A Method to Evaluate the Inertial Response of Frequency Controlled Converter-Interfaced Generation

Antonio Pepiciello,* Alfredo Vaccaro,* Domenico Villacci,* Federico Milano†
*University of Sannio, Benevento, Italy
Email: {apepiciello, vaccaro, villacci}@unisannio.it
†University College Dublin, Dublin, Ireland
Email: federico.milano@ucd.ie

***Abstract*—The paper proposes a method to assess the equivalent inertial response provided by CIG equipped with fast frequency response capability and its impact on the minimum amount of rotational inertia required to guarantee power system's stability. The method is based on the solution of an optimization problem aimed at finding the minimum inertia required by the system to contain frequency and rate of change of frequency deviations within the limits required by system operators. The effectiveness of the proposed method is illustrated through the WSCC 9-bus test system.**

***Index Terms*—Converter-interfaced generation (CIG), renewable energy sources (RES), fast frequency response (FFR), rate of change of frequency (RoCoF), synthetic inertia, frequency stability.**

I. Introduction

A. Motivation

Converter-interfaced generation (CIG) enables the penetration of renewable energy sources but reduces the rotational inertia supplied by conventional synchronous generators. This is recognized as an emerging issue in power system control and operation. Low-inertia systems are in fact expected to be operating increasingly closer to their stability limits [1], [2].

A possible solution to this problem is the implementation of fast frequency response (FFR) through CIG, which can, in turn, compensate the inertial response provided by synchronous machines. FFR is already recognized as an ancillary service in several countries, e.g. Ireland, United Kingdom, New Zealand [3]–[5]. How effective such a FFR is, however, is still an open question. This paper aims to provide a quantitative method to answer this question.

B. Literature Review

The frequency stability limits of a system are assessed based on the value of the Rate of Change of Frequency (RoCoF) and of the minimum instantaneous frequency, the frequency nadir. Both these values must be kept within a narrow range, in order for the grid to work safely and reliably (see, for example, Chapter 18 of [6]).

F. Milano is supported by the Science Foundation Ireland, under project AMPSAS, Investigator Programme, Grant No. SFI/15/IA/3074.

In this vein, the first crucial point involves definitions and measurements. It is key, in fact, to reach a common agreement on the best way to estimate on-line the amount of inertia provided by the generators connected to the system. The main contributions on this topic rely on the disturbance-based approach and on the processing of RoCoF and frequency data measured by, for example, phasor measurement units [7]–[9]. In the IEEE Std C37.118 [10], RoCoF is defined as the first derivative of the estimated frequency associated to the fundamental component of the signal. However, its measurement is greatly affected by estimation techniques, signal models and power system's conditions [11]. This is why a common agreement on the definition of RoCoF is crucial for its correct utilization [12].

Another key aspect of the study of low-inertia systems is related to the provision of inertial response from CIG. This can be achieved through synthetic inertia and FFR. These technologies might support the deployment of RES in power systems by reducing the need to rely on fossil fuel-based synchronous generators.

FFR refers to frequency response schemes that can be triggered within the first few seconds after a disturbance on the network. Typically, FFR control schemes react proportionally to the frequency variation or according to a pre-determined schedule [13], [14]. Synthetic inertia is provided by virtual synchronous machines [15], i.e. systems controlled in such a way that their dynamic behaviour resembles synchronous generators. Both FFR and synthetic inertia can be supplied by various CIG technologies, such as variable wind speed turbines, PV power plants and energy storage, but also by HVDC links and demand response [16].

Regardless the technology utilized to provide synthetic inertia and FFR through CIG, it is relevant to define the amount of such ancillary services that is actually required by the system. The solution to this problem can be obtained by determining the minimum amount of inertial response required to guarantee system's stability after a large disturbance. Nowadays synchronous generators are effectively the only suppliers of inertial response to the system, hence, the minimum amount of inertial response required for stability is strictly related to the maximum share of CIG that can be safely installed. Different approaches to the problem are discussed in the literature [17]–[20], however a widely accepted method is still missing.

In [21], the authors proposed a constrained optimization-based method to estimate the minimum amount of inertia, expressed as a *critical inertia constant*, required to ensure the transient stability of the power system. The method ensures that the values found for H at each generation bus are such that the constraints on critical signals, such as RoCoF and frequency, are satisfied during a transient. The method returns precise numerical values of the inertia constants that guarantee the stability and it maintains the information on the spatial distribution of inertia, which has been shown to be a crucial factor to consider when studying low inertia systems [22].

C. Contribution

In this paper, a relevant extension of the method described in [21] is proposed. In particular, the paper shows how an inertial response system, such as synthetic inertia or fast frequency response, can lower the critical inertia constant in a bus. The proposed method provides a quantitive tool to evaluate the vulnerability of the system to instability or its RES hosting capacity.

D. Organization

The paper is organized as follows. Section II provides a theoretical background on inertia in power systems, Section III describes the optimization-based method to estimate the critical inertia constant at each bus of a network, Section IV presents a case study in which the influence of fast frequency droop control in critical inertia estimation is assessed. Finally, Section V summarizes the main concepts presented in the paper and the obtained results.

II. THEORETICAL FRAMEWORK

Inertia in power systems can be interpreted as the resistance to frequency variations following a power imbalance. It is commonly associated to the amount of kinetic energy stored in the rotors of synchronous machines rotating at their nominal speed, since at present most of the inertial response is supplied by them. However, as power systems are accommodating an increasing share of CIG, part of the energy required for the inertial response could also be provided by it.

Traditionally, the inertia constant H is taken as an index of the amount of inertia supplied by a generator. H is calculated as the ratio between its stored kinetic energy at rated speed E_K, and its rated power S, as follows:

$$H = \frac{E_K}{S}\ [\mathrm{s}]\,. \tag{1}$$

Typical values of H are between 2 and 9 s [23], depending on the technology. H can be thought of as the maximum time interval in which a generator can supply its rated power, just by means of its stored kinetic energy.

The inertia constant is a crucial parameter in the study of electro-mechanical oscillations of a synchronous machine. It appears in the swing equation:

$$2H \cdot \frac{d^2\delta}{dt^2} = P_m - P_e\,, \tag{2}$$

where δ is the rotor angle of the synchronous machine, P_m is the mechanical power and P_e is the electrical power; both positive in case of a generating machine, negative otherwise.

Equation (2) can be reformulated as an aggregated model of an interconnected power system consisting of generators and loads:

$$2H_{\text{tot}} \cdot \frac{d^2\delta}{dt^2} = P_g - P_l\,. \tag{3}$$

In (3), the rotating machines are merged in a single equivalent machine model, the frequency of which is the one located at the centre of inertia of the original system, and it is treated as a global parameter. In this case, P_g is the total generated power and P_l is the total load of the system.

The equivalent inertia of this aggregated system H_{tot} is:

$$H_{\text{tot}} = \frac{\sum_{i=1}^{N_g} E_{K,i}}{\sum_{i=1}^{N_g} S_i}\,. \tag{4}$$

In conventional power systems, dominated by large thermal power plants, the inertia provided in real-time is practically constant and it could be easily estimated by the operators of the system by knowing which machines are in operation. In a scenario where CIG constitutes a significant portion of the grid, the concept of an aggregate and constant index of the inertia of the system is challenging to define. Indeed, the amount of operating synchronous generators, thus the total inertia of today's systems, is highly dependent on the RES production and on the electricity market prices, both uncertain and variable factors.

The potential lack of enough inertial response is raising concerns about the transient stability of the system. Thus, it is vital to estimate the minimum amount of inertia required at each bus of the system, in order to assure that it maintains the stability, after a contingency.

A. Fast frequency response by CIG

A possible solution to operate reliably a low inertia system consists in substituting part of the inertial response, supplied by synchronous generators, with FFR or synthetic inertia [13], [24]. Both these sources of inertial response, provided that CIG can regulate its generated power, are mostly dependent on the adjustments made to the controls of the interfacing converters. In order to work properly, such controls require an accurate and reliable measurement of the frequency signal at the bus.

In this paper, the impact of the FFR of a generic CIG on the minimum amount of inertia required in a system to guarantee its stability, is assessed. The FFR is modelled as a fast frequency droop control, as shown in Fig. 1. In the scheme, $\Delta\omega$ is the frequency error as measured at the point of connection of the CIG and ΔP_g is the variation of active power generated by the CIG. The speed of such a control is defined by the value of the time constant T_d and the value of the gain k_0. While very simple, the control shown in Fig. 1 resembles well the dynamic response of common implementations of FFR for CIG, see e.g. [25] and [26].

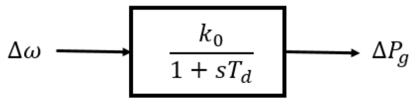

Fig. 1. Frequency droop control.

III. PROPOSED METHODOLOGY

In the context of low inertia power systems, the concept of *critical inertia constant* (CIC), proposed by the authors in [21], appears as an useful index to evaluate the security of the network. In the following, CIC is defined as *the minimum value of H at each generation bus, required to guarantee the frequency stability of the system after a contingency*. The frequency stability is evaluated in terms of RoCoF and instantaneous frequency deviation.

The concept of CIC can be implemented in real-time monitoring tools, to verify that each bus can supply at any time at least the minimum inertia required to keep the system stable after a disturbance. Hence, CICs are strictly related to the estimation of the maximum share of CIG that can be connected to the system at any time, since they set a minimum value of the generation to be provided by synchronous generators.

The estimation of CICs requires the solution of a constrained optimization problem. The objective is to find the minimum amount of inertia at each bus required to guarantee the transient stability of the power system under analysis.

With this aim, the formulation of the optimization problem is as follows. The decision variables are the values of inertia constants H_i at each generation bus. The objective function F to be minimized is the sum of the inertia constants of the generation buses in the network $F = \sum_{i=1}^{N_G} H_i$. The constraints are related to the possible minimum and maximum value of the inertia constants and to indexes required to assess the frequency stability of the system, such as the RoCoF and the frequency nadir [27], [28].

In this paper, the constraint on RoCoF values is set on its average value over different time windows:

- ± 2 Hz/s for a 500 ms time window.
- ± 1.5 Hz/s for a 1000 ms time window.
- ± 1.25 Hz/s for a 2000 ms time window.

and the maximum frequency deviation constraint is chosen to be ± 0.8 the nominal value $f_n = 50$ Hz.

The minimization problem, for a system with N_G generation buses, can be formulated as follows:

$$\begin{aligned} \min_{H_1,\ldots,H_N} \quad & \sum_{i=1}^{N} H_i\,, \\ \text{subject to} \quad & \text{RoCoF}_i^{500} \leq 2 \ \forall i \in [1,\ldots,N_G]\,, \\ & \text{RoCoF}_i^{1000} \leq 1.5 \ \forall i \in [1,\ldots,N_G]\,, \\ & \mathit{RoCoF}_i^{2000} \leq 1.25 \ \forall i \in [1,\ldots,N_G]\,, \\ & 49.2 \leq f_i \leq 50.8 \ \forall i \in [1,\ldots,N_G]\,, \\ & H_{i,\text{min}} \leq H_i \leq H_{i,\text{max}}\,. \end{aligned} \tag{5}$$

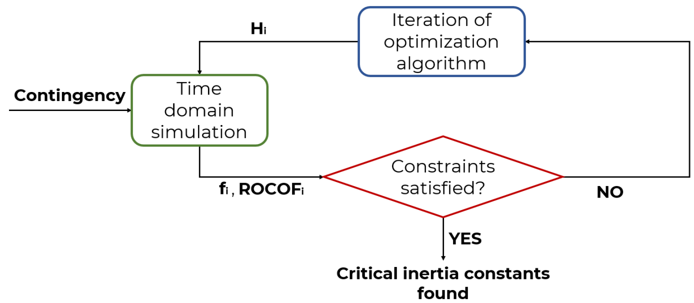

Fig. 2. Flowchart of the proposed method to determine the critical inertia constant.

In this paper, the optimization problem (5) is solved through an iterative optimization algorithm. Each iteration provides a guess on the minimum value of inertia constants that satisfy the stability constraints. At each iteration, a time domain simulation with the values of inertia constants provided is performed and the constraints are evaluated. When the constraints are satisfied, the values of the CICs, i.e. the minimum values of inertia constants that guarantee the transient stability, are found. Figure 2 shows a flowchart of the proposed method.

The value of CIC strongly depends on the contingency chosen for the time domain simulation. The most comprehensive approach to the problem is the solution of different optimization problems, each related to a possible contingency on the system. In this case, the final CICs are chosen as the maximum values obtained from the set of solutions. Another approach, less computationally expensive, is the solution of the optimization problem for a subset of contingencies, considered as the most probable or disruptive for the network. Once the contingency is selected, a time domain simulation is performed at each iteration of the optimization algorithm.

A. Time Domain Simulation

The time domain simulations to be performed at each iteration of the optimization problem can be formulated in several ways, depending on the desired level of accuracy and computational burden. In this paper, time domain simulations are carried out based on the following assumptions, commonly applied in classical transient stability studies [29]:

- Mechanical power input from the synchronous generators is considered constant during the time interval of interest, due to the slow action of the governor.

- Synchronous machine damping is neglected. The asynchronous fraction of the electric power output is assumed to be negligible with respect to the synchronous part.
- Synchronous machines are modelled by an ideal voltage source behind a transient reactance.
- Loads are represented as passive impedances.
- Voltage magnitudes are considered constant during the time interval of the simulation.
- CIG provides FFR through a fast-acting frequency droop control.

The assumptions above are acceptable for a time interval of few seconds, that is the time scale required to study the inertial response of the system [1].

The steps taken to perform the time domain simulation, based on the analysis conducted in [30], are:

- Given a contingency, definition of the admittance matrices before, during and after clearing the fault.
- Solution of the power flow analysis to obtain the initial conditions required to solve the differential equations describing the model. The initial values of the variables at t_0 are: $P_{mi,0}$, the mechanical power supplied by the generators, $\delta_{i,0}$, the initial voltage angle, $\omega_n = 2\pi f_n$, the rotor speed at nominal frequency and $|E_{i,0}|$, the module of the voltage at each bus. Since the starting condition is a steady state, $P_m = P_e$, hence $P_{mi,0}$ can be calculated from the solution of the power flow problem:

$$P_{mi,0} = \sum_{j=1}^{N} |E_i||E_j||Y_{ij,0}|cos(\theta_{ij,0} - \delta_{i,0} + \delta_{j,0}) \quad \forall i\,. \tag{6}$$

- Solution of the differential equations, Eq. (7), representing the model, during the fault and after clearing the fault at t_{clear}. The state variables are the set of angles, δ_i, the rotor speeds ω_i and the power regulation supplied by the CIG at each bus $\Delta P_{\text{CIG},i}$, the block representation of which is in Fig. 1:

$$\begin{aligned} 2H_i \frac{d\omega_i}{dt} &= P_{mi} + \Delta P_{\text{CIG},i} - P_{e,i}\,, \\ \frac{d\delta_i}{dt} &= \omega_i - \omega_n\,, \\ T_d \frac{d\Delta P_{\text{CIG},i}}{dt} &= k_0(\omega_n - \omega_i) - \Delta P_{\text{CIG},i}\,. \end{aligned} \tag{7}$$

Once the state variables have been estimated for the required time interval, the RoCoF and the frequency are calculated and the constraints are verified.

IV. Case Study

This case study considers a modified version of the well-known WSCC 9-bus system, with the generation buses being modelled as areas with both synchronous generators and CIG, as shown in Fig. 3.

As previously stated, the aim of the study is to assess the impact of the inertial response of CIG on CICs. The analysis is carried out with Matlab, version 2019a.

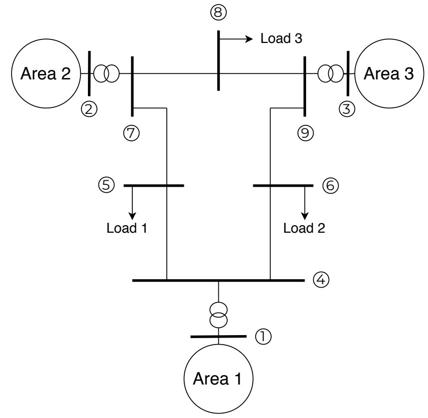

Fig. 3. WSCC 9-bus system with 3 areas. Each area is assumed to include both synchronous and converter interfaced generation.

The contingency considered in this case study is a three-phase fault occurring at bus 7 and the CICs are calculated for different clearing times t_{clear}. The final smooth curves are obtained by a polynomial fitting of the critical inertia constants found over changing clearing times. As shown in Fig. 4, the total amount of inertia required in the system to be stable increases proportionally to the clearing time.

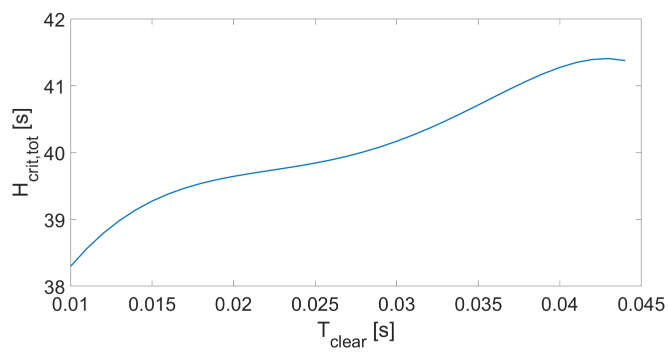

Fig. 4. Sum of critical inertia constants of the network.

Figure 5 shows the values of critical inertia constants obtained in case of no inertial response from CIG (continuous line) and in case of the presence of a frequency droop with $T_d = 10$ s and $k_0 = 1$ (dashed lines) at each generation bus. The graph shows how the presence of FFR capabilities in each area reduces the amount of inertia required at each generation bus to maintain the system stable. This can be also interpreted as an increased capability of the network to host CIG, due to its inertial response capabilities.

To show how the characteristics of the control affect CICs, different simulations are carried out for various values of the time constant T_d, given $k_0 = 1$. The average of the resulting inertia constants over different clearing times is reported in Table I: the Table shows that the total amount of inertia in the system is decreasing as T_d becomes lower, since CIG can provide faster response to the contingency. The simulation with a high T_d returns similar results to the case with no droop,

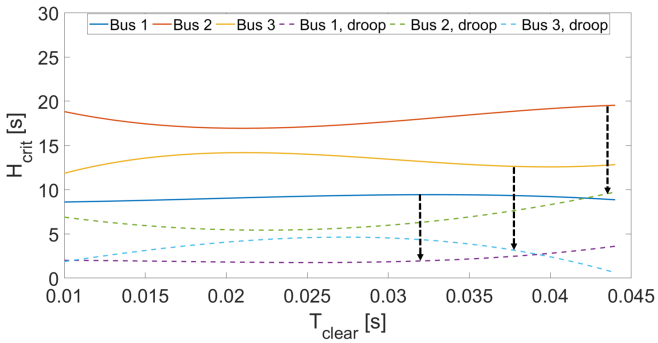

Fig. 5. Critical inertia constants without droop (continuous lines) and with FFR (T_d=10 s, k_0=1).

since the control is too slow to act on the time scale of inertial response, and its effect becomes negligible.

TABLE I
CRITICAL INERTIA CONSTANTS FOR DIFFERENT TIME CONSTANTS OF THE FREQUENCY DROOP

Inertia	T_d [s] 1	10	1000	No Droop
H_1 [s]	0.5	2.1	9.0	9.2
H_2 [s]	2.7	6.9	18.2	17.3
H_3 [s]	0.5	3.3	13.3	14.3

A relevant feature of the proposed method is that it can be utilized to determine the weakest and/or strongest area. For example, in the considered case study, Area 1 is characterized by the lowest critical inertia constant in all considered scenarios. It can be thus concluded that Area 1 is the less vulnerable bus, i.e. the one needing less inertial response from CIG. On the other hand, Areas 2 and 3 are weaker and are thus more dependent on the FFR provided by CIG. Since CIG is stochastic in nature, this conclusion implies that particular care has to be taken for the operations of these areas.

It is also interesting to note that, for $T_d < 1$ s, the system becomes unstable and large inter-area oscillations arise as a consequence of the fast droop control of the CIG and the low values assigned to the inertia constants by the solution of the optimization problem (5), as shown in Fig. 6. The instability arises even without considering particularly detailed power system models. This suggests that the FFR can become unstable well before being fast enough to dynamically couple with the electromagnetic dynamics of transmission lines, as suggested in some recent literature (see, for example, the review provided in [1]).

In order to validate the results, i.e. to check that constraints on RoCoF and frequency nadir are satisfied, a time domain simulation with the average CICs obtained from the optimization is carried out. Figure 7 shows that the oscillations for cases with different time constants T_d are all confined between the prescribed frequency range. The time constant of the control has an effect on the magnitude of the oscillations and on the time required for their damping.

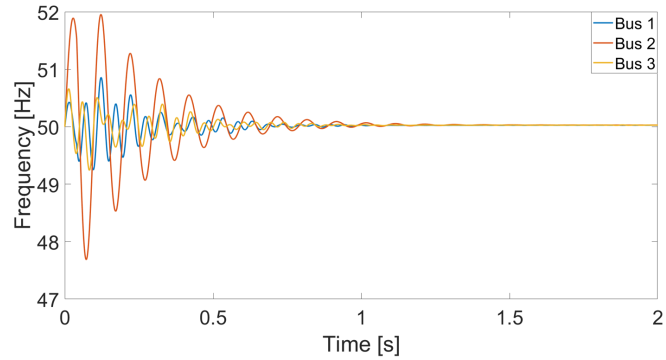

Fig. 6. Frequency oscillations due to FFR (T_d = 0.1 s) and low inertia constants.

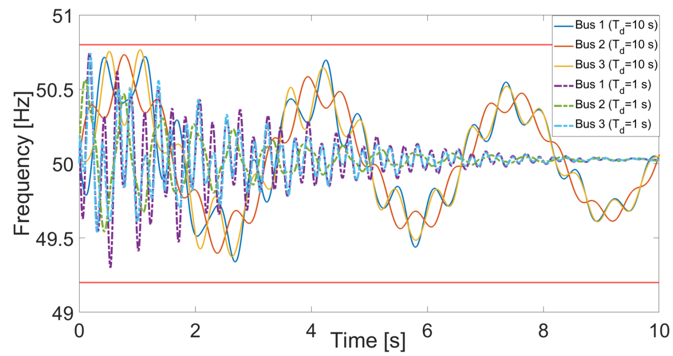

Fig. 7. Frequency values of the areas for different time constants T_d of the frequency droop k_0.

V. Conclusions

A method to estimate the minimum amount of inertia at each generation bus, required to assure the transient stability of the system, is described by defining the concept of critical inertia constant. This concept has a wide range of applications, from determining the maximum share of CIG that can be installed in a network to identifying the weakest buses, i.e. the ones closer to the instability condition.

In this paper, the concept of critical inertia constant is used to assess the impact of inertial response from CIG on the stability of the system. By solving an optimization problem constrained by the solution of a time domain simulation, it is demonstrated that proper controls applied to CIG, can reduce the minimum inertia to be supplied by synchronous generators to guarantee system's stability. A final time domain simulation is carried out to validate the results of the optimization problem.

In a future scenario, in which power systems are dominated by CIG and characterized by low inertia, the concept of critical inertia constants and the proposed method to calculate them, may have a significant role to tackle the upcoming challenges. Further work is ongoing to keep exploring the potential of this concept in future energy systems.

References

[1] F. Milano, F. Dörfler, G. Hug, D. J. Hill, and G. Verbič, "Foundations and challenges of low-inertia systems," in *2018 Power Systems Computation Conference (PSCC)*. IEEE, 2018, pp. 1–25.

[2] T. Ackermann, T. Prevost, V. Vittal, A. J. Roscoe, J. Matevosyan, and N. Miller, "Paving the way: A future without inertia is closer than you think," *IEEE Power and Energy Magazine*, vol. 15, no. 6, pp. 61–69, 2017.

[3] S. EirGrid, "Recommendation on ds3 system services protocol regulated arrangements."

[4] N. G. ESO, "Stability phase one tender interactive guidance document."

[5] M. Pelletier, M. Phethean, and S. Nutt, "Grid code requirements for artificial inertia control systems in the new zealand power system," in *2012 IEEE Power and Energy Society General Meeting*. IEEE, 2012, pp. 1–7.

[6] S. Santoso and H. W. Beaty, Eds., *Standard Handbook for Electrical Engineers*, 17th ed. McGraw Hill, 2018.

[7] P. M. Ashton, C. S. Saunders, G. A. Taylor, A. M. Carter, and M. E. Bradley, "Inertia estimation of the gb power system using synchrophasor measurements," *IEEE Transactions on Power Systems*, vol. 30, no. 2, pp. 701–709, 2014.

[8] D. Zografos and M. Ghandhari, "Estimation of power system inertia," in *2016 IEEE Power and Energy Society General Meeting (PESGM)*. IEEE, 2016, pp. 1–5.

[9] K. Tuttelberg, J. Kilter, D. Wilson, and K. Uhlen, "Estimation of power system inertia from ambient wide area measurements," *IEEE Transactions on Power Systems*, vol. 33, no. 6, pp. 7249–7257, 2018.

[10] "IEEE Standard for Synchrophasor Measurements in Power Sytems," IEEE, Standard, 2011.

[11] G. Frigo, A. Derviškadić, Y. Zuo, and M. Paolone, "Pmu-based rocof measurements: Uncertainty limits and metrological significance in power system applications," *IEEE Transactions on Instrumentation and Measurement*, vol. 68, no. 10, pp. 3810–3822, 2019.

[12] A. J. Roscoe, A. Dyśko, B. Marshall, M. Lee, H. Kirkham, and G. Rietveld, "The case for redefinition of frequency and rocof to account for ac power system phase steps," in *2017 IEEE International Workshop on Applied Measurements for Power Systems (AMPS)*. IEEE, 2017, pp. 1–6.

[13] R. Eriksson, N. Modig, and K. Elkington, "Synthetic inertia versus fast frequency response: a definition," *IET Renewable Power Generation*, vol. 12, no. 5, pp. 507–514, 2017.

[14] Q. Hong, M. Nedd, S. Norris, I. Abdulhadi, M. Karimi, V. Terzija, B. Marshall, K. Bell, and C. Booth, "Fast frequency response for effective frequency control in power systems with low inertia," *The Journal of Engineering*, vol. 2019, no. 16, pp. 1696–1702, 2019.

[15] H.-P. Beck and R. Hesse, "Virtual synchronous machine," in *2007 9th International Conference on Electrical Power Quality and Utilisation*. IEEE, 2007, pp. 1–6.

[16] H. Karbouj, Z. H. Rather, D. Flynn, and H. W. Qazi, "Non-synchronous fast frequency reserves in renewable energy integrated power systems: A critical review," *International Journal of Electrical Power & Energy Systems*, vol. 106, pp. 488–501, 2019.

[17] M. García-Ruiz, G. J. Cantos-Alcántara, J. L. Martínez-Ramos, and A. Marano-Marcolini, "Minimum required inertia for a fully renewable ac interconnected system," in *2019 International Conference on Smart Energy Systems and Technologies (SEST)*. IEEE, 2019, pp. 1–6.

[18] H. Gu, R. Yan, and T. K. Saha, "Minimum synchronous inertia requirement of renewable power systems," *IEEE Transactions on Power Systems*, vol. 33, no. 2, pp. 1533–1543, 2017.

[19] J. O'Sullivan, A. Rogers, D. Flynn, P. Smith, A. Mullane, and M. O'Malley, "Studying the maximum instantaneous non-synchronous generation in an island system—frequency stability challenges in ireland," *IEEE Transactions on Power Systems*, vol. 29, no. 6, pp. 2943–2951, 2014.

[20] A. S. Ahmadyar, S. Riaz, G. Verbič, J. Riesz, and A. Chapman, "Assessment of minimum inertia requirement for system frequency stability," in *2016 IEEE International Conference on Power System Technology (POWERCON)*. IEEE, 2016, pp. 1–6.

[21] A. Pepiciello and A. Vaccaro, "An optimization-based method for estimating critical inertia in smart grids," in *2019 IEEE International Conference on Systems, Man and Cybernetics (SMC)*. IEEE, 2019, pp. 2237–2241.

[22] P. Jacquod and L. Pagnier, "Optimal placement of inertia and primary control in high voltage power grids," in *2019 53rd Annual Conference on Information Sciences and Systems (CISS)*. IEEE, 2019, pp. 1–6.

[23] P. Tielens and D. Van Hertem, "The relevance of inertia in power systems," *Renewable and Sustainable Energy Reviews*, vol. 55, pp. 999–1009, 2016.

[24] D. Groß, S. Bolognani, B. K. Poolla, and F. Dörfler, "Increasing the resilience of low-inertia power systems by virtual inertia and damping," in *Proceedings of IREP'2017 Symposium*. International Institute of Research and Education in Power System Dynamics …, 2017, p. 64.

[25] J. Van de Vyver, J. D. M. De Kooning, B. Meersman, L. Vandevelde, and T. L. Vandoorn, "Droop control as an alternative inertial response strategy for the synthetic inertia on wind turbines," *IEEE Transactions on Power Systems*, vol. 31, no. 2, pp. 1129–1138, March 2016.

[26] R. K. Varma and M. Akbari, "Simultaneous fast frequency control and power oscillation damping by utilizing PV solar system as pv-statcom," *IEEE Transactions on Sustainable Energy*, vol. 11, no. 1, pp. 415–425, Jan 2020.

[27] ENTSO-E, "Rate of change of frequency (rocof) withstand capability," 31 January 2018.

[28] ——, "P1 – policy 1: Load-frequency control and performance [c]," 19 March 2009.

[29] E. W. Kimbark, *Power system stability*. John Wiley & Sons, 1995, vol. 1.

[30] P. M. Anderson and A. A. Fouad, *Power system control and stability*. John Wiley & Sons, 2008.