CHAPTER V

SPINNING RESERVE PRICING UNDER PARTIALLY DEREGULATED STRUCTURE

5.1 Introduction

Spinning reserve is generating capacity that is spinning and synchronized with the system and available to serve load on a moment's notice. Utilities must maintain or purchase some generation capacity as spinning reserve to serve load in the event that the operating generating units, transmission lines, or other equipment that is serving load suddenly or unexpectedly fails. The amount of spinning reserve that a system requires to carry must be based on an acceptable level of risk and economy decision-making. Historically, the amount of spinning reserve is determined by rule of thumb, such as some multiple, i.e. one or one and one-half times of the largest operating unit, or as some percentage of the system load being served [25].

In the past decade, power industry has moved form a vertically integrated and highly regulated structure to one that has been more competitive. In this new environment, generation, transmission, and distribution are fully or partially unbundled, and customer are allowed to choose their suppliers [88]. Consequently, the traditional approaches to operate and control a power system such as providing spinning reserve needs some modifications.

In the competitive electricity market, the provision of spinning reserve for maintaining the reliability and security of the system is scheduled and allocated by the central coordinating authority. The method for allocating and pricing spinning which is determined based on Lagrange multiplier is presented in [89]. In the other work [90], they proposed a basic decision making for power producers for participating in reserve market. In this paper, the reserve price is determined based on how reserve payments are made for actual power delivered or for power that is merely reserved.

This chapter presents a method to determine the spinning reserve price under partially deregulated structure by considering system uncertainties and bilateral transactions. For modeling the partially deregulated system, a portion of the total demand is supplied by private generation companies (GENCOs) through bilateral contract transactions. In this model, standard deviation of load forecast error is used to represent the demand uncertainty, meanwhile generating unit uncertainty is modeled by a two-state Markov model. Three demand levels, i.e. low, medium, and high, are created to handle demand uncertainty. They are then combined with three spinning reserve strategies based on deterministic criterion to result in the total of nine scenarios to be analyzed by the decision analysis method. The best strategy which gives minimum expected total cost is selected among the created scenarios. The unit commitment problem for each scenario is created and solved by a Mixed-Integer Linear Programming (MILP) method. The expected total cost of each scenario is composed of expected generation cost, and expected risk cost which is calculated by considering all possible combinations of GENCO failure. The reserve price, which should be paid by the GENCO if the spinning reserve is utilized, can be determined by balancing the increase of cost of the additional reserve and the obtained revenue from utilizing reserve power. The effectiveness of the proposed method has been tested with a modified IEEE-24 bus system, a modified EGAT system. Sensitivity analysis with respect to the amount of BC demand and the number of GENCOs is also reported.

5.2 Problem Formulation

5.2.1 Frame Work of Partially Deregulated Utility

In short-term operation, the system operator in a vertically state-owned utility has an obligation to supply its forecasted demand at a specified reliability level, which is usually defined via operational reserve requirement, of which the spinning reserve plays a major role and used directly as a constraint in a unit commitment problem.

Under a partially deregulated system, a GENCO owns a number of generating units. Meanwhile, the state-owned utility is described here as an original system, of which all the units are called as original system units. On the demand side, there are two types of demand, i.e. the state-owned or original system demand and the GENCO's customers or bilateral contracted (BC) demand. It is assumed that BC demand is constant for the whole scheduling periods. The BC demand is also classified into firm (D_{BC_firm}) and non-firm or ($D_{BC\_non\text{-}firm}$) demands. As all generating units may face failure, the BC firm demand may not be supplied at a certain risk level. The assumption is that the GENCO does not have sufficient capacity to back-up its owned firm demand which needs back-up spinning reserve, ancillary services, from the original system. Hence, the amount of spinning reserve provided by the original system has to consider the need to ensure the reliability of both the original demand and the BC firm demand. An illustration model of the partially deregulated system with two GENCOs involved in the bilateral transaction is shown in Figure 5.1.

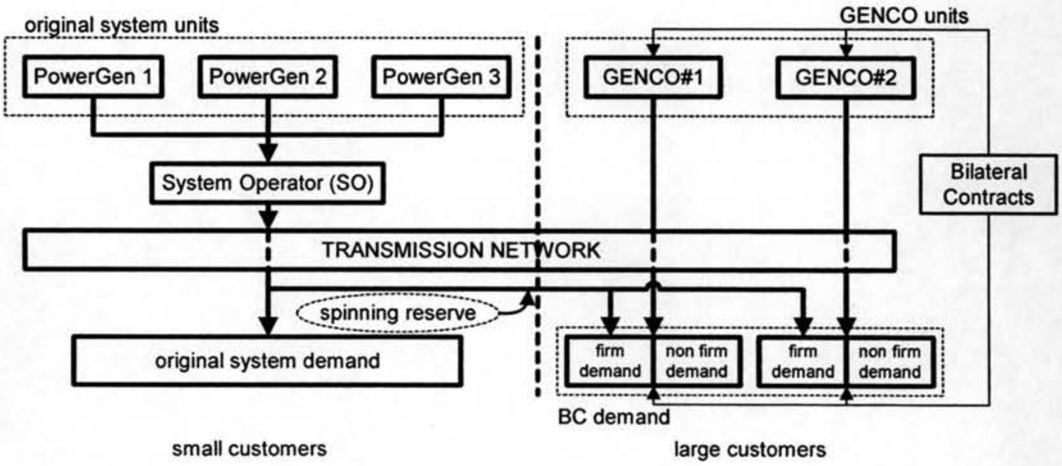

Figure 5.1 Model of partially deregulated utility

5.2.2 Load Uncertainty Model by Considering Bilateral Contract Transactions

Demand uncertainty can be determined, based on historical forecasting performance, by a probability distribution function. In this research a discrete normal distribution comprising three load levels, i.e. low, medium and high as shown in Figure 5.2, is used to represent the load uncertainty.

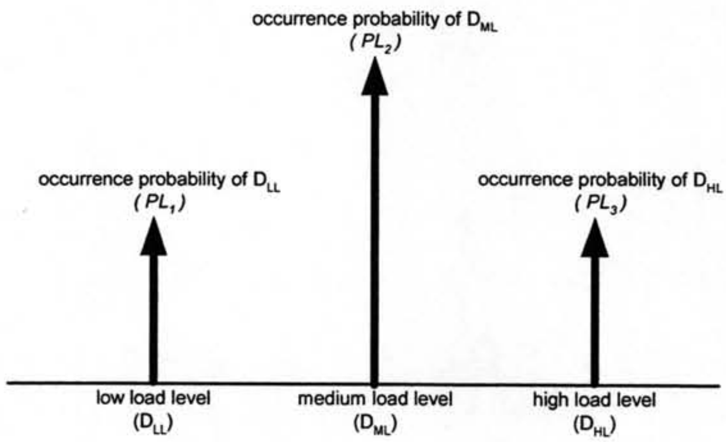

Figure 5.2 Discrete normal distribution function of demand uncertainty model

Let's assume that the mean value of the total forecast demand, summation of all the original system demand and the GENCO demand, at interval time t is $FD(t)$ and standard deviation is σ (t). In the proposed partially deregulated model as shown in Figure 5.1, some part of the demand might be directly contracted by GENCOs through bilateral aggreement, denoted by $D_{BC}(g)$. The demand left to the state-owned utility can be presented as

$$MD_{org}(t) = FD(t) - \sum_{g=1}^{NG} D_{BC}(g) \quad \text{......} \quad (5.1)$$

where NG is the number of GENCO.

In general, the longer the lead time is, the higher uncertainty in the forecasted value will be [79], [53]. Suppose that the predefined standard deviations in the first and last hours (T) of the scheduling horizon are denoted by σ(1) and σ(T) respectively. With the assumption that the standard deviation increases linearly with the considered lead time, the standard deviation in each considered hour, i.e. the first to the last, can be approximated by

$$\sigma(t) = \sigma(1) + \frac{\sigma(T) - \sigma(1)}{T-1}(t-1), \quad \forall t \in [1, T] \quad \text{......} \quad (5.2)$$

Based on equations (5.1) and (5.2), the low, medium, and high load levels can be generated as described in 5.3.

$$\begin{aligned} D_{LL}(t) &= MD_{org}(t) - \sigma(t) MD_{org}(t), \\ D_{ML}(t) &= MD_{org}(t), \qquad \forall\, t \in [1,T] \quad \text{......} \quad (5.3) \\ D_{HL}(t) &= MD_{org}(t) + \sigma(t) MD_{org}(t), \end{aligned}$$

5.2.3 UC Problem Formulation under Partially Deregulated Utility

The objective function of a UC problem in the partially deregulated utility is defined as to minimize the total cost, subjected to prevailing constraints. The unit constraint is similar with the formulated problem as presented in the previous chapters. Meanwhile, for scheduling spinning reserve, the minimum amount of spinning reserve is defined based on total capacity of the system and the needs of back-up power for the BC demand. Details of the spinning reserve requirement will be explained later.

5.3 Methodology

The objective of this chapter is to determine suitable reserve prices which provides a balance between the increase of the total cost as of the additional reserve and the bilateral transactions.

Similar with the employed model of the uncertainty presented in Chapters 3 and 4, the uncertainty on the supply side is considered via generating unit's Outage Replacement Rate (ORR), whereas the demand will be considered through the forecast error distribution function. The basic concept of the decision analysis for solving generation scheduling problem as presented in Chapter 2 is also utilized in this chapter.

For a given total load forecast data, it is assumed that there is a certain error around each forecasted value which, in this chapter, will be represented by a three-discrete distribution function, denoted as low load (D_{LL}), medium load (D_{ML}), and high load (D_{HL}). Three spinning reserve strategies will be considered in the decision tree model to investigate the impact of different amount of reserve to obtain the best strategy. The spinning reserve strategy is initially determined as a specific percentage of demand at each corresponding time interval.

The scenarios take into account all possible load levels and spinning reserve strategies. Since three spinning reserve are considered with three possible load levels, there are nine possible scenarios as shown in Table 3.1. It is assumed that some units of the original system are spin-off to be GENCOs units whereas a certain percentage of the original demand has been taken to be GENCOs' direct customers. The spinning reserve requirement based on the rest of generation capacity and the demand of the original system should be firstly determined in the initial step. This calculation is needed instead of just applying the initial value of each spinning reserve strategy since at a certain value of the BC demand, which may be higher than the capability of the original system. In this case, the initial spinning reserve requirement from the original system may not be sufficient to cover the BC demand, if the GENCOs units are unavailable. The detailed procedures of specifying the spinning reserve requirement will be explained later. The step is then preceded by determining the committed units using the MILP-UC module, of which the result from this step will be used to determine the expected generation cost (GC) and the risk cost (RC). Since the calculation of risk cost will be conducted many times, hence it is necessary to develop capacity outage probability table (COPT) for all time intervals before proceeding to the next step. The COPT for each time interval will be recalled to calculate risk cost.

Since it is assumed that there are a few GENCOs involved in the bilateral transactions, meanwhile each GENCOs generating unit has a failure probability in supplying its BC firm demand, the calculation of expected generation cost and risk cost has to take into account all the failure probability. Then, the expected generation cost and risk cost by considering only the original system demand is carried out. The expected total cost is the sum of the generation cost and the risk cost after weighted by its failure probability. The best strategy is selected among the created scenarios for the minimum expected total cost. The calculation procedure of the proposed method is presented in the flowchart in Figure 5.5. Detailed explanation of each calculation steps is described below.

5.3.1 Spinning Reserve Calculation

Under the defined market structure, state-owned utility should schedule its spinning reserve for its owned demand and for the BC firm demand to a certain extent which provide sufficient benefit to the utility. Initial intention is defined that the original system should cover all BC firm demand in addition to the original system demand. Therefore the scheduled spinning reserve may not be sufficient to supply the BC firm demand. Accordingly, the spinning reserve must be readjusted so that the original system will only provide the maximum spinning reserve based on the available generation capacity. Detail of the calculation procedure of spinning reserve strategy determination is shown in the flowchart in Figure 5.3.

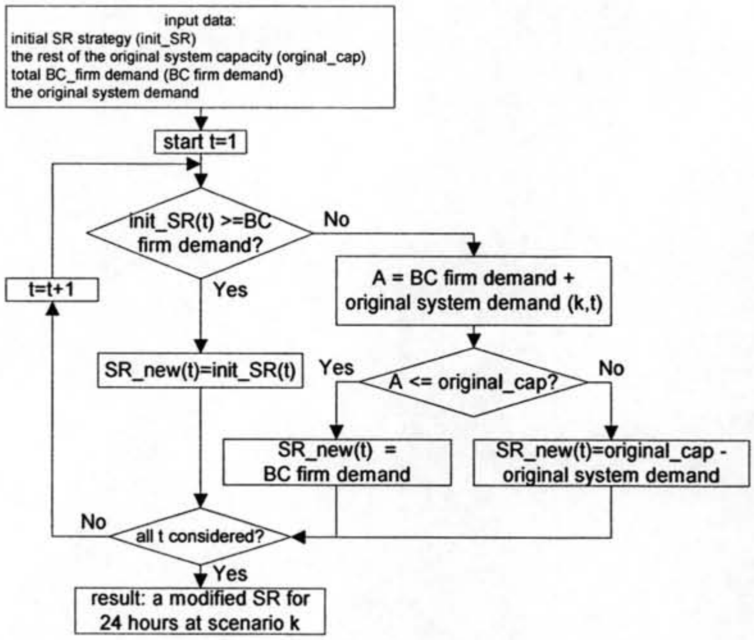

Figure 5.3 Flowchart for spinning reserve readjustment

5.3.2 Expected Total Cost Calculation

In a conventional vertically integrated system, the calculation of expected total cost which comprises generation cost and risk cost can be easily calculated [23]. In the partially deregulated utility, the calculation becomes much more complicated since it has to consider the probability of GENCOs units being in a failure state. Since the original system may have to provide spinning reserve for the BC firm demand of the GENCOs. Hence if one of the GENCO units is fail, the corresponding BC firm demand will be taken over by the original system. Consequently, the calculation of expected generation cost and risk cost has to take into account all generating units failure probability. The expected total cost is then multiplied by the corresponding failure probability of the GENCO, which is expressed in the term of Unit Commitment Risk (UCR). The UCR of each GENCO is calculated based on both the failure probability of each unit in association with its BC demand. Meanwhile, the value of failure probability for a combination of more than one GENCOs is represented by the multiplication of the UCR of each GENCO. The whole combinations can then be used to calculate the failure probability of the original system.

Assuming that the number of GENCOs is NG, the first step is to develop a set of non-repetitive combination by choosing n GENCOs out of NG to be in a failure state. A set of non-repetitive combination of choosing n from the available NG GENCOs of the scenario k is denoted as

$$S_{kn} = C(NG, n) \quad \text{(5.4)}$$

For instance, if NG=3 and let n=2, hence the set of C(3,2) is expressed as $S_{k2} = \{\{1,2\},\{1,3\},\{2,3\}\}$. For detail notations, we notate the order of each subset member of S_{kn} as *m*th. The *m*th subset of S_{kn} is symbolized as S_{knm}. In this case, the third subset member of S_{k2} is $S_{k23} = \{2,3\}$. If each GENCO in the subset S_{knm} is indexed by *z*, hence the notation of GENCO#g in the subset S_{knm} can be symbolized as g_z. In the above example, the subset S_{k23} can be rewritten as $S_{k23} = \{2_{z=1}, 3_{z=2}\} = \{2_1, 3_2\}$.

To determine the associated cost of the subset S_{knm}, firstly we have to define the total demand to be supplied by the original system which corresponds to the subset S_{knm}. Since we have to calculate the generation cost and risk cost for all possible load levels, hence we have to determine the total load demand for all considered load levels. The total demand of subset S_{knm} at time *t* at load level *j* which is denoted as $D^{knm}_{org\_BC}(j,t)$ is the sum of the original system demand at time *t* at load level *j* and the summation of all BC firm demands of the corresponding GENCOs in the subset S_{knm}. It can be formulated as

$$D^{knm}_{org\_BC}(j,t) = D_{org}(j,t) + \sum_{g_z \in S_{knm}} D^{knm}_{BC\_firm}(g_z) \quad \text{(5.5)}$$

The generation cost of S_{knm}, which is denoted by GC^{knm}_{tj}, is obtained by dispatching the demand in (5.5) to the committed units which is delivered from the MILP-UC module. For a special case in which the reserve requirement for backing-up the BC firm demand can not be fully provided by the original system, due to the limitation of the capacity generation, the total load demand in (5.5) should be recalculated. The recalculation procedure of the dispatched load in order to match with online generation capacity is shown in Figure 5.4. Next, the modification of the results of the dispatched load for each load level and time interval, which is expressed as $DD_{org\_BC}^{knm}(j,t)$, are used to determine the generation cost and risk cost. Afterward, the expected generation cost of S_{knm}, taking into account load uncertainty, and denoted by EGC_t^{knm}, can be calculated as

$$EGC_t^{knm} = \sum_{j=1}^{3} PL_j \bullet GC_{tj}^{knm} \qquad (5.6)$$

where PL_j is the occurrence probability of load level j.

Meanwhile for calculating the expected risk cost, the detail procedure of risk cost calculation as explained in [23] is implemented in this chapter. The risk cost of S_{knm} which is denoted by ERC_t^{knm}, is computed by

$$ERC_t^{knm} = \sum_{j=1}^{3} PL_j \bullet EUE_{tj}^{knm} \bullet VOLL \qquad (5.7)$$

where $VOLL$ stand for Value of Loss Load which in [23] is stated as EUE_price.

The occurrence probability of the subset S_{knm} is a multiplication product of all UCR in S_{knm}. The individual UCR is determined based on the COPT which is developed using the ORR of the corresponding GENCO units. This unit commitment risk calculation is called as security function approach [25]. Since the ORR is a function of lead time, hence the value of UCR is different for each time interval. The occurrence probability of subset S_{knm} at time t can be formulated as

$$P_t^{knm} = \prod_{g_z \in S_{knm}} UCR(g_z, t) \qquad (5.8)$$

where $UCR(g_z,t)$ is the UCR at time t of GENCO#g_z in the subset S_{knm}. The expected total cost of subset S_{knm} after weighted by the occurrence probability of the subset S_{knm} can be formulated as

$$ETC_t^{knm} = (EGC_t^{knm} + ERC_t^{knm})P_t^{knm} \qquad (5.9)$$

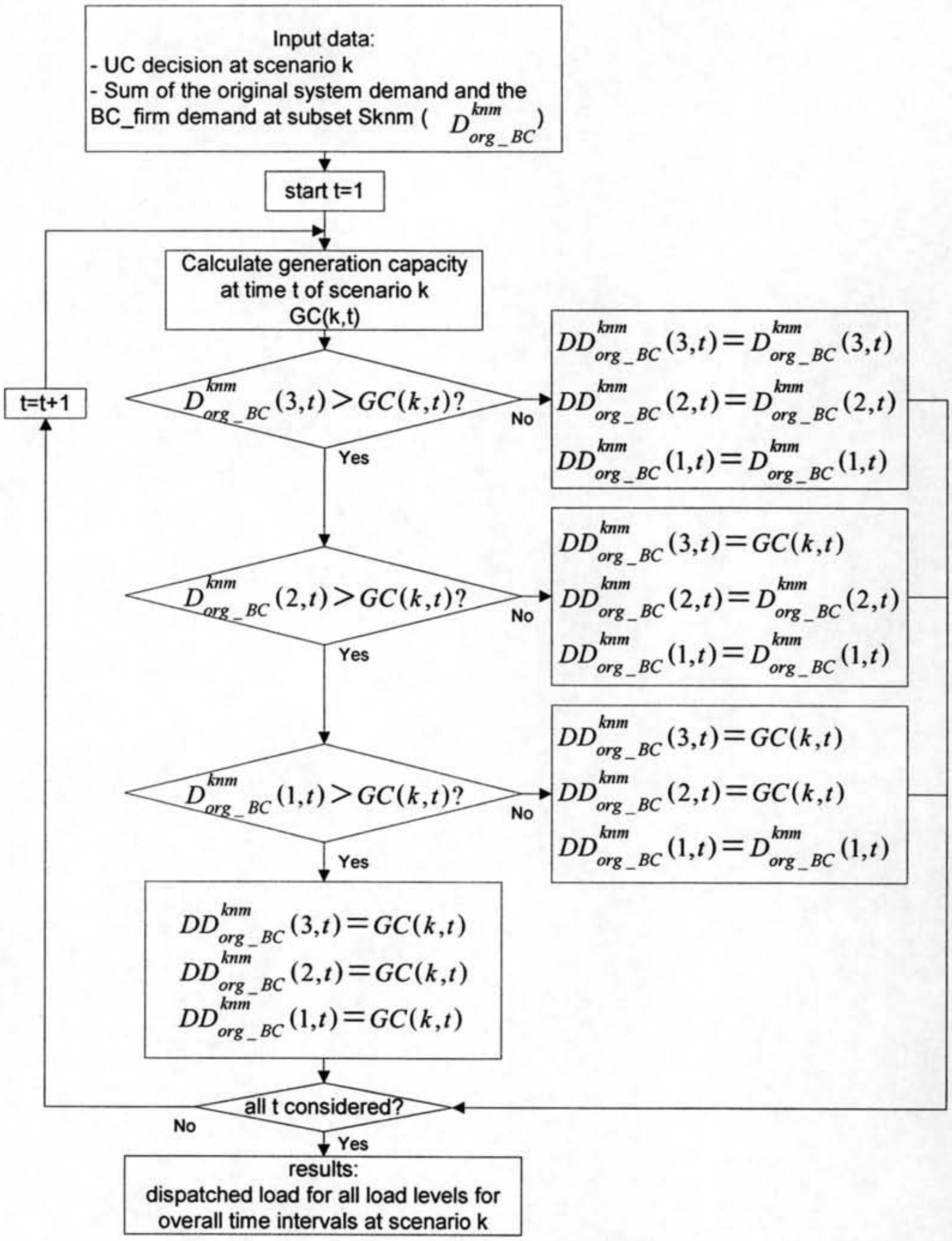

Figure 5.4 Flowchart for recalculation of dispatched load

For providing the spinning reserve to GENCOs, the original system should be able to earn benefit. The amount of benefit depends on the amount of the provided reserve, utilization probability, and price. As an example, for the subset S_{knm}, the total spinning reserve which should be provided at time t is the sum of all BC firm demands of the corresponding GENCOs in the subset S_{knm}. The amount of received benefit is the multiplication product of the amount of spinning reserve and the occurrence probability of the subset S_{knm} as stated in (5.8) together with the spinning reserve price. Accordingly, the expected benefit from the payment of the spinning reserve of subset S_{knm} can be formulated as

$$ESRB_t^{knm} = SRP \bullet P_t^{knm} \bullet \sum_{g_z \in S_{knm}} D_{BC\_firm}^{knm}(g_z) \quad (5.10)$$

After all combinations of GENCOs have been calculated, the calculation of expected total cost of the original system demand only, that is the event of the GENCOs do not need back-up from the original system, can be conducted. If we denote the expected generation cost and expected risk cost at time t as EGC_t^{k0} and ERC_t^{k0} respectively, these costs of this event can be formulated as stated in (5.11) and (5.12) respectively.

$$EGC_t^{k0} = \sum_{j=1}^{3} PL_j \bullet GC_{tj}^{k0} \quad (5.11)$$

$$ERC_t^{k0} = \sum_{j=1}^{3} PL_j \bullet EUE_{tj}^{k0} \bullet VOLL \quad (5.12)$$

The occurrence probability of this event is given by

$$P_t^{k0} = 1 - \sum_{n=1}^{NG} \sum_{m=1}^{M} P_t^{knm} \quad (5.13)$$

The expected total cost for this event can be defined as

$$ETC_t^{k0} = (EGC_t^{k0} + ERC_t^{k0}) P_t^{k0} \quad (5.14)$$

Based on (5.9), (5.10), and (5.14), the expected total cost for scenario k can be formulated as

$$ETC^{k} = \sum_{t=1}^{T} \left[\sum_{n=1}^{NG} \sum_{m=1}^{M} \left\{ ETC_t^{knm} - ESRB_t^{knm} \right\} + ETC_t^{k0} \right] \quad (5.15)$$

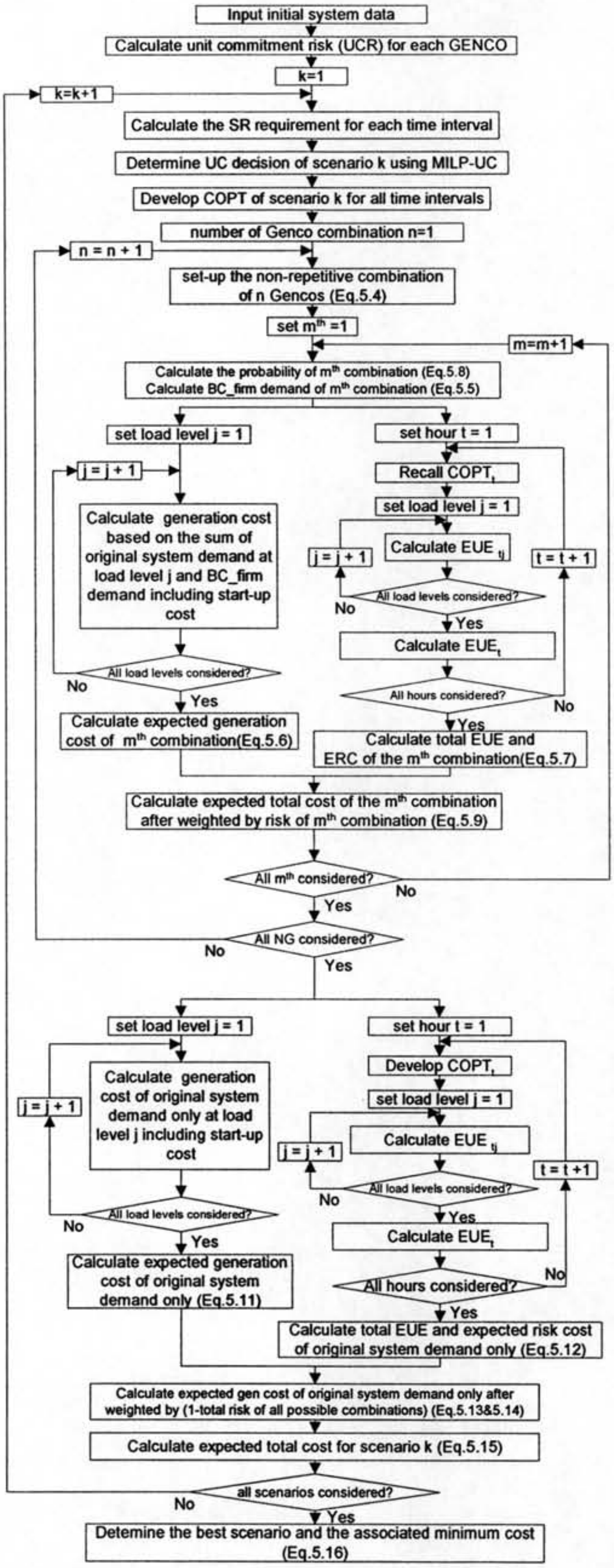

Figure 5.5 Flowchart of the proposed method

To obtain the best expected total cost among developed scenarios, the above procedure is repeated for other scenarios. Finally, the best scenario taking into account uncertainty of both generation and demand sides with the consideration of bilateral transactions can be determined by selecting the scenario which provides minimum total cost, as defined in (5.16).

$$\text{The best scenario} = \min\left\{ETC^k\right\}, \quad \forall k \in [1,9] \qquad (5.16)$$

5.4 Spinning Reserve Price Calculation

Spinning reserve price is determined by balancing between the increase of unit cost of original system due to the increase of provided reserve to the BC firm demand and the obtained benefit from the reserve revenue. In a restructured market, the spinning reserve payment can be determined based on two criteria, i.e. payment for the power delivered and payment for the allocated reserve [91]. In the first criteria, a generator which sells power as reserve is paid with a reserve price for that reserve power only if it is actually used. The reserve price is therefore higher than the spot price, since excess generation capacity has higher per unit cost than the spot price. In this case, a generator receives a profit on sales of reserve only for the time periods when the reserve actually needs to be generated. The generator receives zero revenue if the reserve is not called. For the second criteria, the payment is determined based on the allocated reserve power. A generator receives the reserve price per unit of reserve power for every time period that the reserve is allocated, does not depend whether or not it is used. If the reserve is used, then the generator receives the spot price for the reserve power that is generated. Since the reserve may not be called for most of the time, reserve power has a very low expected cost, and hence the price of reserve will be much lower than the spot price of power. A generator receives a small profit for each time period in which the reserve is allocated but not used; however, the generator has to absorb the loss if the reserve is called.

In this research, we focus only on the first criteria in which the determination of the reserve price is calculated based on the power delivered to GENCOs. Details of the reserve price calculation procedure can be summarized below.

Step 1. Determine which unit would be spun-off to be GENCO units and how much demand would be contracted to the GENCOs.

Step 2. Determine the best strategy and its associated total cost of the original system in providing reserve power for the BC firm demand, using procedures presented in section 5.3 with the reserve price firstly set at zero. Additional result from this step is the expected reserve energy to be utilized by GENCOs, expressed in MWh.

Step 3. Determine the best strategy and its associated total cost of the original system without providing reserve to BC demand by using procedure presented in CHAPTER 3.

Step 4. Subtract the obtained total cost in step#2 with the obtained total cost in step#3.

Step 5. Calculate reserve price by dividing the obtained result in step#4 by the utilized reserve energy.

5.5 Numerical Results

5.5.1 Case 1: IEEE-24 Bus Test System

A modified IEEE 24-bus system [80] is considered in this section to demonstrate the effectiveness of the proposed method to determine the best short-term operating strategy in a partially deregulated system by considering system uncertainty on both generation and demand sides. The IEEE 24-bus system comprises 26 generating units with total installed capacity of 3,105 MW and total demand of 54,910 MWh. The generating unit data is shown in Appendix A including the hourly total system demand [92]. Three initial spinning reserve strategies based on deterministic criterion are set for each hour at 8%, 10%, and 12% of the load demand representing low, medium, and high spinning reserve strategy respectively. It is assumed that the occurrence probability of low, medium, and high load level is 0.2, 0.6, and 0.2 respectively. Meanwhile, the load forecast uncertainty is represented by the standard deviation (SD), i.e. 1% in the first hour and 4% in the last hour. It is assumed that the *VOLL* is 2,000$/MWH. For solving the unit commitment problem based on mixed-integer linear programming (MILP-UC), a quadratic fuel cost function of each generating unit as shown in Appendix A has been linearized to two segments. The

MILP-UC and economic dispatch model has been developed using TOMLAB/CPLEX V10.0.

In this section, the impact of both purchased BC demand and the number of GENCO to the unit cost are investigated. The calculation of spinning reserve for various BC demand and number of GENCOs are also reported.

a) Impact of BC demand

In this analysis, one privately owned GENCO is considered while the BC demand is represented as a percentage of the total system peak demand, and the involved units of bilateral transactions are shown in Table 5.1. It is assumed that the whole capacity of the GENCO units is utilized to supply their BC demand, hence the percentage of BC demand is not an integer value as shown in the table. For initial assumption, the spinning reserve is firstly priced at 30$/MWh. The results are shown in Table 5.2 and Table 5.3. The reserve revenue in Table 5.2 is obtained by multiplying the expected utilized reserve with the assumption of reserve price. Meanwhile, the unit cost in the last column of Table 5.3 is obtained by dividing the total cost in the last column of Table 5.2 with the corresponding original system demand in the fifth column.

Table 5.1 IEEE-24 bus spin-off GENCO units

BC demand (% of peak demand)	GENCO units	GENCO's unit capacity (MW)
5.81	unit#17	155
11.61	units#17 - 18	310
17.42	units#17 - 19	465
23.2	units#17 - 20	620
30.6	units#17 - 21	817
37.98	units#17 - 22	1,014
45.36	units#17 - 23	1,211

Table 5.2 Simulation results with varied BC demand

BC demand (% of peak demand)	Generation cost ($)	Risk cost ($)	Expected Reserve Utilized (MWh)	Expected Reserve Revenue ($)	Total cost ($)
(1)	(2)	(3)	(4)	(5)	(6)
5.81	671,730	190,234	24	727	861,237
11.61	626,140	214,980	96	2,883	838,237
17.42	582,690	188,700	214	6,432	764,958
23.20	542,270	145,200	377	11,338	676,132
30.60	464,510	106,606	618	18,554	552,562
37.98	396,990	78,132	914	27,437	447,686
45.36	329,190	86,718	1,264	37,941	377,967

Table 5.3 Unit cost with varied BC demand

BC demand (% of peak demand)	Forecasted demand (MWh)	BC demand (MW)	Total BC demand (MWh)	Original system demand (MWh)	Unit cost ($/MWh)
(1)	(2)	(3)	(4)	(5)	(6)
5.81	54,910	155	3,720	51,190	16.83
11.61	54,910	310	7,440	47,470	17.66
17.42	54,910	465	11,160	43,750	17.49
23.20	54,910	620	14,880	40,030	16.88
30.60	54,910	817	19,606	35,302	15.65
37.98	54,910	1,014	24,336	30,574	14.64
45.36	54,910	1,211	29,064	25,846	14.63

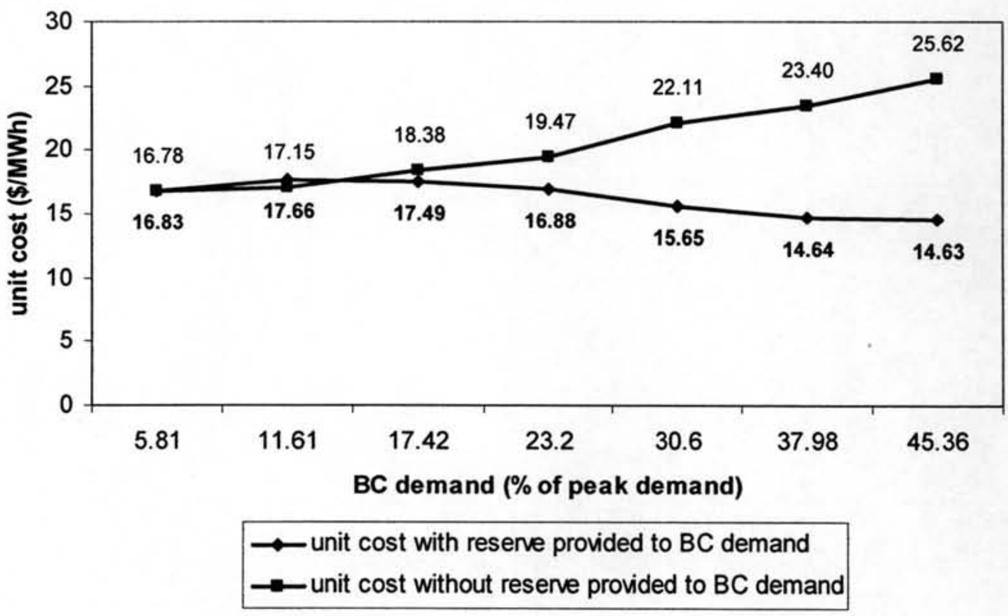

Figure 5.6 Unit cost with varied BC demand

Figure 5.6 shows the comparison of the expected unit cost which is expressed in \$/MWh, at various BC demand. Even though the expected total cost decreases for the BC demand in the range of 5.81% and 11.61%, but the unit cost tends to increase as the dominant increase of the risk cost. The risk cost increases since the original system has to cover the failure probability at higher BC demand, meanwhile the spinning reserve is still scheduled based on the initial spinning reserve strategies. The increase of reserve revenue results in lower total cost. However it doesn't give significant effect to the unit cost. At higher amount of the BC demand, the unit cost tends to decline since the original system schedule more reserve than the initial spinning reserve strategy to meet the minimum requirement of BC firm demand. Consequently, the risk cost decrease significantly hence unit cost follows. At higher BC demand, the reserve revenue becomes much more significant in reducing the total cost hence the contribution in the reduction of per unit cost also increases. The effect of reserve revenue to the reduction of unit cost at higher of BC demand can be obviously observed if the reserve price is varied in a certain ranges. The discussion of this topic will be presented in later sections.

b) Impact of number of GENCOs

In this subsection, it is assumed that units#17-22 are spun-off to be GENCO units. The total generation capacity of these units is 1,014 MW which represents 37.98% of peak of total system demand. At this simulation, all GENCO capacity of is intended to supply BC demand. For modeling the number of GENCO, these units are divided into some GENCOs as shown in Table 5.4.

Table 5.4 Simulation of IEEE-24 bus with varied number of GENCOs

Number of GENCO	GENCO name	GENCO unit	GENCO capacity (MW)
1	GENCO#A	units#17 - 22	1,014
2	GENCO#A	units#17 - 19	465
	GENCO#B	units#20 - 22	549
3	GENCO#A	units#17 - 18	310
	GENCO#B	units#19 - 20	310
	GENCO#C	units#21 - 22	394

Table 5.5 Simulation results of IEEE-24 bus with varied number of GENCOs

Number of GENCO	Generation cost ($)	Risk cost ($)	Expected Reserve		Total cost ($)	Unit cost ($/MWh)
			Utilized (MWh)	Revenue ($)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	396,990	78,132	914	27,437	447,686	14.64
2	387,800	27,780	492	14,781	400,799	13.11
3	379,550	13,023	337	10,118	382,455	12.51

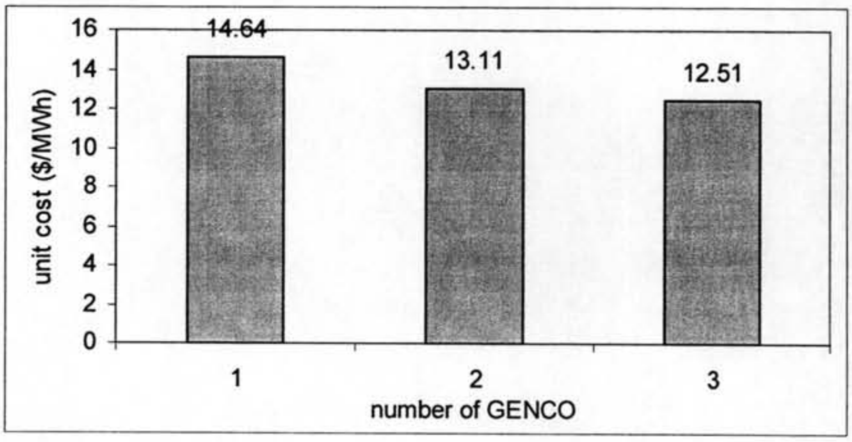

Figure 5.7 Unit cost with varied number of GENCOs

The simulation result is shown in Figure 5.7. It is found that the unit cost tends to decrease as the number of GENCOs increases. The decline of unit cost is dominantly caused by the decrease of unserved energy. At the same amount of BC demand divided into some GENCOs, the total unserved energy of all GENCOs become much smaller than if supplied by only one GENCO. Meanwhile, the expected benefit from reserve selling not gives contribution to the decline of total cost since at more number of GENCOs the expected benefit of reserve selling also tends to decrease. The decrease of reserve selling because the failure probability of each GENCO reduces at fewer units involved.

c) Impact of reserve price

In order to investigate the impact of reserve price to the obtained unit cost, the simulation is conducted by varying reserve price in the range of 15$/MWh and 120$/MWh. The amount of BC demand is similar to the simulation results in part (a) of this subsection. The results are shown in Figure 5.8.

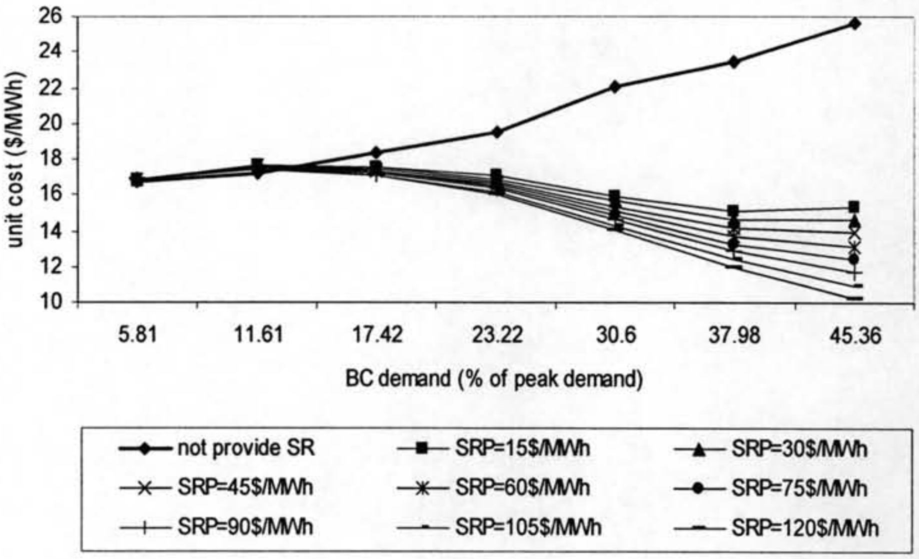

Figure 5.8 Unit cost with varied spinning reserve price

As shown in Figure 5.8, by varying the reserve price, the unit cost does not change significantly at small value of BC demand, i.e. less than 17.42%. At that range, the probability of spinning reserve utilization of GENCOs is quite small hence the expected reserve selling has not significant effect to the drop of unit cost. At higher percentage of BC demand, the risk of the GENCO increases thus the probability of using spinning reserve becomes higher and consequently reserve selling increases.

At a relatively small BC demand, i.e. at 5.81% and 11.61%, the unit cost of providing spinning reserve is higher than the unit cost without providing the reserve to the BC demand, even though the reserve price has been increased up to 120$/MWh. It means that the reserve price has to be increased up to a certain level hence the reserve revenue will cover the increase of cost by providing reserve.

For higher BC demand, the unit cost without reserve providing becomes less than the unit cost with the reserve providing because the reduction of risk cost as impact of higher reserve. This reason can be understood by showing the obtained unit cost if the risk cost as not considered in the calculation of total cost. Figure 5.9 shows the obtained unit cost by excluding the risk cost at various reserve prices. The bolted line shows the unit cost at which the original system does not provides spinning reserve for GENCOs. If the unit cost curve at a certain value of reserve price is lower than the bolted line, it means that the considered reserve price could provide expected revenue to cover the increase of the generation cost.

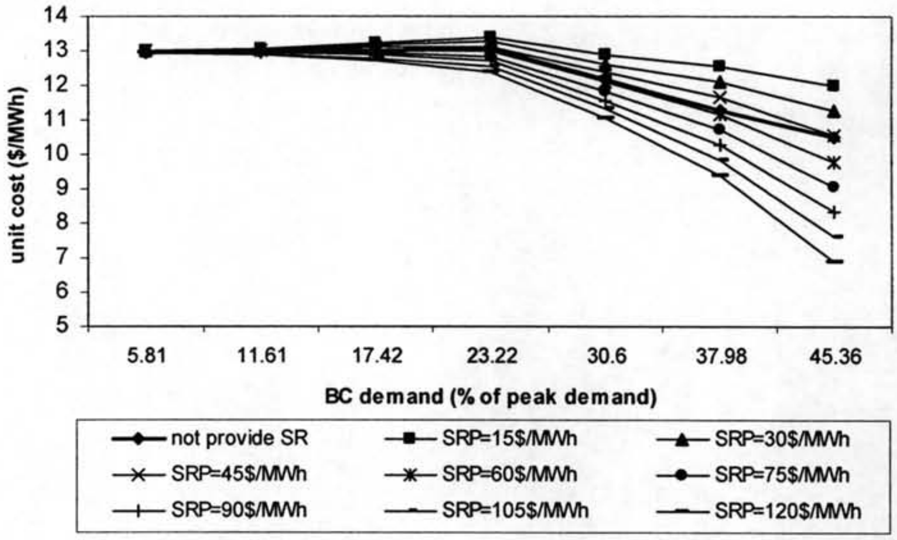

Figure 5.9 Unit cost with varied reserve price without considering risk cost

d) Calculation of minimum reserve price

Calculation of minimum reserve price can be done by applying the procedure presented in section 5.4. As presented in the previous subsection c, the value of reserve price of which the reserve revenue can cover the increase of unit cost tends to differ neither for each case of BC demand or each case of number of GENCOs. According to this case, it is necessary to determine the reserve price for each case of simulation which is done by varying the amount of BC demand and the number of GENCOs.

For various BC demand simulation, the comparison of unit cost in Figure 5.8 shows that the unit cost of reserve providing is higher than the unit cost without providing reserve only for the two first cases, i.e. 5.81% and 11.61% of the demand. For these two cases, the minimum value of spinning reserve prices which can cover the increase cost of providing reserve are 124$/MWh and 280$/MWh respectively. At higher percentage of contracted demand, the unit cost of the original system with the reserve power provided for the BC firm demand is lower than the unit cost without providing reserve thus the reserve price becomes zero. The reason is because at a small system size, the risk cost plays dominant role in the total cost hence if the original system has to schedule higher reserve power as the consequence of higher contracted demand, it will cause the reduction of the risk cost. This fact can be seen in Table 5.2.

5.5.2 Case 2: Replication of IEEE-24 Bus Test System

In this subsection, the proposed method was tested with the four times replication of IEEE-24 bus system. The replication is intended to obtain a close-to-realistic system size. The demand is also replicated accordingly. The system comprises 104 thermal units with total installed capacity of 12,420 MW and total demand of 219,640 MWh. Sensitivity analysis is carried out in the same way as in Case 1.

a) Impact of BC demand

In this analysis, one GENCO and several cases of BC demand are simulated by spinning-off some units in the original system to be BC units. The involved units in each case are similar with the simulation in subsection 5.5.1 part (a). It is assumed that reserve is initially priced at 30$/MWh, i.e. that is around two times of the unit price of the original system without considering bilateral transactions. Detail results are presented in Table 5.6. The impact of BC demand can be investigated by comparing the unit cost between the cases of supplying the demand with and without the BC demand. The comparison results are graphically shown in Figure 5.10.

Table 5.6 Simulation results with varied BC demand

BC demand (% of peak demand)	Generation cost ($)	Risk cost ($)	Expected Reserve		Total cost ($)
			Utilized (MWh)	Revenue ($)	
(1)	(2)	(3)	(4)	(5)	(6)
5.81	2,688,500	9,135	378	11,338	2,686,296
11.61	2,524,000	54,164	1,462	43,857	2,534,307
17.42	2,375,600	284,040	3,183	95,478	2,564,162
23.2	2,249,700	533,060	5,478	164,331	2,618,429
30.6	1,981,000	640,860	8,755	262,638	2,359,222
37.98	1,754,000	1,066,040	12,650	379,500	2,440,540
45.36	1,507,000	1,530,940	17,103	513,090	2,524,850

Table 5.7 Unit cost with varied BC demand

BC demand (% of peak demand)	Forecasted demand (MWh)	BC demand (MW)	Total BC demand (MWh)	Original system demand (MWh)	Unit cost ($/MWh)
(1)	(2)	(3)	(4)	(5)	(6)
5.81	219,640	620	14,880	204,760	13.12
11.61	219,640	1,240	29,760	189,880	13.35
17.42	219,640	1,860	44,640	175,000	14.65
23.2	219,640	2,480	59,520	160,120	16.35
30.6	219,640	3,268	78,424	141,208	16.71
37.98	219,640	4,056	97,344	122,296	19.96
45.36	219,640	4,844	116,256	103,384	24.42

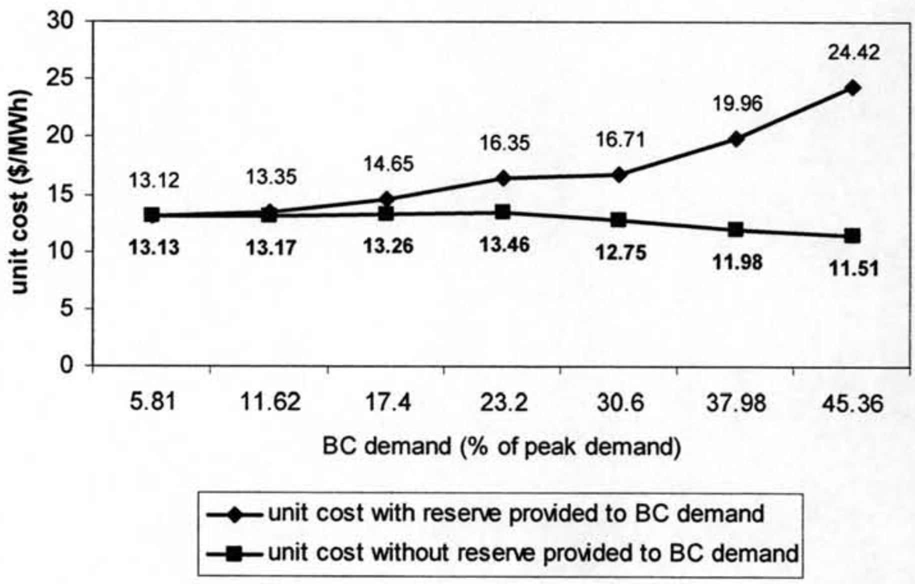

Figure 5.10 Unit cost with varied BC demand

As can be seen from that figure, in the two first cases of BC demand i.e. 5.81% and 11.62% of peak demand, the difference cost between with and without reserve providing is as (-0.11)% and 1.36% respectively. In these ranges of BC demand, the scheduled spinning reserve still enough to cover the BC firm demand hence a small increase of unit cost at that range of BC demand is resulted from the probability of supplying power to BC firm demand as presented in (5.6). The negative sign in the case of 5.81% BC demand means that the assumption of reserve price is higher than the minimum reserve price which is needed to keep the unit cost of original system equal to the unit cost without considering BC demand.

It can be seen that by comparing the result shown in Figure 5.10 and Figure 5.5 that since the system in this case is larger than the one in section 5.5.1, the unit cost of the original system without the BC demand in this case, i.e. less than 15$/MWh, is a little lower.

As BC demand increases, the system has to provide additional reserve to back-up BC firm demand hence as a consequence the difference between two costs as depicted in Figure 5.10 raises. From the third to the last case of BC demand the difference are 10.47%, 21.48%, 31.05%, 66.54%, and 112.22% respectively. The increase of unit cost is also caused by the raise of risk cost at higher BC demand as can be seen from Table 5.6.

Higher value of unit cost compared with the case without reserve provided to the BC demand can be interpreted that the assumption of reserve price is too low hence the obtained benefit from reserve selling cannot cover the raise of unit cost. The determination of an acceptable reserve price is presented in part (d).

2) Impact of number of GENCOs

In this analysis, the spun-off units of the original system to be GENCO units are similar as in subsection 5.5.1, i.e. units#17-22. Since the original system is replicated four times, therefore the number of spun-off units of each number of GENCOs is also replicated accordingly. It is assumed that the value of loss load and spinning reserve is priced at 2,000$/MWh and 30$/MWh respectively. The results are shown in Table 5.8 and Figure 5.11. The unit cost in the last column of Table 5.8 is obtained by dividing the total cost in the sixth column with the total of the original system demand, i.e. 122,296 MWh.

Table 5.8 Simulation result with varied number of GENCOs

Number of GENCO	Generation cost ($)	Risk cost ($)	Expected reserve		Total cost ($)	Unit cost ($/MWh)
			Utilized (MWh)	Revenue ($)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1,754,000	1,066,040	12,650	379,500	2,440,540	19.96
2	1,652,300	120,190	8,234	247,032	1,525,458	12.47
3	1,528,900	16,317	6,103	183,093	1,362,124	11.14

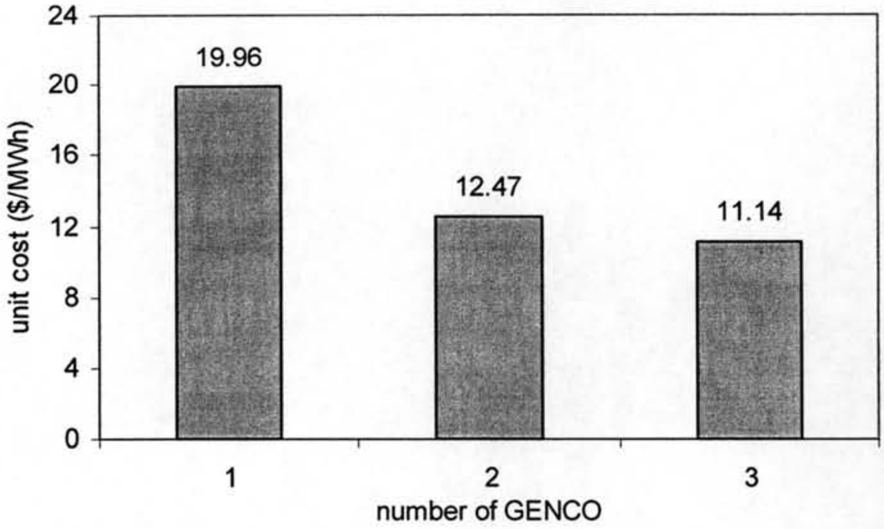

Figure 5.11 Unit cost with varied number of GENCOs

The trend is similar to the results by simulating small system size in subsection 5.5.1. In this case, the reduction of unit cost from one GENCO, i.e. 19.96$/MWh, to three GENCOs, i.e. 11.14$/MWh, is 44.18%.

3) Impact of reserve price

In this simulation, the reserve price is varied from 15 to 150$/MWh. The simulation result is shown in Figure 5.12. From Figure 5.12 it can be seen that, the reserve price at 30$/MWh and 45$/MWh makes the unit cost with reserve power provided for the BC demand lower than the unit cost without reserve providing for the case of 5.81% and 11.62% respectively. For other cases are at 120$/MWh, except for the case of 30.60% which is at 95$/MWh.

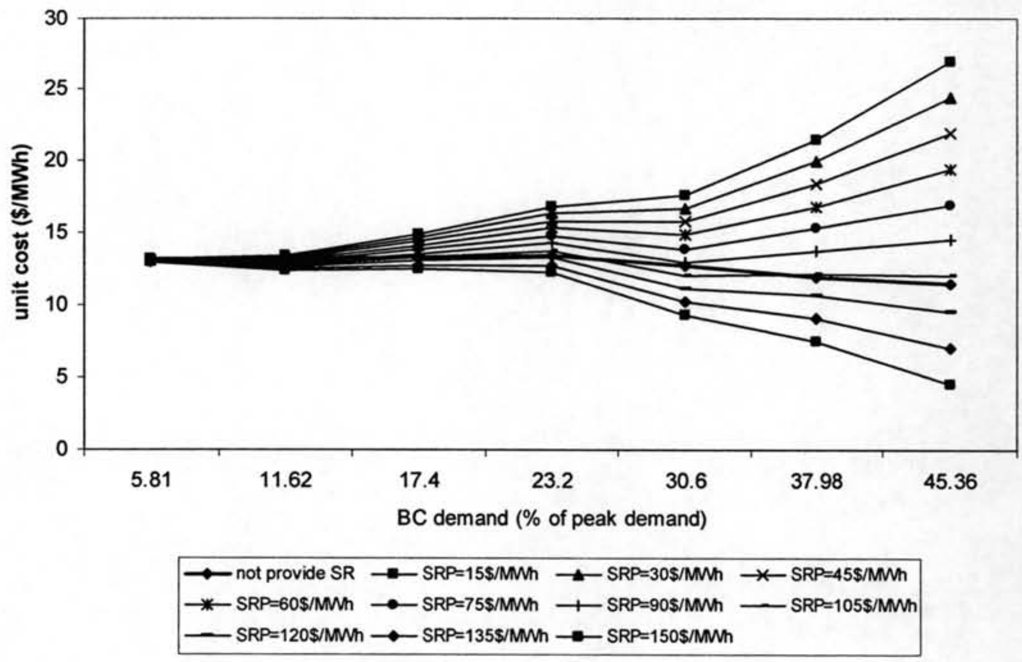

Figure 5.12 Unit cost with varied reserve prices

If risk cost is not considered, the simulation result is shown in Figure 5.13. From that figure, it can be seen that by excluding risk cost in the total cost, the reserve price which makes unit cost of providing reserve to the BC demand is lower than unit cost without providing reserve are at 15$/MWh for the two first cases of BC demand and at 30$/MWh for the remaining cases.

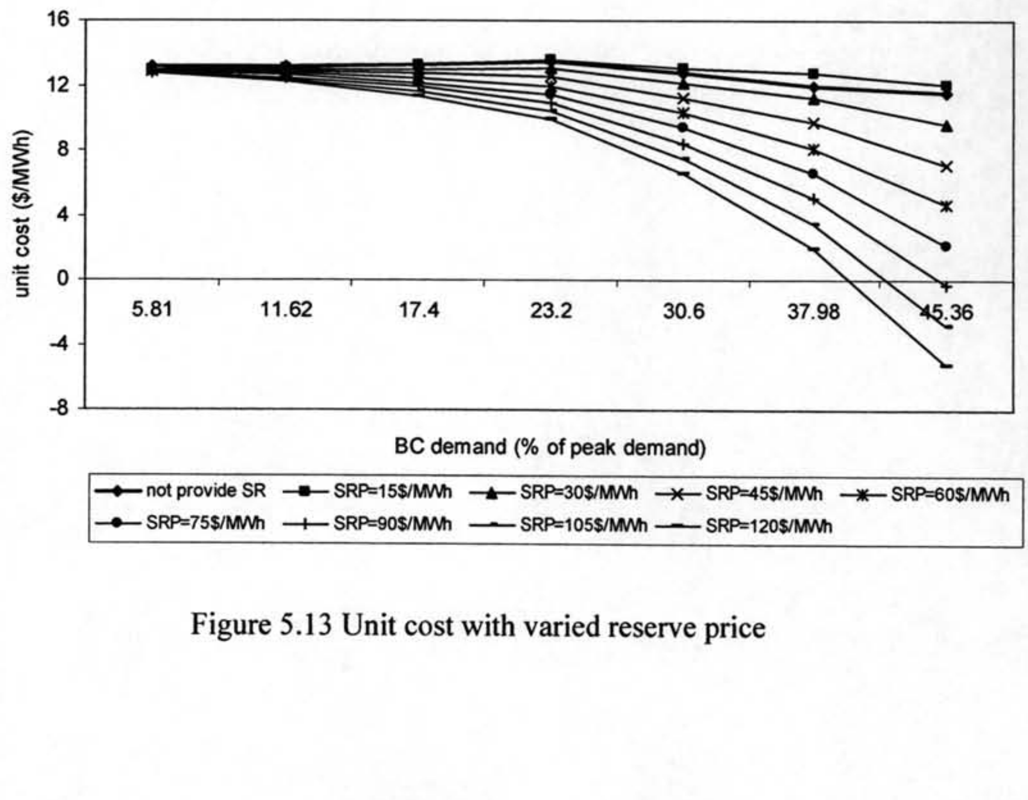

Figure 5.13 Unit cost with varied reserve price

d) Calculation of minimum reserve price

To calculate the minimum reserve price, firstly, we have to determine the total cost of the original system demand with and without reserve provided for BC demand. The total cost of the original system with reserve provided for BC demand can be calculated by using the proposed method as presented in Figure 5.5 by neglecting the reserve revenue. Meanwhile, the total cost without reserve provided can be calculated by using the proposed method in Chapter 3. Finally, the minimum reserve price can be obtained by dividing the difference between these two costs with the expected utilized reserve. The numerical results with various BC demands are shown in Table 5.9.

Table 5.9 Reserve price with varied BC demand taking into account risk cost

BC demand (% of peak demand)	with reserve provided		w/o reserve provided		Exp. utilized reserve (MWh)	Minimum reserve price ($/MWh)
	Total cost ($)	Unit cost ($/MWh)	Total cost ($)	Unit cost ($/MWh)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
5.81	2,697,635	13.17	2,689,266	13.13	378	22.14
11.61	2,578,164	13.58	2,500,334	13.17	1,462	53.24
17.42	2,659,640	15.20	2,321,062	13.26	3,183	106.38
23.20	2,782,760	17.38	2,155,408	13.46	5,478	114.53
30.60	2,621,860	18.57	1,800,225	12.75	8,755	93.85
37.98	2,820,040	23.06	1,465,472	11.98	12,650	107.08
45.36	3,037,940	29.39	1,189,744	11.51	17,103	108.06

As shown in the third column of Table 5.9, the unit costs with reserve provided for BC demand tend to increase at higher BC demand dominantly due to the increase of risk cost as presented in Table 5.6. In the case of the original system does not provide reserve power to the BC demand, the unit cost tends to slightly increase up to a certain value of BC demand which then decreases significantly at higher BC demand. For overall cases, as one expected, the unit costs of the original system without reserve provided to BC demand are less than with reserve provided. To cover this increase of unit cost of the original system due to the reserve provided for BC demand, a certain amount of reserve price should be paid by GENCOs which is calculated based on the increase of unit cost and the utilized reserve. The obtained minimum reserve prices are shown in the last column of Table 5.9. The trend shows that the reserve price increases at higher BC. In the first two cases of BC demand, the reserve prices are 22.15$/MWh and 53.24$/MWh, i.e. 1.69 and 4.44 times of unit cost of original system without providing reserve respectively. At higher BC demand, the reserve price increases sharply and reaches to a maximum reserve price at 108.06$/MWh or 9.39 times of unit cost.

The reserve prices by including risk cost to the total cost in this large system size are much more expensive than the obtained results in the small system size case. As has been discussed in subsection 5.5.1, in the case of small system size, the original system also obtains benefit from providing reserve to BC firm demand through the reduction of risk cost. It is found that if the more reserve is provided, the more benefit will be obtained, as can be seen in Figure 5.8. In addition, the increase of generation cost, which is resulted from both higher reserve allocation and additional generation cost due to the probability of the original system to supply real power to the BC firm demand as stated in (5.6), is much smaller than the drop of risk cost due to the higher reserve allocation. Thus as a consequence, the trend of the unit cost becomes decrease. On contrary, for the case of large system size, risk cost increases at higher reserve allocation as can be seen in Table 5.6.

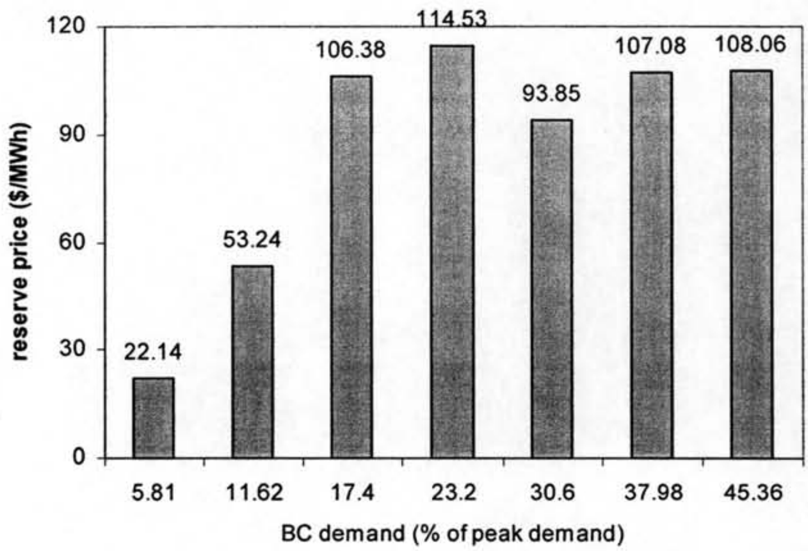

Figure 5.14 Minimum reserve price with varied BC demand by considering risk cost

To investigate the impact of risk cost to the reserve price, Table 5.10 shows the calculation of minimum reserve price without considering risk cost. As can be seen, the unit costs of the original system with and without reserve provided for BC demand are in the same trend with the obtained results by considering risk cost presented in Table 5.9. In this case, the percent increase of unit cost from the first to the last case is

12.36%, much smaller than the increases resulted from the same case by considering risk cost, i.e. 123.04%. It can be concluded that the high increase of reserve price as presented in Figure 5.14 is dominantly caused by the contribution of risk cost. As a further consequence, the increase of reserve price at higher BC demand by neglecting risk cost is much smaller than the results by considering risk cost, as can be seen in the last column of Table 5.10. At that column, the comparison between reserve price and unit cost without providing reserve for all cases are in the range from 0.90 to 2.61, much smaller than the obtained reserve price by taking into account risk cost.

Table 5.10 Reserve price with varied BC demand without taking into account risk cost

BC demand (% of peak demand)	with reserve provided		w/o reserve provided		Exp. utilized reserve (MWh)	Minimum reserve price ($/MWh)
	Total cost ($)	Unit cost ($/MWh)	Total cost ($)	Unit cost ($/MWh)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
5.81	2,656,400	12.97	2,651,980	12.95	378	11.69
11.61	2,504,300	13.19	2,463,720	12.98	1,462	27.76
17.42	2,372,300	13.56	2,276,640	13.01	3,183	30.06
23.20	2,249,700	14.05	2,092,200	13.07	5,478	28.75
30.60	1,980,500	14.03	1,721,580	12.19	8,755	29.58
37.98	1,753,600	14.34	1,380,560	11.29	12,650	29.49
45.36	1,507,000	14.58	1,087,740	10.52	17,103	24.51

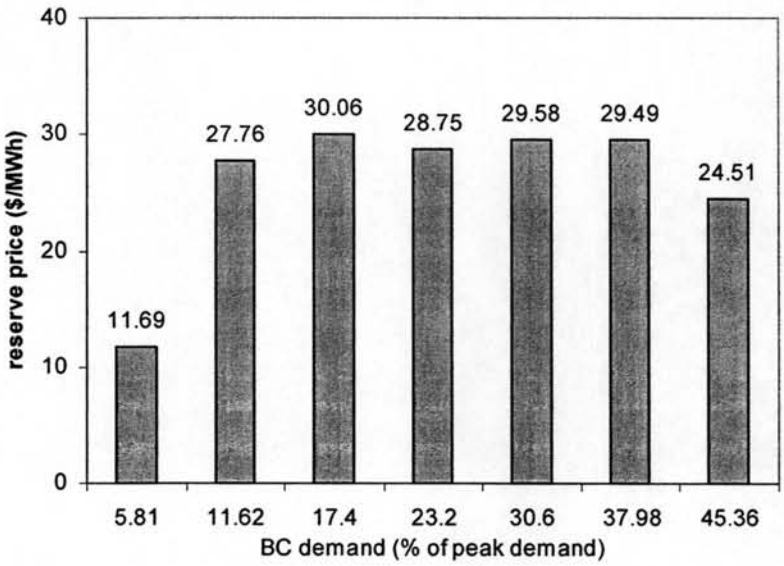

Figure 5.15 Minimum reserve price with varied BC demand without considering risk cost

If the number of GENCOs is varied as has been simulated in part (b) of this subsection, the calculation of minimum reserve price for all cases are numerically shown in and graphically shown in Figure 5.16. The minimum reserve price is calculated by dividing the difference between the total cost with and without reserve provided for BC demand by the original system demand, i.e. 122,296 MWh. The great reduction of reserve price at higher number of GENCOs is mainly caused by the sharp decrease of expected unserved energy as shown in the third column of Table 5.8.

Table 5.11 Minimum reserve price with varied number of GENCOs

No. of GENCO	with reserve provided		w/o reserve provided		Minimum reserve price ($/MWh)
	Total cost ($)	Unit cost ($/MWh)	Total cost ($)	Unit cost ($/MWh)	
(1)	(2)	(3)	(4)	(5)	(6)
1	2,820,040	23.06	1,465,472	11.98	107.08
2	1,772,490	14.49	1,465,472	11.98	37.28
3	1,545,217	12.64	1,465,472	11.98	13.07

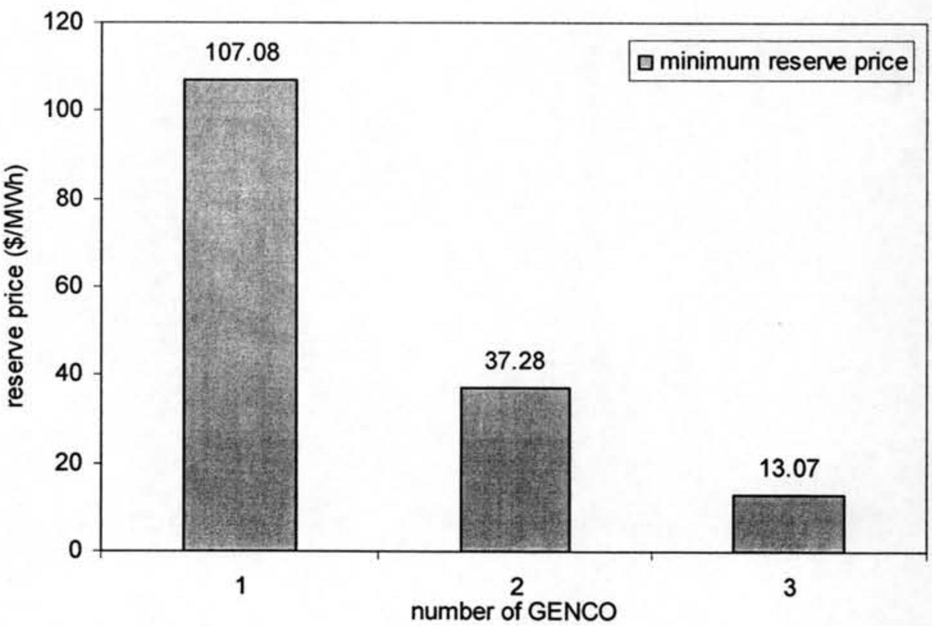

Figure 5.16 Minimum reserve price with varied number of GENCO

5.5.3 Case 3: Electricity Generation Authority of Thailand (EGAT) System

The proposed method is also tested on a modified Electricity Generating Authority of Thailand (EGAT) system. The system comprises 83 thermal units, 49 hydro plants, 5 pumped storage units, and 4 imported power from Laos and Malaysia [93]. However, only thermal units are considered in this dissertation. The thermal units of this system has a total installed capacity of 18,727MW, peak demand of

14,814MW, and total demand for 24 hours of 286,292 MWh. The complete data of this system are presented in Appendix B. In this case, value of loss load is priced at 2,000$/MWh, which is equal to 70,000 Baht/MWh at exchange rate of 35Baht/$ and spinning reserve is initially priced at 30$/MWh or 1050 Baht/MWh. For simulating the load uncertainty, three load levels which represent low, medium, and high load levels are generated based on the load demand on Saturday, 25 December 2004. The probability of each load level is assumed to be similar to the previous case study. For simulating the impact of bilateral transactions to the short-term operating strategy, some units are assumed to be spun-off from the system to become GENCO's units and then each unit is operated at full capacity for supplying their direct customers. The rest of the units are scheduled by the system operator to supply the original system demand and to provide spinning reserve to the BC firm demand. Sensitivity analysis with respect to the amount of BC demand, the number of GENCOs, and spinning reserve price is presented and discussed below. The calculation of minimum spinning reserve price is presented at the end of the discussion.

a) Impact of BC demand

To analyze the impact of the BC demand in EGAT system case, some EGAT units are spun-off from the original system to become GENCO units. Details of the spin-off units are shown in Table 5.12. The results are shown in Table 5.13.

Table 5.12 EGAT units spin-off GENCO units

BC demand (% of peak demand)	EGAT's unit to be GENCO's unit	GENCO's unit capacity (MW)
11.88	units#36 - 42	1,760
21.60	units#36 - 44	3,200
28.41	units#36 - 47	4,208
35.21	units#36 - 50	5,216

Table 5.13 Simulation results with varied BC demand

BC demand (% of peak demand)	Generation cost (Baht)	Risk cost (Baht)	Reserve		Total cost (Baht)
			Exp. utilized (MWh)	revenue (Baht)	
(1)	(2)	(3)	(4)	(5)	(6)
11.88	243,540,000	118,055	1,025	1,077,090	242,580,965
21.60	204,580,000	1,611,890	2,274	2,387,910	203,803,980
28.41	182,280,000	2,656,640	3,783	3,971,940	180,964,700
35.21	161,860,000	3,276,070	5,649	5,931,765	159,204,305

Table 5.14 Unit cost with varied BC demand

BC demand (% of peak demand)	Forecasted demand (MWh)	BC demand (MW)	Total BC demand (MWh)	Original system demand (MWh)	Unit cost (Baht/MWh)
(1)	(2)	(3)	(4)	(5)	(6)
11.88	286,292	1,760	42,240	244,052	1,003
21.60	286,292	3,200	76,800	209,492	996
28.41	286,292	4,208	100,992	185,300	1,020
35.21	286,292	5,216	125,184	161,108	1,062

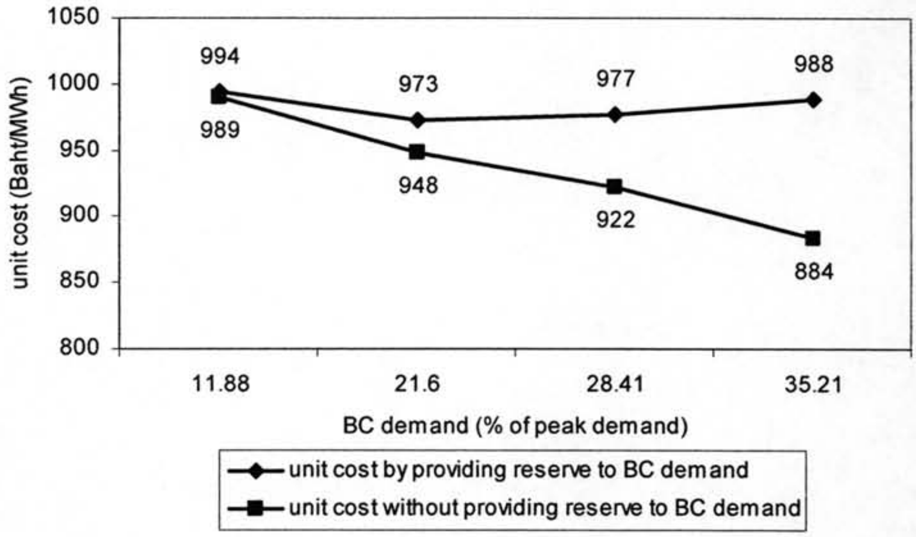

Figure 5.17 Unit cost with varied BC demand

Figure 5.17 shows the comparison of unit cost with and without providing reserve to BC firm demand. It is found that the increase of unit cost caused by the provision of additional reserve. This result is almost similar with trend as presented in Case 2 which shows that the unit cost increases at higher BC demand.

b) Impact of number of GENCO

Three GENCOs are simulated in this simulation. Table 5.15 shows the list of units for each GENCO. The results are shown in Table 5.16.

Table 5.15 Simulation of EGAT with varied number of GENCOs

Number of GENCO	GENCO name	GENCOs unit	GENCO's unit capacity (MW)
1	GENCO#A	units#36 - 47	4,208
2	GENCO#A	units#36 - 41	1,479
	GENCO#B	units#42 - 47	2,729
3	GENCO#A	units#36 - 39	1,040
	GENCO#B	units#40 - 42	1,440
	GENCO#C	units#43 - 47	1,728

Table 5.16 Simulation results of EGAT with varied number of GENCOs

Number of GENCO	Generation cost (Baht)	Risk cost (Baht)	Reserve		Total cost (Baht)	Unit cost (Baht/MWh)
			Exp. utilized (MWh)	Revenue (Baht)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	182,280,000	2,656,640	3,783	3,971,940	180,964,700	977
2	180,040,000	76,405	1,984	2,083,410	178,032,995	961
3	178,590,000	2,503	1,038	1,438,395	177,154,108	956

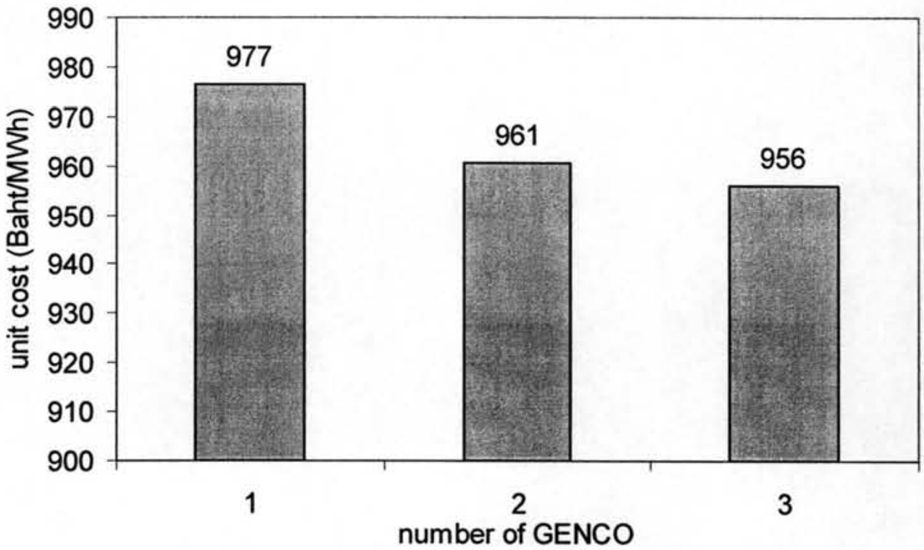

Figure 5.18 Unit cost with varied number of GENCOs

Figure 5.18 shows the impact of different number of GENCOs to the unit cost for EGAT system. It is found that the trend of reduction of unit cost at higher number of GENCOs is similar with the result in the previous case, i.e. due to the decrease of risk cost. The reduction of unit cost from the first (1 GENCO) to the last case (3 GENCOs) is as 2.11%. This small difference of unit cost among the various number of GECNOs is caused by a relatively reliable of EGAT's units as shown in Appendix

B. This fact can be seen from the obtained results in Table 5.16 which show a very small contribution of risk cost to the total cost. From the obtained results, it can be concluded that if the units in the system are quite reliable, the variation of number of GENCOs would not has significant impact to the reduction of unit cost.

c) Impact of spinning reserve

In this sensitivity analysis, the spinning reserve price is varied from 30$/MWh to 240$/MWh which is equal to 1,050 Baht/MWh and 8,400 Baht/MWh respectively.

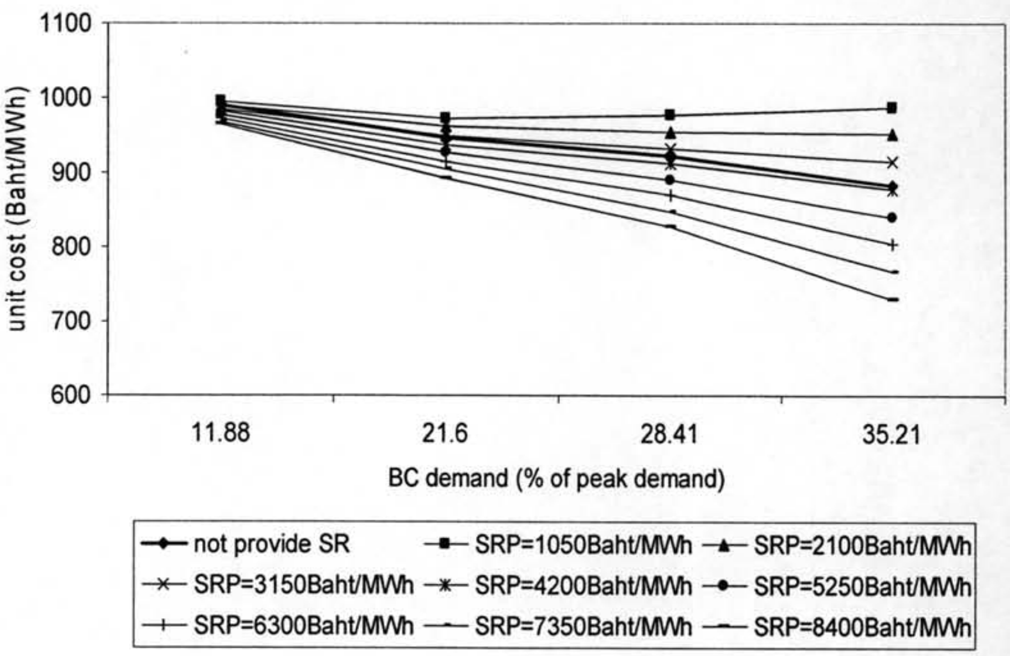

Figure 5.19 Unit cost with varied of reserve prices by considering risk cost

The unit costs with various reserve prices for the system are shown in Figure 5.19. The impact of reserve price to the unit cost can be analyzed by comparing the obtained unit costs with the one of the original system, without considering BC demand. It can be seen from Figure 5.19 that reserve selling can cover the increase of the cost, taking into consideration of BC demand, if the reserve is priced at least at 3,150 Baht/MWh for the first case (11.88%) and 4,200 Baht/MWh for the rest cases.

If risk cost is not taken into account in the determination of total cost, the reserve prices for various BC demands are shown in Figure 5.20. In the case of not considering risk cost, the least of reserve price which covers the cost of considering

BC is as 1,050 Baht/MWh, 2,100 Baht/MWh, 3,150 Baht/MWh, and 4,200 Baht/MWh for the first to the last case of BC demand respectively.

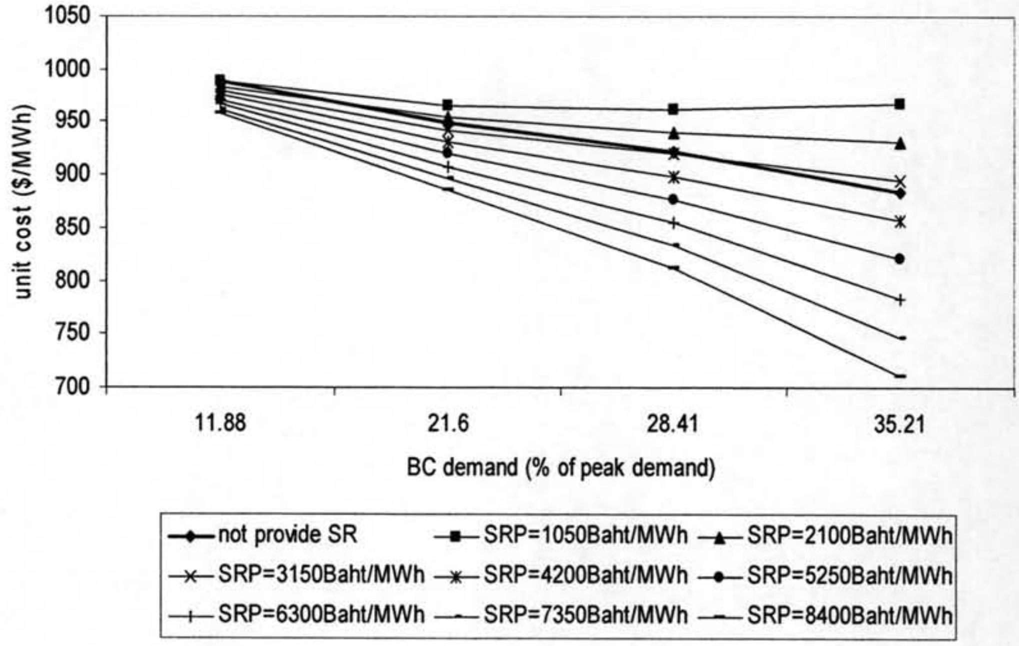

Figure 5.20 Unit cost with varied reserve price without considering risk cost

d) Calculation of minimum reserve price

The fixed value of reserve prices which would keep the unit cost with reserve provided fro BC demand equal to the cost without reserve provided are numerically shown in Table 5.17 and graphically shown in Figure 5.21. The obtained trend of reserve price is similar as in Case 2. However, the comparison between the reserve price and the unit cost without reserve provided is smaller than the one in Case 2 due to the less contribution of risk cost as an impact of the high reliability of the units.

Table 5.17 Minimum reserve price taking into account risk cost

BC demand (% of peak demand)	with reserve provided		w/o reserve provided		Exp. utilized reserve (MWh)	Minimum reserve price ($/MWh)
	Total cost ($)	Unit cost ($/MWh)	Total cost ($)	Unit cost ($/MWh)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
5.81	243,658,055	998	241,400,879	989	1,025	2,200
11.61	206,191,890	984	198,672,336	948	2,274	3,306
17.42	184,936,640	998	170,852,097	922	3,783	3,723
23.20	165,136,070	1,025	142,351,389	884	5,649	4,033

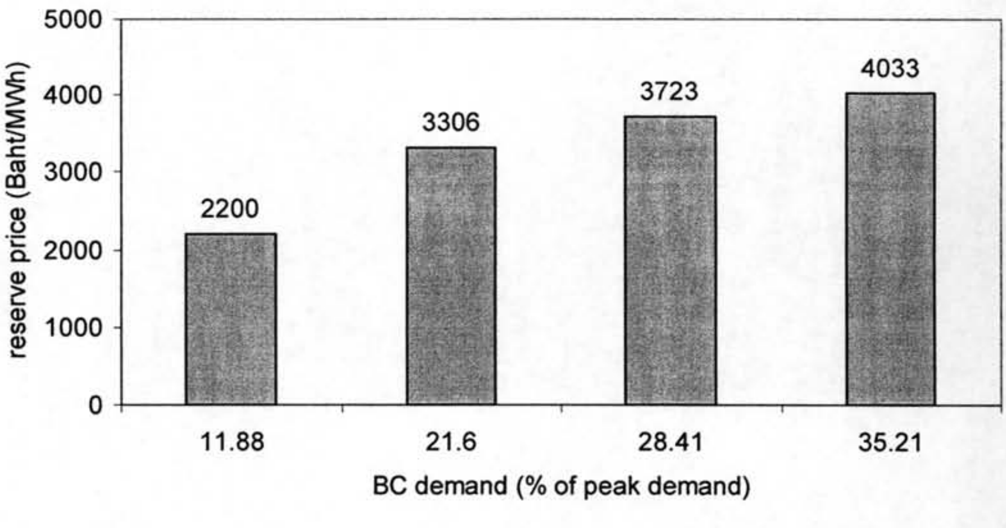

Figure 5.21 Reserve price by considering risk cost with varied BC demand

The minimum spinning reserve prices without taking into account risk cost on the total cost are numerically shown in Table 5.18 and graphically shown in Figure 5.22. The comparison shows that the difference of reserve price between with and without taking into account risk cost are relatively small, i.e. 2.86%, 7.85%, 4.25%, 10.72%, and 9.45% respectively, as the consequence of reliable utilized generating units.

Table 5.18 Minimum reserve price without taking into account risk cost

BC demand (% of peak demand)	with reserve provided		w/o reserve provided		Exp. utilized reserve (MWh)	Minimum reserve price ($/MWh)
	Total cost ($)	Unit cost ($/MWh)	Total cost ($)	Unit cost ($/MWh)		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
5.81	242,300,000	993	240,220,000	984	1,026	2,028
11.61	204,580,000	977	197,380,000	942	2,274	3,166
17.42	182,280,000	984	169,706,000	916	3,783	3,324
23.20	161,860,000	1,005	141,228,000	877	5,649	3,652

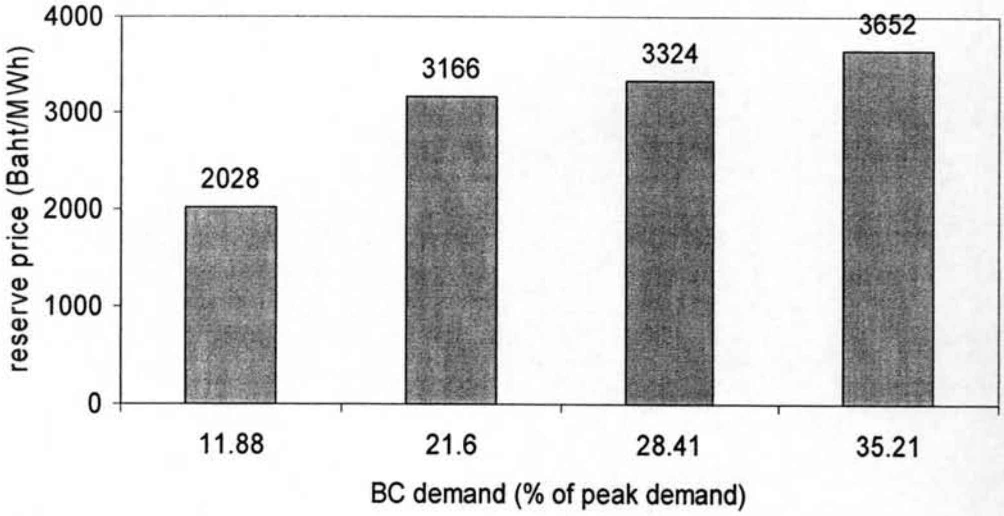

Figure 5.22 Reserve price without considering risk cost with varied BC demand

The minimum reserve prices at various number of GENCOs are shown in Figure 5.23. The different trend of the result is found in comparison with the results in Case 2, of which the reserve price tends to decrease due to the sharp reduction of risk cost at higher number of GENCOs while more expensive reserve price is obtained at higher number of GENCOs. The reason is because the availability of generating units in the system is high, hence the contribution of risk cost to the total cost in the original system is very small compared with the generation cost as can be seen in Table 5.16. Hence even though the risk cost reduces sharply at higher number of GENCOs, but quantitatively the contribution of risk cost reduction to the reduction of total cost is not significant.

Table 5.19 Minimum reserve price with varied number of GENCOs

No. of GENCO	with reserve provided		w/o reserve provided		Minimum reserve price ($/MWh)
	Total cost ($)	Unit cost ($/MWh)	Total cost ($)	Unit cost ($/MWh)	
(1)	(2)	(3)	(4)	(5)	(6)
1	184,936,640	998	170,852,097	922	3,723
2	180,116,405	972	170,852,097	922	4,669
3	178,592,503	964	170,852,097	922	5,650

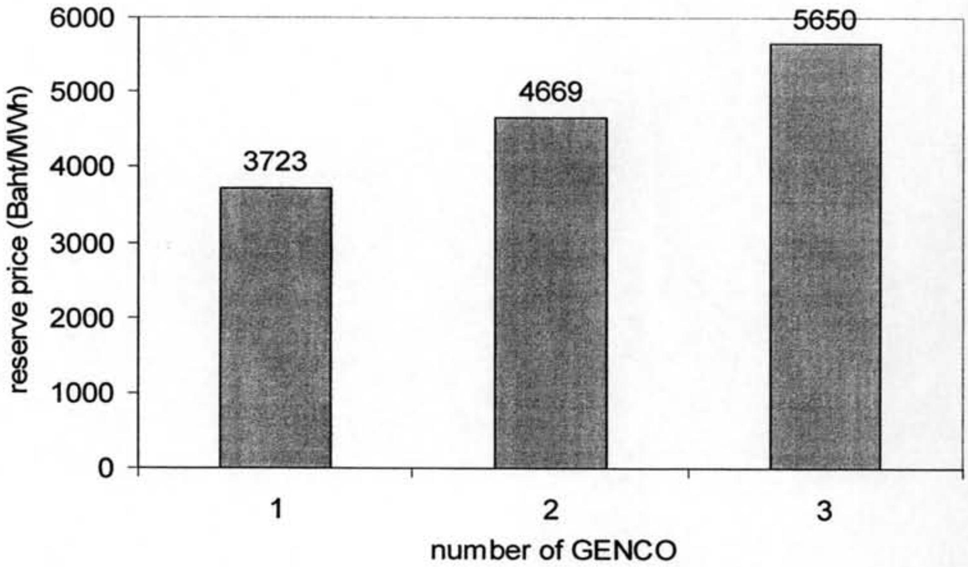

Figure 5.23 Reserve price with varied number of GENCOs

5.6 Conclusion

A method to determine spinning reserve price under a partially deregulated system by considering system uncertainty and bilateral transactions has been presented in this chapter. Numerical results show the capability of the proposed method in determining spinning reserve price of IEEE-24 bus system and its replication and EGAT system. Sensitivity analysis with respect to the amount of BC demand and the number of GENCO has been reported. In the case of small system, the risk cost plays an important role hence by increasing the amount of reserve power to back-up the BC firm demand it causes a high reduction of risk cost. Accordingly, the unit cost of the original system with reserve provided to the BC demand tends to lower than the one without reserve provided, therefore GENCO does not need to pay for the utilized reserve. On contrary, the contribution of risk cost becomes much smaller at large system size with high reliability units. By increasing the amount of reserve provided for BC demand, the unit cost of the original system tends to increase due to the increase of risk cost. To cover the increase of unit cost, the original system obtains revenue from the utilized reserve. The reserve price tends to increase at higher BC demand up to many times of the unit cost without providing reserve is mainly caused by the increase of risk cost.