edgeFLEX

D2.4

Inertia Estimation Concept for Low Inertia Power Systems

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Abstract
This document presents the technical details of the inertia estimation service developed in work package WP2 as a monitoring tool for system operators. The report discusses the algorithm development procedure and the different test use cases used for validation at proof of concept level.

Keyword list
Low Inertia Power Systems, Power System Inertia Estimation, Heterogeneous Inertia, Virtual Synchronous Machines.

Executive Summary

In this deliverable, D2.4, we present the work of task T2.4, Inertia estimation concept for low inertia power systems, within the wider context of the work of WP2 of edgeFLEX. WP2 focuses on developing frequency control and inertial response related estimation and control concepts for dynamically controlled VPP solutions. The main objectives of WP2 are as follows:

- Defining the scenarios and use cases for frequency and inertial response control related concepts of VPPs and low inertia power systems.
- Proposing new concepts for frequency control in current VPPs and as well as for Energy Communities in future VPPs.
- Proposing new concepts to *estimate* the inertia in low inertia power systems.
- Proposing new *allocation* approach for inertial response control for large-scale VPP development.

In today's power grids, synchronous machines, which intrinsically respond to local frequency deviations through their mechanical inertia, constitute the backbone of the system operation and stability. However, this scenario is rapidly changing with the increasing penetration levels of Distributed Energy Sources (DERs) that are interfaced to the grid through power-electronic converters. Consequently, as the penetration of DERs increases, the overall system inertia decreases, resulting in larger and faster frequency deviations after a power imbalance and hence posing a challenge for System Operators (SOs) to maintain the stability of power systems. Therefore, it became more relevant and crucial for SOs to monitor the inertia of the system, in order to perform contingency studies more accurately and take proper actions. In this regard, in task T2.4, we proposed and developed a new inertia estimation approach that can be used by SOs for monitoring purposes.

This deliverable describes the inertia estimation algorithm developed and implemented for the integration into the edgeFLEX platform. The document discusses and validates, through a comprehensive set of simulations, the proposed estimation approach considering different case studies and scenarios. Based on the simulation results, we deduce the following conclusions:

- The inertia estimation algorithm successfully estimates the overall inertia of the system with good accuracy.
- The algorithm works for the estimation of both mechanical and virtual inertia resulting from synchronous machines and Distributed Energy Resources controlled in such a way to mimic synchronous machines inertial response, respectively.
- The inertia estimation algorithm can be used to identify the amount of inertia and damping provided from DERs controlled in such a way to mimic synchronous machines inertial response, i.e. controlled according what is called the Virtual Synchronous Machine (VSM) strategy.

Moreover, the deliverable presents an overview of the preliminary implementation of the inertia estimation algorithm as one of the services of the edgeFLEX platform.

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1. Introduction

With the increased penetration levels of Renewable Energy Sources (RESs), the inertia of the system is decreasing drastically. Moreover, the amount of available inertia has become uncertain depending on the RESs availability at any given time. The ability to accurately estimate the system inertia would allow System Operators (SOs) to assess the system´s state of health and manage the grid with lower constraints.

After knowing the overall inertia of the system at any given time, the system operator can run contingency analysis to quantify the amount of primary reserve and inertial response needed to keep the system within the stability limits for any given disturbance. Hence, the inertia estimation as a tool will enable system operators to procure frequency response services from VPPs in a more efficient manner in the future. However, the inertia estimation algorithm does not interact directly with the market and the outcome of the estimation method is not directly related to the trading of ancillary services.

In the context of future low-inertia power systems, the objective of WP2 is to develop frequency control and inertial response related estimation and control concepts. The focus of the work of Task 2.4 is to develop an inertia estimation algorithm, which can be used for monitoring purposes at the system operator level and implement this algorithm as a platform service.

The inertia estimation is to be achieved by collecting frequency and power measurements from Phasor Measurement Units (PMUs) and power measurements units, respectively, across different substations that are interfacing the generation sources providing inertia in the network and then using this data as input to the estimation algorithm running centrally at the SO control center.

Figure 1: Inertia Estimation Concept for Monitoring Purposes

In Task 2.1, we defined two scenarios for the inertia estimation as summarized in **Fehler! Verweisquelle konnte nicht gefunden werden.**. The scenarios are described in detail in Deliverable D2.1. [1] It is worth mentioning that the inertia estimation algorithm in the case of virtual inertia, estimates the emulated virtual inertia constant provided by the Distributed Energy Sources (DERs).

Table 1 - Inertia Estimation Scenarios

Scenario	Title	Description
S_A	Inertia Estimation at Transmission Level	This scenario focuses on the system inertia estimation, both mechanical and mixed inertia, at the transmission level and considers a mix of generation of both conventional and DERs generation, e.g. large wind power plants connected to the high-voltage level.
S_B	Inertia Estimation at Distribution Level	This scenario focuses on the local estimation of virtual inertia at the distribution level where only

		DERs generation is connected at the medium-voltage level.

The inertia estimation algorithm has been validated in the above-mentioned scenarios through simulation studies on different benchmark systems. Moreover, the estimation algorithm has been implemented as a docker container and integrated in the edgeFLEX solution.

1.1 Objective of the report

The aim of this deliverable is to describe the inertia estimation algorithm developed within the first year of the project, provide validation results obtained through simulations and give an overview of the initial development of the algorithm as a service within the edgeFLEX platform.

1.2 Outline of the report

The report consists of four main parts. The second chapter presents the state-of-the-art of inertia estimation methods. The third chapter recalls the theory behind the power system frequency dynamics model and its relation to the overall system inertia. The inertia estimation algorithm developed within Task 2.4 and the simulation results of the initial validation tests are described in Chapter 4. The fifth chapter describes the inertia estimation service implementation as part of the edgeFLEX platform.

1.3 How to Read this Document

In this deliverable we use the terminology agreed upon within edgeFLEX consortium and which can be found in deliverable D1.1 [2]. The edgeFLEX platform will provide different *services*, including the inertia estimation, for SOs and VPPs. Each of the services is described by one or more *scenarios* that provide a general overview of what that service is about. Within a scenario, several *use cases* are included to implement the service into a specific context or application. The peculiarity of a use case is its specificity in treating a particular aspect of the service; e.g. the application of the inertia estimation algorithm to a benchmark network of IEEE. Finally, the performance of the service is evaluated, in each use case, through *KPI*s. Hence, the performance of a service described by its scenario, will be evaluated through the KPIs defined in each use case.

This report can be read as a standalone document. However, the interested reader can refer to the following deliverables to get a better overview of the concepts and services developed within the edgeFLEX project.

- D1.1 - Scenario description for dynamic-phasor driven voltage control for VPPs (M12) [2]: This deliverable provides an overview of the state of the art in terms of VPPs and introduces to the reader the terminology adopted within the project.
- D2.1 - Scenario description for frequency and inertial response control for VPPs (M12) [1]: in this deliverable the scenarios and the relevant use cases of the frequency and inertial response control and estimation concepts of WP2 are defined.
- D4.1 - Description of EdgeFLEX platform design (M12): detailed information on the overall edgeFLEX platform, where the inertia estimation is integrated as a service, can be found in [3].

2. State-of-the-art of Power System Inertia Estimation

The worldwide legislations to incorporate the reduction of CO_2 emissions and the increase Renewable Energy Sources (RES) penetration is changing the share of power generation between conventional and RES power generation; the backbone of today's power grids i.e. the conventional Synchronous Generators (SGs) are being replaced by power-electronic driven RESs. Such transition is impacting the system operation and introducing new challenges to the System Operators (SOs).

The newly installed RESs do not contribute to the overall system mechanical inertia, due to the fact that they either do not have rotating masses, such is the case of PVs, or are decoupled from the rest of the power system by power electronic devices like in the case of wind generation. Therefore, replacing SGs, which are able to provide inherent inertial response, with RES is reducing the overall system inertia.

As aforementioned, lower values of system inertia result in larger Rate of Change of Frequency (RoCoF) and frequency deviations in case of power imbalances. Insufficient amount of system inertia can result in triggering RoCoF protection relays of SGs and Under-Frequency Load Shedding (UFLS). Consequently, monitoring of system parameters, as well as assessment of frequency response are critical for the secure operation of power systems with low and uncertain values of inertia. Towards these goals, power system inertia needs to be monitored and estimated.

The SOs can then use this information to run contingency analysis to assess the frequency response for a certain disturbance and accordingly the SO can take the appropriate countermeasures like connecting more rotating masses, planning outages, procuring primary reserves and even procuring virtual inertia as an ancillary service in the future.

Power system inertia estimation has been a hot research topic in the recent years for academics and TSOs. The inertia estimation mainly relies on active power and frequency measurements.

The majority of the proposed inertia estimation methods in literature work with Phasor Measurement Unit (PMU) data collected after a disturbance, and are based on a simplified representation of the swing equation that does not take into account the effect of the primary control action and the load voltage and frequency dependency and their effect of the system frequency dynamics. Following this approach, in [4] the overall system inertia of Great Britain has been estimated in terms of total kinetic energy assuming accurate knowledge of generator units' inertia constants. Based on the single machine infinite bus model, in [5] the inertia constant is obtained from the offline analysis of the electromechanical modes and eigenvalues of the power system oscillations.

A very simple approach has been used to estimate the overall inertia of the Nordic power system online [6], assuming the knowledge of the generator units' inertia constants and monitoring of the connection of these generating units to the system. However, the rated inertia constant can deviate from the actual value in case of SGs and this simple approach will not be suitable to estimate the variable virtual inertia provided from DERs. In [7], the authors base their estimation method on a simplified swing equation representation, not taking into account the primary control action. In this approach, smoothing filters are applied as sliding data windows to estimate the inertial response from the measured frequency and active power. Other inertia estimation methods are based on regression and updating the system model in a recursive way to minimize the Mean Square Error (MSE) between predicted and actual values of inertia. In [8] an Extended Kalman Filter is used to estimate the total inertia of the system, yet this approach assumes some initial knowledge of the overall actual system inertia and good only for small uncertainties. The authors in [9] also proposes an estimation method based on regression models but they take into account the primary frequency control action of the different generation units. However, the load power changes due to voltage and frequency dependency are not taken into account.

In edgeFLEX we consider an inertia estimation algorithm based on regression models that take into account the power changes due to the frequency variations, resulting from the load frequency dependency and generation frequency dependency in order to improve the estimation accuracy.

3. Frequency Dynamics in Power Systems

3.1 Introduction

In this chapter, we introduce the basic dynamic frequency model for power systems which constitutes the reference model for the parametric estimation method we use for the inertia estimation in chapter 3.5. The frequency dynamics in large power systems are governed by the electromechanical dynamics of synchronous generators. Moreover, the frequency dependency of loads affects the frequency dynamics.

In the following subsections, the dynamics of synchronous generators and power converters, in addition to load frequency dependency, are recalled and their relation to the power system frequency is established.

3.2 Dynamics of Synchronous Generators

To understand the dynamic behaviour of Synchronous Generators (SGs), let us consider an active power imbalance in the system that would disturb the equilibrium state of the generator. Like any physical moving object, the SG will show a resistance to the change in its motional state, in other words the SG will exhibit an intrinsic inertial response. Therefore, if the load demand increases, the rotating masses of the SG will decelerate and release Kinetic energy to counteract the power imbalance and vice versa if the load demand decreases, the rotating masses will accelerate and absorb the excessive energy. This rotating masses' speed is tightly linked to the system frequency, hence any power imbalance results in variations in the system frequency.

The electromechanical dynamics of SGs can be expressed in terms of the classical nonlinear Swing Equation (SE), which relates the rotating masses angular speed ω to the power imbalance ΔP, as:

$$\boldsymbol{M}\frac{\boldsymbol{d\omega(t)}}{\boldsymbol{dt}} = \Delta\boldsymbol{P} \qquad \Delta\boldsymbol{P}(\boldsymbol{t}) = \boldsymbol{P_m} - \boldsymbol{P_e}(\boldsymbol{t}) \tag{1}$$

Three quantities basically define the dynamic behaviour of SGs when an equilibrium state has been breached: 1) the *mechanical power* P_m i.e. the SG set-point. 2) the *electric power* P_e fed into electric grid, i.e. the generator output power 3) the kinetic energy stored in the rotating masses of the generators, which is related to the moment of *inertia M* of the generators.

When the system is in equilibrium state, i.e. the generation meets the load demand $\Delta P = 0$, the angular speed $\omega = 2\pi f$ and the system frequency f are equal to their nominal values.

However, following any disturbance, the frequency will change. The larger the moment of inertia M, the slower the Rate of Change of Frequency (RoCoF).

Note that no control equipment is considered so far in order to understand the principal dynamic behaviour.

Frequency control structures are needed to maintain a constant system frequency. In the subsequent section we present the Primary Frequency Control (PFC) action, which is done locally at the power plant level.

3.2.1.1 Primary Frequency Control

The primary control is done locally based on the set-points for frequency and power. These quantities are measured locally, and any deviation from the set values results in a signal that will influence the prime mover of the SG in order to increase or decrease power generation, so that the frequency of the system is kept within acceptable limits. However, due to the proportional control, there will be a steady-state error in the frequency.

The proportional feedback control adjusts the power generation set-point of the generator according to the frequency deviation:

$$\boldsymbol{P_m(t) = P^* + u(t) = P^* + K(\omega^* - \omega(t))} \quad (2)$$

Note that the SG turbine dynamics play an important role in the PFC action by introducing time delays in changing the SG output power. The turbine dynamics of thermal power plants can be described using the following model:

$$\boldsymbol{PFC = \frac{1+sT_z}{1+sT_p} K(\omega^* - \omega)} \quad (3)$$

Where K is the total primary (droop) control gain and T_z as well as T_p are the time constants of the turbine-governor system.

Consequently, including a PFC action in SGs yields the following frequency dynamics:

$$M\frac{d\omega(t)}{dt} = P_m(\mathrm{t}) - P_e(t) = P^* + PFC(t) - P_e(t) \quad (4)$$

3.3 Dynamics of Power Converters

Today more and more DERs are connected to the power grid and so the frequency dynamics are not solely dependent on the SGs dynamics. In contrast to SGs, DERs do not have inherent response to power imbalances; solar panels have no inertia and wind turbines are interfaced to the grid through power converters hence they are decoupled from the network.

It is worth mentioning, that most power electronic converters connected to the grid today are grid-following converters, in other words they require a connection to a strong grid to be able to synchronize and they do not adjust their output power according to the system needs. Such converters can be modelled as loads with negative demand.

In this section, we are mainly interested in the converters that are controlled according to the so-called grid-forming control strategies which have strong influence on the frequency dynamics. In view of the urgent demand for addressing the inertia concern, the focus of this work is on grid-forming converters with virtual inertia provision capabilities, i.e. they change their output power according to the rate of change of frequency, namely the Virtual Synchronous Machine (VSM). For simplicity, in what follows we use the term machine for both SGs and converters emulating SGs.

Virtual inertia can be provided with power *electronic converters* and a proper supplementary *control strategy* to absorb or discharge power from the *energy storage,* as shown in Figure 2.

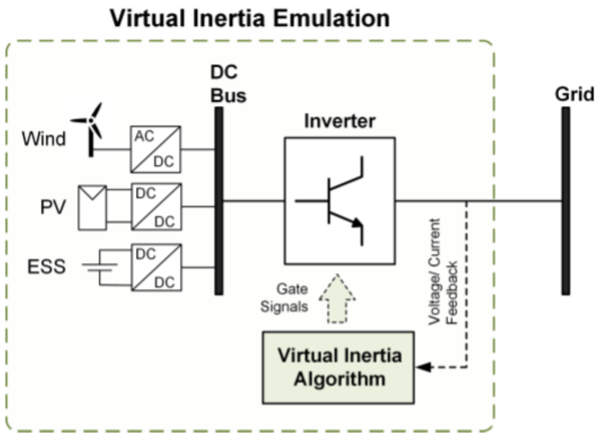

Figure 2 Virtual Inertia Emulation Concept [10].

For the role of the inertia provision to move from SGs to VSMs, the VSM must emulate the behaviour of SGs based on the power balance of the VSM virtual inertia expressed in terms of the classical nonlinear Swing Equation (1). This results in the well-studied closed-loop behaviour compatible with legacy power systems.

As aforementioned, the structure of the VSM normally consists of energy storage and a power converter equipped with a specific control strategy. The VSM mimics the inertia and damping property of SG so that DERs can support the grid in case of power imbalance and deliver power from them to the power grid via the converter connected between DC bus/source and the grid. Since the frequency problem is essentially caused by the imbalance of active power, the virtual inertia is realized by controlling the active power as shown in Figure 3.

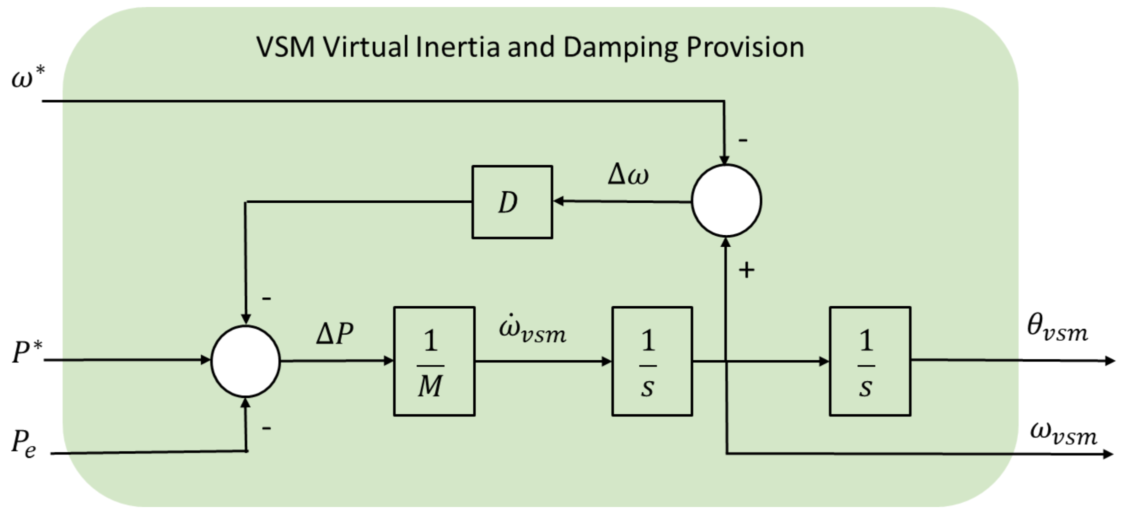

Figure 3 VSM Virtual Inertia and Damping Provision

Thus, the power balance of the VSM inertia and the VSM phase displacement are defined as follows:

$$\boldsymbol{M_{VSM}\frac{d\omega_{VSM}}{dt} = P^* - P_e - D_{VSM}(\omega_{VSM} - \omega^*)} \tag{5}$$

$$\boldsymbol{\frac{d\theta_{VSM}}{dt} = \omega_{VSM}} \tag{6}$$

Where P^* is the reference input power, P_e is the measured electrical power flowing from the VSM into the grid, while the emulated moment of inertia is defined as M_{VSM} and the emulated damping is D_{VSM}. The internal speed or angular frequency and phase displacement of the VSM are ω_{VSM} and θ_{VSM}, respectively.

As shown, the VSM dynamic behaviour is quite similar to SGs. However, it is worth noting that the damping and inertia coefficients of VSMs are not related to physical properties but rather to control parameters and available amount of energy storage. Moreover, VSMs do not have rotating bulky parts, hence their response can be ten times faster than SGs.

3.4 The Centre of Inertia Frequency Dynamics

In the previous sections, we considered the frequency dynamics of a single machine. Now the aim is to derive the frequency dynamics model of the whole system containing *n* machines. With some simplifications we can describe the dominant frequency dynamics by only one differential equation which constitutes the sum of all the swing equations describing the dynamics of the different machines.

$$\sum_{i=1}^{n} M_i * \frac{d\omega_{gi}}{dt} = \sum_{i=1}^{n} \frac{\omega_s}{\omega_{gi}} * \left(P_{mi} + P_{PFC,i} - P_{ei}\right) \tag{7}$$

For convenience, we drop the notation for time dependency in the frequency model dynamics. In a strongly interconnected system, the different machines local frequencies are strongly coupled and very slightly from each other, hence we can represent the system frequency as a weighted average of the individual frequencies, so we define the so–called Centre of Inertia (COI) frequency of the system, ω_{COI}:

$$M_{tot} \frac{d\omega_{COI}}{dt} = P_{m,tot} + P_{PFC,tot} - P_{e,tot} \tag{8}$$

Where M_{tot} is the total moment of inertia of the system. $P_{m,tot}, P_{PFC,tot}$ and $P_{e,tot}$ are the total mechanical set-point of the system, the total PFC action and the total generated electric power respectively.

3.5 Load Models and Factors that affect the Frequency Behaviour

Part of the power system loads are dependent on the frequency and the voltage of the system. In fact, the loads frequency dependency is quite important for power systems stability as it has a stabilizing damping effect on the frequency. Thus, this dependency is traditionally modelled by the damping coefficient D. The load demand decreases according to the frequency drop as follows:

$$\Delta P_L = -D\Delta\omega \tag{9}$$

Including the load frequency dependency into the overall system dynamics (8), results in the following frequency dynamics model:

$$M_{tot} \frac{d\omega_{COI}}{dt} = P_{m,tot} + P_{PFC,tot} - P_{e,tot} - D\Delta\omega_{COI} \tag{10}$$

As for load voltage dependency, it depends on the type of load. Loads can be divided into three types, constant impedance Z-loads, constant current I-loads and constant power loads P-loads, hence the overall load can be modelled using the so-called ZIP model [11]:

$$P_L = P_{L0}\left(k_p + k_i\left(\frac{V_L}{V_{L0}}\right) + k_z\left(\frac{V_L}{V_{L0}}\right)^2\right) \tag{11}$$

Taking the load voltage dependency into consideration, results in the following frequency dynamics:

$$M_{tot} \frac{d\omega_{COI}}{dt} = P_{m,tot} + P_{PFC,tot} - P_{e,tot} - \Delta P_L \tag{12}$$

Where $\Delta P_L = P_L - P_{L0}$.

4. Power System Inertia Estimation

In edgeFLEX we consider an inertia estimation algorithm [12] based on system identification methods. Using appropriate mathematical models, we can extract the system parameters, by mapping the model's output to the actual system's output.

We mainly consider two regression models, in one model we consider the load frequency dependency as in (10), and we estimate both the overall inertia and damping of the system. In the other model (12), we consider the power variations resulting from the load voltage dependency and we estimate the overall system inertia and the load factor.

These regression models are fitted to frequency $f = \omega/(2\pi)$ and power measurement P_e and the system parameters such as inertia M and damping D (or load coefficient k_z) are estimated using the gradient descent method [9].

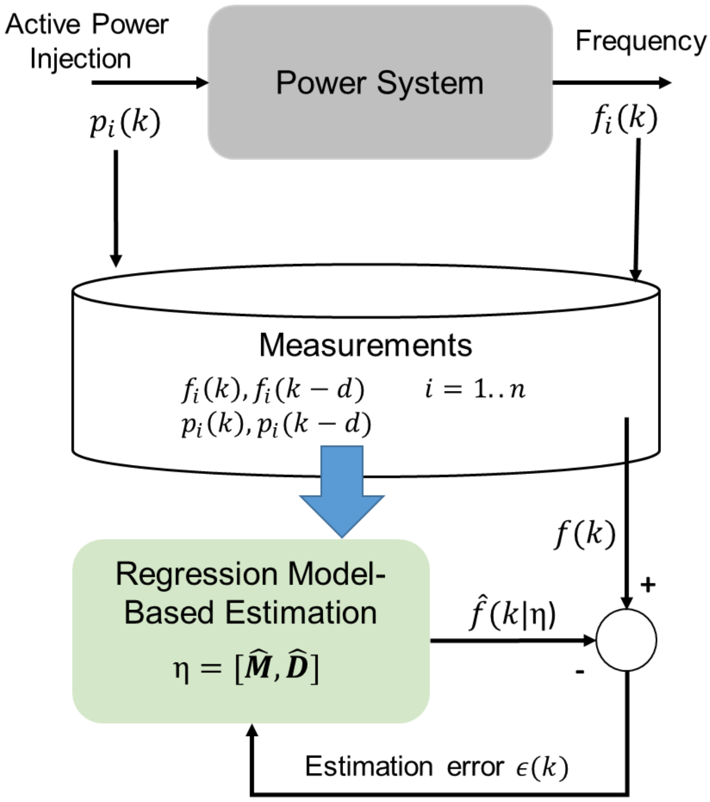

Figure 4 Power System Identification

As illustrated in Figure 4, relying on post processing of power and frequency measurements, the goal of the system identification is to find the system parameters that minimize the error between the estimated frequency and the system frequency.

4.1 Inertia Estimation Use Cases

It is relevant to validate the proposed estimation algorithm for both scenarios defined in **Fehler! Verweisquelle konnte nicht gefunden werden.**. With this aim, we defined three use cases for the inertia estimation that vary in different aspects: the inertia source (mechanical or virtual), the topology of the system and the scope of estimation (system level or device level). The performance and accuracy of the inertia estimator is investigated via three use cases, estimation of overall system's inertia tested in IEEE benchmark transmission systems WSCC 9-bus System [13] and the IEEE 39-bus System [14] and estimating the virtual inertia and damping offered by the BESS converter virtual inertia control which can be used to identify how much inertia and damping are provided.

- Modified WSCC 9-bus system: only includes conventional generation with homogeneous inertia and static load profiles, for the inertia estimation algorithm validation.
- Modified IEEE 39-bus system: includes a mixed generation of SGs and RESs and a more realistic representation of a transmission system.
- Real-world distribution network model with a VSM converter.

For the purpose of evaluating the performance of the proposed algorithm and the different implementations tested we will consider the estimation error, defined as [1], as the most relevant KPI.

4.1.1 Modified WSCC 9-bus System

The WSCC 9-bus system is a highly symmetrical transmission network that consists of three SGs, equipped with automatic voltage controllers and turbine governors providing PFC, in addition to three loads.

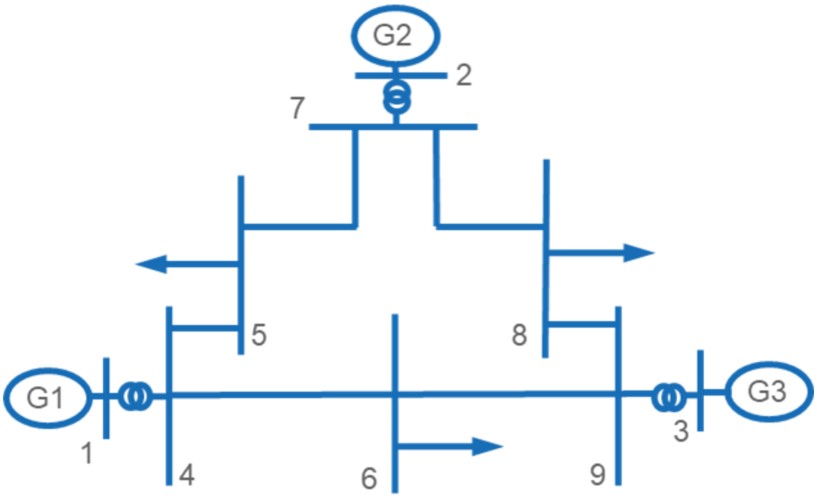

Figure 5 WSCC 9-bus System

For validating the estimation method, in this use case we consider the estimation of homogeneous mechanical inertia. With this aim, we modified the inertia constants of the WSCC 9-bus System given in [13], so that the three SGs are identical with an inertia constant of 3.7s and turbines time constants of 5s. Hence, the overall system inertia constant of the system is 3.7s.

The estimation using the regression method, requires having frequency dynamics in the system ensuring enough excitation for the convergence of the estimation method. Hence, we apply a load step to the system, causing a power imbalance and consequently resulting in a change in the system frequency.

Initially, the system is at steady state. At time t= 25s, the active power demand of the load increases by 0.5 p.u. This increase of active power demand is covered by the generation. Directly after the disturbance, the inertial response of the generators occurs, and the frequency begins to decrease. After a while, the primary frequency control reacts to frequency deviating from its set value by providing additional power. This results in a corresponding reduction of the electrical power provided by the inertial response as the system RoCoF decreases. The frequency response of the WSCC-bus system and the output power of each SG following a load-step are illustrated in Figure 6 and Figure 7, respectively.

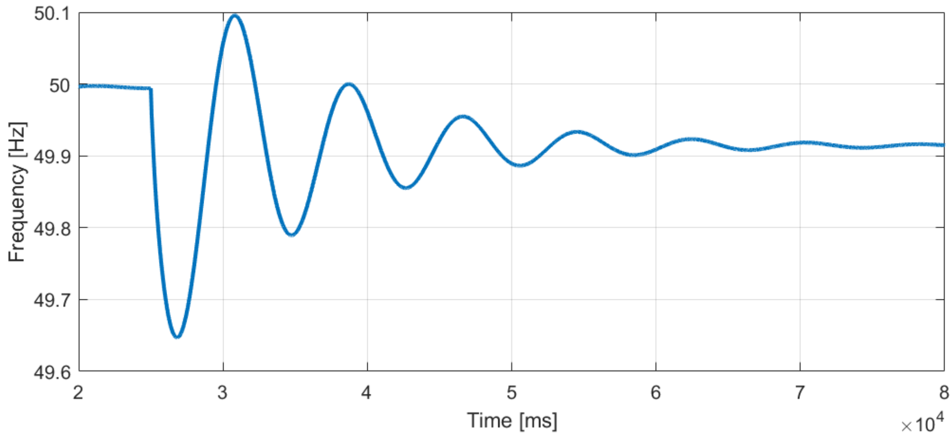

Figure 6 Frequency Response of the WSCC-bus system following a load-step

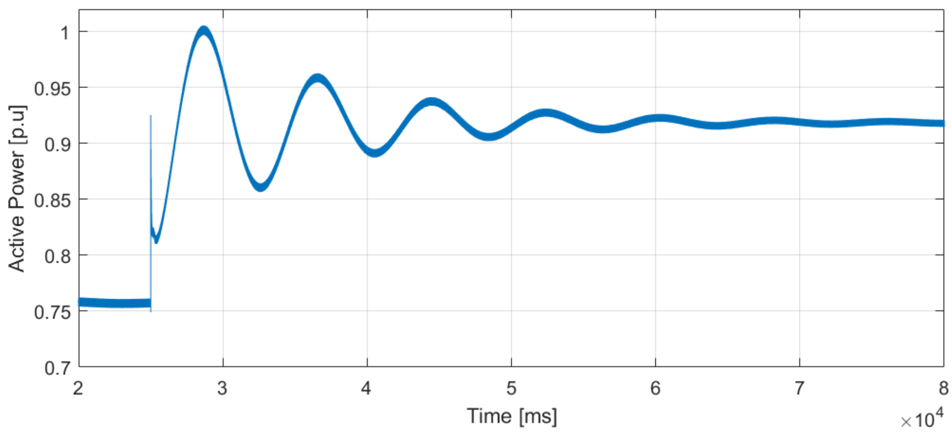

Figure 7 Output Power of SGs following a load-step

We consider the two regression models (10) and (12); in the first model we take into account the load and generation frequency dependency and in the second model we take into account the load voltage dependency, respectively. The results of these methods are presented in the following subsections.

4.1.1.1 Inertia and Damping Estimation

As aforementioned, we consider an inertia estimation algorithm to estimate the overall system inertia based on regression models that take into account the power changes due to the frequency variations, resulting from the load and generation frequency dependency $D\Delta f$ and generator units' primary frequency control action P_{PFC}:

$$M\frac{df}{dt} = P^* + P_{PFC} - P_e - D\Delta f \tag{13}$$

For convenience, in (13) the time dependency and the COI notation are dropped and we consider the frequency dynamics model in terms of the frequency f instead of the angular frequency $\omega = 2\pi f$. This regression model (13) is fitted to the aggregated system frequency f and power measurement P_e and the system parameters such as inertia M and damping D are estimated using the gradient descent method [9].

The trajectories of the estimated system's overall inertia constant and damping are depicted in the figures below.

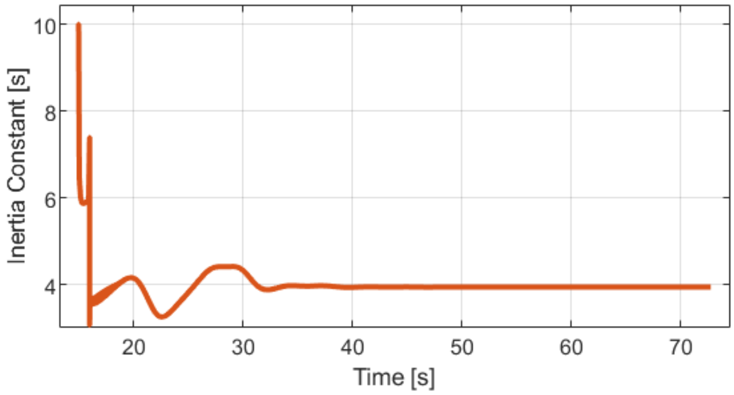

Figure 8 Trajectories of the estimated Inertia Constant using Regression Model 1

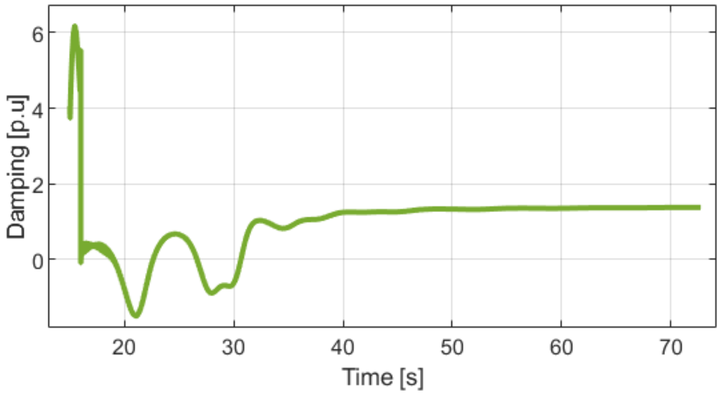

Figure 9 Trajectories of the estimated Damping Coefficient

It can be observed that the estimation takes 57.22 s to converge to the estimated values of inertia and damping of 3.941s and 1.372 p.u., respectively.

To evaluate the estimation method, we calculate the relative estimation error for the inertia constant:

$$\textbf{Inertia Estimation error} = \frac{3.941-3.7}{3.7} * 100\% = 6.51\% \quad (14)$$

As demonstrated, the inertia estimator successfully estimates the overall inertia of the system with an estimation error of less than 7%.

4.1.1.2 Inertia and load factor Estimation

To further improve the estimation method, we consider the load voltage dependency; the voltage variation following a load step is depicted in Figure 10. To represent the active powers of the loads voltage dependency, a model that is composed of constant impedance (Z), constant current (I) and constant power (P) components (ZIP load model) is used:

$$\boldsymbol{P_L(t) = P_{L0}\left(k_p + k_i\left(\frac{V_L(t)}{V_{L0}}\right) + k_z\left(\frac{V_L(t)}{V_{L0}}\right)^2\right)} \quad (15)$$

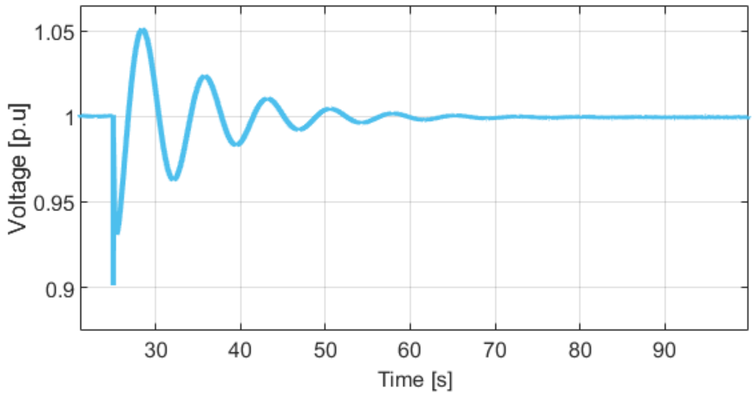

Figure 10 Voltage Response Following a Load Step

Consequently, the frequency dynamics of a power system defined by SG dynamics and taking into account the load voltage dependency are described as follows:

$$\boldsymbol{M}\frac{\boldsymbol{d}}{\boldsymbol{dt}}\boldsymbol{f}(\boldsymbol{t}) = \boldsymbol{P}^{*} + \boldsymbol{P}_{\boldsymbol{PFC}}(\boldsymbol{t}) - \Delta\boldsymbol{P}_{\boldsymbol{e}}(\boldsymbol{t}) = \boldsymbol{P}^{*} + \boldsymbol{P}_{\boldsymbol{PFC}}(\boldsymbol{t}) - (\boldsymbol{P}_{\boldsymbol{dist}} + \Delta\boldsymbol{P}_{\boldsymbol{L}}(\boldsymbol{t})) \tag{16}$$

In the WSCC-bus system we modelled the loads as constant impedance loads since the constant power characteristic does not have any contribution in the variation of power demand. These regression models are fitted to the system f and power measurement P_e and the system parameters such as inertia M and the load coefficient kz are estimated using the gradient descent method [9].

The trajectories of the estimated system's overall inertia constant and load coefficient are depicted in the figures below.

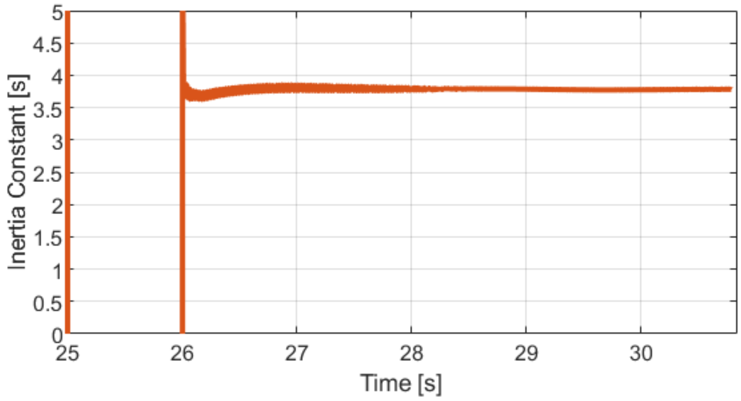

Figure 11 Trajectory of the Estimated Inertia Constant using Regression Model 2

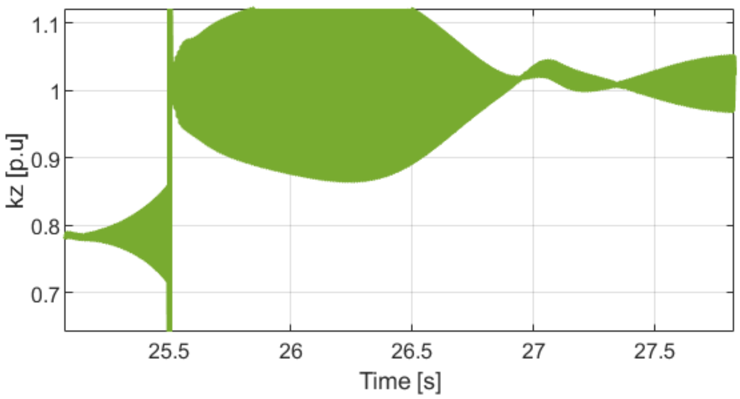

Figure 12 Trajectories of the Estimated Impedance Load Factor

It can be observed that estimation takes 5.78s to converge to the estimated values of inertia and load coefficient of 3.782s and 1.04 p.u., respectively.

To evaluate the estimation method, we calculate the relative estimation error of the inertia constant:

$$\boldsymbol{Inertia\ Estimation\ error} = \frac{\mathbf{3.782-3.7}}{\mathbf{3.7}} * \mathbf{100\%} = \mathbf{2.216\%} \tag{17}$$

It is demonstrated that the second estimation model that takes into account the voltage dependency, has higher convergence speed and accuracy. The higher accuracy can be explained thanks to the fact that the loads' power change dependency related to the voltage is stronger than its dependency to frequency.

4.1.2 Modified IEEE 39-bus System

The IEEE 39-bus power system, also known as the New-England Power System [14] is the largest test system considered in Task D2.4. This model is widely employed as a benchmark transmission system for stability studies and performance evaluation of different monitoring and control concepts. The power system, shown in Figure 13, consists of 39 buses, 10 SGs (equipped with PFC and Power System Stabilizers) and 19 loads.

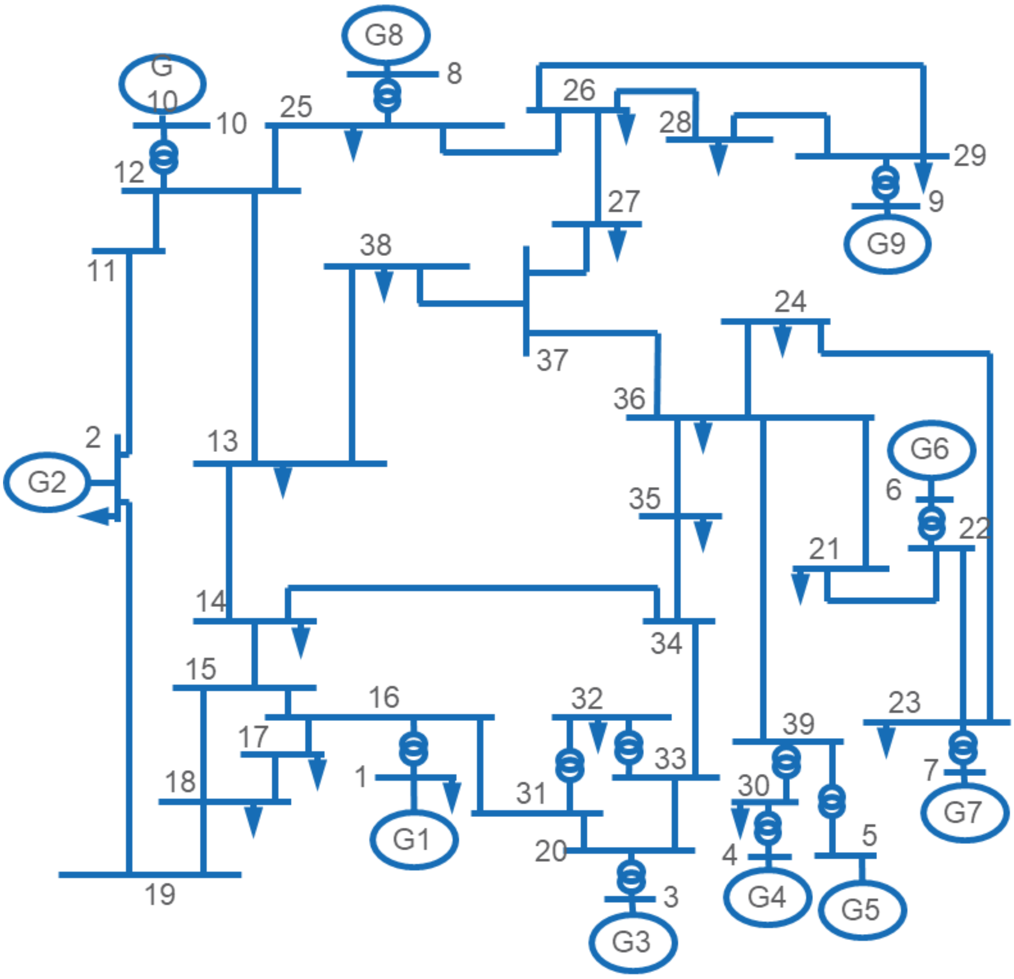

Figure 13 - IEEE 39-bus System

The 39-bus system is utilised in this use case to evaluate the performance of the inertia estimation method for systems with heterogeneous inertia, i.e. different distribution of inertia in the system and different sources of inertia (virtual inertia or mechanical inertia).

With this aim, we modified the benchmark system by replacing three SGs (G10, G8 and G5) with VSM converters of the same capacity, emulated inertia constant, droop coefficient and operating set-point. The overall system inertia constant of the system is 3.32s.

In our test, we apply a load step to the system, causing a power imbalance and consequently resulting in a change in the system frequency.

The trajectory of the estimated system's overall inertia constant is depicted in Figure 14. It can be observed that the estimation converges to the estimated values of inertia constant of 3.206s.

To evaluate the performance of the estimation method in this use case, we calculate the relative estimation error for the inertia constant:

$$\boldsymbol{Inertia\ Estimation\ error} = \frac{\mathbf{3.206-3.32}}{\mathbf{3.32}} * \mathbf{100}\% = \textit{-3.43\%} \tag{18}$$

As demonstrated, the inertia estimator successfully estimates the overall heterogeneous inertia of the system with an estimation error of less than 4%.

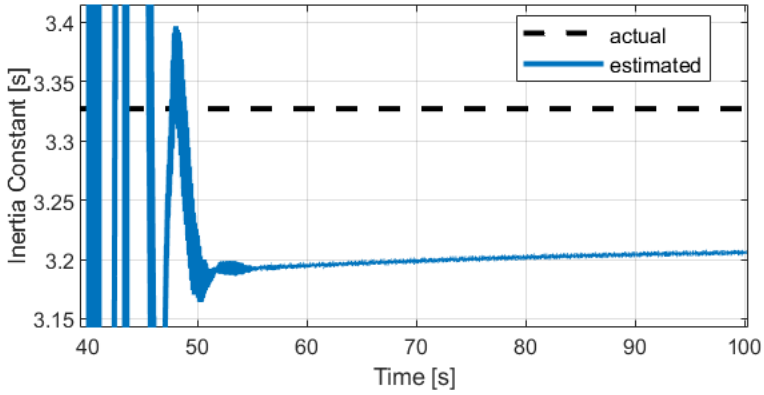

Figure 14 Trajectory of the estimated Heterogeneous Inertia Constant

We also evaluated the performance of the estimation method with different PFC parameters (i.e. different droop coefficients). Figure 15 shows that the PFC action has little influence on the estimation accuracy, however, smaller droop values result in relatively longer convergence times.

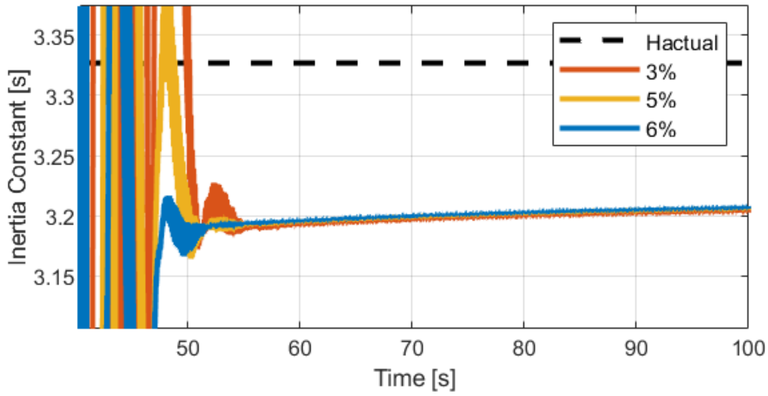

Figure 15 Trajectory of the Estimated Heterogeneous Inertia Constant with Different Values of System Droop

4.1.3 VSM Parameters identification

In the previous section, we considered the use case of the inertia estimation method to estimate the overall system's inertia with multiple generation units providing inertia. In this section, we evaluate the performance of the inertia estimation method in estimating the virtual inertia and damping provided by the VSM converters control action. Thus, virtual inertia estimation is the focus of use case 3.

We consider the VSM inverter connected to a distribution network. The inverter emulated inertia constant and damping coefficients are 3s and 50 p.u., respectively. We apply a load step to the network and then we apply the inertia estimation method to the VSM converter frequency and power measurements to estimate its emulated inertia and damping.

The trajectories of the estimated VSM inertia constant and damping are depicted in the figures below.

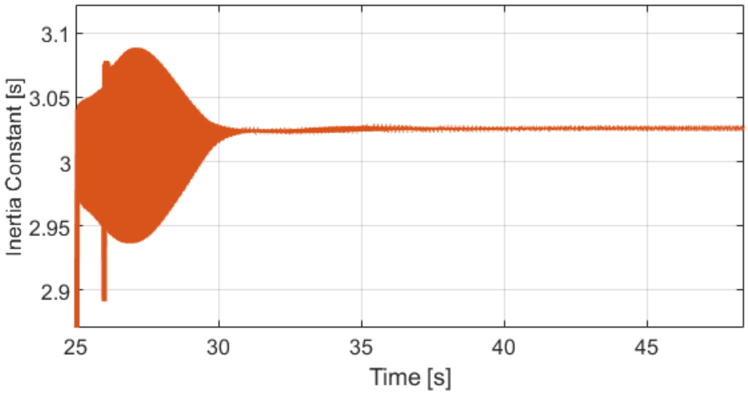

Figure 16 Trajectory of the estimated VSM Virtual Inertia Constant

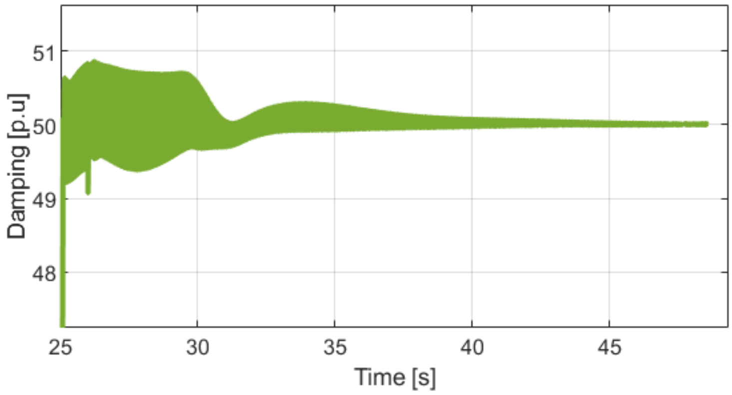

Figure 17 Trajectory of the estimated VSM Damping Coefficient

It can be observed that estimation takes 23.53s to converge to the estimated values of inertia and damping of 3.026s and 50.0056 p.u., respectively.

To evaluate the estimation method, we calculate the relative estimation error as a KPI:

$$Inertia\ estimation\ error = \frac{3.026 - 3}{3} * 100\% = 0.73\%$$

$$\boldsymbol{Damping\ estimation\ error} = \frac{\mathbf{50.0056 - 50}}{\mathbf{50}} * \mathbf{100\%} = \mathbf{0.011\%} \tag{19}$$

It is demonstrated that the estimation method can estimate the VSM virtual inertia and damping coefficient using local frequency and power measurements with an estimation error of less than 1%.

5. Interaction with edgeFLEX Architecture

5.1 Functional and Component Requirements of the Inertia Estimation Algorithm

For deploying the inertia estimation in a real-world scenario, the following requirements have to be met:

- **Objective:** estimation of the system inertia at the SO level.
- **Timeframe:** The inertia estimation algorithm relies on the presence of sufficient excitation in the system i.e. frequency variations. In this context, the inertia estimation will execute periodically, following the rescheduling of the generation every hour.
- **Triggering Event:** Generation rescheduling events i.e. scheduled power set-point changes that take place normally in the operation of power systems.
- **Frequency and Power Measurements:** Synchronized measurements with time stamps are needed for the inertia estimation.
- **Accuracy of Frequency and Power Measurements:** The PMUs and power measurement units must have accuracy and granularity that are high enough to capture the fast changes in frequency. Measurement time resolution should be in the range of milliseconds.
- **Manner:** The inertia estimation is to be executed at the control centre of the SO.
- **Information exchange between SOs:** Exchange of estimated inertia values from neighbouring control areas i.e. TSOs or DSOs and TSOs for further contingency analysis and overall system inertia calculation.
- **Data Recordings:** Data storage of frequency measurements and active power measurements is required for the inertia estimation execution is achieved using post processing of measurements.

Asset Requirements:

- **Generating units:** Conventional synchronous generators and/or RESs generation with Energy Storage Systems (ESSs) allowing the RESs to provide virtual inertial response.
- **Power converters control strategy:** The power converters provide the interface between the grid and the different DERs. These converters must have *proper control strategies* that enable the RESs to mimic the behaviour of synchronous generators by providing **inertial response**, i.e. change their output power according to the rate of change of frequency.
- **Measurement devices:** the generating units are connected to the high-voltage (transmission) network through step-up substations. These substations need to have PMUs to measure the frequency and power measurement devices to measure the power flow at the generator buses.
- **Supervisory control and data acquisition (SCADA) and Energy Management System (EMS)** at the control centre of the SO to collect the measurements data and run the inertia estimation algorithm.

5.2 Inertia Estimation as a Service

To implement the inertia estimation algorithm as a service within the edgeFLEX platform, the algorithm has been implemented as a Python code and the needed communication interfaces have been developed. The inertia estimation service, constituted of the estimation algorithm and the relevant communication interfaces, is organised as a docker container in a git repository to facilitate the service integration in the edgeFLEX platform. The service integration into the platform architecture is illustrated in Figure 18.

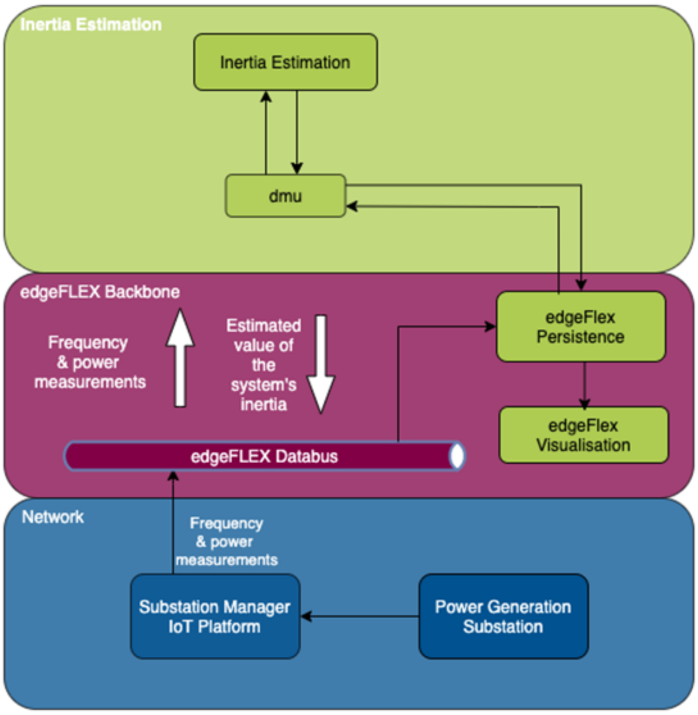

Figure 18 - Inertia Estimation Platform Integration [3]

As shown in Figure 18, the inertia estimation service relies on the edgeFLEX backbone services. The inertia estimation algorithm relies on post processing of data; hence the edgeFLEX persistence service is needed to store the frequency and power measurements as well as the outcome of the estimation method i.e. the estimated value of inertia. As for the communication between the estimation service and the persistence service, we use the MQTT protocol.

The interested reader may refer to [3] for more details on the inertia estimation service integration and interaction with the rest of edgeFLEX services.

6. Conclusion

This deliverable describes the inertia estimation algorithm that has been implemented as a service for the edgeFLEX platform. The algorithm is intended to be used by system operators to accurately monitor the overall system inertia. This value is to be used in contingency analysis and so to anticipate the challenges of reduced system inertia and take countermeasures against these challenges.

We apply dynamic regression to power and frequency measurements in order to estimate the inertia as a power system parameter. The preliminary computer-based test results indicate that the inertia estimation method developed within task 2.4, shows good performance when it comes to estimation accuracy for different types of inertia (mechanical and virtual).

Moreover, we describe the functional and component requirements for real-world deployment of the inertia estimation and give an overview of the algorithm integration as a service in the edgeFLEX architecture.

The research will be further extended in task T2.5 during the second phase of the project. We will consider how to utilize the inertia estimation output in developing an inertia allocation algorithm that can be used by the SO as a planning tool for allocating inertia in the system.

7. List of Figures

8. References

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9. List of Abbreviations

RES	Renewable Energy Sources
SO	System Operator
VSM	Virtual Synchronous Machine
DER	Distributed Energy Sources
VPP	Virtual Power Plant
ESS	Energy Storage System
SG	Synchronous Machine
PFC	Primary Frequency Control
COI	Center of Inertia
RoCoF	Rate of Change of Frequency