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Power system inertia estimation: Utilization of frequency and voltage response after a disturbance

Dimitrios Zografos [a,*], Mehrdad Ghandhari [a], Robert Eriksson [b]

[a] Department of Electric Power Systems, KTH Royal Institute of Technology, Teknikringen 33, 10044 Stockholm, Sweden
[b] Market and System Development, Svenska Kraftnät, Sturegatan 1, 17224 Sundbyberg, Sweden

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ABSTRACT

Power system inertia is gradually being reduced due to the ongoing replacement of conventional synchronous power plants by intermittent generation. This affects the frequency response of the system and necessitates the estimation of power system inertia, so that sufficient power reserves are retained. This paper contributes with a novel disturbance-based inertia estimation method, that simultaneously estimates the power change after a disturbance. The proposed method accommodates the frequency and voltage dynamics, which significantly affect the system's power change, and hence the inertia estimation. Two separate approaches – that are also capable of standing alone – are combined, in order to accommodate the dynamics. An extended version of the Nordic32 test system is used for the application of the method, where several case studies and a comparison are investigated, so as to examine the method's accuracy and robustness.

1. Introduction

The frequency of electric power systems should remain in a specific range, close to its nominal value. The frequency changes due to an imbalance between active power generated (and imported through high voltage direct current (HVDC) links) and consumed (and exported) in the power system, including the system losses.

Electric power systems are constantly evolving. Nowadays, there is a tendency of substituting the conventional synchronous power plants with renewable energy sources (RES) and of installing a large amount of HVDC links. This evolution is challenging, as the newly installed sources of power offer intermittent generation (solar and wind power plants) and either do not have rotating parts (solar power plants and HVDC) or are decoupled from the rest of the system by power electronic devices (wind power plants) [1,2]. This results in power systems with variable and even reduced inertia. Therefore, the quality of the traditional and fully functional frequency control of the power systems is put under risk.

The frequency stability of the system depends on three factors: the amount of active power imbalance, available reserves, and inertia (Fig. 1). The inertia is the resistance that the power system opposes to changes in its frequency by means of the kinetic energy that is stored in its rotating masses [3].

The system will require greater inertia and faster and greater reserves in order to retain its frequency stability in case of a large power imbalance, compared to a smaller one.

The reduction of inertia and its challenges have already been identified by transmission system operators (TSOs) [4,5] and several researchers [6–10] worldwide. In case of a large disturbance and since the amount of inertia is decreased, the probability of a large frequency deviation increases [11]. In order to avoid an event of frequency instability, the amount of inertia available should be identified so that enough reserves are preserved. Moreover, if information about the amount of inertia is available, additional adaptive frequency control, that involves the participation of the loads, can be employed [12,13].

Inertia estimation is of great importance and this is depicted in the amount of previous work that is dedicated to it. Most of the studies have focused on estimating inertia by using frequency measurements after a disturbance (disturbance-based estimation). In [14], researchers used an average frequency signal to estimate the inertia of the 60 Hz power system of Japan. In [15], the inertia of the power system of Great Britain (GB) was estimated. In [16], several methods to estimate power system inertia of the Nordic power system were investigated. In [17], electric power and Rate Of Change Of Frequency (ROCOF) measurements at the connection points of the generators with the grid were considered to be avail-

* Corresponding author.
E-mail address: dzo@kth.se (D. Zografos).

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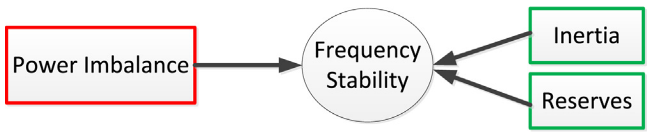

Fig. 1. Factors that determine the system's frequency stability.

able. In this case, the power system inertia of the IEEE 39 bus system was estimated. In [18], frequency measurements from a single location were employed in order to estimate power system inertia of the Western Electricity Coordination Council (WECC). In [19], an inertia constant estimation was performed, where frequency and active power measurements from a single location were assumed to be available. In a method developed in [20], the total power change after the disturbance was estimated simultaneously with the inertia constant. The method employed frequency signals from all generators and was tested in Nordic32 test system.

The inertia estimation methods that have been presented in the past, have several challenges that need to be tackled. A lot of these methods are using a frequency signal from a single location, which is not an accurate representation of the system frequency during the dynamics [4]. Furthermore, in large power systems (e.g. Nordic [4]), frequency measurements are not available for the whole system. Therefore, the estimation method should provide precise results even if less information is available.

Moreover, the past presented disturbance-based methods consider that the total power change of the system after the disturbance is constant and equal to the amount of the initial disturbance. However, this is not accurate, since the total power change is highly influenced by the dynamics of the system, especially in the first 1–2 s after the disturbance. These dynamics are related to the voltage and the frequency response of the system. The dynamics associated with the voltage are attributed to the loads, which are voltage dependent. The dynamics associated with the frequency are attributed to the frequency dependent loads, but also to the governors, which change their response according to the frequency. Therefore, system dynamics have a significant impact on the total power change and should be taken into account in the inertia estimation method.

The main contributions of this paper can be summarized as follows:

- a novel disturbance-based inertia estimation method is proposed, that accommodates the system's frequency and voltage dynamics to simultaneously approximate the total power change,
- the performance of the proposed method is examined, while different amount of available data is considered,
- a comparison between the proposed estimation method and a generic method that is similar to methods that are presented in the literature is implemented [14–16]. The comparison shows the better performance of the proposed method by means of the mean and the variance of the errors.

2. Methodology

The method described in this paper is a disturbance-based inertia estimation method, based on the swing equation. The swing equation describes the motion of a synchronous generator. If a total inertia constant and an average frequency for the whole system are considered (by transforming the system to the Center Of Inertia (COI) reference frame [16]) and the mechanical and electrical powers of the generators are summed up, then the swing equation can be employed to describe the electromechanical dynamics of a multi-machine power system:

$$2H\frac{df(t)}{dt} = \Delta P_m(t) - \Delta P_e(t) = \Delta P(t), \qquad (1)$$

where H is the total inertia constant of the system in seconds, $df(t)/dt$ is the ROCOF in per unit per second, $\Delta P_m(t)$, $\Delta P_e(t)$, and $\Delta P(t)$ are the total mechanical, electrical, and power change respectively in per unit.

The mechanical power change $\Delta P_m(t)$ is attributed to the governors' response, either to a disturbance or to a change in their reference value. In case of a power imbalance in the system, the governors respond in accordance to the frequency change and modify the mechanical power output. Therefore, such a response has a significant impact on $\Delta P_m(t)$ and hence, on $\Delta P(t)$.

The electrical power change $\Delta P_e(t)$ is equal to:

$$\Delta P_e(t) = \Delta P_{dist} + \Delta P_L(t), \qquad (2)$$

where ΔP_{dist} is the size of the disturbance and $\Delta P_L(t)$ is the change in the total load demand. The sign of ΔP_{dist} is considered to be positive in case of a disturbance that causes power deficiency (e.g. loss of generation) and negative in case of a disturbance that causes power surplus (e.g. disconnection of a load). The change in the total load demand $\Delta P_L(t)$ is attributed to the voltage and frequency dependency of the loads. If a power imbalance is considered again, the frequency and the voltage change and the frequency and voltage dependent loads change their demand accordingly. Therefore, the amount of $\Delta P_L(t)$ in such a case is significant and has a substantial impact on $\Delta P(t)$.

In this paper, two approaches are introduced (R and V approach) to express the power change due to the frequency and voltage dynamics. This is achieved by the use of two functions ($h_1(f(t))$, $h_2(V(t))$):

$$\Delta P(t) = h_1(f(t)) + h_2(V(t)) - \Delta P_{dist}. \qquad (3)$$

The R approach deals with $h_1(f(t))$ and accommodates the system's frequency dynamics. These include the response of the governors (connected to $\Delta P_m(t)$), as well as the frequency dependency of the loads (connected to $\Delta P_e(t)$). The V approach deals with $h_2(V(t))$ and accommodates the system's voltage dynamics, which refer to the voltage dependency of the loads (connected to $\Delta P_e(t)$). These two approaches can be employed separately to estimate the power system inertia, however each of them does not fully accommodate the system dynamics on its own. Therefore, these two approaches are combined to form the proposed RV method.

2.1. R approach

In the R approach [20], the following is considered:

$$\Delta P(t) = h_1(f(t)) - \Delta P_{dist}. \qquad (4)$$

In order to approach $h_1(f(t))$, the governor's behavior is examined. More specifically, in steady state, the relationship between the stationary mechanical power change and the frequency deviation is given by: $\Delta P_m = -R\Delta f$, where ΔP_m is the mechanical power change, R is a constant called system gain, and Δf is the steady state frequency deviation. However, this relationship is valid for steady state conditions and cannot express system dynamics. Thus, for the purpose of this paper, R is substituted by a time varying function $R(t)$, that accommodates the dynamic response of the system that is related to $\Delta f(t)$. Hence, $R(t)\Delta f(t)$ is introduced to directly accommodate the frequency dynamics. By substituting $h_1(f(t))$ with $R(t)\Delta f(t)$, (1) ends up to:

$$2H_{est}\frac{df(t)}{dt} = h_1(f(t)) - \Delta P_{dist} = R(t)\Delta f(t) - \Delta P_{dist}, \qquad (5)$$