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PS1 – System Control Room Preparedness: Today and in the Future

Operational metering, forecast & validation of effective Area Inertia

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SUMMARY

As power grids decarbonise and increasingly interconnect, inverter-connected generation, energy storage and HVDC links make up a growing share of energy resources connected to power grids compared to conventional synchronous plant. This leads to lower system inertia, with steeper changes in grid frequency following a sudden loss of infeed or load. This results in a more severe disturbance to grid frequency and voltage angle in the initial seconds, and a faster subsequent rate of frequency excursion. The first raises risks of consequential generation and network trips, and the second shortens the time period available to re-balance the grid before disruptive actions such as load shedding are triggered. The regional distribution of inertia is important as well as the overall system total – frequency and Rate of Change of Frequency (RoCoF) cannot be approximated as equal across the network. The power system acts as multiple centres of inertia linked by network corridors – the frequency and angles diverge following a disturbance, particularly in the case of low inertia regions.

It is thus becoming important to the secure operation of many grids that inertia is carefully managed, on a system basis and increasingly also a regional basis. Since actions to manage inertia typically come at significant cost, accurate monitoring and forecasting of inertia is becoming crucial to inform secure and economic grid operation. "Effective area inertia" is a measure that characterises the inertia-like behaviour of a region of a network, relating a net power imbalance for the area to RoCoF. This measure includes not only the physical rotating inertia of synchronous generation, but also any other influences such as the behaviour of load, power electronic connected generation and storage.

This paper describes a system that has been developed and now field-deployed to continuously and passively meter the effective inertia of the Great Britain (GB) power system on a regional basis in real-time, using synchrophasor measurements. The system also applies machine learning to provide forecasting of inertia, based on predictors such as anticipated levels of demand and synchronous, solar and wind generation. Both real-time metered inertia and forecast inertia for a region are automatically validated against real grid behaviour each time a frequency disturbance occurs. The paper also describes initial results from evaluation of the metered and forecast inertia values.

KEYWORDS

Inertia – Forecast - Wide-Area Monitoring – Synchrophasor - Phasor Measurement Unit – RoCoF - Machine Learning

1 INTRODUCTION

1.1 Inertia Concepts & Ongoing Trends

Inverter-connected generation, energy storage and HVDC links make up an increasing share of energy resources connected to power grids compared to conventional synchronous plant. This trend is driven by decarbonisation of energy systems, in particular the associated shift to renewable generation and need for increased flexibility and control in the dispatch of energy resources and networks. Another driver is the increase in cross-border HVDC interconnections - partly motivated by decarbonisation, but also by energy cost and security concerns such as dependence on fuel imports.

This growth in inverter-connected energy resources leads to reducing system inertia, as they replace the large synchronously-connected rotating masses of conventional generators.

Lower inertia leads to steeper changes in grid frequency following a sudden loss of infeed or load. This results in a more severe disturbance to grid frequency and voltage angle in the initial seconds, and a faster subsequent rate of frequency excursion. The first raises risks of consequential generation and network trips, and the second shortens the time period available to re-balance the grid before disruptive actions such as load shedding are triggered. This is further discussed in Section 1.2.

The regional distribution of inertia is important as well as the overall system total. Frequency and Rate of Change of Frequency (RoCoF) cannot be approximated as equal across the network. The power system acts as multiple centres of inertia linked by network corridors – the frequency and angles diverge following a disturbance, particularly in the case of low inertia regions.

This variation in frequency and RoCoF across a power system is illustrated in the disturbance in the network of Great Britain (GB) on 9th August 2019 [1], shown in Figure 1 – which featured the sudden loss of 1131MW generation and is discussed later. Close to the loss of power infeed from two sources, RoCoF significantly exceeded 0.125Hz/s Loss of Mains threshold (see Section 1.2) in the initial second of the disturbance – while in other locations, the RoCoF was well within this limit for the first second.

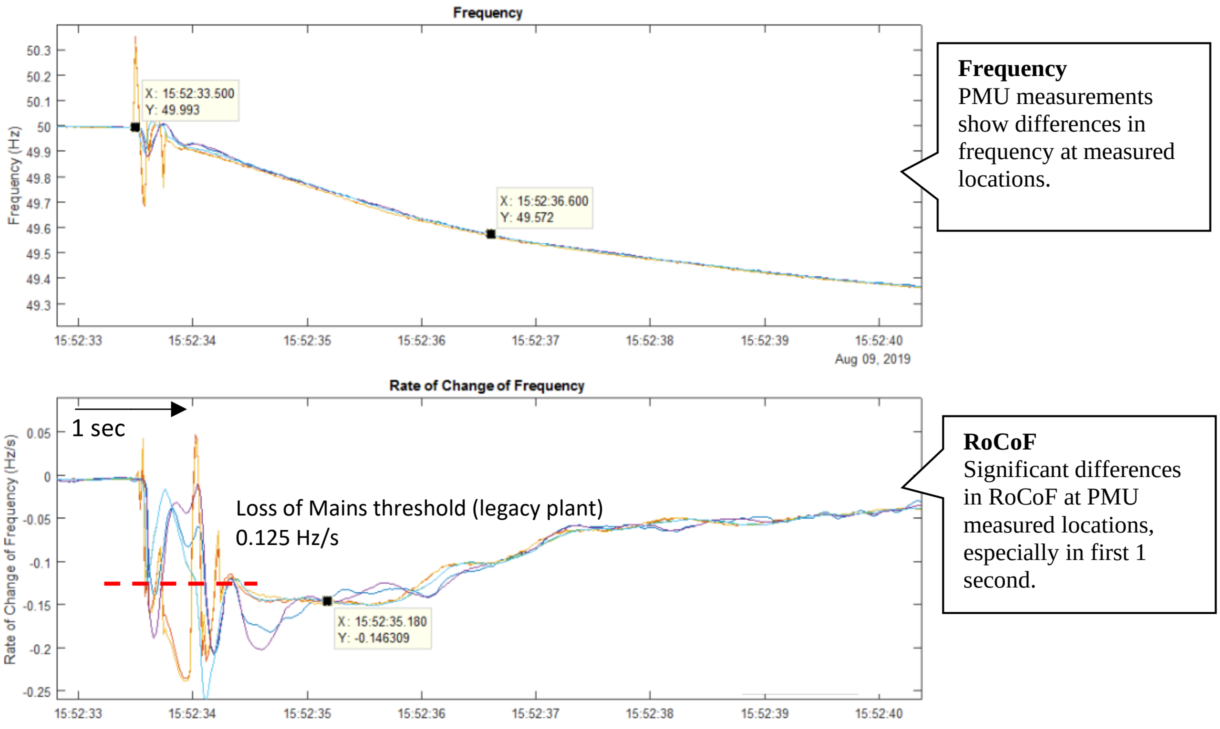

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Figure 1. Frequency & RoCoF after infeed loss in the Great Britain (GB) transmission system, 9 Aug'19

1.2 Challenges from Inertia

Reducing inertia in one or more regions of the system influences angle stability as well as frequency and RoCoF behaviour, driving a number of challenges to system security following a sudden loss of load or infeed.

The first challenge is that a high regional or system RoCoF due to low inertia can lead to the sudden disconnection of large volumes of embedded generation, through unintended triggering of Loss of Mains protection.

Loss of Mains protection is designed to act to disconnect an embedded generator in the event that its local grid becomes separated from the rest of the system. This is done in order to prevent the formation of an uncontrolled power island, which would present risks to people and equipment due to issues such as protection relay sensitivity, network earthing, isolation of equipment for safe work, and operation beyond equipment ratings or safety limits. Typical Loss of Mains protection will trigger based on a sustained RoCoF level, for example 1Hz/s sustained for 0.5seconds.

Since Loss of Mains disconnection of generation will tend to occur near the times and locations in the grid already featuring the most severe frequency and angle swings, it can significantly increase the severity of a disturbance and trigger further consequences. In the case of the August 2019 GB event highlighted in Figure 1, embedded generation totalling 350MW is estimated to have disconnected in this way immediately following the initial 1131MW generation loss (which itself comprised 3 separate losses). Following 410 MW of further subsequent generation losses, this event ultimately featured the disconnection of 931MW of demand (3.2%) by under-frequency load shedding. As readers will gather, this was a complex and interesting power system event – it is thoroughly detailed in [1], which the authors recommend reading.

An additional challenge from reducing inertia is the potential for the occurrence of out-of-step conditions or islanding of low inertia regions following a disturbance, due to large localised frequency and angle movements.

Finally, reducing inertia at a system level will lead to a faster overall rate of frequency excursion during a disturbance. This means that frequency response must act faster and/or with higher volume in order to arrest the system frequency excursion before the system frequency reaches levels at which disruptive action such as load shedding is triggered.

It should be noted that although fast-acting frequency response is valuable from the perspective of containing such frequency changes, response based purely on locally measured frequency can result in unintended destabilisation of a network. More intelligent schemes can be necessary which take account of regional power imbalance, or wide-area frequency measurement – it should be noted that such schemes are already being deployed in multiple grids on a demonstration or operational basis [2] [3].

1.3 Managing Inertia

It is thus becoming important to secure operation of many grids that inertia is carefully managed, on a system basis and increasingly also a regional basis. Such management must balance system security and economy, since actions to manage inertia typically come at significant cost, for example:

- Provision of faster-acting and/or greater volume of frequency response services
- Market trades to replace low inertia generation with high inertia (often high-carbon) generation,
- Payments to constrain the largest expected generation loss, or
- Fees to non-generating plant providing inertia as a service.

The cost of managing RoCoF in the GB grid has increased tenfold in the last 4 years, from approximately £30m in the year ending March 2017 to nearly £350m in the year ending March 2021 [4].

Accurate monitoring and forecasting of inertia in real-time, energy market and capital investment timescales is therefore crucial to feed secure and economic grid operation.

"Effective area inertia" is a measure that characterises the inertia-like behaviour of a region of a network, relating a net power imbalance for the area to RoCoF. This measure encompasses not only the physical rotating inertia of synchronous generation but also other influences on the relationship between power imbalance and RoCoF that are less straightforward to model – such as behaviour from load, inverter-connected generation, and storage. As the share of synchronous generation reduces, these other sources of inertia-like behaviour become more significant – and overall effective area inertia becomes more challenging to model using conventional methods.

2 SOLUTION FOR METERING, FORECAST & VALIDATION OF EFFECTIVE AREA INERTIA

A system has been developed and now field-deployed to continuously and passively meter the effective inertia of the GB power system on a regional basis in real-time, using synchrophasor measurements. In addition, the system applies machine learning to provide forecasting of inertia, based on predictors such as anticipated levels of demand and synchronous, solar and wind generation. Both real-time metered inertia and forecast inertia for a region are automatically validated against real grid behaviour each time a frequency disturbance occurs.

The system is outlined in Figure 2, and detailed in this section and its subsections. Previous publications [5] have described the key theoretical aspects of the metering, forecast and validation approaches, and results from their offline application to real data from a region of the GB power system. This section will therefore focus on the architecture and functionality of the operational system deployed in GB.

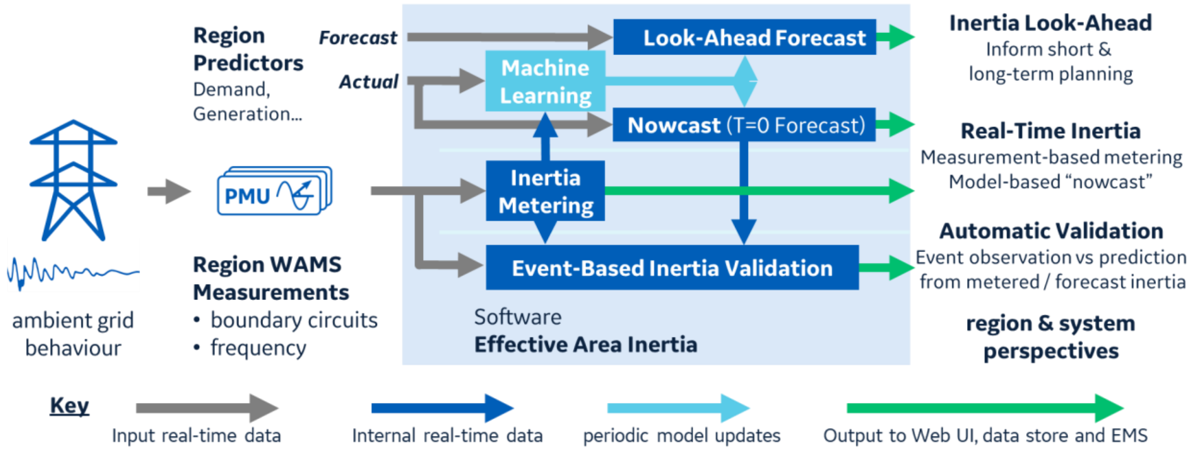

Figure 2 - Overview of Effective Area Inertia Metering, Forecast & Validation Solution

The core system resides within the GB Electricity System Operator (ESO), with the inertia metering, forecast and validation software solution deployed on an on-premises private cloud infrastructure. It may be noted that hosting on an on-premises cloud was incidental in the project and not an intrinsic requirement of the solution, which is equally suitable for deployment on bare-metal or virtualized computing infrastructure.

PMU data is collected by Phasor Data Concentrators at each of the three Transmission Network Owners responsible for the three transmission network areas of the GB system, and streamed over an IP network via the IEEE C37.118 protocol to the ESO. The present deployment utilises PMU data at 10fps.

Real-time measurements and forecasts of regional demand and generation, used for generating inertia forecasts, are received at 5–30-minute intervals from the corresponding source ESO systems such as operational metering, the energy balancing system and energy forecasting systems.

Real-time and historical inertia metering, forecast and validation results from the solution are presented to users in UIs accessible via web browser, and are also retrievable via an open web Application Programming Interface (API) to support extraction of data for manual analysis or to other systems. An interface also exists to provide live metered and forecast inertia values to the EMS via the standard IEC 60870-5-104 protocol.

2.1 Inertia Metering Module

As outlined in Figure 2, the effective inertia metering application uses measurements of regional frequency and boundary power flow from standard PMUs in order to extract an effective area inertia value for each monitored region. The approach takes advantage of ambient perturbations in active power between regions of the grid, which are always present due to natural oscillations in the power system – no forced stimulation or direct monitoring of individual generators is required.

Frequency measurements are taken from a handful of locations within each region, in order to build a frequency measurement representative of the region. AC and DC power flows across each region boundary are monitored – whilst full observability is targeted, some unmonitored cross-boundary flows at lower voltages (<132kV) are neglected at this stage.

Results are generated at 5-minute intervals – this being judged as suitably frequent to be a useful input to system operator decision making and real-time awareness, with more frequent updates being of diminishing benefit given the relatively slow variations from contributors to effective area inertia.

2.2 Inertia Forecasting Module

The effective inertia forecasting application applies machine learning to build a forecast model for each region that relates metered inertia to predictors such as regional demand, connected synchronous generator inertia, and levels of solar and wind generation. Such models can then be executed with predictor values to generate a corresponding inertia forecast. The models are periodically refreshed to include the latest historical data – for example, weekly – in order to continuously improve the quality of forecasts. In the deployed solution, two types of inertia forecast are automatically generated for each region as predictor data is fed to the system.

A "look-ahead" forecast is executed using forecasts of predictor values, generating a forecast for the inertia at each 30-minute interval in the subsequent 24 hours. The intention of such a forecast is to aid in operational planning and give early warning of potential low inertia risks.

A "nowcast" or "T0 forecast" is executed using live actual values of predictors, generating a model-based estimation of the present inertia. This serves three purposes. First, it enables mutual validation with the metered inertia value – giving confidence to operators that the present view of inertia is accurate, and highlighting situations where the two measures have deviated and caution might be advised. Second, it serves as a back-up to the metered inertia value – for example in case of disruption to the flow of PMU data from the Network Transmission Owners. Finally, it is a means by which to assess the performance of the inertia forecasting model on a long-term continuous basis, in-between the frequency disturbances used for event-based validation.

2.3 Inertia Validation Module

As stated in Section 1.1, effective inertia relates RoCoF in a region to its power imbalance, according to the following equation (1):

$$Effective\ inertia = \frac{-\Delta P\ f_0}{2\ RoCoF} \qquad (1)$$

Where ΔP is the change in the region boundary power flow, RoCoF is the region Rate of Change of Frequency, and f0 is the nominal frequency.

The measured and nowcast effective inertia values for a region can thus be validated by comparing observed regional RoCoF during a frequency disturbance with the RoCoF predicted by each inertia value based on the corresponding observed disturbance in regional boundary power.

The effective inertia validation module automatically detects suitable disturbances in the GB system based on RoCoF thresholding, and assesses for each region the error between observed regional RoCoF and that predicted based on the observed boundary power during the disturbance and the metered and nowcast regional inertia values immediately prior to the disturbance. The results of this analysis are stored for later review, as is a capture of the raw PMU data during the event to enable more detailed examination. The analysis includes an assessment of the suitability of the disturbance for inertia validation, in particular identifying whether the load or infeed loss occurred outside the region (a requirement for validation) and assessing the clarity of the event based on the degree of correlation between RoCoF and boundary power.

3 PROGRESS & RESULTS TO DATE

As of December 2021, the metering, validation and forecast solution has been deployed at the GB ESO and is operating fully on the Scotland region of the GB grid – albeit with no visibility of frequency in the North of Scotland at present. Some further PMU installations are pending in order to cover the remaining regions of the GB grid – after which inertia metering, forecast and validation of the full GB power system will be operational.

3.1 Validation of Metered Inertia Results

During the period of operation to date, numerous frequency disturbances were detected by the automatic inertia validation module. Filtering these events for a minimum RoCoF of 0.4Hz/s, a minimum boundary power change of 30MW, and sufficient correlation between boundary power and frequency, gave 19 events covering a 7-month period. It may be noted that the earlier part of this period coincided with system commissioning, and as such the system was unavailable at several points due to activities such as data link changes or software upgrades – it is expected that suitable validation events will be reported more frequently now that commissioning has been completed.

The results of the inertia validation are illustrated in Figure 3, and can be summarised as follows:

- 15 (80%) reported ≤10% or 10 mHz/s error in predicted RoCoF
- 18 (96%) reported ≤15% or 15mHz/s error in predicted RoCoF
- 19 (100%) reported ≤20% or 20mHz/s error in predicted RoCoF

To put these RoCoF error levels in context, it may be noted that the present most constraining RoCoF threshold applied to Loss of Mains protection in the GB system is 0.125Hz/s. This applies only to some legacy equipment, and considerable effort is under way to bring all plant into line with new regulations (ENA G99 / G59.3-7) which apply a higher threshold of 1Hz/s, by September 2022 [6]. Thus, the 20mHz maximum error reported above corresponds to 2% of the 1Hz/s Loss of Mains protection threshold defined by the latest regulations.

Given the absence at present of frequency visibility in the North of Scotland – with PMU installations pending – these results should not be taken as a definitive evaluation of the accuracy of the inertia metering approach at this stage. A more thorough review is planned for 2022 to address this question. However, these initial results are consistent with an offline study of the inertia metering approach conducted previously on a similar region of the GB network [5], and serve as a useful validation of the real-time implementation and continued applicability to the changing GB system.

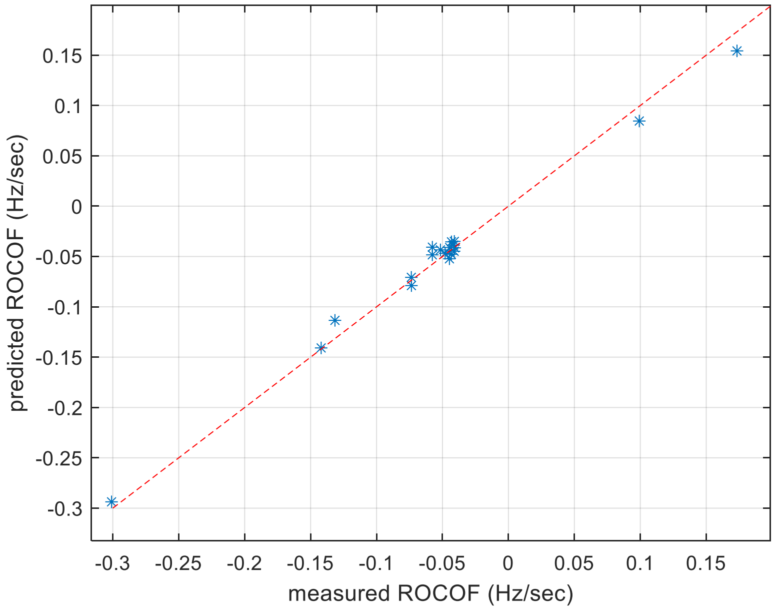

Figure 3 - Event-based validation of Scotland metered inertia results

3.2 Performance of Inertia Forecasting

Figure 4 gives an illustrative example of the performance of the inertia forecasting application – depicting the behaviour of metered inertia and nowcast (t0) inertia.

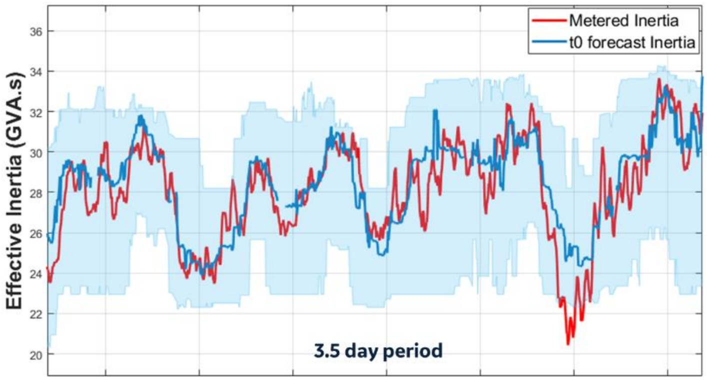

Figure 4 – Illustrative example of performance of Inertia Forecasting – shading indicates forecast confidence band.

It can be seen that the nowcast follows the metered inertia closely for the most part, but that there is deviation in some instances. This is not unexpected, since the two methods are independent – one measurement-based, one model-based. Differences can occur for example due to behaviour not captured in predictor values such as load makeup, and the behaviour of unmetered generation.

4 CONCLUSIONS AND NEXT STEPS

Decarbonisation and increasing interconnection of power grids are leading to a growing share of energy infeed coming from inverter-connected generation, storage and HVDC links – compared to synchronous generation. This leads to reduction in inertia at whole-system and regional levels, which can bring challenges in maintaining system frequency and integrity following sudden generation or load loss. For an increasing number of grid operators, management of inertia is becoming a crucial element of day-to-day operation, and planning in market and investment timescales. Measures to manage or mitigate inertia levels can come at significant commercial and carbon cost – nearly £350m in GB for the year ending

March 2021 [4]. Accurate monitoring and forecasting of inertia is therefore crucial to support secure and economic operation as grids continue to decarbonise.

This paper has described a software solution for the passive metering, forecast and validation of effective area inertia, and its operational deployment in the GB system. Initial results from the solution have been presented, which indicate that the metering and forecast applications are performing in line with expectations.

A more comprehensive analysis of the performance of the inertia metering and forecast applications will be conducted in 2022, once a more substantial period of data has been collected. Additional PMU deployments are also anticipated, which will extend visibility to the remainder of the GB system.

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