Effects of Wind Speed Forecasting Error on Control Performance Standard Index

S. M. Eslami*, H. Rajabi Mashhadi**(C.A) and H. Modir Shanechi***

Abstract: Increasing the penetration of wind turbine generations, needs more study about controlling frequency impacts of power system. Frequency control is changed with unbalancing real-time system generation and load. Also wind turbine generations have more fluctuations and make system more unbalance. Then Automatic Generation Control (AGC) loop helps to adjust system frequency and the scheduled tie-line powers. The quality of AGC loop is measured by some indices. It is expected a proper measure shows the AGC performance just as it acts (operates). One of well-known measures in literature which was introduced by North American Electric Reliability Corporation (NERC) is Control Performance Standards (CPS). Previously it is claimed that a key factor in CPS index is $\sigma/\sqrt{K*P}$. This paper focuses on impact of a day ahead wind speed forecast error on this key factor and CPS. The study system is a two area system. One area has only thermal power and other area constitutes of significant wind farm and thermal power. Effects of wind speed standard deviation and also degree of wind farm penetration are analyzed and importance of mentioned factor criticised. After that, influence of mean speed forecast error on this factor is noticed.

1 Introduction

The main purpose of the electric power systems is to provide the customers' demand with electricity, featuring high quality voltage and frequency. The errors in load forecasting and generation planning are the main factors results the frequency moving away from its permissible range and tie-line transmitted power deviating from the scheduled value. Generally, two approaches may be applied in order to solve afore-mentioned problem. The first approach is to improve load forecasting accuracy [1] and the second solution is to provide sufficient reserve power for the system.

However, technical limitations of generating units prevent the system from reaching desired frequency. Therefore, the frequency error is inevitable in the power systems. Thus, the AGC system tries to maintain power system frequency within permissible limits by adjusting the system generation. To evaluate performance of the AGC, proper performance indices should be used. A suitable index should be able to reflect the actual quality of the AGC system.

Due to the accelerating penetration of the Wind Turbine Generators (WTGs) in recent years and future planning, the conventional indices must be reviewed and modified necessarily [2].

The indices are divided into two categories of deterministic and probabilistic. Owing to the uncertain nature of the WTGs in the power system and the large forecasting error of the wind power generation, the probabilistic indices seem to be more appropriate. The main goal of this paper is to study different statistical indices and evaluate AGC indices in power system which has large penetration of the WTGs.

Early studies on AGC were initiated in 1950. In a pioneering study by Cohn [3], the Area Control Error (ACE) was introduced as the error of the frequency control system, and the regulation has been analyzed based on different qualities of Economic Dispatch (ED) and AGC loop and then suitable state has been introduced. System frequency and tie-line power must be measured and then are used in frequency control loop. Besides, those measurements have errors. The influence of the measuring error in output of frequency control loop has been studied [4]. The requirements of

the AGC loop have been introduced in different items, one of these items is the significant differences between settling times of AGC, Load Frequency Control (LFC) and ED loops. Furthermore, the appropriate constant values for governor and recloser dead-bands have also been studied in [5]. The IEEE standard terms and definitions on AGC can be found in [6].

Later on, Control Performance Standards (CPS), the standard rules for frequency regulation service, including A1, A2, B1 and B2 rules were adopted by North American Electric Reliability Council (NERC). The A1 and A2 criteria were employed during normal conditions while B1 and B2 rules were applied during emergency conditions [7].

In an AGC system, the goal is to keep changes in tie-line power error (ΔPtie) and frequency error (ΔF) as small as possible. However, reaching this goal results in too much wear and tear in generating units [8]. Hence, the average value of the ACE signal is forced to zero, not instantaneous ACE. In fact, removal of a non-zero value from the averaged ACE signal requires changes in generation level and energy transfer between control areas. On the other hand, in 50 % of the control actions to bring the negative value of ACE to zero, a positive change in generation has had an inverse effect on ACE and vice versa [6].

Large rate of changes in ACE may require fast changes in the units' generations with its associated financial cost. Furthermore, large values of ACE result in large deviation in the units' generations. It is to be noted that repeatation rate and amplitude of changes are important, and ACE doesn't reflect deviation speed. So ACE is not a good index for AGC. A good AGC index must be directly related to AGC quality [9].

In 1999, CPS1 and CPS2 indices were introduced by NERC. Compared with previous indices, there is less maneuvering and wear & tear in the units' generation when these indices reach to accepted standard values. So system operation using NERC indices is more economic.

CPS1 and CPS2 are based on limiting the standard deviation of Δf, during different periods of time. The time-window for calculating the average values has a great impact on their results [9]. Short time-window used for average calculation reduces the effect of the idea of using the statistical information and is getting closer to calculations with online data. On the other hand, long time-window does not monitor deviations of the system. These indices have also been used as control signals in AGC (in replacement of ACE integral) [10].

It is proven that permitted values of error in CPS1, guarantees permitted value of CPS2 [11]. Indicator of Regulating Trajectory Tracking (IRTT) and Regulating Help Indicator (RHI) indices have also been defined by EDF [12]. Like CPS1 and CPS2, these indices are based on the average calculation of the product of the two terms. These two terms are functions of ΔPtie and ΔF (or ACE). There are some differences in the monitoring

of the system operation using CPS or RHI. In some situations, RHI index detects the system status as improper and identifies a need for emergency operations, while CPS rules detect the system situation as normal or correctable with normal control methods and does not require emergency operations.

On the other hand, from the viewpoint of the power generation regulation, fossil fuel generators have basic differences with WTGs. For instance, to regulate the power generation in a certain value, the fuel should be provided and the technical condition of the unit should be proper.

Although ambient temperature is one of the technical parameters of the generation units, it is possible to forecast it with a great accuracy for the next days [13]. Therefore, appropriate generation planning could be done for the next days if sufficient fuel is available. In this condition, the error of actual generation and planned generation will be very small. Although such a small error is not considerable, but accumulation of the small errors of the units or loads in the system will result in large frequency and tie-line power errors. This would be important for the system.

To decrease the frequency error of the system, units with fast maneuvering ability serve as the AGC units. These units can easily change their output in less time compared to other units. Since the generation of the WTGs is usually at their maximum power point, they cannot increase their generations to take part in the AGC. On the other hand, due to the large error in wind speed forecasting, power generation error of a WTG is much more than a conventional unit. Therefore, not only WTGs cannot operate in AGC, but also their presence in the system requires participation of more thermal units in the AGC.

Hence due to ever-increasing penetration of WTG, a crucial question arises: Are conventional control performances enough in power systems with large-scale wind power penetration? In this paper, we are going to find an answer to this question.

The rest of this paper is organized as follows. In section 2, a test system is explained and the relevant mathematical equations are presented. In section 3, probabilistic equations are defined. The zero-mean error in wind speed forecasting is discussed in subsection 3-1 and the non-zero mean condition is addressed in subsection 3-2. Finally, concluding remarks are presented in section 4.

2 Problem Description

In this paper, the test system consists of two control areas. Errors in generation planning and load forecasting have been considered for both control areas.

The system frequency error and tie-line power error is denoted by Δf and ΔP_{tie}, respectively and K_i shows the frequency response characteristic of the i-th control area. Unit of "f" and "Δf" is Hz. Units of P, ΔP, P_1, P_2, ΔR_1, ΔR_2, ΔG_1, ΔG_2, ΔL_1, ΔL_2 are MW. Units of K_1, K_2
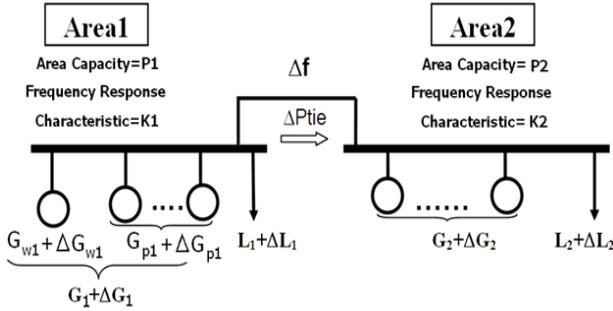
Fig. 1 schematic diagram of the test system.

and K are pu.MW/Hz. If the load forecasting error and generation planning error in area 1 are denoted by ΔL_1 and ΔG_1, respectively, then the overall error in load forecasting and generation planning of the first area would be [14]:

$$\Delta R_1 = \Delta G_1 - \Delta L_1 \tag{1}$$

Hence:

$$\Delta f = (\Delta R_1 + \Delta R_2)/(K * P) \tag{2}$$

where:

$$P = P_1 + P_2 \tag{3}$$

$$K = (K_1 * P_1 + K_2 * P_2)/P \tag{4}$$

and

$$\Delta P_{tie} = (K_2 * P_2 * \Delta R_1 - K_1 * P_1 * \Delta R_2)/(K*P)) \tag{5}$$

where, P_1 and P_2 are generation capacities of the two control areas in Fig. 1.

Assuming $\Delta R_2 = 0$ we'll have:

$$\Delta f = \Delta P_{tie}/(K_2 * P_2) \tag{6}$$

Therefore, according to Eq. (6), an increase in the power transmitted from the first area results on the frequency increase in the power system. It's different of a general system. In general, we think that after increasing output power of an area or increasing loads of that area.

Therefore, according to Eq. (6), an increase in the power transmitted from the first area results on the frequency increase in the power system. It's different of a general system. In general, we think that after increasing output power of an area or increasing loads of that area, frequency of that system must be decreased. So, the system operator in the first area detects this condition as unusual. On the other hand, the second area senses the frequency increase as a normal and expected response of the system, since the additional power is transmitted into this area through tie-line (although the second area does not need this power).

Considering $\Delta R_1 = 0$, we will have

$$\Delta f = -\Delta P_{tie}/(K_1 * P_1) \tag{7}$$

In Fig. 2, the operating line with negative slope is related to Eq. (7). The behavior of the system in this condition is opposite to the system behavior associated

with positive-slope line. According to Eq. (7), increase in the transmitted power from the first control area decreases the frequency of power system, which is quite in the contrary to the system behavior associated with Eq. (6). However, if ΔR_1 and ΔR_2 are non-zero, then the slope of the operation is the function of the parameters of these two control areas (K_1, K_2, P_1, P_2) and the load disturbances (ΔR_1, ΔR_2). This condition holds in the power system during at all times.

Generally, if the operating point lies in quadrature 1 or 3, it means that control area 1 is the main source of disturbances, but if it lines in quadrature 2 or 4, the major part of the load disturbance happens in the control area 2. Probabilistic approaches have been used here to study these behaviors.

3 AGC Probabilistic Modeling

It's assumed in this paper that the first control area has significant WTG penetration. The wind speed forecast error has a non-zero mean and significantly large standard deviation. In proportion to the wind speed forecast error, is the difference between the planned generation and the actual generation. Hence, it's reasonable to say that the error in estimation of the WTGs generation has a non-zero mean and large standard deviation. The probability distribution of the load and generation error in the control areas have been considered as normal distribution:

$$PDF(\Delta R_1) = N(\mu_1, \sigma_1)$$
$$PDF(\Delta R_2) = N(\mu_2, \sigma_2) \tag{8}$$

Second area does not have any WTGs. Therefore, generation of this area has zero-mean error. Also the correlation between the generation and load planning errors of these two control areas is neglected and it is assumed that these parameters are independent. Hence, we'll have:

$$PDF(\Delta R_1, \Delta R_2) = PDF(\Delta R_1) * PDF(\Delta R_2) \tag{9}$$

Since,

$$\Delta R = \Delta R_1 + \Delta R_2 \tag{10}$$

$$PDF(\Delta R_1, \Delta R_2 = \Delta R - \Delta R_1) = N(\mu_1, \sigma_1) * N(0, \sigma_2) \tag{11}$$

$$PDF(\Delta R_1, \Delta R) = \frac{1}{2\pi \times \sigma_1 \times \sigma_2} \times \exp\left[-\frac{(\Delta R_1 - \mu_1)^2}{\sigma_1^2}\right] \times$$

$$\exp\left[-\frac{(\Delta R - \Delta R_1)^2}{\sigma_2^2}\right] = \frac{1}{2\pi \times \sigma_1 \times \sigma_2} \times \exp\left[-\frac{1}{2}\frac{\mu_1^2}{\sigma_1^2}\right] \times$$

$$\exp\left[-\frac{1}{2}\frac{\sigma_1^2 + \sigma_2^2}{\sigma_1^2 \times \sigma_2^2} \times \left[\left(\Delta R_1 - \frac{\sigma_1^2}{\sigma_1^2 + \sigma_2^2} \Delta R\right)^2\right]\right] \times$$

$$\exp\left[-\frac{1}{2}\frac{\Delta R^2}{\sigma_1^2 + \sigma_2^2}\right] \times \exp\left[\frac{\mu_1}{\sigma_1^2} \times \Delta R_1\right] \tag{12}$$
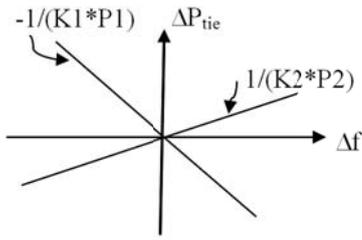
Fig. 2 ΔP_{tie}–Δf Curve.

Five terms can be identified in Eq. (12). The first term is independent of ΔR and ΔR_1 and only depends on constant values of σ_1 and σ_2. Second term is related to μ_1 and σ_1. Values of μ_1 and ΔR_1 appear in the fifth term. This term can take large and quite different values when μ_1 and ΔR_1 are large. The remaining terms are functions of ΔR_1, ΔR, σ_1 and σ_2.

ΔR_1 is a variable in the first control area which cannot be measured by the second area. In order to analyze the probability of frequency error and tie-line power flow error, this probability should be expressed based on the parameters and signals which are available to whole system. The error signals ΔP_{tie} and Δf can be measured in all control areas. Therefore, the probability density functions should be rephrased to include ΔP_{tie} and Δf, instead of ΔR and ΔR_1. Substituting:

$$\Delta R = K * P * \Delta f \tag{13}$$

$$\Delta R_1 = \Delta P_{tie} + K_1 * P_1 * \Delta f \tag{14}$$

in Eq. (12), we'll have:

$$PDF(\Delta f, \Delta Ptie) = \frac{1}{2\pi \times \sigma_1 \times \sigma_2} \times \exp\left[-\frac{1}{2}\frac{\mu_1^2}{\sigma_1^2}\right] \times$$

$$\exp\left[\frac{\mu_1}{\sigma_1^2} \times \left(\Delta Ptie - K_1 \times P_1 \times \Delta f\right)\right] \times$$

$$\exp\left[-\frac{1}{2}\frac{\sigma_1^2+\sigma_2^2}{\sigma_1^2 \times \sigma_2^2}\left(\Delta P_{tie} + K \times P \times \left(\frac{K_1 \times P_1}{K \times P} - \frac{\sigma_1^2}{\sigma_1^2+\sigma_2^2}\right)\Delta f\right)^2\right] \times \tag{15}$$

$$\exp\left[-\frac{1}{2}\frac{\left(K \times P \times \Delta f\right)^2}{\sigma_1^2+\sigma_2^2}\right] \times \exp\left[\frac{\mu_1}{\sigma_1^2} \times \left(\Delta P_{tie} + K_1 \times P_1 \times \Delta f\right)\right]$$

3.1 Zero Mean Error

Analyzing the factor $K*P*\Delta f$ in the fourth term in different conditions, if:

$$\frac{K_1 \times P_1}{K \times P} - \frac{\sigma_1^2}{\sigma_1^2+\sigma_2^2} > 0 \tag{16}$$

Setting $\sigma_1^2 + \sigma_2^2 = \sigma^2$ where σ is the standard deviation of ΔR, then Eq. (16) is restated as:

$$\frac{\sigma_1}{\sqrt{K_1 * P_1}} < \frac{\sigma}{\sqrt{K * P}} \tag{17}$$

Therefore, the parameter $\sigma_i/\sqrt{K_i * P_i}$, which is denoted by g_i in the following, plays an important role

in determining the location of the constant-PDF contours in different control areas. It should be noted that g_i's unit is $\sqrt{MW*Hz}$ which is the unit of the square root of $\Delta f*\Delta P$. We named it as the ability of disturbing system. An area with larger σ_i has more ability to disturb power system. Large K_i makes AGC operation faster and there will be less frequency error. Finally, large P_i means more nominal power of the control area, and its higher capability in maneuvering in AGC actions. Hence, we can interpret g_i as the ability of the control area in disturbing power system and its incapability of maneuvering for controlling system frequency. An area with large g_i can make the system more disturbed and can't works well in AGC, while an area with small g_i not only can maneuver enough for reducing error due to its disturbances, but also can contribute to reduce error occurred by other areas.

Analyzing Eq. (15), first consider the case $\mu_1 = 0$; hence, the second and third terms are equal to one. Fig. 3 shows contours with same probabilities for different values of $k = g_1/g_2$.

Based on Fig. 3, even add odd quadrants of the ΔP_{tie}-Δf plane have different probabilities.

If g_i for two control areas is the same, the diameters of the ellipse are parallel to the horizontal and vertical axes and the probabilities of being in each of four quadrants are equal. In other words, the probability of being in normal state (quarters 2 and 4) or abnormal state (quarters 1 and 3) are the same for control area 1. Besides, the probability of presence in all quadrants is the same. However, electrical control area in the first and third quadrants of the ΔP_{tie}-Δf plane observes opposing behavior. In this case, the other control area will restore the frequency to its nominal value.

The probability of being in different quadrants of the plane is not the same if g_is change. For a constant g_1, an increase in g_2 will increase the probability of being in the first and third quadrants. Hence a decrease in g_2 will increase the probability of being in the second and fourth quadrants.
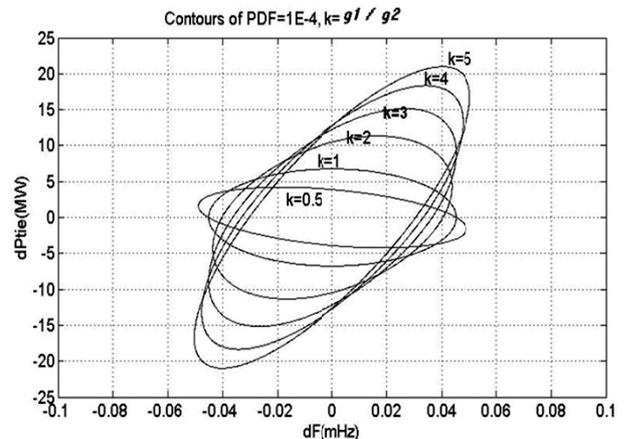

Fig. 3 Contours of constant PDF.

If the first control area competes for controlling system frequency, then:

1- It's more appropriate that major part of its probability distribution be in the second and fourth quadrants, since such units are more effective for corrective actions in the system.

2- It should have large values of ΔP_{tie} and Δf. By small values of ΔR_1.

Contrary to the previous condition, if the first area is small and has large values of σ_1, it can sense large values of ΔP_{tie} and Δf for small values of ΔR_1, which is not appropriate for this area and also other areas.

A change in g_1 has several effects on PDF (Δf, ΔP_{tie}): the axis of symmetry of the PDF changes and also the skewness of its curve will also change.

Therefore, the probability of being in the plane quarters will change. For a better understanding of being in the first and third quarters, the Cumulative Density Function (CDF) for the probability of operation of the first control area in the first quadrant (called $H1_1$) is shown in Fig. 4.

For identical values of g1 and g2, this probability is equal to 50 % while for larger values of g1, the probability increases. The parameter $H1_1$ can also be defined similarly.

$H1_1$ is the probability of operation of the first control area in the first quadrant of the plane. Similarly, $H1_2$, $H1_3$ and $H1_4$ can be defined. Now, $H1_{13} = H1_1 + H1_3$ is the probability of operation of the first control area in the first and third quadrant. Likewise, $H1_{24}$ is the probability of operation of first control area in the second and fourth quadrants. Sum of $H1_{24}$ and $H1_{13}$ is equal to unity.

In Fig. 4, $H1_{13}$ versus k = g1/g2 is plotted for different values of P1. For small values of P1, sensitivity of $H1_{13}$ to k is also small. If the installed capacity in control area 1 increases, then $H1_{13}$ will rise. If the initial installed capacity in area 1 is 10 MW and additional 10 MW is also installed (k = 1.8), then $H1_{13}$ will increase about 3%. On the other hand if the installed capacity in area 1 is 100 MW and additional 400 MW is also installed (k = 1.8), then $H1_{13}$ will increase about 2%.

So it can be concluded that installing a large wind farm does not affect $H1_{13}$ more than installing a small wind farm.
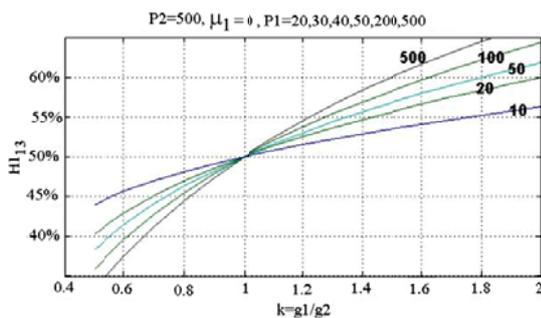

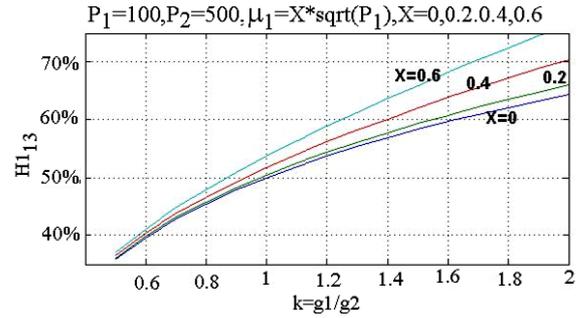**Fig. 4** $H1_{13}$ versus k, different P1.

Fig. 5 $H1_{13}$ versus k–different Mean1.

3.2 Non-Zero Mean Error

As mentioned earlier, the error of estimating wind speed has a non-zero mean. Therefore, in presence of WTGs, the mean error in generation planning will be non-zero [15, 16]. In this case, the center of the contours will not coincide with the center of coordinates and will be displaced. These changes may have significant effects on the values of $H1_{13}$ and $H1_{24}$. The curves in Fig. 5 show the effect of $\mu1$ on $H1_{13}$.

For X = 0 (zero mean error) and k = 1.8, $H1_{13}$ is about 63%. For this value of k and X = 0.4 (non-zero mean error), $H1_{13}$ will be about 67 %. It means that non-zero mean error of the wind forecasting forces 4% changes in $H1_{13}$. In addition, it was seen before that increasing the installed capacity of a wind farm from 100 MW to 500 MW leads to only 3% increase in $H1_{13}$ (with zero mean error).

Hence wind speed forecasting error has more effect on AGC performance than installing more wind farms.

Based on Fig. 5, if $\mu1$ is non-zero and there is an identical g_i for all areas, then $H1_{13}$ will not be 50 %. Therefore, g_i is not a proper index for determining the condition of the system. Hence an appropriate index should be defined for determining the performance of AGC in different control areas.

Fig. 6 shows the effect of $\mu1$ on the contours of the constant probability. In this case, not only the probability of operation in the first and third quadrants changes, but also the maximum error in the first quadrant decreases and the absolute value of the maximum error in the third quadrant increases. Hence, it can be said that in the condition of having a non-zero value for the mean error of generation and load, the maximum value of error is larger and happens with higher probability.

The curves in Fig. 6 show the percentage of operation in the first and third quadrants for non-zero mean of generation and load error. Increase in the average of power error can be due to the large error in wind speed forecasting. This error would surely have some effects on the performance of the AGC.

It can be understood from the above figure that for small values of g_1, having a non-zero μ_1 would cause a large change in the curve of $H1_{13}$. Therefore, in order to decrease the value of $H1_{13}$, sufficient amount of reserve
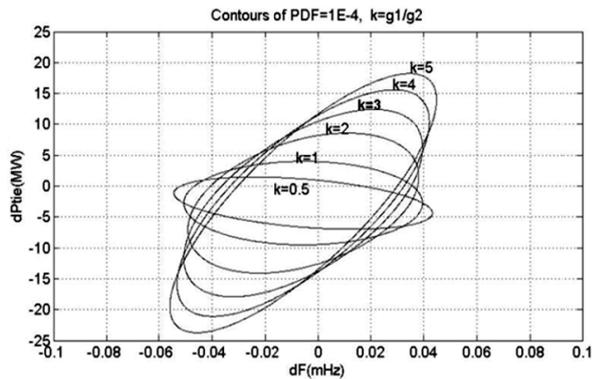
Fig. 6 Countors with non-zero μ_1.

should be considered for WTG to prevent a large frequency error and tie-line power flow in the time of operation and hence to avoid poor performance of the AGC.

4 Conclusion

The high penetration of bulk wind farms may considerably affect the power system and therefore it's required to re-assess conventional performance indexes. In this paper, it was assumed that the wind speed forecasting has non-zero mean error and therefore there is non-zero mean generation error in the presence of WTGs. For a system with small WTG and non-zero mean error in wind speed forecast, the corresponding control area has a large effect on the AGC. WTG is responsible for this big error which AGC must remove it. Furthermore, it was shown in this paper that the index $\sigma/\sqrt{K*P}$, which had been previously introduced as a good index and used in CPS1 & CPS2, is not an efficient decision criterion to assess the effectiveness of a unit or control area in load frequency control. Therefore, better indices for monitoring AGC performance in the presence of large WTG penetration should be defined.

Finally, it was found in this paper that wind speed forecasting error has more effects on the AGC than installing more wind farms. As another finding, installing small wind farms has more influence on AGC than installing large wind farms. We are working to define new and better index in next researches.

Appendix

The nomenclature is as follows:

AGC	Automatic Generation Control
WTG	Wind Turbine Generator
CPS	Control Performance Standard
ACE	Area Control Error
LFC	Load Frequency Control
NERC	North American Electric Reliability Corporation
ED	Economic Dispatch
IRTT	Indicator of Regulating Trajectory Tracking
RHI	Regulating Help Indicator

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Sayyed Mahdi Eslami was born in Mashhad, Iran, in 1966. He received the B.Sc. and M.Sc. degrees both from the Department of Electrical Engineering of Sharif University of Technology, Tehran, Iran in electrical power system engineering. He is studying for Ph.D. degree in the Ferdowsi University of Mashhad, Iran. His research interests are wind farm operation, power electronics and drives.

Habib Rajabi Mashhadi was born in Mashhad, Iran, in 1967. He received the B.Sc. and M.Sc. degrees with honor from the Ferdowsi University of Mashhad, both in electrical engineering, and the Ph.D. degree from the Department of Electrical and Computer Engineering of Tehran University, Tehran, Iran, under joint cooperation of Aachen University of Technology, Germany, in 2002. He is as Professor of electrical engineering in Ferdowsi University of Mashhad and is with the Center of Excellence on Soft Computing and Intelligent Information Processing, Ferdowsi University of Mashhad, Mashhad, Iran. His research interests are power system operation and planning, power system economics, and biological computation.
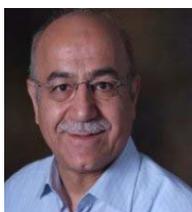
Hassan Modir Shanechi, Senior Member IEEE, obtained his M.Sc. in Electrical Engineering with Distinction from Tehran University and his Ph.D. in System Science from Michigan State University. He was with the EE Department of Ferdowsi University, Mashhad, Iran and also an associate professor at the Department of Electrical Engineering, New Mexico Tech 2001-04. He joined the Electrical and Computer Engineering Department at Illinois Institute of Technology in August 2007. His general area of research is nonlinear and intelligent systems. He has been especially active in the area of power system dynamics and security. His research interests include power system operation, economics, and dynamics, large scale and intelligent systems, and distributed energy resources.