two area system with the 700 MW load using aggregated method and the proposed method are given in Table 7. From Table 7 and using the proposed method, generators 3, and 5 should respectively back down 5, and 40 MW, from their accepted value in the energy market in order to participate in the reserve market. This total 45 MW reduction in the energy market will be compensated by generators 4 and 6 with the amounts of 5 and 40 MW, respectively. The rest of reserve requirement (70–45 = 25 MW) is provided by generators 1 and 4 as listed in Table 7. By participation of generator 5 in the reserve market, generator 5 is serving the local reserve of 35 MW and contributing 5 MW for reserve to area A. The required reserve of area A (35 MW) is satisfied with the sum of local generation (30 MW) and imported reserve power from area B (5 MW), as listed in Table 7. It should be noted that area B is importing energy and exporting reserve, and flows are in opposite directions. Finally it is noted that the total cost of our proposed method encountering a congestion case is exactly the same as the aggregated method.

3.2.2. Example 2: six bus test system

With this overview, we can now consider the original six bus case. The energy market clearing, residual capacity, available reserve of each unit, and also energy costs for this range of load with considering the transmission constraint is listed in Table 2. The effect of transmission constraint on the market clearing results of this system using the disaggregated, aggregated, and the proposed methods are given in Tables 3–5, respectively. As stated in the case 1, using the disaggregated method for the loads higher than 700 MW there is no feasible solution. From Table 5, if the transmission constraints are considered, the proposed method has a feasible solution for all load ranges, just like the aggregated method. Energy flow after clearing the energy market, and the energy and reserve flows obtained by the proposed method for all range of loads are listed in Table 8. Suppose that the system load level is 800 MW. From Table 8, it is clear that after clearing the energy market, the lines L1, L2, L5, and L6 are congested. Using the proposed method, the line flows of lines L1, L2, and L6 are reduced and the rest of their capacities are saved and made available for reserve flow. It is clear from Table 8 using the proposed method; the system is able to transmit energy and reserve through the existing lines without violating the transmission capacity. By comparing the results of Tables 4 and 5, it is seen that from the social welfare point of

Table 8
Line flow after clearing the energy market and using the proposed method

System load (MW)	Line flow			
	Line no.	Energy flow after clearing energy market (MW)	Proposed method	
			Energy flow (MW)	Reserve flow (MW)
500	L1	70	45	11.5
	L2	30	55	5.5
	L3	45	70	0
	L4	−15	−40	−6
	L5	40	40	11
	L6	70	70	0
	L7	25	25	2.5
600	L1	70	53.6	16.4
	L2	64	66	4
	L3	68	70	−2.6
	L4	30	8.4	3.4
	L5	62	56.8	13.2
	L6	70	70	0
	L7	30	25	3
700	L1	70	70	0
	L2	70	46.2	23.8
	L3	63	39.2	16.1
	L4	61	64.8	−18.5
	L5	70	64.6	5.4
	L6	70	70	0
	L7	30	30	−3.5
800	L1	70	56	14
	L2	70	66	4
	L3	52	48	4.4
	L4	44	70	−7.6
	L5	70	70	0
	L6	70	63.2	6.8
	L7	35	35	−3
900	L1	70	51.7	0.6
	L2	70	70	0
	L3	57	61	0.1
	L4	67	70	0
	L5	70	70	0
	L6	70	70	0
	L7	37	37.8	−5.3
1000	L1	50	27	5
	L2	70	70	−1
	L3	60	50	−2
	L4	70	70	0
	L5	70	63	2
	L6	70	70	0
	L7	38	43	−5

view, when the transmission constraints are considered, in most cases the total cost of the proposed and the aggregated methods are the same. Only in a special test case (load level 700 MW) a slight difference is seen.

The proposed method has the advantages of both aggregated and disaggregated methods. The proposed method is very simple and transparent, similar to the disaggregated clearing model. On the other hand, similar to the aggregated model, it leads to feasible solutions with the same quality in cases in which the disaggregated model can not clear the market. Moreover, it also outperforms the disaggregated model from the social welfare point of view.

4. Conclusion

An approach for clearing the reserve market in the disaggregated framework was presented. A separated environment for clearing the energy and reserve markets was used. The reserve market is cleared such that the reserve cost (considering capacity cost and energy cost of reserve), and also the opportunity cost are minimized. The approach was applied to a six unit test system. The simulation results show the effectiveness of the proposed method. It is shown that in the merit order method, there exist some cases in which the feasible solution is not achievable and the maximum available capacity in the reserve market is less than the required reserve. The proposed method however, solves this problem in a simple and optimum manner similar to the aggregated method. The total cost of the proposed method is also less than the merit order method, while there is a slight difference between the total cost of the proposed method and the aggregated method. Simulation results show that the proposed method has the benefits of both aggregated and disaggregated methods. From one side, it preserves the simplicity and transparency of the disaggregated method; and on the other side, its total cost is very close to the aggregated method.

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