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Generation Scheduling and Evaluation of Risk under Frequency Dependant Availability Based Tariff

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Abstract: Indian power sector is undergoing structural as well as regulatory changes to inculcate competition, improve grid operation. Under changing scenario, the utilities have exposed to many uncertainties and challenges. Implementation of Availability Based Tariff (ABT) is one of the important steps taken by Indian Ministry of Power and govt, so that utilities can earn commercial benefits keeping pace with satisfactory grid operation. The special feature of ABT is the correlation of system frequency with the price of power available at grid. The ABT has Unscheduled Interchange (UI) component which depends on frequency. The volatile nature of frequency results in uncertainty in the price of power. Hence to ascertain the price of power, it is necessary to predict frequency. Frequency being a randomly varying parameter, its prediction is difficult. An attempt is made to use Artificial Neural Network (ANN) as a viable tool for predicting frequency. Once frequency is predicted, UI rate can be estimated to enable utilities to take operational decisions. Under ABT, frequency plays a governing role in scheduling the available generation while fulfilling load. Hence, Generation Scheduling (GS) has become an adaptive decision making problem linked up with frequency and price of power. An approach of incorporating power available at grid as additional generator with duly modified cost curve in GS task is reported. The technical as well as commercial benefits experienced by Indian power sector are validated through results along with calculation of additional cost likely to be incurred by the utility due to error in estimating frequency.

Key words: Availability based tariff, artificial neural network, frequency prediction, generation scheduling, modified, India

INTRODUCTION

The deregulation of power sector and starting of power exchanges in India have put forth many challenges before power system participants. Under this changing power environment, the utilities have exposed to uncertainty associated with system condition, price of power, market behavior, attitude of market players, available generation and load demand, etc. In this study, the peculiar frequency based pricing structure, i.e., ABT and associated uncertainty are discussed.

With the aim of bringing discipline in the grid operation, frequency dependant Availability Based Tariff (ABT) has been introduced in India in 2002 for exchange of power between utilities and central sector. This tariff has Unscheduled Interchange (UI) component dependant on frequency. The efforts of correlating system condition with price of power are well appreciated globally (Mark Lively, 2005). The maximum benefits of ABT can be derived by the utility only if it can schedule internal generation and grid drawal to match the prevailing frequency at any time. It can be done by incorporating grid-source as an additional generator whose cost curve depends upon frequency. To know the price of power, it is necessary to predict frequency. Artificial Neural Network (ANN) can map input-output, irrespective of their relation may be random, non-linear, complex, known or unknown, making it a viable solution to predict random variable like frequency. An ANN is therefore, developed using available statistics of frequency in Indian grid for last 5 years to estimate a day ahead frequency. The error in frequency prediction results in error in UI rate estimation. The difference in UI rate estimation can be used to calculate risk of paying additional UI charge by the utility. This additional UI charge is called in this RESEARCH as Cost at Risk (CaR), similar to Value at Risk (VaR) in share market.

The aim of this study is to present the peculiar ABT tariff structure and inclusion of frequency as additional input parameter along with load for generation scheduling

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task and validate the experiences of Indian power sector. The benefits such as disciplined and accountable power exchange, merit order operation of generating units and increased plant utilization along with overall minimization of system production cost are reconfirmed through results on 26 bus test system.

MATERIALS AND METHODS

Availability based tariff: In India, there are generating plants owned and controlled by every state. The state load is supplied by these plants as well as power purchased from private players through power purchase agreements and from generating plants owned and controlled by central government.

ABT is a rational tariff structure for bulk power transfer between state electricity boards and central sector generating stations. This tariff is linked with frequency which is the simplest and transparent indicator of generation-loading. The most significant aspect of ABT is the splitting of the earlier monolithic charge structure into three components; fixed charge or capacity charge, variable charge or energy charge and Unscheduled Interchange (UI) charge.

Fixed or capacity charge: The payment of the fixed cost to the generating company is linked to the availability of the plant that is its capability to deliver MWs on a day-to-day basis.

Variable or energy charge: The energy charge comprises of the variable cost (mainly fuel cost) of the power plant for generating energy as per the given schedule for the day. The energy charge is not according to the actual generation or plant output but is for the scheduled generation.

Unscheduled Interchange (UI) charge: This charge is to be paid when there is deviation from the schedule. This part of tariff is linked with frequency which highlights the behavior of power system. In the earlier tariff mechanism, there was no incentive/disincentive for deviation from the generating/drawal schedule by a utility. Under ABT, beneficiary draws more or less than the schedule causing grid frequency to deviate from the nominal value (50 Hz). The incentives and disincentives imposed vary with the grid condition at the time of deviation and the magnitude increases with the frequency deviation.

The UI rate is high when frequency is low and vice-versa. Therefore, it is always beneficial for a generator to generate more than the schedule whenever frequency is low and UI rate is higher than its fuel cost and to back-down generation whenever the frequency is high and the UI rate is less than its energy cost. This optimizes the generation capacity and it provides the opportunity to beneficiaries to deviate from the schedule depending upon its commercial interest. The system frequency is normally allowed to float in the band between 49.0-50.5 Hz giving dynamic nature to load dispatch. The UI charge thus forces all generators of the grid and constituent systems to operate according to their merit order, resulting in reduced cost of generation. This tariff mechanism has dramatically improved the grid discipline in India.

Inclusion of frequency based pricing in generation scheduling: The optimum generation scheduling is normally done a day in advance on the basis of anticipated load, generation, network condition, system and device constraints. This serves as the guideline in deciding load dispatch in real time. Actual generation clusters around scheduled generation to adapt to real time changes.

Due to ABT, the generation scheduling has become a decision making problem linked with the price of power (UI rate) which depends on frequency. Thus, it has become necessary to include frequency as one of the parameters along with anticipated load and generation while deciding schedule of generation. The conventional formulation of generation scheduling is modified to incorporate frequency dependant part of tariff.

The UI rate is accounted for; in generation scheduling optimization problem by considering power available from grid as an additional generator with incremental cost of generation as UI rate.

The cost function of grid generator is modified accordingly. In this case, the system demand will be fulfilled by state utility through generation from their own generating stations called as internal generators and through entitlements from central sector generating stations as grid generator. Thus under ABT, the GS problem is an optimization problem of minimization of total cost of power generated by internal generators and purchased from grid generator. The cost function to be minimized is thus:

$$C_t = C_{gr}\left(P_{gr}\right) + \sum_{i=1}^{n} C_i\left(P_{gi}\right) \tag{1}$$

subject to constraints:

$$\left(P_{gr} + \sum_{i=1}^{n} P_{gi}\right) - P_L - P_D = 0 \tag{2}$$

$$P_{gi(min)} \le P_{gi} \le P_{gi(max)} \quad (3)$$

$$P_{gr(min)} \le P_{gr} \le P_{gr(max)} \quad (4)$$

Here:

C_i = Cost of active power generation in $ per MW per h by ith generator
C_{gr} = Cost of purchase of power in $ per MW per h from grid generator
P_{gi} = Power output of ith generator (MW)
P_{gr} = Power to be purchased from grid generator (MW)
P_L = Transmission loss (MW)
P_D = Load demand (MW)
$P_{gi(min)}$ = Minimum generation limit of ith generator
$P_{gi(max)}$ = Maximum generation limit of ith generator
$P_{gr(min)}$ = Minimum limit on drawal of power from grid generator
$P_{gr(max)}$ = Maximum limit on drawal of power from grid generator

Power purchased from grid generator has two parts as:

$$P_{gr} = SI + UI \quad (5)$$

Scheduled Interchange (SI): This is scheduled power (MW).

Unscheduled Interchange (UI): This is the deviation from scheduled power depending on real time system condition. UI can be positive (overdrawal) or negative (under drawal). Total cost of power purchased from the grid C_{gr} (P_{gr}) also has two parts as follows:

- Cost of power corresponding to scheduled interchange C_{si}
- Cost of power corresponding to unscheduled interchange C_{ui} = UI Charge

$$C_{gr}(P_{gr}) = C_{si}(SI) + C_{ui}(UI) \quad (6)$$

Where, C_{gr} (P_{gr}) is fixed cost (frequency independent) +variable cost (frequency dependent):

$$C_{ui}(UI) = \text{UI Charge} = UI \times \text{UI rate}(f) \quad (7)$$

The Lagrange multiplier technique is used to solve the GS problem using estimated frequency as additional input to decide cost function of grid generator. The variation in frequency is random, hence its accurate prediction is difficult. But the estimation of frequency during scheduling phase will be contributory in making schedule more realistic to minimize real time adjustments and the cost.

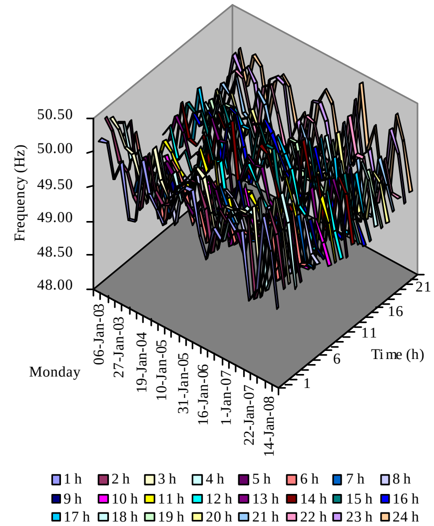

Fig. 1: Frequency variation on Monday (January, 2003-January, 2008)

Use of ANN for frequency prediction: The system frequency depends upon instantaneous load, generation and network condition of all the constituent systems. Generally network and generation availability (except renewable energy) is known beforehand but the load has a continuous random variation. It makes frequency a random variable. The hourly frequency data collected from SLDC, Kalwa, India is analyzed for its volatility. Figure 1 shows the hourly variation of frequency of all Mondays of January from year, 2003-2008. It is observed that frequency variation lies within the band and there exists certain pattern highlighting the effect of load, generation, time of day, type of day, type of month covering the effect of season and atmospheric condition along with other factors. As price of unscheduled flow of power depends on frequency, volatile nature of frequency introduces uncertainty in the price of power and making accurate estimation of UI rate difficult.

Use of ANN for day ahead frequency prediction: The prediction of frequency is a difficult task due to complex and non linear relation of frequency and factors affecting it. The real time measurement of frequency is well handled by many research groups using different techniques which is useful in understanding the behavior of power system for stability study, automatic generation control action, load shedding decision, computer based relaying and static state estimation. Many digital algorithms as zero crossing technique, level crossing technique, least square error technique, Newton method, Kalman filter and discrete fourier transform are developed (Yang and Liu, 2001; Phadke *et al.*,1983). The day ahead prediction of frequency is important in India due to implementation of ABT. ANN is a tool of Artificial Intelligence. It learns by experience the functional relationship between input-output through training. ANN has proved to be capable of finding inherent internal interdependencies within data (Haykin, 2001). It is well accepted tool for prediction of randomly varying parameters such as load and market clearing price (Amjady, 2007; Niimura, 2006). Hence, an attempt is made in this study to use ANN for predicting day ahead hourly frequency. The development of ANN is discussed in next paragraphs.

Selection of architecture and learning rule: The feed forward neural network along with Error Back Propagation (EBP) algorithm is used for forecasting frequency. The single hidden layer and logistic sigmoid activation function is used.

Selection of input parameters and training of ANN: The selection of appropriate input parameters is an important step in supervised learning of ANN (Haykin, 2001). As stated earlier, the frequency depends upon load and generation balance. The consideration of only frequency values as input data for past few years inherently accounts for the effect of generation load balance. The historical data of frequency values for last 5 years, i.e., from 2004-2008 collected from SLDC, India is used to form the train- and test-set.

The network is trained starting with one hidden node and increasing it till performance goal is reached. The momentum coefficient and learning rate are tuned while training the network.

Prediction accuracy of ANN: Once training is over, the next step is to check the prediction accuracy of trained network by using the optimum set of weights obtained from the trained network.

The frequency of few days is predicted using ANN and compared with actual frequency values of those days. The days for which frequency is predicted were not used during the development of ANN. The quality of a model is measured by Absolute Percentage Error (APE) as follows:

$$\text{APE} = \left|\frac{(f_{\text{actual}} - f_{\text{pred}})}{f_{\text{actual}}}\right| \times 100 \tag{8}$$

Where:

f_{actual} = Actual system frequency, Hz

f_{pred} = Predicted frequency, Hz

For the time series of predicted and actual frequency values, the quantity APE is modeled as a random variable defined by its Mean Absolute Percentage Error (MAPE) as follows:

$$\text{MAPE} = \frac{1}{N}\left\{\sum_{i=1}^{N}(\text{APE})_i\right\} \tag{9}$$

Where, N is the no. of time block. The correlation coefficient is a measure of how well the trend in the predicted values follows the trend in the past actual values. The correlation coefficient is a number between 0 and 1 (Jonhson, 2001). The value close to 1 highlights the better fit:

$$\text{Correl coeff.} = \frac{\sum(x-\bar{x})(y-\bar{y})}{\sqrt{\sum(x-\bar{x})^2\sum(y-\bar{y})^2}} \tag{10}$$

Where, x and y is the set of random values.

Development of ANN for frequency prediction of July: The ANN is developed to predict hourly frequency of Monday of January. The 24 frequency values of previous day and 24 frequency values of previous week's same day are chosen to form 48 inputs to neural network. The 24 frequency values of the day are output of the network. When network is trained, 5 hidden nodes are needed to meet the performance goal, resulting optimum ANN structure as 48-5-24.

Table 1 shows the comparison between actual frequency and that predicted by ANN for sample days. The performance of ANN is acceptable as MAPE is <1% and correlation coefficient is close to 1. ANN can understand the effect of load and generation on frequency automatically when trained with sufficient historical frequency data. Figure 2 shows the actual frequency and that predicted by ANN on 7th January, 2008.

Thus results prove the feasibility of ANN for prediction of frequency. Once frequency is predicted, the price of power can be estimated. Next paragraph discusses the use of predicted frequency for deciding the strategy of generation of power from own generator as well as drawal of power from grid.

Table 1: Performance of ANN for frequency prediction

	January (2008)			
	7th	14th	21st	28th
Min-APE	0.01	0.01	0.00	0.00
Max-APE	0.65	0.83	0.56	0.52
MAPE	0.17	0.38	0.19	0.18
Correl coeff.	0.80	0.75	0.90	0.85

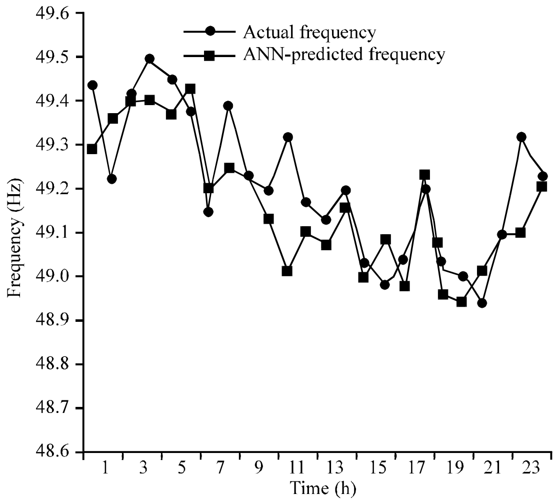

Fig. 2: Actual and ANN-predicted frequency on 7th January, 2008

RESULTS AND DISCUSSION

The generation scheduling algorithm under frequency based tariff is tested on 26 bus test system using sample load curve and hourly frequency values. The 26 bus system consists of 6 generators out of which one generator is considered as grid generator with remaining 5 generators as internal generators. The transmission line connecting grid generator to the rest of the system is considered to have large capacity. Figure 3 shows the sample load curve and hourly frequency values predicted by ANN.

The results are discussed below. Frequency dependant GS approach when implemented on 26 Bus test system for fulfilling load at given frequency conditions, reveals following results.

Generation by internal generators and grid generator: ABT offers flexibility to ramp up and back down generation to earn UI charge benefits. It is obvious that at high frequency condition, state draws more power from grid as it will be beneficial to back down its costly internal generation as against cheaper grid power at low UI rate. When grid frequency is <50 Hz, the grid shares fewer load as UI rate is very high. The internal generators follow their individual cost curves and share the maximum load. Total internal generation can be compared with generation from grid generator to emphasize on the strategic generation to earn UI benefits. Based on frequency condition, the contribution by these two sets of generator varies as shown in Fig. 4.

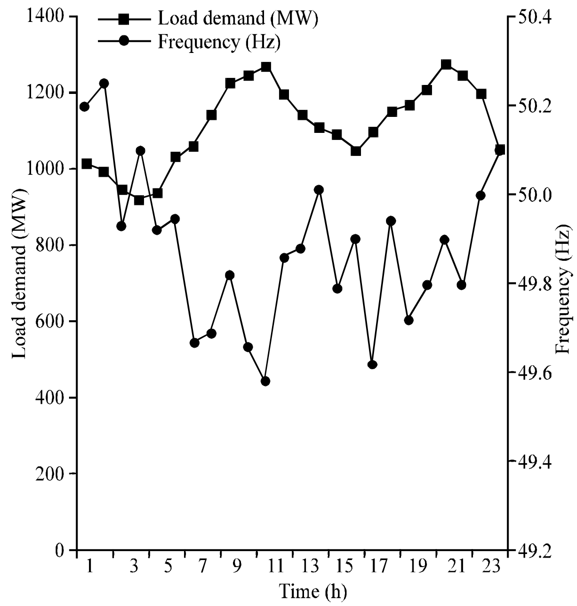

Fig. 3: Sample load curve and hourly anticipated frequency

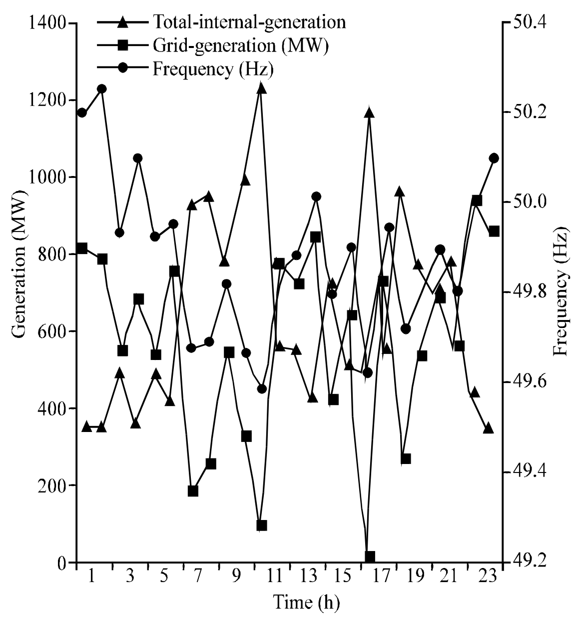

Fig. 4: Contribution of internal generators and grid generator

Figure 5 shows the contribution of grid generator for supplying the load demand at different frequency conditions at different hours.

Use of UI rate for generation scheduling: The optimum solution of minimization of total cost of producing power is achieved when incremental fuel cost of all generators become equal. It is observed that the incremental fuel cost

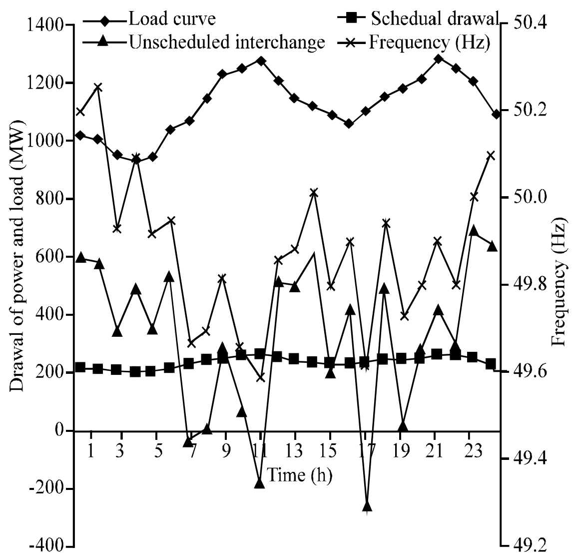

Fig. 5: Strategic drawal of power from grid generator

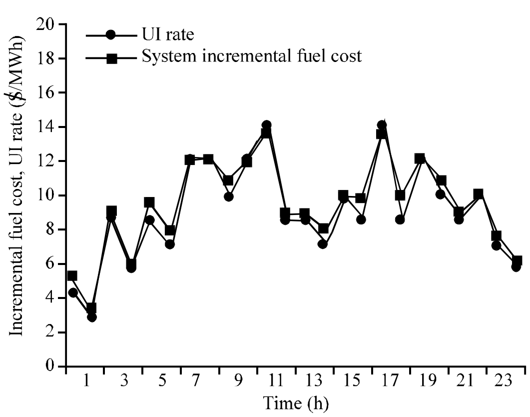

Fig. 6: Relation between UI rate and incremental operating cost

optimizing the solution follows UI rate as shown in the Fig. 6. This indicates the impact of UI rate on optimal decision. The coincidence of incremental generation cost (λ) with UI rate suggests a simple alternative method of deciding generation scheduling. Once frequency is predicted with acceptable accuracy, the UI rate can be estimated and can be used in the Eq. 10 to calculate the contribution of every generator knowing the cost coefficients of the generators:

$$\lambda = a_i \times Pg_i + b_i \quad i = 1 \text{ to } n \tag{11}$$

Where:

λ = Incremental production cost of generating plant = UI rate
a_i, b_i = Cost coefficients of ith generator
Pg_i = Active power generated by ith generator

This analytical method provides a simple and powerful alternative to the use of iterative optimization method. It certainly saves the computational time and complexity with reasonable accuracy in case of large power system.

Saving in total system cost: The total cost incurred by the utility while serving the daily load is $309783 considering only own set of generators. This cost is compared with the one calculated after including regional pool power along with internal generators. The total daily production cost while serving the given load curve is $286755.2. When power available at regional pool is simulated and incorporated while scheduling generation a day ahead, it enables to earn UI benefits resulting in saving to the tune of 7.4%.

Cost at Risk (CaR): The suggested modification in the GS in the earlier discussion reduces the system cost by taking advantage of purchase of cheaper power from grid at lower UI rate. The success of the method depends upon accurate prediction of UI rate which in turn depends on predicted frequency. This risk of additional cost to be borne by utility due to prediction error may be called as Cost at Risk (CaR).

Depending on frequency deviation UI rate will vary. The over-estimation of frequency results in increase in the UI rate and under-estimation of frequency results in lowering of UI rate. The deviation of actual frequency from predicted value may result not only in loosing the benefit but carries the risk of increase in the cost of operation due to higher UI rate if actual frequency is below the predicted value. The deviation in UI rate gives additional UI charge to be paid and saving earned by the utility. The utility is more concerned with the additional UI charge likely to be paid. This additional cost is the risk to which utility is exposed due to uncertainty in frequency prediction. This cost-risk is called as Cost at Risk (CaR).

Frequency prediction error: Knowing the fact that no prediction model is perfect, the error in predicting frequency is analyzed further to evaluate the performance of ANN. The frequency of few sample days is predicted using trained ANN and compared with actual frequency. The error in predicting frequency is calculated as follows:

$$\text{Error}_{\text{Freq}} = \left(f_{\text{actual}} - f_{\text{pred}}\right) \tag{12}$$

Where:

$\text{Error}_{\text{freq}}$ = Error in frequency prediction (Hz)
f_{actual} = Actual system frequency (Hz)
f_{pred} = Predicted frequency (Hz)

Table 2: Frequency of occurrence of prediction error

Range of error in predicting freq. (Hz)	No. of occurrence
-0.3 to -0.4	7
-0.2 to -0.3	18
-0.1 to -0.2	37
0.0 to -0.1	69
0.0 to 0.1	77
0.1 to 0.2	36
0.2 to 0.3	15
0.3 to 0.4	5

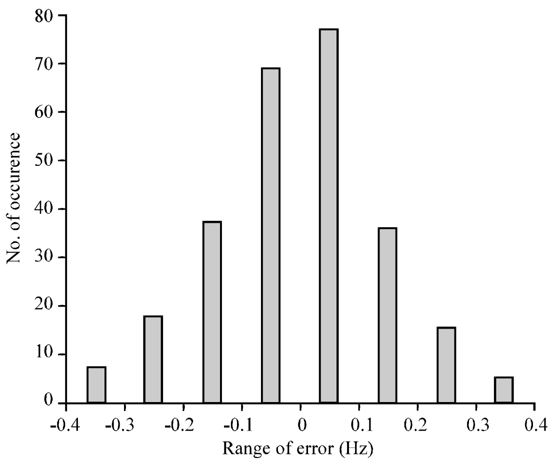

Fig. 7: Distribution of frequency prediction error

This error has random nature. The occurrence of error in different ranges is calculated and is shown in Table 2. The nature of probability distribution of prediction error is almost normal as can be shown from histogram of Fig. 7. Since, distribution of error is almost normal, mean error and standard deviation can be calculated. The mean error in frequency prediction works out to be 0.01 Hz and standard deviation of ±0.15 for the current ANN. When mean error of 0.01 Hz is incorporated in predicted frequency for refinement very small change in the system cost is noticed.

Probable Frequency Error (PFE): Since, error in predicting frequency is random, there can only calculate the probability of occurrence of error. This is termed as Probable Frequency Error (PFE) in this study.

The percentage confidence or confidence level is the degree of certainty that a value of random variable will be included within the interval defined by confidence interval. The confidence interval is given by following formula:

$$\bar{X} \pm Z_c\left(\frac{\sigma}{\sqrt{n}}\right) \tag{13}$$

Where:

- $\bar{X}$ = Mean value of frequency prediction error (Hz)
- Z_c = Critical value corresponding to level of significance (α)
- α = Level of significance used to compute the confidence level (99, 95 and 90% confidence level is considered in the present research)
- σ = Standard deviation of frequency prediction error
- n = No. of samples used to calculate confidence interval

Table 3: Frequency of occurrence of prediction error

	Confidence level		
	99%	95%	90%
(PFE) up (Hz)	0.38	0.29	0.26
(PFE) dn (Hz)	-0.37	-0.28	-0.24

Table 4: Additional UI charge (cost at risk)

	Daily system cost under ABT based GS	Cost at risk (confidence level) 99%	95%	90%
	$286,755.00	$42,790.52	$31,746.79	$26,984.77
CaR (%)	-	14.9	11.07	9.4

The confidence interval (±frequency limit) is actually the possible variation of predicted value of frequency at each time block at specified level of confidence.

The positive limit gives the magnitude by which actual frequency will be higher than the predicted frequency. This difference is called as a Probable Frequency Error-up and denoted it as (PFE) up. Similarly, negative limit gives the magnitude by which actual frequency will be lower than predicted frequency. This difference is called in this research as Probable Frequency Error-dn and denoted it as (PFE) dn.

Knowing the mean and standard deviation of prediction error, the probable frequency errors are calculated at 90, 95 and 99% confidence level and are shown in Table 3.

Evaluation of Cost at Risk (CaR): At each hour, knowing the (PFE) dn at the specific degree of confidence, the additional UI rate is evaluated and the additional UI charge to be paid by utility is calculated. For this, same unscheduled interchange is assumed to occur as calculated by optimization method such as Lagrange multiplier technique.

The daily additional cost is then compared with the total system cost in terms of dollar and percentage. Table 4 shows the daily system cost under ABT and cost at risk at 99, 95 and 90% confidence level. About 99% confidence level indicates that there is 99% probability that the cost at risk will be within $42790.52 (14.9%) and only 1% probability of cost exceeding it. About 95% confidence level indicates that there is 95% probability that the cost at risk will be within $31746.79 (11.07%) and only 5% probability of exceeding it.

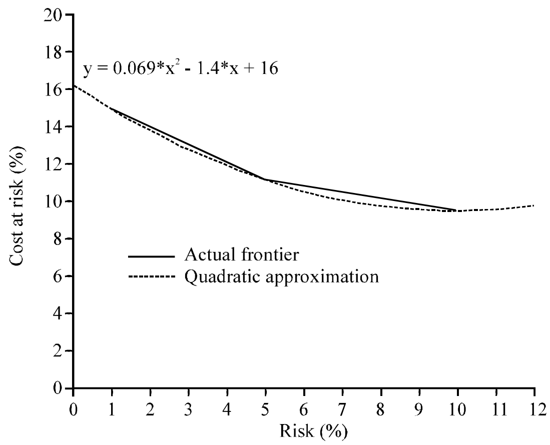

Fig. 8: Correlation between risk (%) and CaR (%)

About 90% confidence level indicates that there is 90% probability that the cost at risk will be within $26984 (9.4%) and only 10% probability of exceeding it. The graph of percentage CaR utility will be exposed to and percentage risk based on confidence level is shown in Fig. 8. This graph is the performance characteristic of ANN in predicting frequency when trained using historical frequency data under ABT scenario. An utility can decide what cost (%) at risk it can sustain at specific confidence level which can be used for rescheduling own generation and deciding the drawal schedule from the grid.

CONCLUSION

The deregulation has introduced electricity as a tradable commodity and granted autonomy to constituent systems. The ABT introduced in India has frequency dependent unscheduled interchange charge. The mechanism has dramatically streamlined the operation at regional pools with a scheme of penalties and rebate. The frequency based pricing structure is included in GS task to understand the commercial and operational implications of ABT as experienced by Indian power sector.

To optimize GS decision, the conventional formulation is modified to account for the frequency dependent UI rate. To estimate UI rate, the frequency is predicted using ANN with acceptable accuracy.

The results highlight the benefits gained such as strategic drawals, saving in total system cost, merit order operation of every plant, improved plant utilization and sensible accountability towards schedules and drawls. The effect of frequency prediction error of ANN is analyzed by evaluating probable deviation in frequency and the additional UI charge that utility may have to pay extra. The concept of cost at risk similar to value to risk in share market will help the utility in deciding drawal from central sector, remaining within affordable possible risk of additional cost at desired confidence level.

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