CHAPTER IV
SHORT-TERM OPERATING STRATEGY BASED ON PROBABILISTIC CRITERION

4.1 Introduction

In short-term operation planning, one of the common problems faced by many electric utilities concerns the uncertainty from both load forecast error and generating unit unavailability. This uncertainty might lead to uneconomic operation if it is not managed properly. This chapter explicitly demonstrates how to include the uncertainties to obtain the best operating strategy for any power systems. The uncertainty of the load forecast is handled using decision analysis method, meanwhile the uncertainty of the generating unit is assessed through the risk cost. In Chapter 3, the spinning reserve requirement is determined based on deterministic criterion, i.e. a percentage of forecasted demand. By using deterministic criterion, it does not take into account the stochastic nature of the system such as generating unit outage and demand uncertainty. Therefore, it can lead to over-scheduling which although more reliable, is uneconomic. On the other hand, it can lead to under-scheduling which, although less costly, can produce unacceptable risk of system failure [87].

To directly consider the system uncertainty in the generation scheduling processes, the spinning reserve requirement is determined based on a probabilistic criterion. By using probabilistic criterion, it is possible to set up acceptable risk levels for an utility's service reliability and then to minimize total generation cost within those levels. Consequently, the expected unserved energy or customer outages are obtained as an output indicator. The amount of spinning reserve requirement using this method depends heavily on the pre-set reliability level, but no universal agreement exists on what level to adopt. To cope with these problems, the probabilistic criterion for determining spinning reserve requirement in this chapter is combined with deterministic criterion by including the expected risk cost to the expected total cost.

4.2 Problem Formulation

The objective function of the UC problem in this chapter is as presented in (2.1), i.e. minimization of operation cost while the operation is subjected to the prevailing unit and system constraints. The unit constraint is minimum and maximum generation constraint (2.5), minimum up and down time constraint (2.6), and start-up cost constraint (2.7). Meanwhile, the considered system constraints are demand (2.3) and spinning reserve constraint (2.4).

For the purpose of probabilistic reserve assessment, spinning reserve is assessed according to the desired level of reliability (EUE_{max}). Other kinds of reliability indices, e.g. LOLP, risk index, can also be used to assess the reliability level. In this dissertation, the level of reliability is represented by expected unserved energy (EUE) constraint. This reliability constraint is given by

$$EUE_{tot} - EUE_{\max} \leq 0 \quad \text{.......................................} \quad (4.1)$$

The generating unit unavailability, and the demand uncertainty can be modeled as presented in Chapter 3. The demand uncertainty which is represented by low, medium, and high load levels is shown again in Figure 4.1.

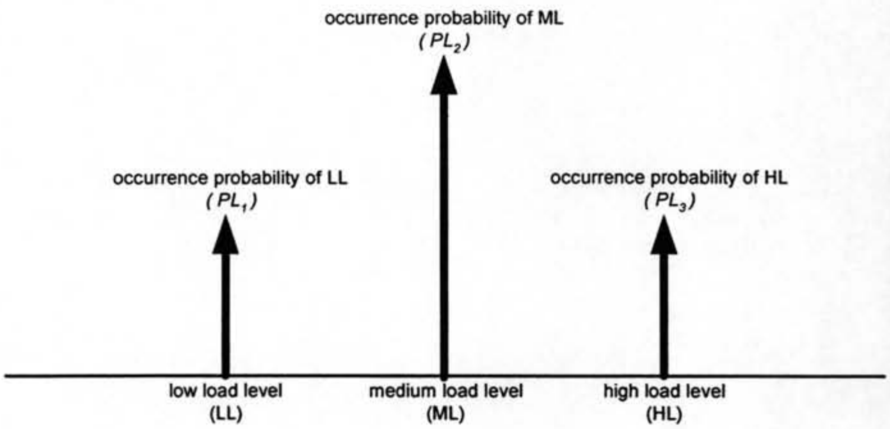

Figure 4.1 Demand uncertainty model

4.3 Methodology

4.3.1 Scenarios Development based on Probabilistic Criterion

In Chapter 3, a key objective is to define the best strategy through scenario development. It will give us information to determine and use the appropriate load level and the appropriate spinning reserve level to balance between generation and risk costs. By using this approach, the determination of spinning reserve strategy is based on the past experience which may not appropriate for the considered system. For example, spinning reserve requirement as of 10% of the forecasted demand might be too low for a small system size with a relatively big capacity of the biggest unit compared with the maximum demand. By applying too low spinning reserve, the obtained risk cost will be too high compared with the generation cost as presented in Chapter 3. On the other hand, by employing the same spinning reserve level, it might be too high for a large system size. As the consequence of high spinning reserve for large system size, the generation cost becomes too high and on the contrary the risk cost becomes very small. Accordingly, it is needed to develop a procedure to determine the best operating strategy in which the amount of spinning reserve requirement is determined by balancing between the increases of generation cost and the decreases of risk cost.

A probabilistic reserve assessment technique enables the correct level of reserve to be set based on a given reliability index and by considering the reliability of the individual scheduled units. One of the previous works dealt with the probabilistic reserve assessment for short-term generation scheduling problem by taking into account demand uncertainty is reported in [44]. In this paper, UC problem is solved using Lagrange Relaxation method based on the mean of the forecasted demand. Reserve requirement for each time interval is assessed based on both the committed units for the corresponding time interval and the pre-assigned 'risk index'. A capacity outage probability table (COPT) is formed based on the committed units in this interval. Demand uncertainties are then incorporated to give a risk index for each commitment pattern in the schedule. This is compared to the given maximum acceptable risk index and, when necessary, the spinning reserve requirement is updated. A weakness of the risk index approach to probabilistic reserve assessment is the lack of an intuitively quantifiable interpretation of this index. The purpose of reserve is not to reduce a risk index below some arbitrary level but to avoid customer outages.

In this research, a decision analysis combined with probabilistic reserve assessment methods is utilized to solve generation scheduling problem taking into account demand uncertainty. Reserve requirement in this proposed method is assessed based on a given maximum expected unserved energy (EUE_{max}) which represents a quantifiable of maximum allowed customer outages. Meanwhile, the implementation of decision analysis is represented by developing several scenarios which is created based on the number of load level. Generation scheduling problem for each scenario is solved based on both the demand of the corresponding load level and the initial value of spinning reserve requirement. The generation cost and total EUE for the scheduling period is then calculated based on the committed units by incorporating demand uncertainty. The obtained total EUE is compared with the given EUE_{max} and then reserve is updated when total EUE is higher than EUE_{max}. Finally, the best operating strategy is then selected among these developed scenarios which give minimum total cost. Details of the procedure are explained below.

Since three load levels are taken into account in this research, there are three possible scenarios. The developed scenarios take into account all possible loads are shown in Table 4.1. For simplicity, the created scenarios are indexed as k=1, 2, and 3 in the same order with the sequence of the considered load level, i.e. LL, ML, and HL, as j=1, 2, and 3 respectively. The representation of decision tree of these scenarios is shown in Figure 4.2.

Table 4.1 The verified scenarios using probabilistic criterion

Load level	UC decision	Scenario
Low (LL)	UC (SR_{LL},LL)	1
Medium (ML)	UC (SR_{ML},ML)	2
High (HL)	UC (SR_{HL},HL)	3

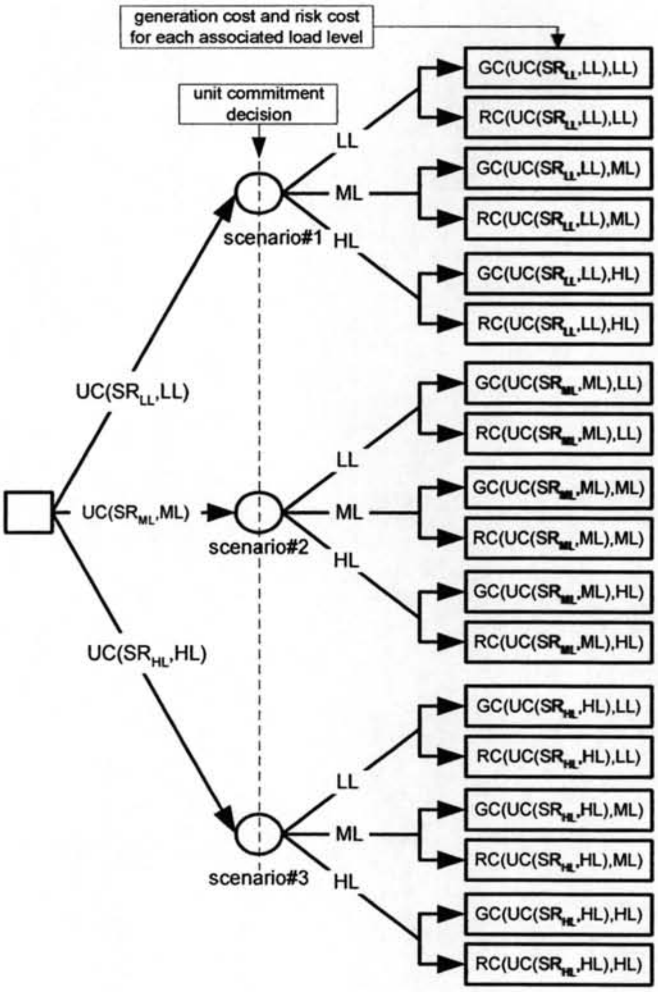

Figure 4.2 Scenario tree for probabilistic criterion

For each scenario, the optimal UC decision is determined using a developed program based on a MILP method. In the UC formulation, the spinning reserve requirement is determined based on a probabilistic criterion which is represented by a desired level of reliability, denoted by EUE_{max}. With the obtained UC decision, the economic dispatch calculation is done for each load level. If the solution of economic dispatch problem is infeasible, which means that there are at least one interval in which the total capacity of the committed units is less than the load demand at the corresponding interval, the spinning reserve requirement should be increased by updating the value of SR. If all of the dispatch problems have been solved, with the same number of committed units under each UC decision, the expected unserved energy for each interval can also be calculated. Based on the sum of the expected unserved energy for all intervals, then it can be used to evaluate whether the desired level of reliability has been reached. Updating the spinning reserve requirement is needed if the EUE_{max} is still higher than the predefined value of EUE_{max}.

The calculation of expected generation cost (EGC), expected risk cost (ERC) and expected total cost (ETC) can be performed after the desired level of EUE_{max} has been reached. The expected total cost of each UC decision can be obtained by adding up both of the generation cost and risk cost and then weighted by each load level probability. The best scenario which results in the minimum total cost will be selected among the developed scenarios. The detail flowchart of this proposed method is shown in Figure 4.3.

4.3.2 Expected Generation Cost Calculation

Once a scenario is selected with a specified load demand and assigned spinning reserve requirement, these data is used as input to determine the UC decision. A mixed-integer linear programming (MILP) method is employed to solve the conventional UC problem, called as UC-MILP module. In order to meet the requirement of the MILP method, the UC problem is linearized as proposed in [64]. The objective function formulation is to minimize the generation cost. Once the UC decision is generated from the UC-MILP module, economic dispatch is conducted to calculate the generation cost.

For a given scenario k at load level j and iteration m, economic dispatch is performed based on linear programming method (LP-ED) to obtain the dispatched power and fuel cost of each committed unit. The generation cost for the related load level, denoted by $GC_j^{k,m}$, can be obtained by adding up the fuel cost, denoted by $FC_j^{k,m}$ and start-up cost, denoted by $STC^{k,m}$.

$$GC_j^{k,m} = FC_j^{k,m} + STC^{k,m} \qquad (4.2)$$

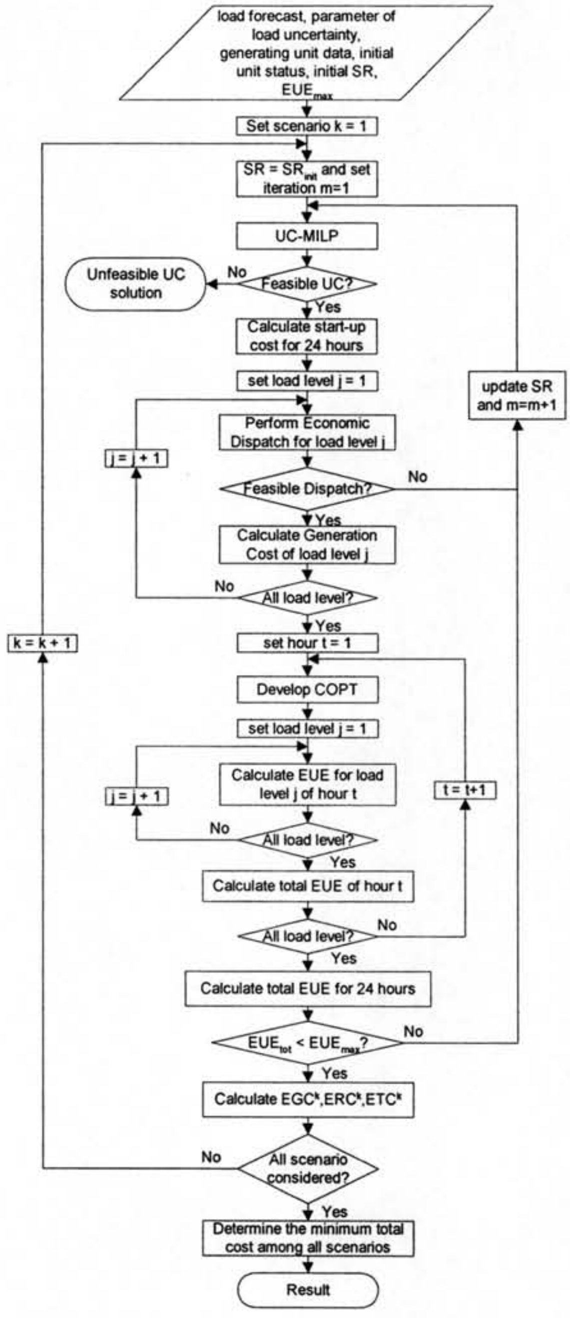

Figure 4.3 Flowchart of the proposed method based on probabilistic criterion

At the end of the iteration in which the reliability level has been achieved, the total expected generation cost of scenario *k* by taking into account load uncertainty, which denoted by EGC^k, can be calculated by

$$EGC^k = \sum_{j=1}^{3} PL_j GC_j^{k,m} \quad \forall k \in [1,3] \qquad (4.3)$$

where PL_j is the occurrence probability of load level j.

4.3.3 Expected risk Cost Calculation

Once a UC decision at iteration# m of scenario# k is obtained from the UC-MILP module, this information can be used to calculate the risk cost. It can be obtained by multiplying the expected unserved energy and the predefined EUE price. The initial step for each time interval is to develop a capacity outage probability table (COPT) [25] based on the ORR of the committed units. Suppose that the number of states in the developed COPT is NS. Each state represents an expected generation outage, the remained in-service capacity CR_s and the probability PR_s corresponding to the state [84]. The EUE for each hour t of the considered load level j can be calculated by

$$EUE_{t,j}^{k,m} = \sum_{s=1}^{NS} PR_s LOSS_s \left(LOAD_{t,j} - CR_s\right) \; \forall t \in [1,T] \quad \text{.......................} (4.4)$$

where $LOSS_s$ is obtained by

$$LOSS_s = \begin{cases} 1, & if\ CR_s < LOAD_{t,j} \\ 0, & otherwise \end{cases} \quad \text{...} (4.5)$$

with all considered load levels, the total EUE for the considered interval or hour is given by

$$EUE_{t,tot}^{k,m} = \sum_{j=1}^{NL} PL_j EUE_{t,j}^{k,m} \;\; \forall t \in [1,T]; \forall k \in [1,3] \quad \text{..............................} (4.6)$$

Therefore the total EUE for the scheduling time horizon of scenario k at iteration m is given by

$$EUE_{tot}^{k,m} = \sum_{t=1}^{T} EUE_{t,tot}^{k,m}, \; \forall \mathrm{k} \in [1,3] \quad \text{..} (4.7)$$

Updating of the spinning reserve requirement is conducted based on the evaluation of total EUE obtained in (18).

Finally, based on the obtained total EUE at the last iteration and the predefined EUE price (\$/MWh), the expected risk cost of scenario k, denoted by ERC^k, can be calculated by

$$ERC^k = EUE_{tot}^{k,m} EUE\_price, \;\; \forall k \in [1,3] \quad \text{.......................................} (4.8)$$

Since the calculation of COPT which involves a large number of units generally requires long computation time, a modified generating unit using efficient round-off model as proposed in [85] is implemented in this work.

4.3.4 Expected Total Cost Calculation

As explained in the previous section, we can obtain the expected total cost, of scenario *k*, called ETC^k, as shown in (4.9).

$$ETC^k = EGC^k + ERC^k, \forall k \in [1,3] \quad (4.9)$$

To obtain the best expected total cost among the developed scenarios, the above procedure is repeated for other scenarios. The best scenario taking into account uncertainty on both generation and demand side can be determined by selecting the scenario which provides minimum total cost as defined in 4.10.

$$\text{The best cost} = \min\left\{ETC^k\right\}, \forall k = [1,3] \quad (4.10)$$

4.3.5 Calculation Procedures of Expected Total Cost

The summary of the algorithm for determining the best operating strategy is as follows.

Step 1, choose scenario#k, starting from k=1.

Step 2, set the iteration m=*1* and the initial value of spinning reserve, SR_{init}^k. The value of spinning reserve requirement is expressed as a percentage of load demand at the corresponding hours.

Step 3, solve the unit commitment problem using MILP method and obtain the committed units for the entire scheduling horizon.

Step 4, evaluate the feasibility of the UC solution. If the solution is infeasible, it means that the available unit cannot meet the forecasted demand at the predefined EUE_{max}, then terminate the process, otherwise decrease the predefined EUE_{max}.

Step 5, calculate start-up cost, $STC^{k,m}$, based on the committed units.

Step 6, solve the economic dispatch problem based on the obtained committed units and load demand of scenario# j[th], and obtain the fuel cost, $FC_j^{k,m}$.

Step 7, if the economic dispatch solution is feasible then go to Step#8. Otherwise update the SR using (4.11).

$$SR^{k,m} = SR^{k,m-1} + 0.5\% \quad \text{.........} (4.11).$$

Step 8, calculate the generation cost $GC_j^{k,m}$ as sum of fuel cost and start-up cost using (4.2).

Step 9, if j is less than the number of load levels, proceed the calculation to the next load level in which $j = j+1$, and then go to Step#6.

Step 10, develop COPT based on the committed units of hour t starting from t=1.

Step 11, calculate $EUE_{t,j}^{k,m}$ for all possible load levels using (4.4), and then calculate $EUE_{t,tot}^{k,m}$ using (4.6).

Step 12, if t is less than T (the scheduling period), proceed to the next hour in which $t=t+1$, then go to Step#10. Otherwise calculate total EUE for T hours using (4.7).

Step 13, evaluate $EUE_{tot}^{k,m}$, if it is more than the predefined EUE_{max}, update the SR using (4.11), then go to Step#3. Otherwise go to Step#14.

Step 14, calculate EGC^k, ERC^k, ETC^k using (4.3), (4.8), and (4.9) respectively.

Step 15, if all scenarios have been considered, determines the minimum total cost and its associated scenario using (4.10). Otherwise proceed to the next scenario in which $k = k+1$, and then go to Step#2.

4.4 Numerical Results

The proposed method has been implemented to solve a 130 unit system which is five times replication of a 24-bus system [80]. The replication is done to obtain a larger system size close to an actual system. The reliability data used in the chapter is based on the modified actual information from a utility in Thailand. The quadratic fuel cost function has been linearized to two segments approximation. A fixed start-up cost, i.e. cold and hot start-up, is applied in our analysis. Meanwhile, the demand uncertainty is modeled by low, medium, and high load level with its associated probability. The load forecast uncertainty is represented by the standard deviation (SD), defined as a fixed percentage of the expected values. The desired reliability level is represented by the EUE_{max} which is expressed as a percentage of the expected energy demand of the corresponding load levels.

Several sensitivity analysis with respect to standard deviation, reliability level, probability of each possible load, and EUE price have been conducted to verify the impact from each parameter on the investigation of each strategy.

a) Impact of Reliability Level

The impact of reliability level is simulated by assuming that the SD of the load forecast error is fixed 1% in the first hour and 4% in the last one. The EUE is priced at 2000$/MWh and the probability of low, medium and high load level is 0.2, 0.6, and 0.2 respectively. The level of reliability depends on the pre-assigned value of the maximum allowed limit EUE_{max} ranging from 0.005 to 0.05. The simulation results are shown in Figure 4.4.

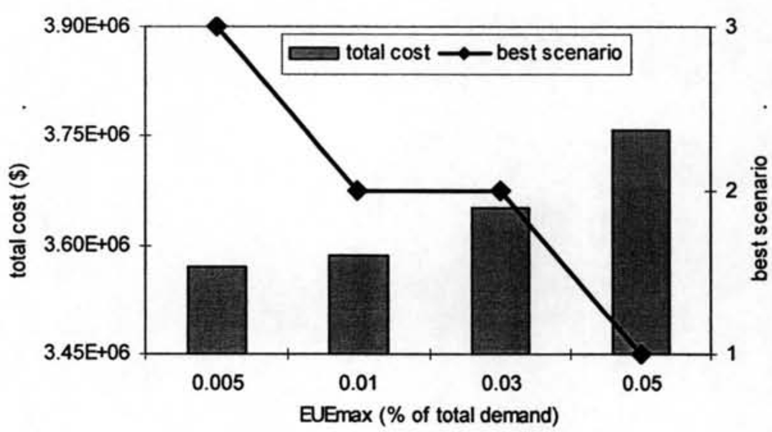

Figure 4.4 Correlation between of EUE_{max} and the best scenario

The results show that the expected total cost increases as the EUE_{max} increases. It is found that the expected generation cost decreases as the EUE_{max} increases. By increasing the EUE_{max}, as the consequence the risk cost also increases. The increase of risk cost is higher than the decrease of the expected generation cost, hence the expected total cost increases as the EUE_{max} becomes higher. It can be seen that by increasing the EUE_{max} from 0.5% to 5%, the expected total cost increases as of 5.3%. It can be concluded that the increase of expected total cost is dominantly caused by the increase of expected risk cost.

Comparison of the expected total cost (ETC) shown in Figure 4.4 to the obtained results in Chapter 3 subsection 3.4.1 part a, it is found that there are increases of expected total cost which can be seen in Figure 4.5. The increase of ETC at higher EUE_{max} is mainly due to the increase of expected risk cost.

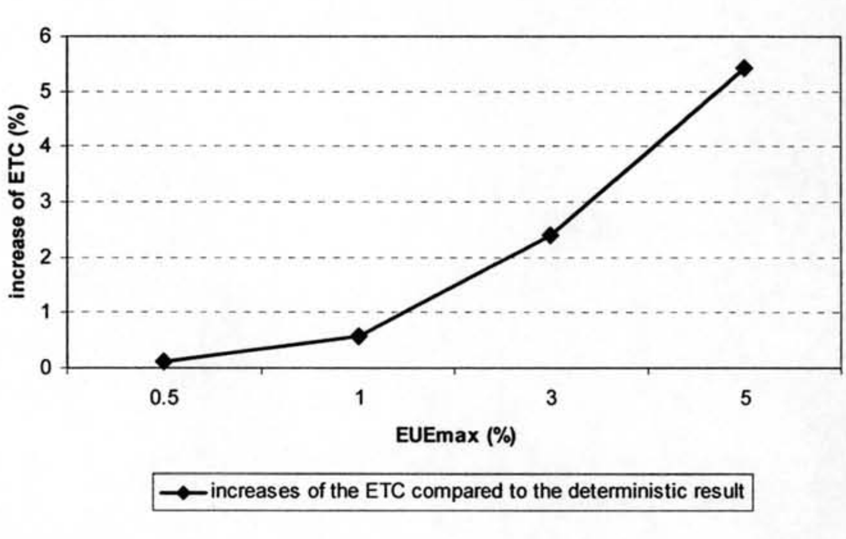

Figure 4.5 Increase of expected total cost at higher EUEmax

b) Impact of Demand Uncertainty

In this sensitivity analysis, the probability of the future demand is varied. The SD in the first and last hour is fixed at 1% and 4% respectively, while the EUE is priced at 2000$/MWh. The load forecast error is represented by normal distribution function with the medium load level probability is varied in the range from 0.4 to 0.9. The update of spinning reserve requirement is terminated when the EUE_{max} reach 1% of total demand.

The results show that the expected total cost decreases as the probability of medium load level increases, as is seen in Figure 4.6. By increasing the probability of medium load level from 0.4 to 0.9, the expected total cost decreases as of 0.28%. The decrease of total cost is due to the impact of less spinning reserve required as the probability of medium load level increased.

It can also be found from the results that the accuracy of the load forecast has an impact on the selected scenario. The better load forecast accuracy will result in the lower load level strategy.

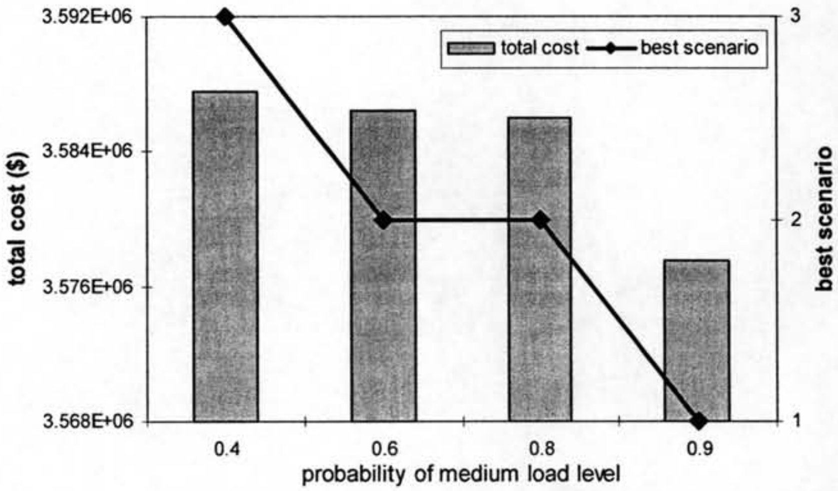

Figure 4.6 Correlation between load probability and the best scenario

The comparison of the presented results in Figure to the same simulation by using deterministic criterion in Chapter 3 show that there are small increases of expected total cost as of 0.55%, 0.59%, 0.66%, and 0.49% respectively for the probability of medium load level of 0.4, 0.6, 0.8, and 0.9 respectively. The increases of expected total cost is due to the use of EUE_{max} at 1% which results in higher expected risk cost as has also been presented in part b.

c) Impact of EUE Price

In this sensitivity analysis, EUE price is varied to verify its impact on the operating strategy. The results are shown in Figure 4.7. As one expected, the higher EUE price causes the higher total cost. The selected scenario is sensitive to the change of EUE price at a relatively low price up to 700$/MWh. After that value, the best scenario is found at scenario# 2nd.

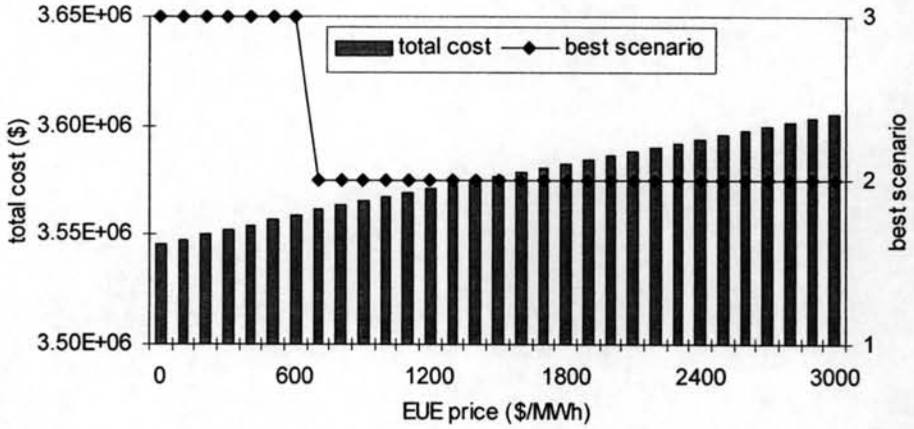

Figure 4.7 Correlation between EUE price and the best scenario

4.5 Conclusion

An approach for directly incorporating generating unit unavailability and load forecast uncertainty in the determination of the best short-term operating strategy has been presented in this chapter. The load uncertainty is accomplished using decision analysis model. The best scenario is determined by selecting among the created scenarios. The effectiveness of the proposed method has been tested using a modified of IEEE 24-bus system. The sensitivity analysis with respect to the change of standard deviation, the desired reliability level, probability of load level, and EUE price has been conducted. The sensitivity analysis with respect to EUE_{max} shows that at higher EUE_{max}, the best scenario tends to be appropriate at lower load level strategy. It is also found that the lower load level strategy is also appropriate at a better accuracy of forecasted demand. The results prove that the proposed method has a capability to solve a realistic short-term planning problem taking into account system uncertainties.