Online Estimation of Power System Actual Frequency Response Characteristic

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***Abstract*—In power systems, the system frequency as well as the real power interchange between balancing authority areas must be maintained at the nominal value and the scheduled values, respectively. To this end, the area control error (ACE), which incorporates information about potential mismatches in the values of these two quantities, is calculated and fed to the automatic generation control (AGC) system, the goal of which is to drive the ACE to zero. The purpose of this paper is to present a systematic method to estimate, in real time, the actual frequency response characteristic (AFRC) and to use it in the ACE calculation. In such a case, the AGC system only reacts to internal disturbances and not to external ones. To do so, we use a simplified model to represent power system dynamics, and a sliding exponentially weighted window blockwise least squares algorithm for the estimation of the AFRC. The proposed methodology is illustrated in the 9-bus 3-machine WECC system model, and in a 140-bus 48-machine system.**

I. Introduction

Power systems are divided into several balancing authority (BA) areas that are responsible for maintaining (i) load-interchange-generation balance within the BA area, and (ii) the interconnection frequency as close as possible to its nominal value at all times. They do so by implementing frequency control, which is considered to be one of the most important aspects of ancillary services. Frequency control consists of primary control, secondary control or automatic generation control (AGC), and tertiary control. To ensure that reliability obligations of each BA area (within the interconnection) are maintained, the North American Electric Reliability Corporation (NERC) has introduced various frequency performance criteria, such as CPS1, CPS2 and BAAL. Most BA areas implement tie-line bias control, and the AGC command is driven by the value of the area control error (ACE), which includes two terms: (i) the deviation of the sum of tie line flows between the BA area and other BA areas from the scheduled values, and (ii) the BA's obligation to support frequency. The second term depends on the frequency bias factor, which is unique for each BA area, and ideally reflects the area's natural response.

Each BA area responds to a frequency deviation according to the natural response of its turbine governors and its load. The actual frequency response characteristic (AFRC) of a BA area is the change in frequency that occurs from a change in load-resource balance in an interconnection. The change of frequency is influenced by the natural load response to frequency and the governor response, which is determined by the generators' droop settings. The amount of frequency decline from a lost generator or a change in load varies throughout the year. The use of the AFRC as the frequency bias factor in the ACE calculation is ideal, since it makes the AGC system to only react to internal disturbances and not to external ones. The AGC system underperforms when smaller or larger values than the AFRC are selected. Most independent system operators use the 1% of peak load method to calculate the frequency bias factor used in ACE, and keep it constant for the entire year. In most cases, the 1% load method is greater than the AFRC and causes over-regulation in the BA area, which increases the regulation cost. To this end, BA areas are interested in improving their control operations and maintaining the control performance at satisfactory levels by selecting more appropriate values for the frequency bias factor. One way to achieve this goal is by estimating online the AFRC, and using it as the frequency bias factor.

A thorough literature review of research in AGC systems is given in [1]. A flexible AGC algorithm that includes flat frequency, flat tie-line and tie-line bias control is presented in [2]. The authors pinpoint that the use of the AFRC in the calculation of the ACE is important. In [3], the authors present an adaptive controller with self-tuning technique for the AGC system. In [4], it is shown that the value chosen for the frequency bias factor is a very complicated procedure and that it is important in the interaction between BA areas.

In this paper we propose a method for the online estimation of the AFRC and its use as the frequency bias factor. In order to estimate the AFRC, we need to use an appropriate model that describes the system's dynamic behavior, which only depends on the BA area's variables, such as synchronous speed, total mechanical power and the AGC system; all these models are described in Section II. In Section III, we use this model to derive a relationship between the ACE, the frequency deviation, the total generation and the AFRC at each time instant. We use this relationship and a sliding exponentially weighted window blockwise least-squares algorithm to estimate online the AFRC, since there are available measurements of the ACE, frequency and total generation. In Section IV, we demonstrate the proposed method on the 9-bus 3-machine WECC system, and a 140-bus 48-machine system, and we make some concluding remarks in Section V.

II. Power System Model

Let us assume that we have M balancing areas within an interconnected system, denoted by $\mathscr{A} = \{1, \dots, M\}$. For each $m \in \mathscr{A}$, we denote by $\mathscr{A}_m \subset \mathscr{A}$ the set of balancing areas that have lines with the area m, and $\mathscr{G}_m$ the set that indexes all generators in area m. We use a simplified power system model to represent its dynamic behavior; this model does not explicitly consider the individual states of each generator, such as the deviation of the rotor electrical angular velocity from the nominal $\Delta\omega_i$, and the mechanical power P_{SV_i} of generator i, but the area's states. To this end, for each BA area $m \in \mathscr{A}$, we define

$$\Delta\omega^m = \frac{\sum_{i\in\mathscr{G}_m} M_i \Delta\omega_i}{\sum_{i\in\mathscr{G}_m} M_i}, \quad (1)$$

$$P_{SV}^m = \sum_{i\in\mathscr{G}_m} P_{SV_i}, \quad (2) \qquad P_G^m = \sum_{i\in\mathscr{G}_m} P_{G_i}, \quad (3)$$

$$D^m = \sum_{i\in\mathscr{G}_m} D_i, \quad (4) \qquad \frac{1}{\tilde{R}_D^m} = \sum_{i\in\mathscr{G}_m} \frac{1}{R_{D_i}\omega_s}, \quad (5)$$

$$T_{SV}^m = \frac{\sum_{i\in\mathscr{G}_m} T_{SV_i}}{|\mathscr{G}_m|}, \quad (6) \qquad M^m = \sum_{i\in\mathscr{G}_m} M_i, \quad (7)$$

where P_{G_i} is the electrical output; $M_i = \frac{2H_i}{\omega_s}$, with ω_s being the synchronous reference rotating speed and H_i being the inertia constant; D_i is the damping torque term; R_{D_i} is the droop; and T_{SV_i} is the governor time constant of generator i [5].

Then, we can describe the area's m dynamic behavior by

$$M^m \frac{d\Delta\omega^m}{dt} = P_{SV}^m - P_G^m - D^m\Delta\omega^m, \quad (8)$$

$$T_{SV}^m \frac{dP_{SV}^m}{dt} = -P_{SV}^m + z_m - \frac{1}{\tilde{R}_D^m}\Delta\omega^m, \quad (9)$$

where z_m is the AGC command for area m. The actual power interchange between areas m and m' is $P_{mm'}$, and is positive for leaving area m'. We determine $P_{mm'}$ by

$$P_{mm'} = \sum_{\substack{l\in\mathscr{B}_{mm'} \\ l'\in\mathscr{B}_{m'm}}} V_l V_{l'} \big(G_{ll'} cos(\theta_l - \theta_{l'}) + B_{ll'} sin(\theta_l - \theta_{l'})\big), \quad (10)$$

where $\mathscr{B}_{mm'}$ is the set of nodes in area m with tie lines to nodes in area m'; V_l is the voltage magnitude and θ_l is the voltage angle at bus l; and $Y_{ll'}e^{ja_{ll'}} = G_{ll'} + jB_{ll'}$ is the network admittance matrix. The actual frequency of area m is denoted by f_m and is given by

$$f_m = f_{\text{nom}} + \frac{1}{2\pi}\Delta\omega^m, \quad (11)$$

where f_{nom} is the system nominal frequency. Then, the area control error (ACE) for area m, ACE_m, is given by

$$ACE_m = \sum_{m'\in\mathscr{A}_m} (P_{mm'_{sch}} - P_{mm'}) - b_m(f_m - f_{\text{nom}}), \quad (12)$$

where $P_{mm'_{sch}}$ is the scheduled power interchange between areas m and m'; and b_m is the bias factor for area m, which is negative.

Let us assume that we have two BA areas, $\mathscr{A} = \{1, 2\}$, and that the bias factor $b_1 = \beta_1$, where β_1 is the AFRC of area 1, and $b_2 = \beta_2$, respectively. If there is a change of load in area 1 by ΔP_{L_1}, then from (12) we have that $ACE_1 = \Delta P_L$ and $ACE_2 = 0$. This means that only area 1 reacts to the load increase ΔP_{L_1}. This is known as non-interactive control and it is fair in the sense that the area, in which the load disturbance has occurred, is the only one that reacts to restore the frequency and net tie flow to the desired values.

The AGC's goal is to drive the ACE to zero. We follow the AGC model given in [6, p. 352-355]. We define a new state for the AGC system, z_m, which at the steady state is the total power generated in the balancing area m. The differential equation describing the AGC system dynamics is

$$\frac{dz_m}{dt} = -z_m - \eta_m ACE_m + P_{G_m}, \quad (13)$$

where η_m is the controller gain. Each generator i in BA area m participates in the AGC by a participation factor κ_i^m. So the generator i command output is P_{C_i}, which is determined by

$$P_{C_i} = P_{G_i}^\star + \kappa_i^m (z_m - \sum_{j\in\mathscr{G}_m} P_{G_j}^\star), \quad (14)$$

where $P_{G_i}^\star$ is the economic dispatch signal for generator i. We can see from (14) that $z_m = \sum_{i\in\mathscr{G}_m} P_{C_i}$.

The AFRC of area m is equal to $\beta_m = -(\frac{1}{\tilde{R}_D^m} + D^m)$. We have that $\Delta f_m = f_m - f_{\text{nom}}$ and $\frac{d\Delta\omega^m}{dt} = 2\pi\frac{d\Delta f_m}{dt}$. Then, we combine (8) and (9) into one equation using the Laplace transformation, and ignore the second-order terms since they are negligible due to the system's inertia. Thus, we have that

$$s2\pi(M^m + D^m T_{SV}^m)\Delta f_m + \beta_m\Delta f_m + \beta_m(1+s) = z_m - (1 + sT_{SV}^m)P_G^m. \quad (15)$$

III. Estimation of Area's Frequency Response Characteristic (AFRC)

In order to estimate the AFRC, we use (15) in combination with (13) to obtain

$$-\eta_m ACE_m = sK_m\Delta f_m + (1+s)\beta_m\Delta f_m + s(1 + T_{SV}^m)P_G^m, \quad (16)$$

where $K_m = 2\pi(M^m + D^m T_{SV}^m)$. We now express Δf_m as $\Delta f_m = s\frac{1}{2\pi}\sum_{i\in\mathscr{G}_m}\gamma_i\theta_i$, with $\gamma_i = \frac{M_i}{M^m}$, and substitute in (16). We also use the moving average definition $\overline{ACE}_m(k) = \frac{1}{T}\int_{t_{\text{start}}(k)}^{t_{\text{end}}(k)} ACE_m(t)dt$, with $t_{\text{end}(k)} = kT$, and $t_{\text{start}}(k) = (k-1)T$. For every step k, referring to time instant $t = t_{\text{end}}(k) = kT$, we use (17) at the top of the next page to calculate the AFRC, since we have measurements for all the necessary values. We use the sliding exponentially weighted window blockwise least squares (SEWBLS) algorithm for the online estimation of the frequency bias factor for BA area m β_m [7].

In order to formulate our problem we introduce the following variables:

$$y(k) = \phi(k)\beta_m(k), \quad (18)$$

$$w(k) = y(k) + v(k), \quad (19)$$

$$\beta_m(k) = \frac{\eta_m \overline{ACE}_m(k) + \left(P_G^m(t_{\text{end}}(k)) - P_G^m(t_{\text{start}}(k))\right)(1+T_{SV}^m) + K_m\left(\Delta f_m(t_{\text{end}}(k)) - \Delta f_m(t_{\text{start}}(k))\right)}{\Delta f_m(t_{\text{end}}(k)) - \Delta f_m(t_{\text{start}}(k)) + \frac{1}{2\pi}\sum_{i\in\mathscr{G}_m}\gamma_i\left(\theta_i(t_{\text{end}}(k)) - \theta_i(t_{\text{start}}(k))\right)} \tag{17}$$

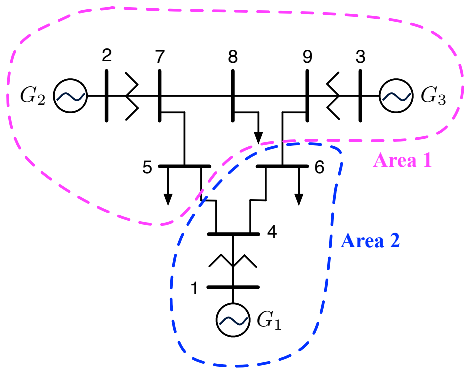

Fig. 1: One-line diagram of the WECC three-machine nine-bus power system.

where $y(k)$ is the system's output, $w(k)$ is the measured output and $v(k)$ is a zero-mean white Gaussian sequence that accounts for measurements noise and modeling errors. We have that $\phi(k)$ is the denominator, and $y(k)$ is the nominator of (17), respectively. The SEWBLS solution is

$$\hat{\beta}_m(k) = \left[(\phi_{k-L+1}^k)^T \Lambda_{k-L+1}^k \phi_{k-L+1}^k\right]^{-1} \left[(\phi_{k-L+1}^k)^T \Lambda_{k-L+1}^k w_{k-L+1}^k\right], \tag{20}$$

where $\phi_{k-L+1}^k = [\phi(k-L+1), \phi(k-L+2), \dots, \phi(k)]^T$, and Λ_{k-L+1}^k is an $L \times L$ diagonal matrix with diagonal elements being the forgetting factors, $\lambda^{L-1}, \lambda^{L-2}, \dots, \lambda^0$. The values of λ vary from 0 to 1. After several tests, we concluded that a time period of $T = 1$ min and a window length of $L = 30$ min provides good results in terms of convergence speed and accuracy.

IV. Numerical Examples

In this section, we present several case studies to demonstrate the capabilities of the proposed methodology. We use a small system, the three-machine nine-bus system, to present the insights we gained into the AGC system. We demonstrate that setting the frequency bias factor equal to the AFRC is beneficial for the interconnection. We also show that when using the estimation of the AFRC as the frequency bias factor, the system frequency has smaller oscillations than when using other values. Furthermore, we include a larger system to show that there are no computational limitations in the proposed method.

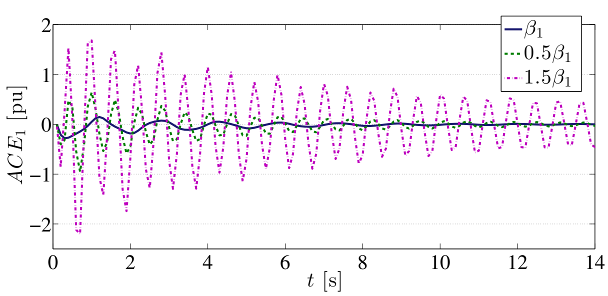

Fig. 2: Area Control Error of area 1, ACE_1, where the load change $\Delta P_L = 0.15$ pu occurred.

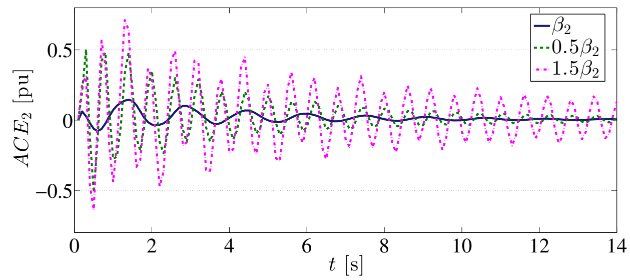

Fig. 3: Area Control Error of area 2, ACE_2.

A. Three-Machine Nine-Bus Power System

We illustrate the proposed methodology with the standard three-machine-nine-bus Western Electricity Coordination Council (WECC) power system model, which is depicted in Fig. 1; this model contains three synchronous generating units in buses 1,2 and 3, and load in buses 5, 6 and 8. The machine, network and load parameter values may be found in [5]. As depicted in Fig.1, we consider two BA areas $\mathscr{A} = \{1, 2\}$. We increase the load at bus 5 by 0.15 pu. In order to keep the tie line power at the scheduled value, the generation must be increased in area 1. However, the frequency deviates from the nominal value in both areas. Area 1 exports to area 2 which results in $ACE_1 < 0$, since it is under-generating; and $ACE_2 > 0$, since area 2 is importing less than scheduled, as depicted in figures 2-3. We implement the AGC system by modifying the frequency bias factors b_1 and b_2 among three values: (A-i) the AFRC, (A-ii) 0.5AFRC, and (A-iii) 1.5AFRC respectively. The AFRC for area 1 is $\beta_1 = -0.7394$ pu/Hz and for area 2 $\beta_2 = -0.4121$ pu/Hz. We notice in Fig. 2, in case (A-i), where $b_1 = \beta_1$, the ACE_1 converges quicker to zero and has lower in magnitude oscillations. The reason is that the value of ACE represents how many MW are needed to restore the area's frequency, instead of a smaller or bigger value in the case of $0.5\beta_1$ and $1.5\beta_1$, respectively. In addition, in Fig. 3,

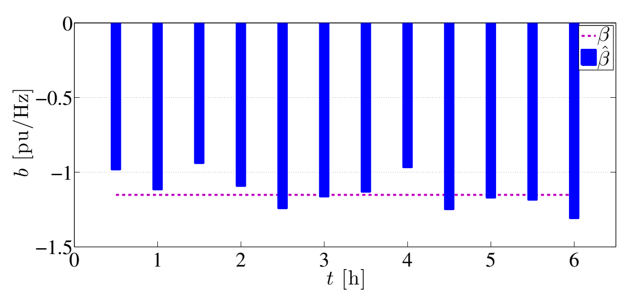

Fig. 4: Online estimation of the AFRC.

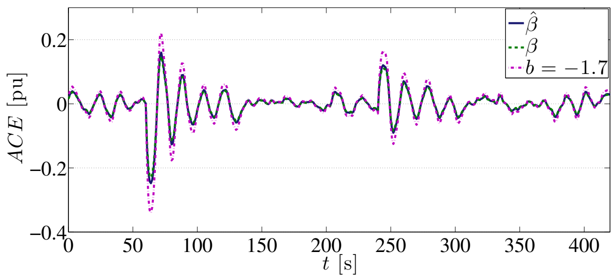

Fig. 5: ACE for cases (A-iv) $b = \hat{\beta}$, (A-v) $b = \beta$ and (A-vi) $b = -1.7$pu/Hz.

we may see that ACE_2 is smallest in the case where $b_2 = \beta_2$, and therefore, the area participates the least in regulation.

We now consider the system as one BA area and modify the system's load as a stochastic differential equation: $dX_t = aX_t + \zeta W_t$, with $a = -5 \cdot 10^{-6}$ and $\zeta = 0.01$, and W_t is a Wiener process, as described in [8]. The online estimation of the AFRC β with $\lambda = 0.95$ in the SEWBLS for a period of 6 hours is given in Fig. 4. We notice that the algorithm provides a good approximation of the AFRC, which in this case is $\beta = -1.152$ pu/Hz, since the maximum relative absolute error observed is 18.5%. In Fig. 5, we depict the system's ACE, when using (A-iv) the online estimation $b = \hat{\beta} = -1.241$ pu/Hz for hour 3, (A-v) the AFRC $b = \beta$, and (A-vi) $b = -1.7$ pu/Hz for the period of 7 minutes. We may see that case (A-v) provides the best results, since the best choice for the frequency bias factor is the AFRC. We notice that case (A-iv) is very close to case (A-v), as desired. The reason is that the estimation is very close to the AFRC. Case (A-vi) has the largest deviation from case (A-v), and presents the biggest oscillations. We also note that for this time period the maximum absolute value of ACE is for case (A-iv) 0.24 pu, for case (A-v) 0.23 pu, and for case (A-vi) 0.34 pu, which further supports the fact the the use of the online estimation $\hat{\beta}$ in b is a good practice.

B. 140-bus system

In this section, we demonstrate the scalability of the proposed methodology to the online estimation of the AFRC for large power systems. In particular, we examine the IEEE 48-machine test system, which consists of 140 buses and 233 lines [9]. To implement our analysis method, we use the MATLAB-based Power Systems Toolbox (PST) [10], and add the AGC system model described in (13)-(14) to it. We use the proposed algorithm to estimate the AFRC and use it in the calculation of the ACE. We modify the system's load in a similar way as in the 9-bus 3-machine system. In Fig. 6, the system's frequency is plotted for the period of 7 minutes by using: (B-i) the estimated AFRC $b = \hat{\beta} = -5381$ MW/Hz, (B-ii) the ARFC $b = \beta = -5475$ MW/Hz, and (B-iii) the value $b = -16424$ MW/Hz in the ACE calculation. One can see that the proposed method yields good results and the system frequency is close to the nominal. In addition, the maximum deviation of the system frequency from the nominal value is 0.05 Hz for case (B-i), 0.06 Hz for case (B-ii), and 0.08 Hz for case (B-iii).

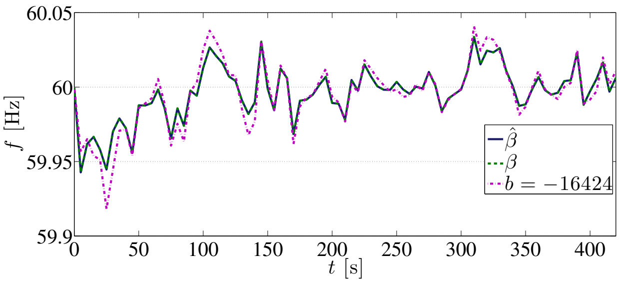

Fig. 6: System frequency for cases (B-i) $b = \hat{\beta}$, (B-ii) $b = \beta$ and (B-iii) $b = -16242$ MW/Hz.

V. Concluding Remarks

In this paper, we presented a systematic method for estimating the AFRC of a power system, and use it in the ACE calculation. To this end, we used a simplified model to represent the BA area's dynamics and incorporate the AGC system model. We end up with a second order differential equation representing the system dynamics. The network effects are incorporated in the values of generators' output. We use the aforementioned relationship to express the AFRC as a function of the area's variables that we have measurements of. Then, we may use the SEWBLS algorithm to estimate the AFRC. We illustrate the application of the proposed methodology via two numerical examples. We show that the use of the AFRC gives better results in the frequency regulation, in terms of the magnitude of the oscillations and the time the frequency converges to the nominal value. Furthermore, we show that the proposed method gives a good approximation to the AFRC.

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