A Survey on Inertia Related Challenges and Mitigation Measures

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***Abstract*—The amount of kinetic energy in the Nordic power system decreases due to structural changes in the power system. In this paper, the Nordic Transmission System Operators (TSOs) provide a summary of a survey, which was sent out to some small- and medium-sized synchronous areas, in order to learn from their experiences with low kinetic energy situations. The paper summarizes the responses received, thereby providing a view on: the current and future assessment of inertia in the system (including key drivers behind the change), and mitigation methods for low inertia situations.**

survey; inertia; frequency stability; renewable energy; synchronous system

I. Introduction

The Nordic power system is going through large structural changes which challenge the way the Transmission System Operators (TSOs) plan and operate the system. The changes will pave the way to the next generation power system, which will secure the future welfare, value creation, and help us reach carbon-neutrality. The main changes are [1]:

- The share of renewable energy sources in the energy mix is increasing, and more energy will to a larger extend be produced by small-scale, renewable and distributed power plants. Large-scale wind farms are also foreseen. Most of those units are connected by means of power-electronic converters.
- Nuclear power plants are de-commissioned earlier than initially planned in Sweden, while Finland is constructing new.
- Denmark and Finland have shut down many fossil-fueled power plants.
- The Nordic power system will be more strongly connected through HVDC interconnectors with other synchronous systems, for example the central European system, due to the commissioning of more interconnectors.
- More coupled markets, including exchange of balancing reserves.
- Changed load characteristics, for example industrial loads are connected to the grid through power-electronic converters.

Frequency stability of power systems is highly dependent on the amount of kinetic energy in the system, as demonstrated in Fig. 1 [2]. The figure shows the response in system frequency during a sudden loss of production.

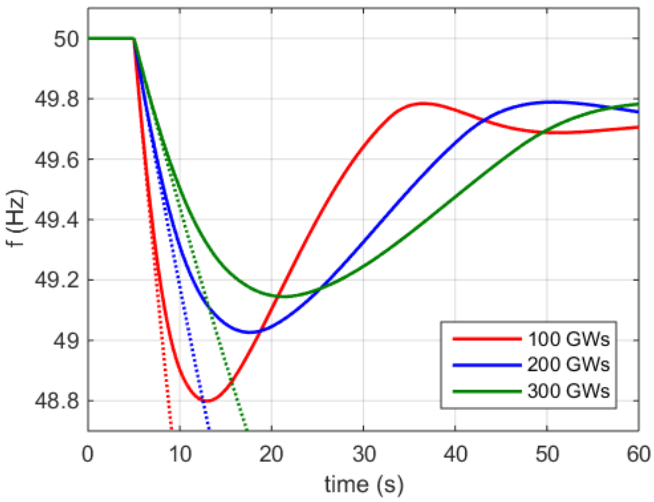

Figure 1 The effect of the amount of kinetic energy on the behaviour of frequency after a loss of production with (solid) and without (dotted) Frequency Containment Reserves (FCR)

Reduced kinetic energy has an impact on the ability of the system to resist changes in frequency due to imbalance between power production and consumption. All rotating machines connected synchronously to the system contribute to this kinetic energy. Much renewable generation connected through converters to the grid continues to replace the conventional generation. As a result, the amount of kinetic energy in the system decreases and may reach critical levels unless no countermeasures are taken. Such situation may result in involuntary production or consumption shedding after the occurrence of a dimensioning incident. Furthermore, an increase in HVDC import capacity may also contribute to the decrease in the kinetic energy of the system.

The structural changes identified in the Nordic power system are not unique, and similar changes are occurring in other systems. Small and medium-sized synchronous systems are likely to already have experience and knowledge on how to handle the challenges. To benefit from the experience gained, a survey was sent out by the Nordic TSOs in the autumn of 2016.

II. Synchronous Systems in the Survey

In total 10 answers were received, Table I shows an overview of the systems which answered the survey. Moreover, the corresponding values for the Nordic synchronous system are also shown.

Most systems have a market-driven dispatch, 3 systems (ESKOM, Faroe Islands, and Hydro-Quebec TransEnergie) have a centralized dispatch, whereas Rhodes in Greece is in a transition towards a market-driven dispatch.

TABLE I. BASIC INFORMATION OF THE SYNCHRONOUS SYSTEMS, WHICH ARE IN THE SURVEY (THE INFORMATION IN THE TABLE IS BASED ON 2015 DATA)

Synchronous area or company name	**Country**	**Min. / Max. load in GW**	**Min. / Max. kinetic energy GWs**	**Specific**
The Nordic power system	Norway, Eastern Denmark, Sweden, Finland	25 / 70	125 / 240	One synchronous area with four transmission system operators (TSOs)
ERCOT (The Electric Reliability Council of Texas)	USA	24 / 70	152 / 389	The Electric Reliability Council of Texas (ERCOT) is the electricity grid and market operator for the majority of the state of Texas.
National Grid (NG)	Scotland, Wales, England	17 / 53	130 / NA [3]	NG is the National Electricity Transmission System Operator (NETSO), for Great Britain
Eirgrid	Ireland	2.3 / 6.4	20 / 46	The synchronous power system of the island of Ireland comprises of both the EirGrid-controlled Irish system and the SONI-controlled Northern Irish system.
Transpower	New Zealand (North Island)	1.7 / 4.5	20 / 41	Two synchronous areas: North Island and South Island. The islands are connected with an HVDC link.
Transpower	New Zealand (South Island)	1.3 / 2.2	11 / 25	
Faroe island	Denmark	0.02 / 0.05	Not available	
AEMO (Australian Energy Market Operator)	Queensland, Victoria, New South Wales, and Tasmania in Australia	14 / 30	72 / 50	Tasmania has a HVDC connection; the other states belong to one synchronous system.
ESKOM	South Africa	19 / 35	Not estimated	
Rhodes	An island in Greece	0.032 / 0.191	0.15 / 0.63	
Hydro-Quebec TransEnergie	Canada	15 / 39	60 / 160	Synchronous area is the Quebec interconnection. Almost all of the interconnection is located on the territory of Québec.

III. The Different Synchronous Areas Compared

Next to the technical characteristics of the synchronous area, as listed in Table I, other elements do play a role when assessing the inertia, and its impact, in a synchronous area.

The dimensioning incident is the single event causing the highest instantaneously-occurring active power imbalance in both positive and negative direction in the synchronous system. This can for example be a trip of a nuclear power station, leading to a frequency dip (as shown in Fig. 1), or a trip of an HVDC link exporting power to another synchronous area, leading to a frequency rise. The dimensioning incident, together with the inertia and frequency reserves in the system at the time of the disturbance, set the minimum and maximum frequency that the system can face under N–1 conditions. The dimensioning incidents for the systems in the survey are depicted in Fig. 2.

Production behind power-electronic interfaces does not contribute to the inertia in the system. The same applies for HVDC links connected between two synchronous areas. Fig. 3 presents the total installed generation capacities in the systems, and the installed capacity of the generation not-contributing to inertia including HVDC capacity. Fig. 4 shows the percentage values of generation that does not contribute to inertia and import HVDC capacities as a share of the installed generation.

Fig. 4 shows that the HVDC import together with the share of generation that does not contribute to the inertia exceeds 30 % in two systems: the UK and Ireland. For two systems, the share is 20–25 %. This does not directly express the number of hours when the inertia is low, but it is an indicator that there may be hours when the inertia is low.

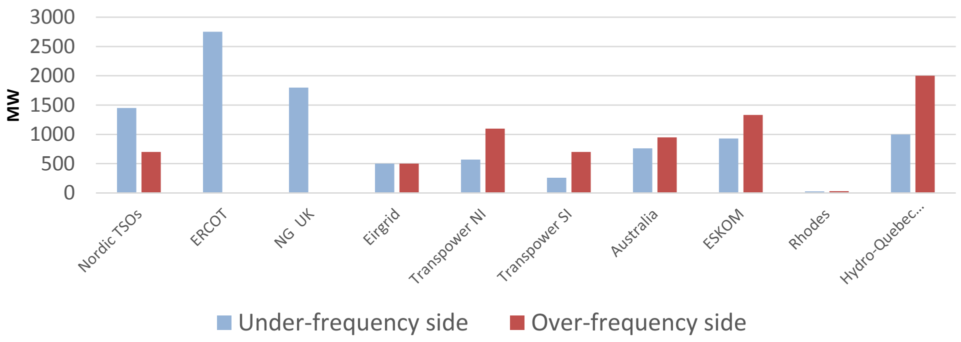

Figure 2 The largest loss (dimensioning incident), that can happen in the system. NI = North Island, SI = South Island. For Rhodes the values are 26 MW for under-frequency and 33 MW for over-frequency

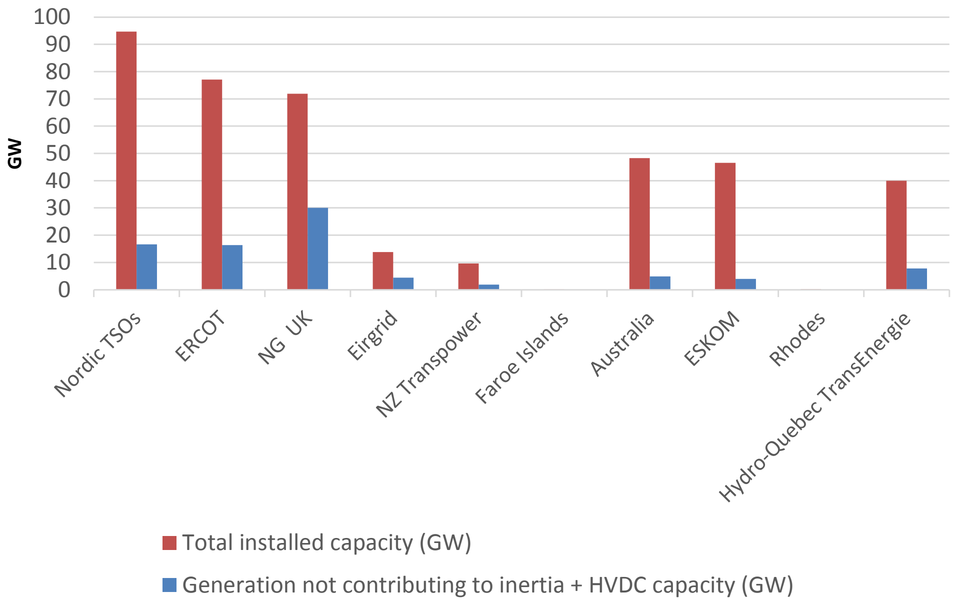

Figure 3 The total installed capacity and the amount of non-synchronous generation, both in gigawatts. For Ercot the number represents summer peak demand where installed wind and solar generation capacity are discounted based on capacity contribution and summer ratings for thermal generation are used

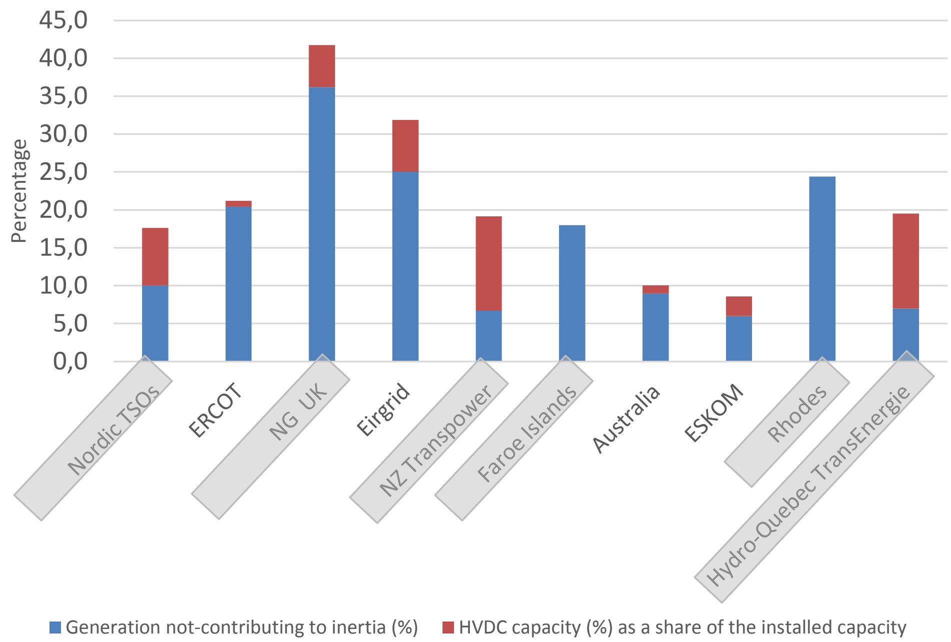

Figure 4 The share of the (combined) installed capacity of generation not contributing to inertia and the transmission capacity of HVDC import in percentages of the system installed capacity. The TSOs that consider low inertia to be an issue are marked with a grey box.

The TSOs that consider inertia to be an issue are marked with a grey box in Fig. 4. Fig. 4 also shows that Eirgrid and ERCOT have a quite high share of generation and HVDC import not contributing to the inertia in the system, but do not consider low inertia to be an issue today. ERCOT states that they have enough inertia at the moment, and that they are monitoring the situation. In 2014, ERCOT performed dynamic simulations for dimensioning their reserves. Eirgrid does not consider low inertia to be an issue for the system today, but the future trends indicate that inertia will decline as the penetration of non-synchronous renewable generation increases further. The TSOs in Ireland have engaged in a number of activities to mitigate the impacts of lower inertia on the system through their DS3 programme [4].

Table I and Fig. 2 – Fig. 4 show that there are variations in the systems when it comes to the system load, kinetic energy, and dimensioning incident. The reasons for the differences are diverse. The acceptable frequency deviation tends to be larger in smaller systems, which explains to some extent why smaller systems can accept relatively larger dimensioning incidents. The normal frequency range in Rhodes is 50 Hz ± 1 Hz, while the corresponding frequency range for other systems is smaller and the deviation from the nominal frequency varies between 0.017 Hz (ERCOT) and 0.5 Hz (Australia and Faroe Island). The share of non-synchronous generation varies both between the systems, and in the same system depending on the generation and exchange situation, and this explains the variations to some extent.

For 6 systems, low inertia is an issue at the moment, whereas 4 answered that currently the inertia is not an issue (for the intact grid). When describing the inertia, 6 systems mentioned frequency stability or maintaining frequency as a challenge, especially frequency after trips of importing HVDC links or after the trip of generators. Two systems mentioned voltage oscillations after a generator trip in this respect. The systems face inertia problems with high HVDC import, when generation from converter-connected power plants is high, with low amounts of generation from conventional synchronous generators, when the demand is low, or when hydro reservoirs have low storage levels.

IV. Main Observations

A. *Low inertia as a challenge*

More than half of the systems in the survey (6 out of 10) indicated that the decreasing inertia is a challenge. According to the answers, the key factor for the transition towards less inertia in the system, is the change in the generation mix. This change reduces the share of the thermal power, or replaces (large) thermal units with smaller units, and increases the share of non-synchronous generation (such as wind and photovoltaic). The following reasons behind this change were mentioned: fossil-fuel costs, CO_2 emission prices, EU-directive towards renewables, aims to have a fossil-free future in 2030. Other reasons mentioned were increased imports via HVDC interconnectors or via weak AC lines and customer-installed distributed photovoltaic generation systems.

B. *Planning the reserves for operation*

Three systems describe the procedure how they dimension the amount of reserves the system needs for a secure operation. ERCOT, National Grid (NG), and New Zealand Transpower dynamically dimension the needed disturbance reserves according to the system state. ERCOT determines the minimum requirement of Responsive Reserve Service (RRS) based on the expected system inertia conditions. RRS is a service used for frequency response and in case of energy scarcity. Load resources tripping with a 0.5 s delay is a part of this service. The reserves in NG vary and are based on the system demand and the largest loss being covered. In New Zealand, the primary reserves are purchased depending on the size of the risk on the system. They have a market tool, the Reserve Management Tool (RMT), which carries out a dynamic study for each trading period to calculate the amount of reserves required.

C. *Inertia assessment*

Among the 10 answers, 9 stated that they assess the current system inertia, and 7 have an on-line inertia assessment in place. Eight systems assess the future inertia. Two systems assess the inertia today with dynamic simulations (NZ Transpower, ESKOM), 6 use generation connection data from the SCADA and combine this with turbine-generator kinetic energy (Nordic, Eirgrid, ERCOT, Faroe Island, NG UK, and Hydro-Quebec TransEnergie).

Five systems use inertia assessment for knowledge building (Nordic TSOs, ERCOT, NZ Transpower, and Faroe Island) and/or archive them for studies (Hydro-Quebec TransEnergie and Nordic TSOs). ERCOT considers the inertia to be adequate at the moment but they are monitoring the trend of the decreasing inertia in the system. NG uses the inertia estimation to check the maximum loss (in megawatts) that the system can face without exceeding the RoCof (Rate of Change of Frequency) limit. Eirgrid uses the inertia estimation as a part of the operational constraints; they have a requirement that the system inertia should not fall below 20 GWs.

D. *Mitigation measures for low-inertia situations*

In today's power system, the systems deal with low-inertia situations in different ways. Three systems (Nordic TSOs, Australia, and ESKOM) indicate that they have no solution in place for dealing with low-inertia situations at the moment. Two systems (ERCOT, Transpower in NZ) have market-based solutions while 5 systems (Eirgrid, Faroe Island, NG, Rhodes, and Hydro-Quebec TransEnergie) have non-market-based solutions. Several answerers do not mention explicitly the details of their non-market-based solutions. Eirgrid indicates that their non-market-based solutions include a central procurement with regulated tariffs, which is expected to transition into an auction-based approach in the future.

The existing solutions can be classified in different groups based on the techniques used:

- Increasing reserves (generation and load) (NZ Transpower, UK, ERCOT).
- Having some kind of operational limits for the system such as a minimum kinetic energy (20 GWs, Eirgrid), limiting the flow on weak AC interconnections (some parts in Australia), ensuring that the RoCoF does not increase after a generator loss (NG UK), or imposing power limitations to

avoid under-frequency load shedding caused by a single contingency (Hydro-Quebec TransEnergie).

- Running at almost idle or minimum power with hydro or thermal units (Faroe Islands).
- Contracted load disconnections as primary reserve using load under-frequency relays. ERCOT, Australia, and Rhodes mention this but all systems have under-frequency load shedding.

Some systems have plans for the near future (2020–2025) or the far future (2025–), for dealing with low inertia. More reserves, synthetic inertia (as an ancillary service for example), more flexible thermal units, adding connections to other synchronous systems, and services from battery storage are mentioned in this respect.

Only Hydro-Quebec TransEnergie has a grid code requirement for inertia. It boils down to the following requirements for wind power plants [5]: "*Wind power plants with a rated output greater than 10 MW must be equipped with a frequency control system. The system must be continuously in service but only act during major frequency deviations. It will not be used for steady-state frequency control. The purpose of the system is to enable wind power plants to help restore system frequency and thus maintain the present level of transmission system performance during major disturbances. To achieve this, the system must reduce large, short-duration frequency deviations at least as much as does the inertial response of a conventional synchronous generator whose inertia (H) equals 3.5 s. This target performance is met, for instance, when the system varies the real power dynamically and rapidly by at least 5% for about 10 s when a large, short-duration frequency deviation occurs on the power system.*"

Among the tools for mitigating low-inertia situations, a question was explicitly asked about synthetic inertia or similar methods. There are two systems applying synthetic inertia: Faroe Islands and Hydro-Quebec TransEnergie. Hydro-Quebec TransEnergie gets the synthetic inertia from wind generation. Faroe Islands gets its synthetic inertia from a 2.3 MW battery, which has the first priority to smoothen the power from Húsahagi windfarm. The battery system is also able to make an instant discharge and give frequency support as virtual inertia. Eighteen wind turbines in Faroe Island have virtual inertia power support but these configurations are undergoing changes at the moment. These are all units connected via power-electronic converters.

The others have various tools such as HVDC, power-electronic converters, or load reduction, but do not state them being synthetic inertia. The answers presented in Fig. 5 show an indication of the types of mitigation measures, and the resources providing it. The figure has therefore no dimensions.

V. Nordic Future System Inertia Study

The survey and the responses presented in this paper, are part of the Nordic Future System Inertia Study. The Nordic TSOs have studied inertia-related issues in their project 'Future System Inertia' phase 1 [2]. The work, started in phase 1, has been continued in the second phase of the project. The objectives of the Future System Inertia 2 project are to anticipate and to avoid the effects of low-inertia situations, by means of proper forecasting tools and mitigation measures. The scope of this study consist of the following elements:

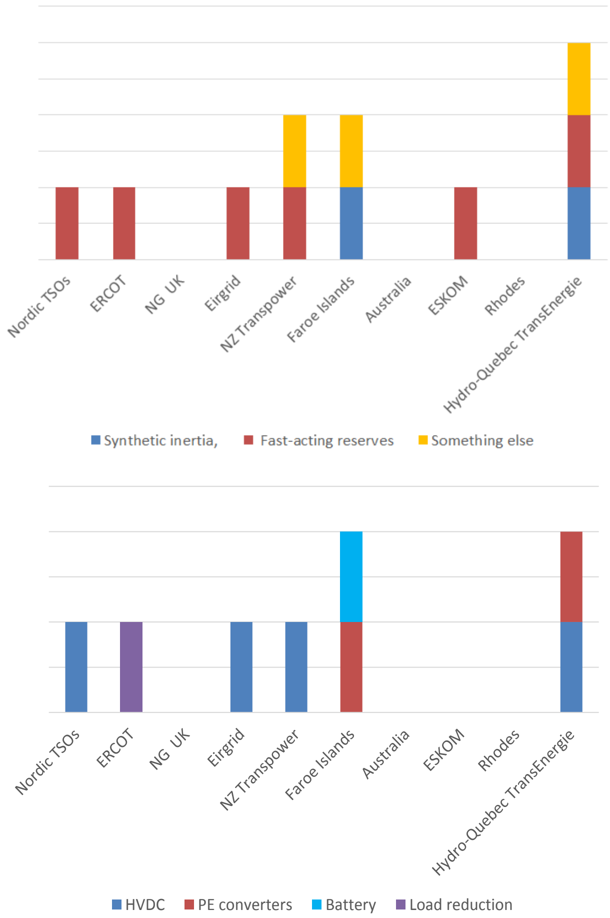

Figure 5 Synthetic inertia, fast-acting reserves, and other tools for supporting the system in low-inertia situations

- Experiences in other synchronous areas,
- Future kinetic energy estimation,
- Measures to handle future low kinetic energy situations,
- Improvement of inertia estimation and operational tools.

With the first bullet point being the main topic of this paper, the three latter elements will be shortly touched upon in the sections below.

A. *Future kinetic energy estimation*

In order to assess the impact of the changes ongoing and foreseen on the kinetic energy in the system, future market scenarios were defined by the Nordic TSOs for the years 2020 and 2025. These market scenarios were the input for market simulations, where the power production and corresponding market prices were simulated, based on the data corresponding to different (hydro) inflow years. In this way, a forecast of the generation units - that will be producing power in the years 2020 and 2025 - was obtained. Those generation units, of which the inertia constants are known, bring inertia into the system, and an estimate of the kinetic energy in the system has been computed.

B. *Measures to handle future low kinetic energy situations*

In order to prevent load shedding (on the under-frequency side), or generation shedding (at the over-frequency side), the frequency in the Nordic synchronous area needs to remain within a frequency band of 49–51 Hz after the occurrence of an N-1 disturbance. The 'dials' to reach this objective are schematically depicted in Fig. 6. The rotating mass in the system can be increased, for example, by introducing (more):

- synchronous condensers,
- operation of Pelton turbines at zero or low power production,
- inertia from gas turbines,
- inertia from the pumps of pump-storage hydro power plants.

The Dimensioning Incident is the largest production or consumption unit that can be the subject to an N −1 outage in the system at a specific moment in time. By reducing the amount of active power being produced in the largest generator, or consumed in the largest load, the impact (frequency excursion) of this so-called dimensioning incident can be limited. The dimensioning incident in the system can be altered by:

- decreasing the output power of the largest unit;
- decreasing the import / export on an HVDC link;
- decreasing power of system protection disconnecting generation to avoid overloading transmission lines.

Instead of active power being extracted from the rotating mass in the system, active power can also be injected when needed to limit the frequency excursions, and to support the frequency restoration. This may be established in the following ways:

- provide extra FCR-D (Frequency Containment Reserves for Disturbances),
- provide synthetic inertia,
- provide FFR (Fast-Frequency Reserves),
- provide EPC (Emergency Power Control from HVDC links),
- reduce loads during the event e.g. disconnect pumps of pump-storage hydro power plants.

The Nordic work on mitigation measures continues with the aim of having efficient tools ready in the short term (2020) and in the longer term (2025).

C. *Improvement of inertia estimation and operational tools*

In order to have a real-time grip on the inertia in the system, all the Nordic TSOs responsible for the Nordic power system have implemented a kinetic energy estimation in their SCADA/EMS, whereas the online dimensioning incident determination was implemented in the SCADA systems as well, within the framework of this project. With

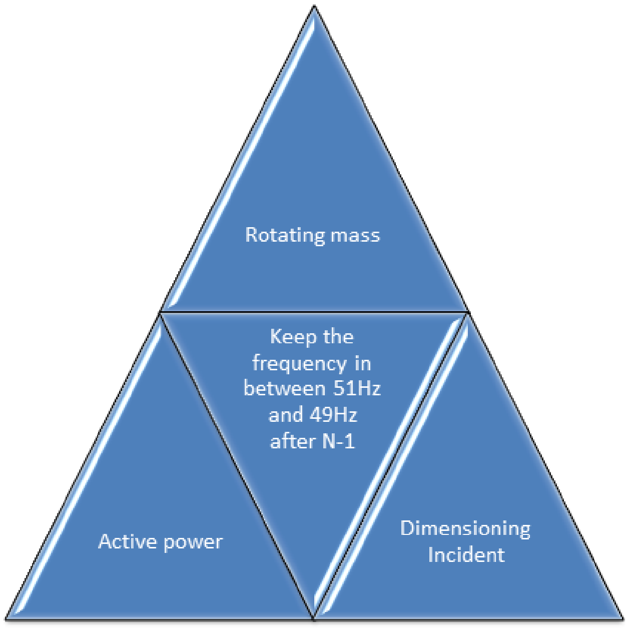

Figure 6 'Dials' to keep 49 Hz < f < 51 Hz after an N−1 event

these online data available, a linear regression model has been implemented in the Finnish SCADA system (and shared with the other Nordic SCADA systems), for an online extreme frequency estimation, in case of a dimensioning incident in the system.

With the work on the European Common Grid Model (CGM) ongoing [6], it is exactly that information (the forecast of power produced by individual generation units and their inertia constants) that will be available for the time frames targeted by the CGMs: year ahead, month ahead, week ahead, two days ahead, day ahead, and intraday. With the CGM being the best estimate of the grid for the targeted time frame (incl. generation, load, topology, and exchanges over DC links), it provides an efficient basis for a kinetic energy forecast in the power system planning.

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