Analysis of power system inertia estimation in high wind power plant integration scenarios

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Abstract: Nowadays, power system inertia is changing as a consequence of replacing conventional units by renewable energy sources (RESs), mainly wind and photovoltaic (PV), electrical grids can suffer more frequency stability challenges [2]. RESs are intermittent and uncertain because they depend on weather conditions [3]. This fact makes them hard to integrate into power systems [4], as they pose stress on their operation [5]: transmission system operators (TSOs) have to deal with not only the uncontrollable demand, but also uncontrollable generation [6].

Moreover, renewable power plants are not connected to the grid through synchronous machines, but through electronic converters [7]. Thus, by increasing the number of renewable sources and replacing conventional synchronous units, the effective rotational inertia of the system can be significantly reduced [8, 9]. The rotational inertia is important to limit the rate of change of frequency (ROCOF) right after a power imbalance [10]. Therefore, power systems with lower equivalent inertia are initially more sensitive to frequency deviations [11, 12]. As a result, frequency control strategies have been developed to effectively integrate RES into the grid [13]. Such methods are commonly referred to as synthetic, artificial, emulated or virtual inertia [14].

The aim of this paper is to estimate and compare the equivalent inertia constant of a power system with high RES integration from the frequency deviations suffered after an imbalance. Several methodologies have been proposed during the past decades in the specific literatures [15–21]. The power system considered in this paper is in line with current grids, involving conventional and wind power plants. Moreover, wind plants include frequency control according to a recent approach [22]. The rest of this paper is organised as follows: the theoretical background of the problem is covered in Section 2. Section 3 reviews and explains the different strategies to estimate the inertia constant of a power system after an imbalance. In Section 4, the power system and different scenarios considered in this paper are detailed. Results are discussed in Section 5. Conclusions are given in Section 6.

1 Introduction

Frequency of a power system deviates from its nominal value after a severe power imbalance between generation and consumption [1]. Owing to the increasing penetration of renewable energy sources (RESs), mainly wind and photovoltaic (PV), electrical grids can suffer more frequency stability challenges [2]. RESs are intermittent and uncertain because they depend on weather conditions [3]. This fact makes them hard to integrate into power systems [4], as they pose stress on their operation [5]: transmission system operators (TSOs) have to deal with not only the uncontrollable demand, but also uncontrollable generation [6].

Moreover, renewable power plants are not connected to the grid through synchronous machines, but through electronic converters [7]. Thus, by increasing the number of renewable sources and replacing conventional synchronous units, the effective rotational inertia of the system can be significantly reduced [8, 9]. The rotational inertia is important to limit the rate of change of frequency (ROCOF) right after a power imbalance [10]. Therefore, power systems with lower equivalent inertia are initially more sensitive to frequency deviations [11, 12]. As a result, frequency control strategies have been developed to effectively integrate RES into the grid [13]. Such methods are commonly referred to as synthetic, artificial, emulated or virtual inertia [14].

The aim of this paper is to estimate and compare the equivalent inertia constant of a power system with high RES integration from the frequency deviations suffered after an imbalance. Several methodologies have been proposed during the past decades in the specific literatures [15–21]. The power system considered in this paper is in line with current grids, involving conventional and wind power plants. Moreover, wind plants include frequency control according to a recent approach [22]. The rest of this paper is organised as follows: the theoretical background of the problem is covered in Section 2. Section 3 reviews and explains the different strategies to estimate the inertia constant of a power system after an imbalance. In Section 4, the power system and different scenarios considered in this paper are detailed. Results are discussed in Section 5. Conclusions are given in Section 6.

2 Theoretical background

2.1 Inertia constant \( H \)

From a traditional point of view, after a power imbalance, the kinetic energy stored in the rotating masses of a generator is released following expression below [23]:

\[
E_{\text{kin}} = \frac{1}{2}J(2\cdot\pi\cdot f_m)^2,
\]

where \( J \) is the moment of inertia and \( f_m \) is the rated rotational frequency of the machine. The inertia constant \( H \) of a generator is defined as the ratio between the stored kinetic energy \( E_{\text{kin}} \) and its rated power \( S_r \) [24]. \( H \) determines the time interval during which an electrical generator can supply its rated power only by using the kinetic energy stored in its rotating masses [25]

\[
H = \frac{E_{\text{kin}}}{S_r} = \frac{J(2\cdot\pi\cdot f_m)^2}{2\cdot S_r}.
\]

Depending on the type of conventional units (i.e. steam, combined cycle, hydroelectric etc.), typical inertia constants are in the range of 2–10 s, as indicated in Table 1.

2.2 Swing equation of a power system; equivalent rotational system inertia

Power systems include several synchronous generators. Thus, it is possible to estimate the equivalent rotational system inertia \( (H_{eq}) \) by using [34]

\[
H_{eq} = \sum CP \cdot H_i \cdot S_{B,i}.
\]

\( H_i \) refers to the inertia constant of the power plant \( i \), \( S_{B,i} \) is the rated power of power plant \( i \), \( S_B \) is the rated power of the power system and \( CP \) is the total number of conventional plants.
The swing equation of a power system is used to analyse transient stability problems, as well as frequency control design and regulation [35]. Moreover, it relates frequency excursions with the power imbalance [36]

\[
\frac{d\Delta f}{dt} = \frac{1}{2H_{eq}} (\Delta P_m - \Delta P_e),
\]

where \(\Delta f\) is the deviation of the grid frequency, \(H_{eq}\) is the equivalent inertia constant for the power system determined by (3), \(\Delta P_m\) is the mechanical power change supplied by generator and \(\Delta P_e\) is the electrical power demand variation.

Some electrical loads are frequency dependent (such as rotating machines). Consequently, \(\Delta P_e\) is expressed as [37]

\[
\Delta P_e = \Delta P_i + D \cdot \Delta f,
\]

being \(\Delta P_i\) the power change of frequency-independent loads and \(D\) the damping factor (load-frequency response constant). Combining (4) and (5), the swing equation of a power system is obtained [38]

\[
\frac{d\Delta f}{dt} = \frac{1}{2H_{eq}} (\Delta P_m - \Delta P_i - D \Delta f).
\]

2.3 Future definition of inertia constant of a power system

By considering policies to promote the integration of renewables, RES has replaced conventional power plants and, subsequently, synchronous generators [39]. Among the different renewable sources available, PV and wind [especially doubly fed induction generators [40]] are the two most promising resources for generating electrical energy [41]. Both wind and PV power plants are controlled by power converters according to the maximum power point tracking control [42, 43]. This technique prevents both sources to directly contribute to the inertia of the system [44–46], which is considered as one of the main drawbacks to integrating large amounts of RES into the grid [47]. Modern wind turbines (WTs) have rotational inertia constants comparable with those of conventional generators, provided by their blades, drive train and electrical generator. However, this inertia is hidden from the power system point of view due to the converter [48]. Moreover, ROCOF depends on the available inertia [49]. As a result, larger frequency deviations are achieved after an imbalance between supply side and demand when RES replaces conventional units without providing frequency response [50].

Therefore, it is necessary that RES becomes an active agent in grid frequency regulation [51]. Several TSOs require that RES contributes to ancillary services as well [52], especially wind power plants [53]. Toulabi et al. [54] affirm that the participation of WTs in frequency control is necessary. Under these requirements, different solutions providing inertia and frequency control from RES have been under study during the past decades. These technologies are usually known as ‘virtual inertia techniques’ [55] and are explained in [55–59].

If RES providing frequency response were considered, the equivalent inertia of the power system would have two different components: (i) synchronous rotational inertia due to conventional generators \(H_{eq}\) [calculated with (3)] and (ii) virtual inertia corresponding to RES \(H_{V,eq}\) as indicated in (7) [60, 61]. In this way, \(H_{V,j}\) refers to the emulated inertia constant of the power plant \(j\), \(S_{B,j}\) is the rated power of power plant \(j\) and \(VG\) is the total number of virtual generators included in the power system under consideration. The rest of the parameters are the same as (3)

\[
H_{eq} = \sum_{i=1}^{CP} \frac{H_i \cdot S_i}{S_{B}} + \sum_{j=1}^{VG} \frac{H_{V,j} \cdot S_{B,j}}{S_{B}}.
\]

However, the values of \(H_{V,j}\) are not normally known and can be time dependent. Thus, it is difficult to apply (7).

3 Inertia estimation strategies. methodology

Different inertia estimation strategies have been proposed during the past decades [15–21]. Damping factor is neglected in most approaches as its effects are small on the first moments of the imbalance \(\Delta P\).

Inoue et al. [15] propose a procedure for estimating the inertia constant of a power system using transients of the frequency measured at an imbalance. At the onset of an imbalance \((t = 0)\), the frequency deviation is \(\Delta f = 0\). Assuming that the imbalance \(\Delta P = \Delta P_m - \Delta P_i\) is known, and by estimating the ROCOF \((df/dt)\) at \(t = 0\), the inertia constant can be calculated with

\[
H_{eq} = \frac{-\Delta P}{2\pi (df/dt)} \bigg|_{t=0}.
\]

To calculate the ROCOF, a fifth-degree polynomial approximation of \(df/dt\) concerning time is fitted. The time interval is about 15–20 s after the imbalance

\[
\Delta f / f_0 = A_1 \cdot t^5 + A_2 \cdot t^4 + A_3 \cdot t^3 + A_4 \cdot t^2 + A_5 \cdot t + A_6,
\]

where \(t\) is the time. By estimating the coefficients \(A_6 \ldots A_1\), the equivalent inertia constant \(H_{eq}\) is obtained by using (11), as \(A_6\) is approximately equal to the ROCOF at \(t^1\)

\[
A_1 = f'(t = 0') \approx \frac{\Delta f / f_0}{dt} \bigg|_{t=0}
\]

\[
H_{eq} = \frac{-\Delta P}{2 \cdot A_1}.
\]

Chassin et al.’s [16] frequency and power values from the Western Electricity Coordination Council were collected. In this case, ROCOF is estimated by removing noise from the frequency data recorded and applying the first derivative. The equation to estimate \(H_{eq}\) is as below:

\[
Table 1  \quad H\text{ according to generation type, rated power and reference}

| Type of power plant | Rated power, MW | \(H_i\) | \(s\) | Reference | Year |
|---------------------|----------------|--------|-----|-----------|-----|
| thermal (two poles) | not indicated | 2.5–6  | [26] | 1994      |
| thermal (four poles)| not indicated | 4–10   | [26] | 1994      |
| thermal             | 10             | 4      | [27] | 2007      |
| thermal             | 500–1500       | 2.3–2  | [28] | 2008      |
| thermal             | 1000           | 4–5    | [29] | 2011      |
| thermal             | not indicated  | 4–5    | [30] | 2012      |
| thermal (steam)     | 130            | 4      | [31] | 2012      |
| thermal (steam)     | 60             | 3.3    | [31] | 2012      |
| thermal (combined cycle) | 115    | 4.3    | [31] | 2012      |
| thermal (gas)       | 90–120         | 5      | [31] | 2012      |
| thermal (nuclear)   | 100–1400       | 4      | [25] | 2016      |
| thermal (fossil)    | 0–1000         | 5–3    | [25] | 2016      |
| hydroelectric       | not indicated  | 2–4    | [26] | 1994      |
| hydroelectric       | not indicated  | 2–3    | [32] | 1994      |
| hydroelectric       | not indicated  | 2–2    | [32] | 1994      |
| hydroelectric       | 10–65          | 2–4.3  | [28] | 2008      |
| hydroelectric       | 10–75          | 2–4    | [28] | 2008      |
| hydroelectric       | 10–90          | 2–3.3  | [28] | 2008      |
| hydroelectric       | 10–85          | 1.75–3 | [28] | 2008      |
| hydroelectric       | not indicated  | 4.75   | [33] | 2013      |

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\[ H_{eq} = \frac{-\Delta P}{\frac{d\Delta f}{dt}}. \]  

Wall et al. [17] and Wall and Terzija [18] present a robust estimation method for the inertia available in the system. It uses the active power \( P \) and the derivative of frequency \( \frac{d\Delta f}{dt} \) as input data, measured from a single location. The proposed algorithm consists of a set of four filters (two for the total active power – \( P_1 \) and \( P_2 \), and two for the ROCOF – \( R_1 \) and \( R_2 \)) applied as sliding windows, see Fig. 1. Windows have a width of \( A \) data points, and they are separated by a width \( W \).

\[ H_{eq} = \frac{1}{A} \left( \frac{P_1 - P_2}{2R_1 - R_2} \right), \]  

where \( P_1, P_2, R_1, \) and \( R_2 \) are calculated with (14)

\[ P_i(t_h) = \frac{1}{A} \sum_{t_i}^t P_i(t), \]

\[ P_i(t_h) = \frac{1}{A} \sum_{t_i}^{t_w} P_i(t), \]

\[ R_i(t_h) = \frac{1}{A} \sum_{t_i}^t \frac{df(t)}{dt}, \]

\[ R_i(t_h) = \frac{1}{A} \sum_{t_i}^{t_w} \frac{df(t)}{dt}. \]

The result of applying (13) is only \( H_{eq} \) during the time, in which the power imbalance has occurred \( (t_{dist}) \).

Zografos and Ghandhari [19] consider an aggregated load model to represent the behavior of the average system load. The load power change is expressed by

\[ \Delta P_i(t) = P_{\text{prod}} \cdot (V_i(t) - 1) \]  

where \( P_{\text{prod}} \) is the total power production before the disturbance and \( V_i(t) \) is the system's overall voltage profile, approximated by the voltage of the generator buses according to

\[ V_i(t) = \frac{\sum_{i=1}^n \left( V_{iG}(t)/V_{G0,i} \right)}{n}, \]  

being \( V_{iG}(t) \) the voltage at the bus of the generator \( i \) at time \( t \), \( V_{G0,i} \) the voltage before the disturbance at the bus of generator \( i \) and \( n \) the number of connected generators. By combining (6) and (15), the inertial constant of the system is calculated from (17), where \( \Delta P_{\text{dist}} \) is the size of the disturbance at the moment of the disturbance

\[ H_{eq} = \frac{\Delta P(t)}{2 \cdot \frac{d\Delta f}{dt}} = \frac{\Delta P_i(t) + \Delta P_{\text{dist}}}{2 \cdot \frac{d\Delta f}{dt}}. \]  

Tuttelberg et al. [20] simplify the dynamic response to a reduced-order system with the generic form of (18)

\[ H(s) = b_0 \cdot s^{n-1} + b_1 \cdot s^{n-2} + \ldots + b_n, \]  

\[ \text{zeros} = \frac{-b_n \cdot s^{n-1} + \ldots + b_0}{a_0 \cdot s^n + a_1 \cdot s^{n-1} + \ldots + a_0}. \]  

The inertia of a power system \( H_{eq} \) can be determined by the value of its unit impulse response at \( t = 0 \). For a transfer function such as the one presented in (18), the first value of the impulse response can be evaluated in MATLAB with (i) the impulse function, (ii) the gain value of the zero-pole model from \( \text{tf2zpk} \) or (iii) as the ratio of \( a_n \) to \( -b_n \).

Fig. 1 Sample of windows. In this case, \( A = 5 \) and \( W = 2 \)

Zografos et al. [21] introduce two approaches to express the power change due to the frequency and voltage dynamics \( (R \) and \( V \) approaches, respectively)

\[ \Delta P(t) = h_2(f(t)) + h_3(V(t)) - \Delta P_{\text{dist}}. \]  

where \( P_{\text{dist}} \) is the size of the disturbance and \( h_2(f(t)) \) and \( h_3(V(t)) \) deal with the power change due to the frequency and the voltage dynamics, respectively.

In the \( R \) approach, it is considered that \( \Delta P(t) = h_1[f(t)] - \Delta P_{\text{dist}} \). To obtain \( h_1[f(t)] \), the governor’s behavior is analyzed. \( h_2[f(t)] \) relates the mechanical power change and the frequency deviation. It is considered that

\[ \Delta P_{\text{mech}} = -R(t) \cdot \Delta f(t), \]  

being \( \Delta P_{\text{mech}} \) the mechanical power change and \( R(t) \) an unknown time-varying function that accommodates the dynamic response of the system related to \( \Delta f(t) \). Then (6) is converted into

\[ 2 \cdot H_{eq} \frac{df}{dt} = h_2(f(t)) - \Delta P_{\text{dist}} = R(t) \cdot \Delta f(t) - \Delta P_{\text{dist}} \]  

where \( H_{eq} \) is the estimated inertia constant to be found. However, as previously said, \( R(t) \) is also unknown. To compute \( R(t) \), a specifically selected time \( t_{eq} \) is considered. \( t_{eq} \) is recommended to be the first local extreme of the ROCOF curve after the moment of the disturbance. Moreover, (21) is considered for \( N \) discrete points equally distributed around \( t_{eq} \). \( R(t) \) can thus be approximated by the average of the values of \( R(t) \) of the \( N \) neighboring points to \( t_{eq} \). Therefore, a system with \( N+1 \) linear equations and \( N+1 \) unknowns is obtained (22). By solving it, \( R(t_{eq}) \) is obtained

\[ 2 \cdot H_{eq} \frac{df(t_{eq} + i)}{dt} = R(t_{eq} + i) \cdot \Delta f(t_{eq} + i) - \Delta P_{\text{dist}} \]  

\[ R(t_{eq}) = \frac{N+1}{N} \sum_{i=-N/2}^{N/2} R(t_{eq} + i) \]  

\[ \forall i \in Z: -N/2 \leq i \leq N/2; i \neq 0 \]

In the \( V \) approach, it is considered that \( \Delta P(t) = h_3[V(t)] - \Delta P_{\text{dist}} \). To obtain \( h_3[V(t)] \), the load power change due to voltage dependency is analysed

\[ \Delta P_{LV}(t) = P_{\text{prod}}(k_2[V_i(t)]^2 + k_3[V_i(t) + k_4] - P_{\text{prod}}. \]

where \( P_{\text{prod}} \) is the total power production before the disturbance, \( k_2, k_3 \) and \( k_4 \) define the fraction of each component and \( V_i(t) \) is the loads’ aggregated voltage profile, calculated with (16). Then

\[ 2 \cdot H_{eq} \frac{df}{dt} = h_3(V(t)) - \Delta P_{\text{dist}} = -\Delta P_{LV}(t) - \Delta P_{dist}. \]
The application range of this strategy should be selected before 500 ms, and as soon as possible after the disturbance to avoid the governor frequency response. The estimated equivalent inertia is calculated with (25), where \( t_e \) is recommended to be \( t_e \), estimated with (22)

\[
H_{eq} = \frac{R(t_e)\Delta f(t_e) - \Delta P_L(t_e) - \Delta P_{dist}}{2\frac{df(t_e)}{dt}}
\]  

Finally, Table 2 summarises the different inertia estimation methodologies discussed in this work. As can be seen, most of them are based on the power imbalance and ROCOF, in line with the swing equation and the frequency control of conventional generation units.

### 4 System Identification

#### 4.1 Power system modelling

From the supply side, the power system considered for simulation purposes involves conventional generating units (thermal and hydro-power plants) and wind power plants. A simplified diagram of the power system can be seen in Fig. 2, being the variation of the generated power \( \Delta P_L \) the variation of the generated power \( \Delta P_L = \Delta P_{PV} + \Delta P_T + \Delta P_H \) and \( \Delta P_L \) the power imbalance. A base power of 1350 MW is assumed, corresponding to the capacity of the power system. It is considered that the active power of loads is independent on voltage, and as a consequence, the term \( \Delta P_L(t) \) of (17) [19] is not considered, and the \( V \) approach of Zografos et al. [21] is not taken into account. The equivalent damping factor of loads is \( D_{eq} = 1 \, \text{pu} / (\text{puMW} \, \text{puMW}) \) [26]. Simulations have been carried out in MATLAB/Simulink.

Conventional units are modelled according to the simplified governor-based models widely used and proposed in [26], see Fig. 3. The inertia constant for these power plants are \( H_{thermal} = 5 \, \text{s} \) and \( H_{hydro} = 3.3 \, \text{s} \). Wind power plants are modelled according to an equivalent WT, with the mechanical single-mass and turbine control models presented in [63–65]. The frequency controller is included in the WT model as can be seen in Fig. 4. Parameters of both conventional and wind power plants are summarised in the Appendix.

#### 4.2 Frequency control strategies

Under power imbalance conditions, the governor control mechanisms of conventional units modify their active power supply to recover system power balance and, thus, remove the frequency deviation [66]. Grid frequency deviation \( \Delta f \) is subsequently used as an input signal for primary and secondary frequency controls [67]. Primary frequency control is performed locally at the generator, being the active power increment/decrement proportional to \( \Delta f \) through the speed regulation parameter \( R \) [68]. Secondary frequency control involves an integral controller that modifies the turbine set point of each generation unit [69].

WTs can also include frequency control strategies. Different solutions have been proposed in the last decade. These strategies are usually classified as indicated in Fig. 5 [70], excluding the use of energy storage systems. According to the specific literature, examples of these strategies are summarised in Table 3.

Moreover, some approaches can be combined to improve the frequency deviation after the power imbalance [80, 83, 89–93]. As can be seen, an alternative classification can be then proposed: (i) not-including derivative frequency dependence and (ii) including derivative frequency dependence. Additional active power \( \Delta P \) is added to the pre-event power supplied by the wind power plant \( P_t \) in all the cases, except deloading technique. In the fast power excursion, depending on the reference. The hidden inertia emulation uses a proportional derivative controller, being \( K_d \) and \( K_p \) the derivative and proportional constants of the controller, respectively. About the droop control, \( \Delta P \) is proportional to the frequency deviation \( \Delta f \) by the droop constant \( R \). As discussed in Section 5, this frequency controllers modify considerably the estimated inertia values and addresses significant discrepancies among methodologies.

The strategy for variable-speed WTs (VSWTs) implemented in this paper is based on the fast power reserve technique presented in [22] for isolated power systems and assessed in [94] for multi-area power systems. As indicated in Fig. 6, under power imbalance conditions, three operation modes are considered: (i) normal operation mode, (ii) overproduction mode and (iii) recovery mode.

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**Table 2** Summary of inertia estimation methodologies

| Reference | Methodology based on | Year |
|-----------|----------------------|------|
| [15]      | power imbalance and ROCOF | 1997 |
| [16]      | power imbalance and ROCOF | 2005 |
| [17]      | total power supplied and ROCOF | 2012 |
| [18]      | total power supplied and ROCOF | 2014 |
| [19]      | power imbalance and ROCOF | 2017 |
| [20]      | impulse function | 2018 |
| [21]      | power imbalance and ROCOF | 2018 |

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### Table 3: WT frequency control proposals

| Reference | Type of control               | Definition                                      | Year |
|-----------|-------------------------------|-------------------------------------------------|------|
| [71]      | fast power reserve            | $P_i + \Delta P, \Delta P = cte$                | 2009 |
| [72]      | fast power reserve            | $P_i + \Delta P, \Delta P = cte$                | 2009 |
| [73]      | fast power reserve            | $P_i + \Delta P, \Delta P \propto \Omega$       | 2011 |
| [74]      | fast power reserve            | $P_i + \Delta P, \Delta P = cte$                | 2011 |
| [75]      | fast power reserve            | $P_i + \Delta P, \Delta P = cte$                | 2014 |
| [76]      | fast power reserve            | $P_i + \Delta P, \Delta P = cte$                | 2015 |
| [77]      | fast power reserve            | $P_i + \Delta P, \Delta P = cte$                | 2015 |
| [78]      | fast power reserve            | $P_i + \Delta P, \Delta P \propto \Omega$       | 2016 |
| [79]      | hidden inertia emulation      | $P_i + K_d \frac{df}{dt} + K_f \Delta f$        | 2012 |
| [80]      | hidden inertia emulation      | $P_i + K_d \frac{df}{dt} + K_f \Delta f$        | 2012 |
| [81]      | hidden inertia emulation      | $P_i + K_d \frac{df}{dt} + K_f \Delta f$        | 2013 |
| [82]      | hidden inertia emulation      | $P_i + K_d \frac{df}{dt} + K_f \Delta f$        | 2015 |
| [83]      | hidden inertia emulation      | $P_i + K_d \frac{df}{dt} + K_f \Delta f$        | 2016 |
| [84]      | droop                         | $P_i + R \Delta f$                              | 2016 |
| [85]      | droop                         | $P_i + R \Delta f$                              | 2016 |
| [86]      | droop                         | $P_i + R \Delta f$                              | 2017 |
| [87]      | droop                         | $P_i + R \Delta f$                              | 2019 |
| [88]      | pitch angle deloading         | —                                               | 2016 |

Different commanded active power ($P_{cmd}$) values are determined aiming to restore the grid frequency. Fig. 6a depicts the trajectory of $P_{cmd}$ in a $\Omega_{WT} - P$ plot, indicating the three different operation modes. In Fig. 6b, the VSWTs active power variations ($\Delta P_{WT}$) submitted to an under-frequency excursion can be seen, being $\Delta P_{WF} = P_{cmd} - P_{MPPT}(\Omega_{WT})$.

i. In the normal operation mode, the VSWTs operate at the maximum available active power for the current wind speed $P_{MPPT}(v_a)$ and the available mechanical power $P_{int}(\Omega_{WT})$.

\[
P_{cmd} = P_{int}(\Omega_{WT}) = P_{MPPT}(v_a).
\]  

When a generation-load mismatch occurs, the frequency controller strategy switches to the overproduction mode

\[
|\Delta f| > \Delta f_{lim} \rightarrow \text{overproduction}.
\]  

ii. In the overproduction mode, the active power supplied by the VSWTs ($P_{cmd}$) is over the available mechanical power $P_{int}(\Omega_{WT})$ curve. The additional active power $\Delta P_{op}$ is provided by the kinetic energy stored in the rotational masses and is proportional to $\Delta f$ to emulate primary frequency control of conventional generation units [89]

\[
P_{cmd} = P_{int}(\Omega_{WT}) + \Delta P_{op}(\Delta f).
\]  

Overproduction mode remains active until: either the rotational speed reaches a minimum allowed value $\Omega_{WT, min}$ or the commanded power $P_{cmd}$ is lower than the maximum available active power $P_{MPPT}(\Omega_{WT})$

\[
\Omega_{WT} < \Omega_{WT, min} \rightarrow \text{recovery}.
\]  

iii. In the recovery mode, the power supplied by the VSWTs ($P_{cmd}$) is based on two periods: following a parabolic trajectory until the middle of the rotational speed deviation ($\Omega_{V}$ in Fig. 6a) and through an estimated curve proportional to the difference between $P_{int}(\Omega_{WT})$ and $P_{MPPT}(\Omega_{WT})$, being $x$ the proportionality constant:

\[
P_{cmd} = a \cdot \Omega_{WT} + b \cdot \Omega_{WT} + c \cdot \Omega_{WT} \Omega_{WT} \leq \Omega_{V}
\]

\[
P_{cmd} = P_{MPPT} + x \cdot (P_{int} - P_{MPPT}) \Omega_{WT} > \Omega_{V}
\]

The normal operation mode is recovered when either $\Omega_{MPPT}$ or $P_{MPPT}(\Omega_{MPPT})$ are reached by the VSWTs

\[
\Omega_{WT} \approx \Omega_{MPPT}
\]

\[
P_{cmd} \approx P_{MPPT}(\Omega_{MPPT}) \rightarrow \text{normal operation}.
\]

### 4.3 Scenarios

Four different scenarios have been considered for simulations. The first scenario includes only conventional generation units: 88% comes from thermal power plants and 12% from hydro-power plants. Hydro-power capacity remains constant in all the scenarios (12%). However, thermal and wind capacities change depending on the scenario to be simulated by giving a power system with high integration of RES, see Table 4. The equivalent inertia constant $H_{eq}$ determined by (3) is also indicated in Table 4. The power imbalance considered is $\Delta P_L = 0.05 \text{ pu}$ in all simulations.

### 5 Results

According to the different methodologies discussed in Section 3, the equivalent inertia constant $H_{eq}$ is estimated from the frequency control techniques for wind power plants
deviations after a power imbalance. Two different approaches are considered and compared in this work:

i. Wind power plants without participation in frequency control.

ii. Wind power plants with participation in frequency control.

Fig. 7 depicts the estimated $H_{eq}$ according to the different methodologies without considering wind power plant participation in frequency control. In this case, $H_{eq} = H_{eq}$. The different approaches of inertia estimation provide an accurate approximation of the directly connected rotational inertia calculated with (3). The deviation from the estimated inertia value is lower than a 10% error.

Besides, Fig. 7 summarises the estimated $H_{eq}$ from the different methodologies when wind power plants participate in frequency control. In this case, it is expected that the estimated $H_{eq}$ values from $\Delta f$ include the virtual inertia $H_{V,eq}$ referred to (7). However, as can be seen, most methodologies only provide the rotational inertia $H_{R,eq}$ directly connected to the grid [15, 16, 19–21], neglecting the ‘virtual inertia’ emulated and provided by the wind power plants. With these methodologies, the estimation of $H_{eq}$ is again accurate to the value calculated by (3), having a deviation lower than a 10% error.

The frequency controller applied on the equivalent WT does not include a derivative dependence control, see Section 4.2. As a consequence, the ROCOF is hardly modified in comparison with scenarios, where wind power plants are excluded from the frequency control. At the beginning of the frequency oscillations, $\Delta f$ values do not change significantly – see Fig. 8 –, regardless of the integration and participation of wind power plants into the frequency control. Table 5 summarises these ROCOF values (mHz/s) depending on the participation of wind power plants into the frequency control.

Table 4 Capacity of generating units

| Source | Scenario 1 | Scenario 2 | Scenario 3 | Scenario 4 |
|--------|------------|------------|------------|------------|
| thermal, % | 88 | 73 | 58 | 43 |
| hydro-power, % | 12 | 12 | 12 | 12 |
| wind, % | 0 | 15 | 30 | 45 |
| $H_{eq}$ based on (3) | 4.80 | 4.05 | 3.30 | 2.55 |

Fig. 8 Comparison of ROCOF depending on the participation of wind power plants into the frequency control

(a) Wind power plants do not participate in frequency control, (b) Wind power plants participate in frequency control

Table 5 ROCOF values (mHz/s) depending on the participation of wind power plants into the frequency control

| WPI | without control | with control |
|-----|-----------------|--------------|
| 0%  | −256.06         | −256.06      |
| 15% | −301.08         | −298.45      |
| 30% | −369.20         | −364.90      |
| 45% | −474.70         | −410.10      |

Fig. 6 Wind frequency control strategy and VSMTs active power variation [22]

(a) Frequency control strategy, (b) $\Delta P_{WF}$ with the frequency control strategy

Fig. 7 Comparison of equivalent inertia depending on the participation of wind power plants into the frequency control

(a) Estimated $H_{eq}$ when wind power plants do not participate in frequency control, (b) Estimated $H_{eq}$ when wind power plants participate in frequency control

Table 5 ROCOF values (mHz/s) depending on the participation of wind power plants into the frequency control

| WPI | without control | with control |
|-----|-----------------|--------------|
| 0%  | −256.06         | −256.06      |
| 15% | −301.08         | −298.45      |
| 30% | −369.20         | −364.90      |
| 45% | −474.70         | −410.10      |
In this paper, an analysis and comparison of power system inertia estimation methodologies have been carried out. Different approaches proposed in the literature have been implemented and tested under four different supply-side scenarios including thermal, hydro-power and wind power plants from the supply side, according to current mix generation road maps. In this way, wind power plants are increasing their generation capacity from 15 to 45%, reducing the thermal plants capacity accordingly. Furthermore, wind power plants include a virtual inertia frequency control strategy to support frequency excursions under imbalance conditions. The inertia estimation methodologies give an accurate value of the equivalent inertia when wind power plants do not participate in frequency control, with a deviation error lower than a 10% with respect to the global rotational generation units directly connected to grid. By including wind power plants into frequency control, most methodologies estimate the equivalent rotational and virtual inertias. Therefore, both wind power plant frequency control strategies and equivalent inertia estimation methodologies must be revised in detail to give suitable results and avoid significant discrepancies among the different proposals in the new mix generation scenarios.

6 Conclusion

Fig. 9 Estimated equivalent inertia according to Wall et al. [17] and Wall and Terzija [18], total power variation and ROCOF in scenario 4
(a) Estimated equivalent inertia (s), (b) Total power variation (pu), (c) ROCOF (mHz/s)

(ΔP = 0.05 pu), and the ROCOF values are similar regardless of the participation of wind power plants into frequency control as aforementioned. As a result, the estimated $H_{eq}$ changes barely despite including wind power plants into frequency control. Tuttelberg et al. [20] apply an impulse function to the dynamic response, estimating $H_{eq}$ by its value at $t = 0$. Only [17, 18], by considering the total active power supplied and the ROCOF – referred to (13) –, estimate the equivalent inertia as a combination of rotational $H_{eq}^{rot}$ and virtual $H_{eq}^{virt}$ inertias as were expressed in (7).

Fig. 9 compares the equivalent inertia with and without frequency controls from wind power plants in Scenario 4. This inertia is estimated according to Wall et al. [17] and Wall and Terzija [18]. Total power variation and ROCOF are also depicted for the sake of clarity. The disturbance time is $t_{dist} = 50$ s. As indicated in [17, 18] (and previously mentioned in Section 3), Fig. 9a is only the equivalent inertia around $t_{dist}$, as the square in this figure. Moreover, when wind power plants do not participate in frequency control, the equivalent inertia obtained is similar to the value calculated with (3), as already mentioned in Fig. 7a. However, a significant difference exists in the estimated equivalent inertia when wind power plants include frequency control. This increase is due to the ‘virtual inertia’ provided by wind frequency control. This virtual inertia thus depends on how relevant is the wind integration into the generation mix. Moreover, a linear relationship has been found between wind power integration (WPI) and the virtual inertia with $R' \approx 1$. The linear relationship can be determined as

$$H_{V, eq} = 0.0357 \cdot WPI,$$

being WPI the wind power integration into the grid (%). Considering (7), (32) and the base power $S_b = 1350$ MW, it is obtained that the virtual inertia constant coming from WTs is $H_{V, WT} = 3.57$ s, in line with the typical rotational inertia constants of CPs (see Section 2.1) and the WT's inertia values proposed by some authors during the last decade [25, 31, 95, 96].

Finally, Fig. 10 summarises the simulated scenarios in terms of the estimated $H_{eq}$ from the different methodologies when frequency control is also provided by wind power plants. As can be seen, and depending on the methodology, these approaches address significant discrepancies on the equivalent inertia values. Actually, some of them include some virtual inertia from the WT frequency control of [22], whereas the others consider their effects barely significant regarding to the equivalent system inertia. Therefore, both wind power plant frequency control strategies and equivalent inertia estimation methodologies must be revised in detail to give suitable results and avoid significant discrepancies among the different proposals in the new mix generation scenarios.

Fig. 10 Comparison of inertia estimation including wind power plants into frequency control
(a) $H_{eq}$ according to Inoue et al. [15], Chassin et al. [16], Zografos and Ghandhari [19], Tuttelberg et al. [20] and Zografos et al. [21], (b) $H_{eq}$ according to Wall et al. [17] and Wall and Terzija [18]
the typical inertia constants of CPs. Therefore, wind power plant frequency control strategies and equivalent inertia estimation methodologies must be revisited to provide consistent results and avoid significant discrepancies among the different alternatives. Moreover, the estimation of equivalent inertia values is highly dependent on the wind power plant frequency control strategies, and then, different results are determined when derivative frequency dependency is (or not) included in the frequency strategy. Alternative methodologies and processes should be thus proposed by the sector to provide suitable results regarding equivalent inertia estimations in power systems with high renewable penetration.

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Appendix

9.1 Parameters for thermal and hydro-power plants

Tables 6 and 7 [26] summarise the thermal and hydro-power plant parameters used in the simulations.

2. WT model

The WT model is based on [63, 64]. Parameters of the WT model are summarised in Table 8.

| Parameter Description | Value Units |
|-----------------------|-------------|
| $T_{0}$ | speed relay pilot valve | 0.20 |
| $F_{up}$ | fraction of power of high-pressure section | 0.30 |
| $T_{const}$ | time constant of the reheater | 7.00 |
| $T_{ch}$ | time constant (inlet volumes and steam chest) | 0.30 s |
| $R_{t}$ | speed droop | 0.05 pu |
| $I_{s}$ | integral controller | 1.00 |
| $H_{inertia}$ | inertia constant | 5.00 |

| Parameter Description | Value Units |
|-----------------------|-------------|
| $T_{0}$ | speed relay pilot valve | 0.20 s |
| $T_{reset}$ | reset time | 5.00 s |
| $R_{t}$ | temporary droop | 0.38 |
| $R_{p}$ | permanent droop | 0.05 |
| $T_{w}$ | water starting time | 1.00 s |
| $R_{s}$ | speed droop | 0.05 pu |
| $I_{s}$ | integral controller | 1.00 |
| $H_{inertia}$ | inertia constant | 3.00 |

Table 6 Thermal power plant parameters [26]

Table 7 Hydro-power plant parameters [26]
| Parameter | Description                                      | Value | Units |
|-----------|--------------------------------------------------|-------|-------|
| $v_w$     | wind speed                                       | 10.00 | m/s   |
| $K_{pt}$  | proportional constant of the speed controller    | 3.00  | —     |
| $K_i$     | integral constant of the speed controller        | 0.60  | —     |
| $V_{WT}$  | voltage of the WT                                 | 1.00  | pu    |
| $T_{con}$ | time delay to generate the current $I_{inj}$     | 0.02  | s     |
| $T_I$     | time delay to measure the active power $P_e$     | 5.00  | s     |