REPORT

Future system inertia

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ABBREVIATIONS AND SYMBOLS

Abbreviations

COI	Centre of Inertia
EMS	Energy Management System
EPC	Emergency Power Control
FBF	Frequency Bias Factor
FCR	Frequency Containment Reserve
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operation
FIR	Finite Impulse Response
HVDC	High Voltage Direct Current
NAG	Nordic Analysis Group
NOIS	Nordic Operator Information System
PFK	Production disconnection
PMU	Phasor Measurement Unit
RGN	Regional Group Nordic
RAR	Requirements for Automatic Reserves
ROCOF	Rate-of-change-of-frequency
SPS	System protection scheme
TSO	Transmission System Operator

Symbols

E_k	Kinetic energy
f	Frequency
f_{COI}	Center of inertia frequency
f_{extreme}	The minimum or maximum instantaneous frequency
f_{n}	Nominal frequency
f_{start}	Frequency at the start of the disturbance
GD^2	Moment of inertia
H	Inertia constant
H_{tot}	System inertia
J	Moment of inertia
P	Active power
P_{e}	Electrical power
P_{m}	Mechanical power
S_{n}	Rated apparent power
t_{extreme}	The time the frequency reaches f_{extreme}
t_{start}	Start time of the disturbance
ω	Angular velocity
ω_{n}	Rated angular velocity

1. INTRODUCTION

In order to maintain operational security of the power system its frequency must lie within a predefined range, and not deviate too far from the frequency for which the system was designed. If the frequency is not held near its nominal value, protection systems begin to activate in order to protect machinery, and to keep the power system operational.

Large deviations in frequency are often caused by the tripping of large production units or HVDC-links connected to other synchronous systems, which result in sudden imbalances in generated and consumed active power. Frequency can then drop to an unacceptable level, resulting in the disconnection of production units and loads, producing a cascade effect, which may lead to widespread power outages. As production units and HVDC-connections become larger, greater imbalances will arise, resulting in potentially larger frequency deviations (Nordic Analysis Group, 2015).

Synchronous generators help the power system to resist changes in system frequency. All synchronously connected rotating machines contribute to this resistance with their kinetic energy. However, as renewable production begins to replace conventional production, the ability of the system to resist these changes decreases. Modern generating plants such as wind and solar power plants comprise of generating units which interface to the power system through frequency converters. These converters, however, are most often controlled in such a way that operation of the generating plants is independent of the system frequency, resulting in reduced system inertia[1]. The same is true of motor loads which utilise power electronics.

It is expected that electricity will be produced more and more by wind and solar power plants. Additionally, thermal power plants will spend less time synchronised to the power system. Load characteristics are also expected to continue to change, with rotating motors being connected to the power system through frequency converters. High import on HVDC connections to other synchronous systems is also expected to replace traditional production more often (Kuivaniemi, et al., 2015). These factors will impact system kinetic energy.

Knowing the amount of kinetic energy in the power system is necessary for studying many frequency related issues, such as the operation of frequency controlled reserves. Therefore, it is of interest to know the amount of system kinetic energy in order to operate the system securely and as efficiently as possible (Kuivaniemi, et al., 2015). The aim of the project "Future system inertia" is to improve the knowledge of power system behaviour related to the system inertia. It is therefore important to determine what the current level of kinetic energy is in the power system, and what levels of kinetic energy are expected in the near future.

The Nordic Analysis Group (NAG) has initiated the project "Future system inertia" in Autumn 2013 and the project proposal was approved by Regional Group Nordic (RGN) on 19th November 2013 (Nordic Analysis Group, 2013).

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[1] Power system inertia is defined as the ability of a power system to oppose changes in system frequency due resistance provided by rotating masses. Inertia is dependent on the amount of kinetic energy stored in rotating masses connected to the system.

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1.1 SCOPE FOR THE PROJECT

The project scope (Nordic Analysis Group, 2013) includes four tasks:

1. Establishment of systematic process to study frequency disturbances and inertia
2. Harmonising of inertia calculation method
3. Implementation of inertia real-time estimation
4. Study on the impact of future production and consumption changes on inertia

The background for the first task "Establishment of systematic process to study frequency disturbances and inertia" was that even though Nordic TSOs report frequency disturbances in common IT-tool called NOIS, there is no harmonised procedure to report these disturbances. This makes it difficult to use disturbance data to estimate power system kinetic energy. The aim of this task was to create a harmonised procedure to report frequency disturbances in NOIS. This however was a task which was not addressed in this project due to the difficulties in estimating inertia from frequency disturbance data. Further improvements in recording to NOIS were therefore also not addressed either at this stage.

It has been noted that attempts to calculate the inertia of a system from frequency measurements have resulted in widely varying results, which are very sensitive to the frequency data used to calculate this value, and to the calculation method. For that reason the second task "Harmonising of inertia calculation method" was needed. The aim of this task was to define how and with what type of data the calculation shall be performed so that the result is reliable.

The aim for the third task "Implementation of inertia real-time estimation" was to create a real-time estimation of kinetic energy in the Nordic power system. This estimation is needed in order to better prepare for different kinds of operational situations where there might be a reduction in inertia in the system.

The last task "Study on the impact of future production and consumption changes on inertia" was necessary to obtain future scenarios of the Nordic power system kinetic energy and this way to prepare for the development of the system. It is expected that in the future there will be an increased amount of renewables which add little or no rotating mass to the power system, and that old condensing power plants will rarely be connected to the system. These changes will have an impact on the system inertia.

In addition to these tasks a review of a possible way to estimate the minimum instantaneous frequency using estimations of the kinetic energy has been included. This has been done through an empirical analysis, which has been performed by looking at historical disturbances. The analysis compares the change in frequency to the change in power for these disturbances, and finds a relation between these. This relation can then be used to make a rough estimation of the maximum instantaneous frequency deviation.

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1.2 Outline

This report addresses the tasks in the scope of the project, as well as provides some additional background for ease of reading.

In Chapter 2 a presentation of some theory which describes the mechanisms involved in the frequency issues we are studying is given.

In Chapter 3 studies are performed to evaluate different methods of calculating kinetic energy from measured frequency during disturbances. In addition, new methods are developed and tested.

In Chapter 4 the efforts made by the TSOs for calculating and logging the kinetic energy of the system in real time is recorded.

In Chapter 5 a review of different methods to estimate the maximum frequency deviation after a disturbance is presented.

In Chapter 6 scenarios for future production and kinetic energy, created by the Nordic TSOs are described.

In Chapter 7 the conclusions of this study are presented, with references in Chapter 8.

2. Theoretical Background

Inertia of a power system is defined as the ability of a system to oppose changes in frequency due to resistance provided by kinetic energy of rotating masses in individual turbine-generators. To look at the inertia of a larger system with a large numbers of generators, it is convenient to look at kinetic energy of the system, which is the amount of energy stored in these rotating masses. In this chapter we look at inertia and kinetic energy and how they affect the behaviour of frequency in a power system.

2.1 Inertia of a single machine

The inertia constant H describes the inertia of an individual turbine-generator:

$$H = \frac{1}{2}\frac{J{\omega_{\mathrm{n}}}^2}{S_{\mathrm{n}}}\ [\mathrm{s}] \tag{2.1}$$

where
J is the moment of inertia of a generator and turbine [kg·m^2],
ω_{n} is the rated mechanical angular velocity of the rotor [rad/s],
S_{n} is the rated apparent power of the generator [VA].

The inertia constant is given in seconds and it can be interpreted as the time that energy stored in rotating parts of a turbine-generator is able to supply a load equal to the rated apparent power of the turbine-generator. (Kundur, 1994)

Sometimes moment of inertia of a turbine-generator is given in gravimetric units GD^2. Gravimetric units can be converted to joules using (Nissei Corporation, 2009):

$$J = \frac{GD^2}{4} \tag{2.2}$$

where GD^2 is the moment of inertia [kg·m^2].

2.2 Inertia of a power system

The inertia constants and rated apparent powers of individual turbine-generators can be used to calculate inertia of a power system:

$$H_{\mathrm{sys}} = \frac{\sum_{i=1}^{N} S_{\mathrm{n}i} H_i}{S_{\mathrm{n,sys}}} \tag{2.3}$$

where $S_{\mathrm{n,sys}} = \sum_{i=1}^{N} S_{\mathrm{n}i}$, $S_{\mathrm{n}i}$ is the rated apparent power of generator i [VA] and H_i is the inertia constant of turbine-generator i [s].

Motors connected synchronously to power system also contribute to system inertia and can be taken into account in a similar way as generators.

Instead of expressing inertia of a power system in seconds, it is often more convenient to calculate the kinetic energy stored in rotating masses of the system in megawatt seconds (MWs). Then, Equation (2.3) can be written as:

$$E_{\mathrm{k,sys}} = S_{\mathrm{n,sys}} H_{\mathrm{sys}} = \sum_{i=1}^{N} S_{\mathrm{n}i} H_i \ \ [\mathrm{MWs}] \tag{2.4}$$

2.3 THE BEHAVIOUR OF FREQUENCY

Power changes in consumption and production that affect the frequency occur continuously. Small power changes are however only visible as noise in the frequency due to the mass of the synchronous generators in the power system. For large power imbalances, the system frequency can deviate further from the nominal. At the instant a large power imbalance occurs in the system the frequency starts to change. If there is a sudden power deficit after for example a trip of a production unit, the deficit will be delivered from all synchronously connected rotating masses. As the kinetic energy is dissipated the speed of the rotors is decreased and thereby the frequency. How fast the frequency changes depend on the change in active power and the system inertia.

The dynamic behaviour of an individual synchronous turbine-generator i can be described using the motion equation of a rotating mass (the swing equation):

$$H_i \frac{df_i}{dt} = \frac{f_{\mathrm{n}}^{\ 2}}{2 S_{\mathrm{n}i} f_i} (P_{\mathrm{m}i} - P_{\mathrm{e}i}) \tag{2.5}$$

where f_i is the frequency of generator i, f_{n} is the nominal frequency, $P_{\mathrm{m}i}$ is the mechanical power of turbine-generator i, and $P_{\mathrm{e}i}$ is the electrical power of generator i (Kundur, 1994).

Equation (2.5) shows that an imbalance between the mechanical and electrical power of a turbine-generator results in frequency derivative. The rate of change of frequency is defined by the imbalance and inertia of the turbine-generator.

Real power systems consist of a large number of generators and the network which connects the generators to loads. Hence, when an imbalance in the system arises, frequency is not uniform throughout the system (see Figure 2.4).

The following example illustrates how a system behaves when subjected to a large power imbalance, why inertial response is important and how the amount of inertia affects the behaviour of the system.

Example: Frequency control during large disturbances

For simplicity, let us assume that the power system consists of two generators and one load, all connected to a common bus as shown in Figure 2.1. Furthermore, zero losses and constant voltages are assumed. Generator G_1 provides Frequency Containment Reserves (FCR) and the load has a frequency dependence of 0.75 %/Hz i.e. the load decreases by 270 MW when frequency decreases by 1 Hz. Kinetic energy stored in rotating masses of turbine-generator 1 is 200 GWs and kinetic energy of turbine-generator 2 is 8 GWs.

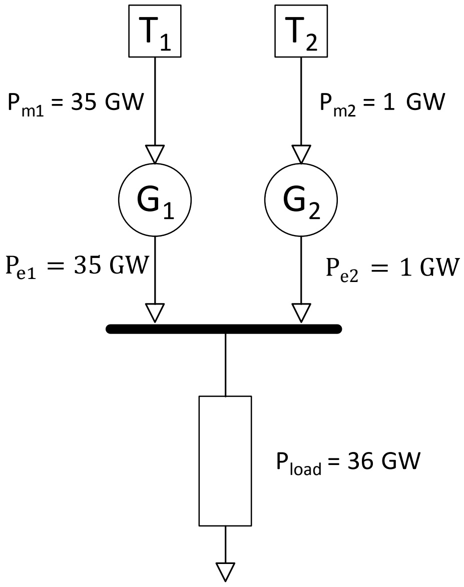

FIGURE 2.1: STATE OF THE POWER SYSTEM BEFORE THE TRIP

At time $t = 5$ s generator G_2 trips. Before the trip, the system is perfectly balanced. Frequency is at 50.0 Hz and mechanical power from turbine T_1 and the electrical power of generator G_1 is 35 GW. Mechanical power from turbine T_2 and the electrical power of generator G_2 is 1 GW. In other words, mechanical power from the turbines equals electrical power from the generators, both of which are equal to the power consumed by the load.

$$P_{\mathrm{m1}} + P_{\mathrm{m2}} = P_{\mathrm{e1}} + P_{\mathrm{e2}} = P_{\mathrm{load}} \tag{2.6}$$

After the loss of generator G_2, generator G_1 has to supply the 36 GW load so electrical power from generator G_1 has to increase by 1 GW to 36 GW. Immediately after the disturbance, mechanical power from the turbine T_1 is still 35 GW as it will take some time for the turbine governor to react to the disturbance. In other words, mechanical power from turbine T_1 is smaller than electrical power from generator G_1 so the turbine-generator begins to slow down according to Equation (2.5). As the turbine-generator slows down, the frequency reduces and the kinetic energy stored in rotating masses of the turbine-generator is transformed into electrical power used to supply the load in a process referred to as inertial response.

As Figure 2.2 shows, the lost 1 GW production is replaced by the inertial response immediately after the disturbance. As soon as the FCR begins to activate or the load begins decreases with decreasing frequency, the inertial response begins to decrease.

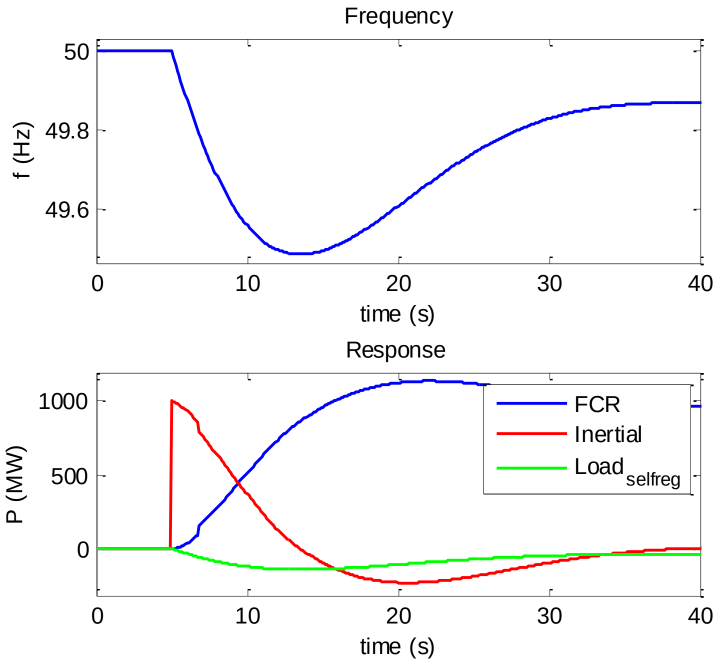

FIGURE 2.2: FREQUENCY, INERTIAL RESPONSE, RESPONSE FROM THE FREQUENCY DEPENDENT LOAD AND FREQUENCY CONTAINMENT RESERVES

Once the maximum instantaneous frequency deviation has been reached, synchronously connected rotating machines begin to accelerate and inertial response changes from positive to negative. Once mechanical power from the turbine is equal to the electrical power from the generator, the frequency stabilises. At that point, inertial response is zero.

Figure 2.3 illustrates how frequency behaves after a loss of production when the amount of kinetic energy in the system varies. The solid lines represent a situation where FCR begins to respond to the decreasing frequency and the dotted lines represent a situation without FCR.

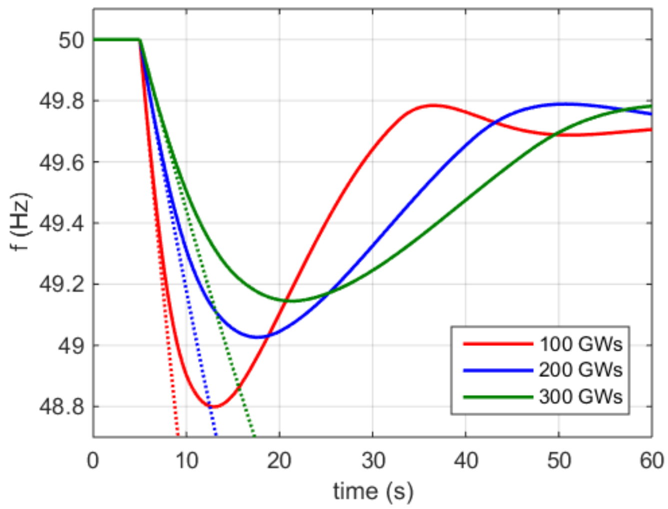

FIGURE 2.3: THE EFFECT OF THE AMOUNT OF KINETIC ENERGY ON THE BEHAVIOUR OF FREQUENCY AFTER A LOSS OF PRODUCTION WITH (SOLID) AND WITHOUT (DOTTED) FCR

Figure 2.3 shows that higher kinetic energy in the system results in slower frequency decay and higher minimum instantaneous frequency.

2.4 Synthetic inertia

Earlier in this chapter the inertia of a power system was defined as the ability of a system to oppose changes in frequency due to resistance provided by kinetic energy of rotating masses. If a power system is subjected to an imbalance between power production and consumption, the system frequency changes. This frequency change is a result of the synchronously connected generators accelerating or decelerating. The kinetic energy stored in rotating masses in the system is dependent on their rotational speed, which begins to change. Because turbine governors have rather long response time, mechanical power stays fairly constant during the first moments of a disturbance. Equation (2.5) indicates that a change in frequency results in a change of electrical power generated by the generators. This change in electrical power is often referred to as inertial response as the change in electrical power comes from the change in kinetic energy stored in rotating masses.

Since non-synchronously connected production units, like modern wind turbine generators, are connected via power converters, their rotational speed is isolated from the system frequency. They therefore do not deliver a natural inertial response and do not contribute to the system inertia.

A controller which emulates the inertial response of a synchronously connected generator can be included in a non-synchronously connected production unit. Inertial response produced by such a controller is often referred to as a synthetic, emulated, artificial or virtual inertial response. Using this kind of controller it may be possible to, for example, extract kinetic energy from the blades and the rotor of a non-synchronously connected wind turbine (Miller, Shao, Pajic, D'Aquila, & Clark, 2014). This can be achieved by measuring the rate of change of system frequency and applying an appropriate electrical torque on the rotor of the wind turbine. This slows the rotor which in turn releases kinetic energy from the blades and the rotor in a similar fashion to a synchronous generator.

HVDC-links could also be controlled in such a way that inertial response is transferred from one synchronous system to another (ENTSO-E, 2014).

2.5 Frequency response indicators

In this report, frequency measurements from frequency disturbances have been collected and investigated in order to investigate relations to the inertia. A set of frequency response indicators is calculated for each frequency disturbance.

It is however important to note the frequency is not the same throughout the whole system. During a disturbance the measurement location in the system plays a role due to the propagation of frequency wave. In Figure 2.4 the measured frequency during a frequency disturbance in the Nordic power system at two locations is shown.

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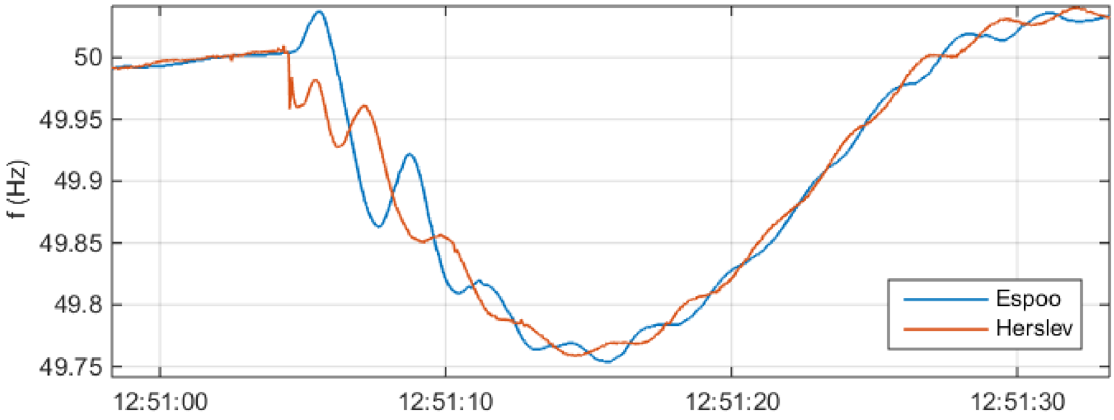

FIGURE 2.4: FREQUENCY IN ESPOO (SOUTHERN FINLAND) AND HERSLEV (DENMARK) AFTER A LOSS OF 580 MW

Inter-area oscillations, where generator groups oscillate against each other, can be seen in the figure.

When examining the frequency after a disturbance, there are features of interest which can affect a power system. Features such as minimum instantaneous frequency and time taken to reach minimum instantaneous frequency can be used to describe the consequences of frequency disturbances, and are used in dimensioning various system parameters.

The frequency in the Nordic power system is measured by several Phasor Measurement Units (PMUs) or similar devices with a sample frequency of 10–100 Hz. Depending on the accuracy of the measurement a filter must be used to reduce the level of measurement noise. The measurement noise can sometimes be observed as very rapid transients or high frequency oscillations in the frequency signal. To reduce the impact of the noise a low pass Finite Impulse Response (FIR) filter using a Hamming window of 600 ms with a cut-off-frequency of 1 Hz has been used in the report. The filter settings in this report have been chosen in an iterative manner to reduce noise to a level which allowed the start time to be to be correctly identified for as many disturbances as possible.

There are several indicators in relation to a frequency disturbance that should be defined. Start time of disturbance, frequency before the disturbance, minimum or maximum instantaneous frequency, maximum frequency deviation and time to reach maximum instantaneous frequency deviation are shown in Figure 2.5, which provides a graphical representation of the different frequency response indicators for a disturbance.

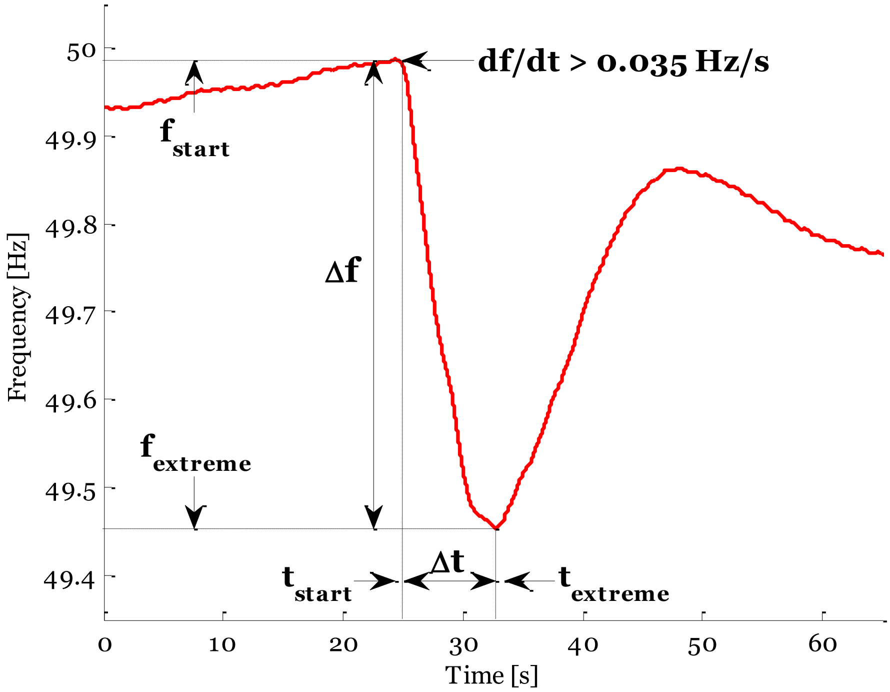

FIGURE 2.5: GRAPHICAL REPRESENTATION OF FREQUENCY RESPONSE INDICATORS

In this figure f is frequency and t is time.

START OF DISTURBANCE

It may be difficult to determine the start time of a frequency disturbance. One way to do this is to examine $\frac{df}{dt}$, known as the RoCoF (Rate of Change of Frequency). In this report the start of the frequency disturbance is defined as the time when absolute value of the RoCoF, calculated from the filtered frequency, exceeds 0.035 Hz/s. This threshold is shown in Figure 2.5.

The value 0.035 Hz/s was chosen for the threshold after performing an empirical analysis. By using this threshold, the start time was found for all studied disturbances, and was not sensitive to the filtered measurement noise. Choosing a lower threshold value results in slightly different start times, and increases the risk of finding an incorrect start time due to measurement noise. In Figure 2.5 the start time of the disturbance is $t_{\text{start}} = 25$ s and the frequency at that time is $f_{\text{start}} = 49.98$ Hz.

Other alternative methods for determining the start of a disturbance could be detrended fluctuation analysis, used in practice at National Grid (Ashton, Saunders, Taylor, Carter, & Bradley, 2014) or methods using voltage angle differences.

MINIMUM (MAXIMUM) INSTANTANEOUS FREQUENCY

The minimum or maximum instantaneous frequency, f_{extreme}, is defined as the highest or lowest frequency during a disturbance, depending on if there was a loss of production or load. The time when the frequency reaches f_{extreme} is defined as t_{extreme}. For the disturbance in Figure 2.5 there is a loss of production and the minimum instantaneous frequency $f_{\text{extreme}} = 49.45$ Hz occurs at $t_{\text{extreme}} = 32.8$ s.

MAXIMUM FREQUENCY DEVIATION AND TIME TO REACH THE MAXIMUM FREQUENCY DEVIATION

The change in frequency, Δf, is defined as the difference between the minimum or maximum instantaneous frequency deviation and the frequency at the start of the disturbance.

$$\Delta f = |f_{\text{extreme}} - f_{\text{start}}| \tag{2.7}$$

In the same way the time to reach the maximum frequency deviation is calculated

$$\Delta t = t_{\text{extreme}} - t_{\text{start}} \tag{2.8}$$

For the disturbance in Figure 2.5 the change in frequency is $\Delta f = 0.53$ Hz and the time to reach the maximum frequency deviation is $\Delta t = 7.8$ s.

3. Inertia estimation using measured frequency disturbances

3.1 Introduction

The goal of the work described in this chapter is to find a method which can be used in the Nordic power system to estimate the amount of kinetic energy using measured frequency during disturbances. Hence, the method has to be such, which can be implemented using a limited set of measurements.

The behaviour of frequency during large disturbances is studied using simulations in order to gain better understanding of the factors that affect the inertia estimation process. Furthermore, inertia estimation methods presented in literature are evaluated using simulations and a method which gives better results is developed.

In large, this chapter comes directly from (Kuivaniemi, et al., 2015) and is based on the work reported in (Kuivaniemi, Estimation of Generator Inertia in the Nordic Power System, 2014) where also a more detailed analysis can be found.

3.1.1 Theoretical background

The kinetic energy and the inertia constant of a synchronous turbine-generator i can be calculated using the motion equation of a rotating mass in Equation (2.5) and is rewritten here for convenience:

$$H_i \frac{df_i}{dt} = \frac{{f_\mathrm{n}}^2}{2S_{\mathrm{n}i} f_i}(P_{\mathrm{m}i} - P_{\mathrm{e}i}). \tag{3.1}$$

where H_i is the inertia constant of turbine-generator i, f_i is the frequency, $P_{\mathrm{m}i}$ is the mechanical power of the turbine, $S_{\mathrm{n}i}$ is the rated power, $P_{\mathrm{e}i}$ is the electrical power of generator i and f_n is the nominal frequency.

Real power systems consist of a large number of generators and the network connecting the generators and loads. In the Nordic power system, accurate frequency and power measurements do not exist for every generator, which makes it impossible to calculate kinetic energy and inertia constant of every generator separately. One way around this problem is to develop a simplified one-bus power system model where all generators are lumped into one single fictitious generator. Such a model is used, for example, in (Akbari, Madani, & Seyed, 2010) and can be expressed as

$$H_\mathrm{tot} S_\mathrm{n} = \frac{1}{2} f_\mathrm{n} \frac{dt}{df_\mathrm{COI}} \Delta P \tag{3.2}$$

where the so called centre of inertia frequency f_COI is used and can be calculated using the inertia constants and frequencies of individual generators:

$$f_\mathrm{COI} = \frac{\sum_{i=1}^{n} H_i f_i}{\sum_{i=1}^{n} H_i} \tag{3.3}$$

H_tot denotes the system inertia, S_n is the sum of rated apparent powers of the generators connected to the system and ΔP represents the change of generated or consumed power in the system after a disturbance. A step by step derivation of the model and the assumptions made can be found in (Kuivaniemi, Estimation of Generator Inertia in the Nordic Power System, 2014).

It can be argued that it is not practically possible to calculate the centre of inertia frequency f_{COI} as the inertia constants and frequencies of individual generators are not known. The argument made in this study is that if it is possible to obtain reliable results using this method, the centre of inertia frequency can be approximated using well-distributed PMU-measurements. Another approach, which has been used in many studies, is to use an arbitrary selected frequency measurement in place of the centre of inertia frequency.

The centre of inertia model contains a large number of simplifications, which have to be recognised. For example, network topology, load behaviour due to voltage and frequency dependent characteristics and changes in losses, are all omitted. The system inertia has to be calculated immediately after the onset of the disturbance since the response from disturbances reserves is not taken into account in Equation (3.2).

3.1.2 Previous work

In (Wall, González-Longatt, & Terzija, Demonstration of an Inertia Constant Estimation Method Through Simulation, 2010) an inertia constant estimation method is demonstrated in a single bus simulation environment. The method requires that the frequency, the mechanical power and the electrical power of every generator in the system is known. This method is considered not suitable for real power systems as in practice it is impossible to obtain such measurements. A somewhat similar method is presented in (Wall, Gonzalez-Longatt, & Terzija, Estimation of Generator Inertia Available During a Disturbance, 2012) and tested in a 39-bus simulation environment. This method estimates the inertia constant of every generator in a system and the system inertia is calculated as the summation of these estimates. This method requires that the frequency and the electrical power of every generator in the system is known. As such measurements are not available in the Nordic power system, this method is also not considered suitable.

In (Wall & Terzija, Simultaneous Estimation of the Time of Disturbance and Inertia in Power Systems, 2014) an inertia constant estimation method which uses frequency measurement and active power measurement from a single location is presented. The method assumes that frequency is homogenous throughout a power system. The article states that the method is suitable only for small power systems and therefore is likely not suitable for the Nordic power system.

The system inertia of 60 Hz system of Japan was calculated in (Inoue, Taniguchi, Ikeguchi, & Yoshida, 1997) using measured frequency disturbances. A fifth order polynomial was fitted to measured frequency transients using a least squares approximation. The purpose of the fit was to restrain the influence of an oscillatory component superimposed on frequency, caused by inter-area power oscillations. It is difficult to assess the performance of the method as it was not tested in a simulation environment. Also, the effect of measurement location on the results was not studied.

The system inertia of the Western Interconnection in North America was calculated in (Chassin, et al., 2005). The study used measured frequency during disturbances from one location only to calculate the system inertia. It is difficult to assess the performance of the method as it was not tested in a simulation environment.

The system inertia of the power system of Great Britain was calculated in (Ashton, Taylor, Carter, Bradley, & Hung, 2013). A fifth order polynomial was fitted to measured frequency data using a linear least squares approximation, just like in (Inoue, Taniguchi, Ikeguchi, & Yoshida, 1997). In the absence of any oscillatory component, the fifth order polynomial fit was not used. Instead, a 500 ms sliding window of a linear fit was applied for 1 second beginning from the onset of the disturbance. The effect of measurement location on the results was briefly studied. The study states that the location of a measurement device has an effect on the results and in some cases large differences in results were seen. The method was not tested in a simulation environment.

The system inertia of the Nordic power system was calculated in (E-Bridge Consulting GMBH, 2011). Frequency measurement from an arbitrarily selected location was used. The time derivatives of measured frequency were filtered using a 1-second moving average filter in order to avoid the influence of inter-area power oscillations. The maximum absolute value of the rate of change of frequency was used to calculate the system inertia. According to the report, the method was tested in one simulation in which it performed well. However, it is difficult to assess the performance of the method as comprehensive simulations were not run.

3.2 SIMULATIONS

3.2.1 SIMULATION MODEL

The simulation model used was a full-scale 6 500-node representation of the Nordic power system. The model has been developed over the last three decades by the Nordic TSOs and is used for grid and operation planning purposes. The simulation model includes models that represent the dynamic behaviour of generators, generator governors and FACTS-devices. (Uhlen, et al., 2003) The dynamic behaviour of motor loads is not modelled. Therefore, loads do not contribute to the system inertia.

Active and reactive loads are modelled as a mixture of constant power, constant current and constant admittance load characteristics. This way, loads are made sensitive to bus voltage. Furthermore, constant power and constant current load components are made sensitive to bus frequency.

Behaviour of frequency in the model was validated against actual PMU frequency measurements distributed throughout the system. This was done constructing a simulation of the trip of HVDC-connection NorNed on 18 March 2014. Simulated frequencies were found to correlate well with measured frequencies during the first few seconds of the disturbance as is shown in Figure 3.1.

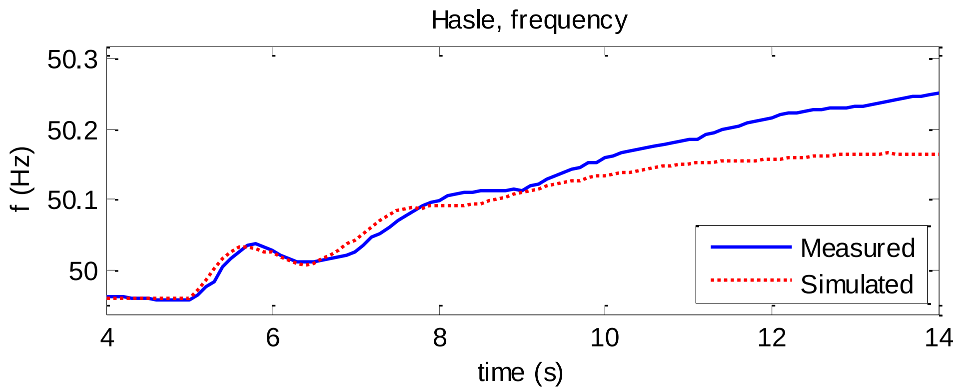

FIGURE 3.1: MEASURED (BLUE) AND SIMULATED (RED) FREQUENCY IN HASLE DURING THE NORNED TRIP

Based on this, the model can be used to study inertia calculation as it models the behaviour of frequency correctly during the time frame (the first few seconds after the onset of the disturbance) which is of interest when using measured frequency during disturbances to calculate the system inertia.

3.2.2 SIMULATION CASES

In addition to the simulation of the trip of NorNed on 18 March 2014, six different simulation cases were created so that the behaviour of frequency can be studied in different operational scenarios (see Table 3.1).

TABLE 3.1 OPERATIONAL SCENARIOS IN DIFFERENT SIMULATION CASES

Case	Operational scenario
1	Low flow from Sweden to Finland and Norway to Sweden
2	High flow from Finland to Sweden and Norway to Sweden
3	High flow from Sweden to Finland and Norway to Sweden
4	High flow from Finland to Sweden and Sweden to Norway
5	High flow from Sweden to Finland and Sweden to Norway
6	Moderate flow from Finland to Sweden and Norway to Sweden
NN-180314	High flow from Sweden to Finland and low flow from Norway to Sweden

Four different frequency disturbances were created in each simulation case. The disturbances were created by tripping of generators and HVDC-links connected to other synchronous systems. Trips of nuclear unit Olkiluoto 2 (Finland) or the unit Oskarshamn 3 (Sweden) or HVDC-connections from Norway to Netherlands (NorNed) and from Finland to Estonia (Estlink 1 or EstLink 2) were used for this purpose (see the red dots in Figure 3.2). Tripping of generators due to AC (Alternating Current) faults, like short circuits, was not used because frequency disturbances are mostly caused by internal unit faults.

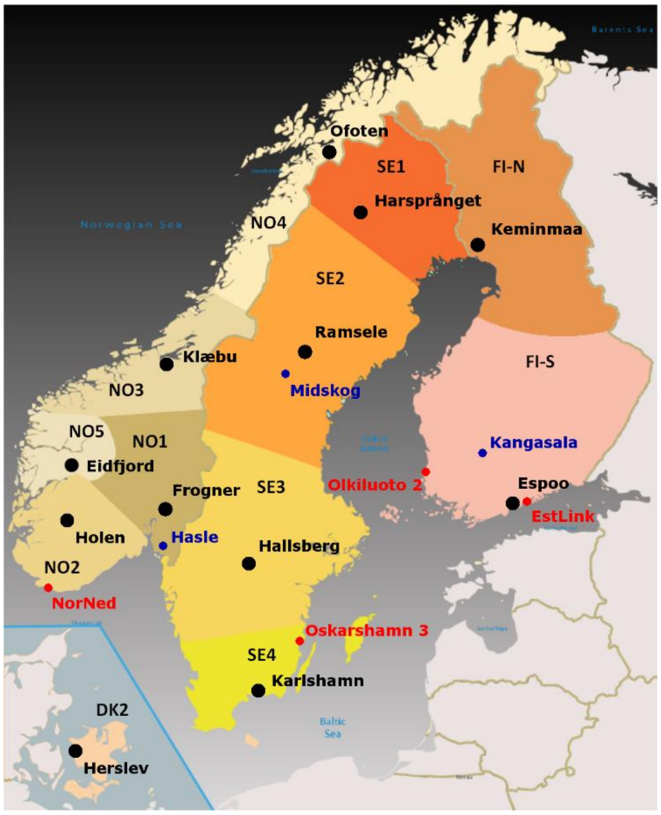

FIGURE 3.2: MEASUREMENT LOCATIONS (BLACK AND BLUE DOTS) AND LOCATIONS OF THE DISTURBANCES (RED DOTS)

3.2.3 SIMULATION RESULTS

The behaviour of frequency in different parts of the system was studied in different operational scenarios and faults in order to gain a better understanding of the factors that have an influence on the inertia estimation process. As the active power balance affects the behaviour of frequency, the behaviour of system load has an effect on the behaviour of frequency. Therefore, the behaviour of system load during the disturbances was also studied.

3.2.3.1 BEHAVIOUR OF FREQUENCY

Figure 3.3 shows the centre of inertia (COI) frequency and frequencies in Espoo (southern Finland) and Hasle (southern Norway) during the trip of NorNed in simulation case NN-180314. As shown in the figure, the initial behaviour of frequency is very different in different locations compared with the centre of inertia frequency. A rather strong oscillatory component is visible in the frequencies of Espoo and Hasle, which needs to be addressed when calculating the system inertia.

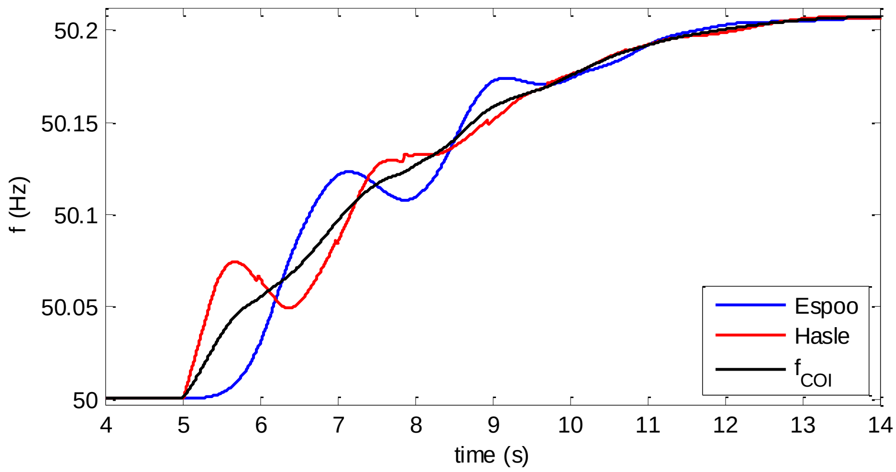

FIGURE 3.3: TRIP OF NORNED (733 MW) AT T = 5.0 S IN CASE NN-180314

The frequency and amplitude of the superimposed oscillatory component is dependent on the operational scenario and fault location as is shown in Figure 3.4. The figure shows a frequency in Kangasala during the trip of NorNed in cases 3 and 5 (see Table 3.1). The power imbalance of the trip is 600 MW in both cases and the kinetic energy of the system is approximately 330 GWs. This illustrates how the operational scenario affects the behaviour of frequency. In addition, frequency during the trip of EstLink 2 in case 5 is also shown. The power imbalance of the trip is also 600 MW. This illustrates how fault location affects the behaviour of frequency.

When comparing the behaviour of frequency during the trip of NorNed in cases 3 and 5 (the black and the blue curves on the figure), it is obvious that operational scenario affects the behaviour of frequency. Frequency oscillations are stronger in case 3 compared with case 5. When the frequency during the trips of NorNed and EstLink 2 in case 5 is compared, it becomes clear that fault location has a major impact on the behaviour of frequency.

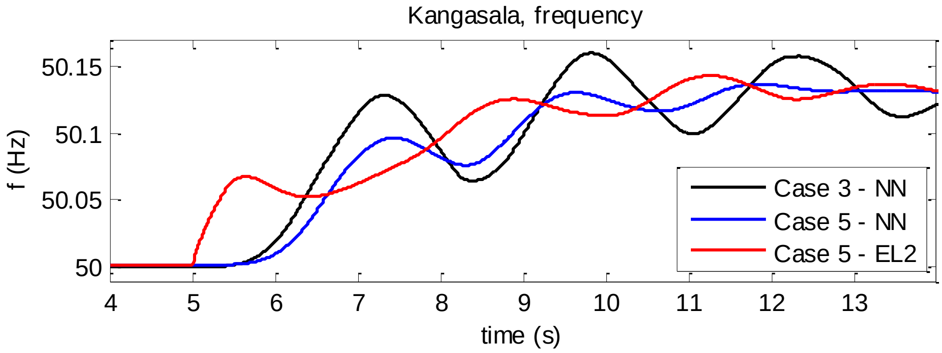

FIGURE 3.4: FREQUENCY IN KANGASALA, FINLAND DURING TRIPS OF NORNED (NN) AND ESTLINK 2 (EL2) AT T = 5.0 S IN CASES 3 AND 5

Studies were also performed to see whether it is possible to find a location where the frequency represents the centre of inertia frequency. This location should exhibit only weak frequency oscillations. During large disturbances, the dominating oscillation is often such that generator groups in southern Sweden, southern Norway and eastern Denmark oscillate against generators in Finland (Uhlen, et al., 2003). Therefore, this location, further on referred to as the neutral location, is supposedly located in between the areas oscillating against each other. This suggests that the neutral location would lie somewhere in central Sweden.

The frequency near Midskog, central Sweden was found to be the closest match to the centre of inertia frequency. Figure 3.5 shows the centre of inertia frequency, frequency in Midskog and their time derivatives during the trip of Olkiluoto 2 in case NN-180314. The blue line on the frequency derivative plot is the $\frac{df_{\mathrm{COI}}}{dt}$ in Equation (3.2) and it represents the system inertia in the simulated system. As the figure shows, just after the trip at $t = 5.0$ s there is some difference in the centre of inertia frequency (the black curve) and the frequency in Midskog (the red curve). Some seconds after the trip the two frequencies align.

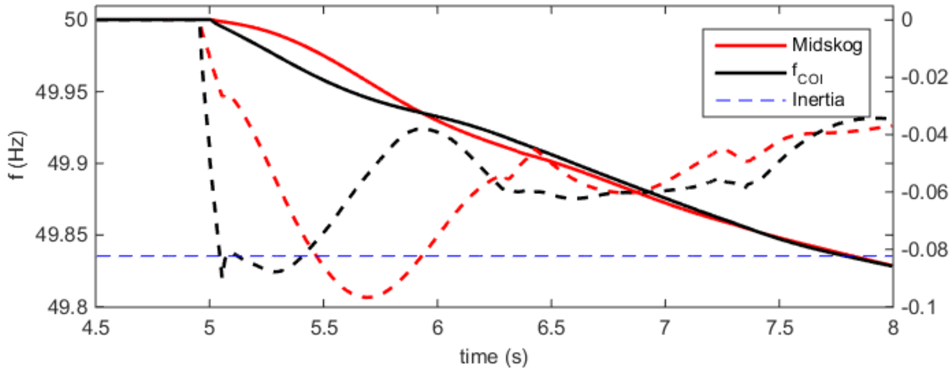

FIGURE 3.5: THE CENTRE OF INERTIA FREQUENCY, FREQUENCY IN MIDSKOG (THE SOLID LINES) AND THEIR TIME DERIVATIVES (THE DASHED LINES) DURING THE TRIP OF OLKILUOTO 2 AT T = 5.0 S IN CASE NN-180314

The location whose frequency is the closest match to the centre of inertia frequency varies depending on the operational scenario and the fault location. The same factors also affect how well the frequency of the neutral location represents the centre of inertia frequency.

3.2.3.2 LOAD BEHAVIOUR

Load behaviour immediately after the onset of the disturbance was studied in every combination of simulation case and fault. The study revealed that the disturbances can cause large changes in system load, as illustrated in Figure 3.6. The change in load is dependent on the operational scenario, power imbalance and location of the trip.

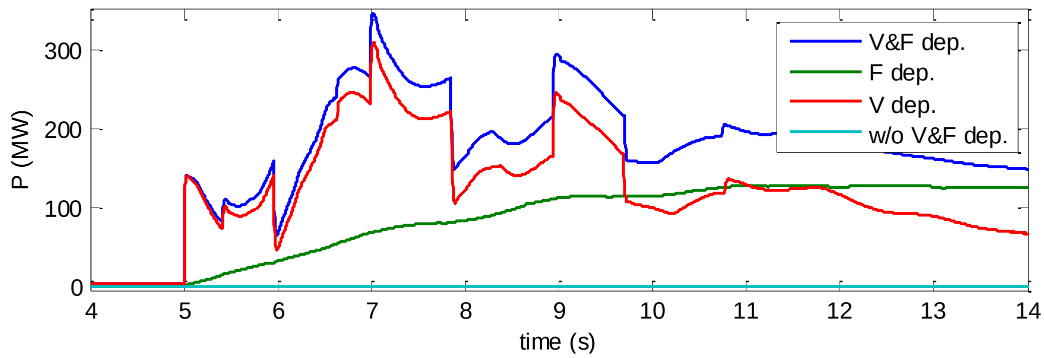

FIGURE 3.6: THE CHANGE IN SYSTEM LOAD DURING THE TRIP OF NORNED (733 MW) AT T = 5.0 S IN CASE NN-180314. SIMULATIONS WERE RUN WITH THE LOAD VOLTAGE & FREQUENCY DEPENDENCE (V&F DEP.), THE LOAD FREQUENCY DEPENDENCE (F DEP.), THE LOAD VOLTAGE DEPENDENCE (V DEP.) AND WITHOUT THE LOAD VOLTAGE & FREQUENCY DEPENDENCE (W/O V&F DEP.).

As Figure 3.6 shows the change in system load is mainly caused by load voltage dependence. The figure shows that without the load frequency dependence, the system load behaves much like load with both the load voltage and frequency dependence during the initial stages of a disturbance. The steep changes in system load visible in the figure are caused by voltage controlling equipment like SVCs and power system stabilisers trying to damp inter-area power oscillations.

3.3 Evaluation Of The Inertia Estimation methods

3.3.1 Methods using an arbitrary frequency measurement

A polynomial fit like the one used in (Inoue, Taniguchi, Ikeguchi, & Yoshida, 1997) was tested using the simulated data. The first order coefficient of the fitted polynomial was interpreted as the rate of change of frequency which in turn was used to calculate the system inertia. The order of the polynomial and the time for which the fit was applied was varied. This method failed to provide adequate results in the Nordic power system. The results were always unrealistic. In order to obtain a good fit and restrain the influence of power oscillations, the time for which the fit is applied has to be rather long (multiple seconds). During that time, the disturbance reserves will activate and therefore influence the behaviour of frequency. This was seen as the main cause of error.

Also, a polynomial fit like the one used in (Ashton, Taylor, Carter, Bradley, & Hung, 2013) was examined. The main difference compared with the above mentioned method was that the rate of change of frequency was taken from the beginning of the fitted curve. Again, the order of the polynomial and the time for which the fit was applied was varied. Also this method failed to provide adequate results. This is explained by the fact that frequency in an arbitrary selected location behaves very differently when the operational scenario and fault location is varied (see Figure 3.4).

Methods which try to suppress the influence of power oscillations with low-pass filtering, like the moving average filter used in (E-Bridge Consulting GMBH, 2011), also provided inconsistent results. This is also explained by the fact that the frequency in an arbitrary location behaves very differently when the operational scenario and fault location is varied.

In (Björnstedt, 2012) the centre of inertia frequency is approximated from an arbitrary selected frequency measurement using a FIR-filter (Finite Impulse Response). The study shows that the approximated centre of inertia frequency is dependent on the measurement location. Based on the results, the approximation is not good enough to be used for inertia calculation.

All the methods described in Section 3.1.2 which can be utilised in practice aim at estimating the system inertia using an arbitrarily selected frequency measurement. According to the simulation results represented in Section 3.2.3.1 frequency behaves very differently in different parts of the system. Also, the behaviour of frequency in an arbitrary location is influenced by the operational scenario and fault location. Therefore, the methods fail to provide adequate results.

3.3.2 Inertia estimation using the frequency of a neutral location

As stated in Section 3.2.3.1, the frequency in Midskog, central Sweden is often the closest match to the centre of inertia frequency. Therefore, inertia calculation using the frequency of Midskog was studied in different operational scenarios and faults.

The best results were obtained when a linear fit using a least squares approximation was applied to the measured frequency. The fit was applied for 700 ms beginning 150 ms after the onset of the disturbance. The slope of the linear fit was used as the $\frac{df}{dt}$ in Equation (3.2). The error in the inertia estimates is shown in Table 3.2 for all the simulation cases and faults.

TABLE 3.2 ERROR IN PERCENTAGES IN INERTIA ESTIMATES CALCULATED USING THE FREQUENCY OF MIDSKOG

Case	Olkiluoto 2	Oskarshamn 3	NorNed	EstLink 1/2
1	4.8	48.1	4.8	3.5
2	10.0	92.9	8.7	5.3
3	24.4	36.6	17.0	34.5
4	18.5	76.2	80.0	11.8
5	1.9	34.3	37.1	2.7
6	6.1	66.3	4.0	1.1
NN-180314	2.2	33.0	6.3	18.8

As Table 3.2 shows, the errors can be quite high. In many cases, the frequency of Midskog is not a good approximation of the centre of inertia frequency, as is shown in Figure 3.7. It is also very difficult to choose optimal parameters for the fit as they depend on the operational scenario and fault location.

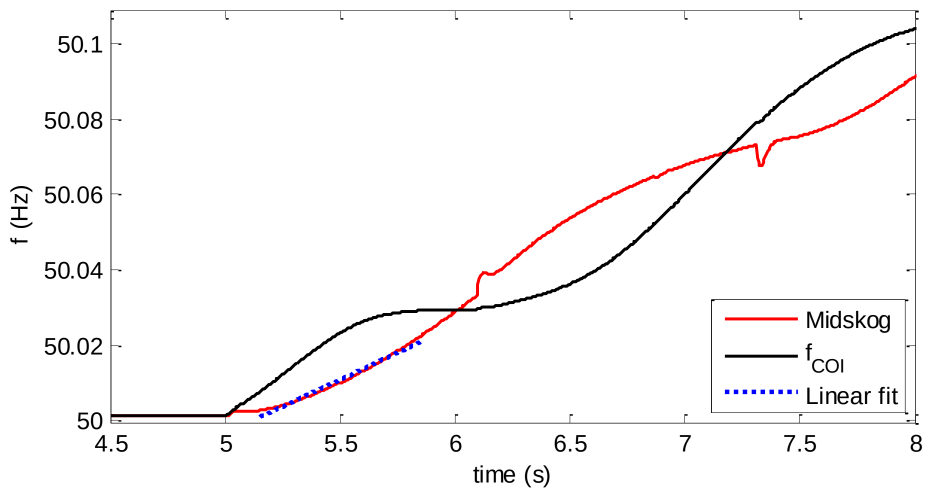

FIGURE 3.7: THE CENTRE OF INERTIA FREQUENCY AND FREQUENCY IN MIDSKOG DURING THE TRIP OF NORNED AT T = 5.0 S IN CASE 4. THE DOTTED LINE IS THE LINEAR FIT APPLIED TO THE FREQUENCY OF MIDSKOG.

In conclusion, it is not possible to form a reliable estimate of the Nordic power system inertia using only one frequency measurement. This is because during the initial stages of a frequency disturbance, the behaviour of frequency in an individual location is heavily affected by the operational scenario and fault location. Also, it is not possible to find a location of which frequency represents accurately enough the behaviour of the system as a whole regardless the prevailing operational scenario and fault location. Therefore, multiple frequency measurements distributed throughout the system are required in order to obtain more accurate inertia estimates.

3.3.3 Inertia estimation using the centre of inertia frequency

As inertia estimation methods using a single frequency measurement failed to provide accurate results, inertia calculation using the concept of centre of inertia frequency (see Section 3.1.1) was studied. The centre of inertia frequency was calculated for every combination of simulation case and fault using Equation (3.3). After that, the system inertia was calculated using Equation (3.2). The centre of inertia frequency is quite linear for 400 to 800 ms after the onset of the disturbance, as Figure 3.7 shows. Therefore, the $\frac{df_{\mathrm{COI}}}{dt}$ in Equation (3.2) was approximated using a linear fit. The best results were achieved when the fit was applied to the centre of inertia frequency for 400 ms beginning from the onset of the disturbance. The slope of the fit was used as the $\frac{df_{\mathrm{COI}}}{dt}$ in Equation (3.2).

The results are shown in Table 3.3. As the table shows, the inertia estimates for the trips of Olkiluoto 2 are quite accurate with errors less than 4 %. On the other hand, the results for the trips of Oskarshamn 3 are highly inaccurate. These show that when a generator or importing HVDC-connection trips, the estimated inertia value is always higher than the actual inertia value.

The inaccuracy for the trips of Oskarshamn 3 is mainly explained by the change in the voltage dependent load. Oskarshamn 3 is the largest unit in the system which in part explains why the results for the trips of Oskarshamn 3 are the most inaccurate.

Table 3.3 Error in percent of inertia estimates calculated using the centre of inertia frequency

Case	Olkiluoto 2	Oskarshamn 3	NorNed	EstLink 1/2
1	0.0	68.5	2.6	4.6
2	3.5	110.0	5.8	8.5
3	3.3	66.4	7.0	37.5
4	3.8	56.2	14.7	9.1
5	3.5	38.2	14.7	18.1
6	0.5	68.3	5.3	5.4
NN-180314	3.5	36.0	3.5	20.3

In conclusion, the centre of inertia model provides inaccurate results when a trip causes changes in bus voltages which in turn lead to changes in the system load. This is due to the fact that the model assumes that changes in the system load are negligible which, according to the simulations, is not a valid assumption. In reality, it is very difficult to estimate the change in the system load. It may be possible to use voltage measurements to assess the reliability of the results.

3.3.4 Inertia estimation using the approximated centre of inertia frequency

In practice, it is not possible to calculate the centre of inertia frequency using Equation (3.3) as it is not possible to obtain frequency measurement of every generator in the system. Therefore, studies were performed to see whether it is possible to construct an approximation of the centre of inertia frequency using a few well distributed frequency measurements.

The Nordic power system was divided into 12 areas according to the bidding zones. In addition, Finland was divided into northern and southern parts. Frequency was assumed to be equal in every node within an area and one measurement location was chosen for every area. The locations were chosen so that locations with an existing frequency measurement device or locations that are going to have a frequency measurement device installed were preferred. The areas and the measurement locations are shown in Figure 3.2 (the black dots represent the measurement locations).

The frequencies of all generators within an area are assumed to be equal. Hence, Equation (3.3) can be expressed as

$$f_{\mathrm{COI}} = \frac{f_{\mathrm{A}} \sum_{i=1}^{n_{\mathrm{A}}} H_{\mathrm{A}i} + f_{\mathrm{B}} \sum_{i=1}^{n_{\mathrm{B}}} H_{\mathrm{B}i} + \cdots}{\sum_{i=1}^{n_{\mathrm{A}}} H_{\mathrm{A}i} + \sum_{i=1}^{n_{\mathrm{B}}} H_{\mathrm{B}i} + \cdots} \tag{3.4}$$

where f_X is the frequency within an area X, n_X is the number of generators within area X and H_{Xi} is the inertia constant of generator i in area X.

According to Equation (3.4), the frequency of an area is weighted with a summation of inertia constants of generators within the area. The weighting factors are calculated using the data in the simulation model. The weighting factors depend on the amount and composition of generators synchronised to the system within an area. Therefore, the weighting factors depend on the operational scenario, but could be approximated, for example, based on production measurements or production plans. During peak load situations it is easier to approximate the weighting factors as it is justified to assume that all generators are synchronised to the system.

The centre of inertia frequency was calculated using weighting factors that correspond to the current simulation case and the system inertia was calculated using the approximated centre of inertia frequency. The results are shown in Table 3.4.

TABLE 3.4 ERROR IN PERCENTAGES IN INERTIA ESTIMATES CALCULATED USING THE APPROXIMATED CENTRE OF INERTIA FREQUENCY

Case	Olkiluoto 2	Oskarshamn 3	NorNed	EstLink 1/2
1	2.6	65.7	0.3	3.1
2	0.5	109.5	4.7	7.0
3	5.2	59.3	6.8	40.2
4	0.1	54.0	19.9	7.7
5	1.2	35.6	18.7	18.2
6	1.2	73.5	5.1	5.7
NN-180314	5.4	35.6	2.2	24.4

Comparison of Table 3.3 and Table 3.4 reveals that the approximation of the centre of inertia frequency is good. The inertia estimates calculated using the approximated centre of inertia frequency deviate only a little from those calculated using the actual centre of inertia frequency. The difference in the errors is between 0.1 and 7.1 %.

In conclusion, it is possible to obtain a good approximation of the centre of inertia frequency if the inertia distribution in the system is known.

3.4 CONCLUSIONS

Estimating system inertia using measured frequency during disturbances proved to be a lot more difficult task than initially thought. Frequency can behave very differently in different parts of the system depending on the operational scenario and fault location. Due to this, inertia estimation using only one frequency measurement proved to be unreliable. The centre of inertia method provides the best results so far but it can be difficult to estimate the centre of inertia frequency accurately. At the time of writing, it is not possible to estimate the centre of inertia frequency due to the lack of necessary frequency measurements. In addition, the behaviour of voltage dependent load was found to have a much larger effect on the results than previously thought.

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4. IMPLEMENTATION OF INERTIA ONLINE ESTIMATION

As inertia estimation using measured frequency during disturbances proved to be challenging and can only provide the inertia estimation during disturbances, another method to estimate inertia continuously is needed. The estimates also needs to be accurate. The aim of this task was to find out the best way to realise real-time monitoring of inertia and also to share this value between the Nordic TSOs and store the value in a manner that it can be used in the analysis of disturbances.

Possible sources of data were considered:

- Hourly production values from Nord Pool Spot
- Production measurements per production type
- Real-time measurements of power plants

Since TSOs have information about the production in their own countries, this real-time estimation was carried out so that each TSO made real-time inertia estimation of its own area. For an estimation of inertia on a Nordic level, these TSO based estimations were combined. This chapter describes how real-time inertia estimation has been performed at each Nordic TSO.

Today this estimation is performed using only information regarding production units and rotating condensers, because of a lack of measurements and knowledge of the characteristics of the loads. The tool was built to calculate estimates of system kinetic energy rather than inertia.

4.1 CALCULATION OF KINETIC ENERGY

Kinetic energy in the Nordic system can be estimated with the help of the circuit breaker positions of production units. When a generator circuit breaker position is closed, it is assumed that the generator can contribute to the kinetic energy of the system. The kinetic energy E_{sys} of the system can then be calculated according to Equation (1.4), which is rewritten here for convenience:

$$E_{\mathrm{k,sys}} = \sum_{i=1}^{N} S_{\mathrm{n}i} H_i \ \ [\mathrm{GWs}] \tag{4.1}$$

where the inertia constant H_i and the rated power $S_{\mathrm{n}i}$ for generator i is retrieved from a generator register, and N is the number of connected generators.

The kinetic energy capacity of each country's power system is shown in Table 4.1.

TABLE 4.1 KINETIC ENERGY OF EACH COUNTRY'S POWER SYSTEM ACCORDING TO THE NORDIC POWER SYSTEM MODEL

Area	Kinetic energy capacity (GWs)
Sweden	170
Norway	100
Finland	90
Eastern Denmark	30

The kinetic energy capacity of the Nordic power system is 390 GWs.

4.2 Implementation of online estimation in the Svenska kraftnät SCADA system

There are 421 generators included in the Swedish contribution to the kinetic energy calculation, with a maximal available kinetic energy of 166.5 GWs. There is no measurement of the generator breaker position for at least 125 generators. The kinetic energy of these is 19.22 GWs, which represents 11.54 % of the maximal available kinetic energy. Furthermore there are at least 173 small generators for which there is no available data for inertia constant.

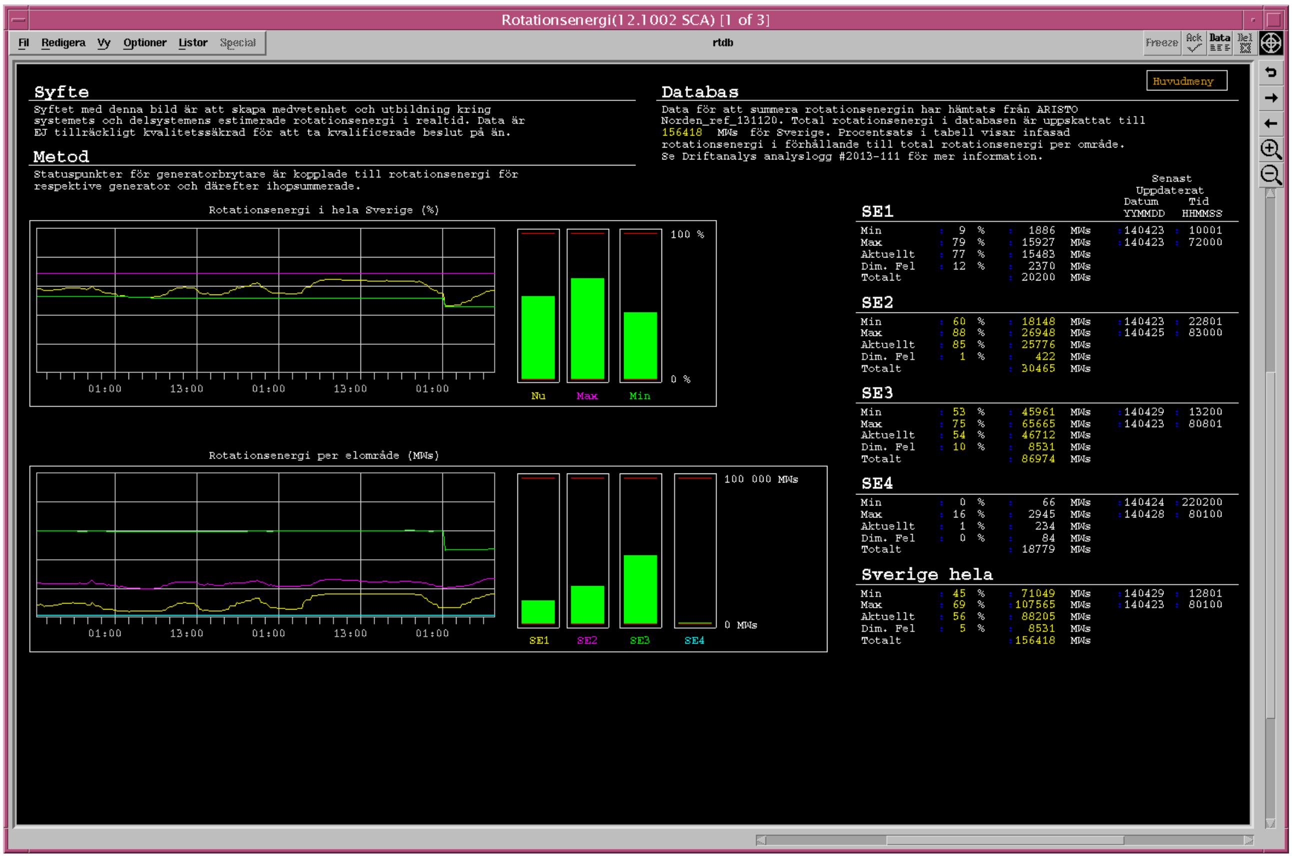

Figure 4.1: Visualisation of inertia data at Svenska kraftnät

The status of every machine, describing whether it is connected to the system or not, is then gathered in the SCADA system. Inertia data from the power system simulation databases can then be connected to the status of the machines, and kinetic energy summed for all machines which are connected. The kinetic energy is calculated separately in each bidding zone. In this way a real time estimation of the systems kinetic energy can be calculated.

The estimate resulting from the SCADA measurements can then be complemented with estimates of missing machines based on their production type, and known system load.

4.3 Implementation of online estimation in the Fingrid SCADA system

The Finnish online inertia estimation tool was implemented in the Finnish SCADA system (Figure 4.2). The estimation tool calculates kinetic energy separately for the following types of production units

- Nuclear power
- Hydropower
- Combined heat and power
- Industrial back pressure power
- Condensing power
- Gas turbines
- Peak power plants

The total kinetic energy in Finland is calculated as a summation of the kinetic energies of different production types.

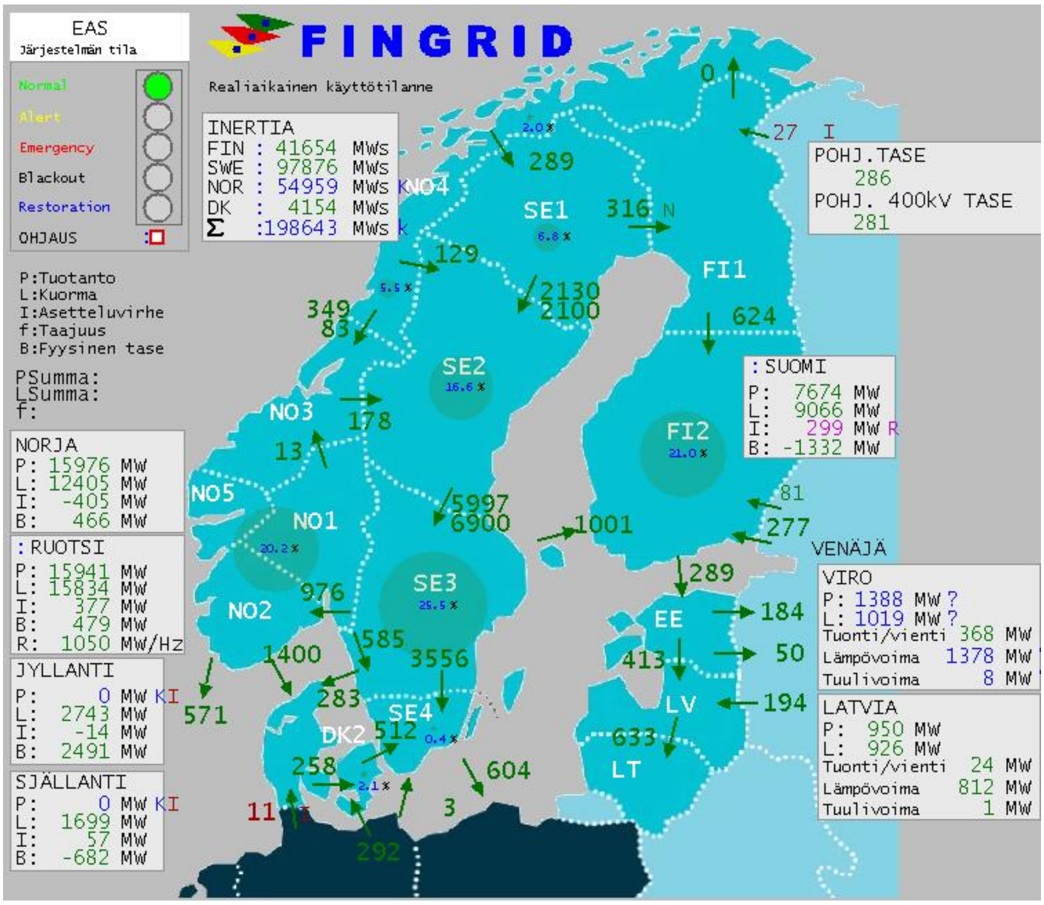

FIGURE 4.2: VISUALISATION OF INERTIA AT FINGRID

Circuit breaker positions and power measurements are used to indicate which machines are synchronised to the system. Circuit breaker positions are preferred but in case such a measurement does not exist, generator power measurements are used. If generator power measurement is above zero, it indicates that the generator is synchronised to the system.

In some cases, the measurement of a generator circuit breaker doesn’t exist and one power measurement contains the sum power of multiple generators. In such a situation, it is not possible to identify which generators are synchronised to the system. In these cases, the kinetic energy is calculated by multiplying the measured power value with a combined inertia constant. Hence, the value obtained is always smaller than the actual kinetic energy. In these cases, the generators are quite small so the effect on the overall result is minor. The calculation process can be improved once more accurate measurements become available.

Furthermore, for some generators, it was not possible to obtain an inertia constant. Today there are approximately 75 generators for which the inertia constant is not known. In these cases, the inertia constant was estimated based on the type and size of the generator.

In addition, approximately 500 MW of production exists in Finland for which no measurement is available. The Finnish SCADA system contains an estimated production value for this non-measured production. The kinetic energy was calculated by multiplying this estimated value with an inertia constant of 3.0 seconds.

4.4 Implementation of online estimation in the Statnett SCADA system

Due to ongoing exchange of EMS system at Statnett, the more accurate measurement method by using individual generator breaker position combined with individual inertia value is postponed to the implementation of the new EMS/SCADA system (likely implemented somewhere between 2016-2018).

The present implementation is based on the total production level in each of eight consumption areas, scaled with an average inertia constant, 3.44 s, factor for inertia, operation point and power factor. The factor has been obtained by comparing result from this simplified method by result from a test of "breaker status method".

The kinetic energy values will be presented in existing SCADA system, with possibilities to trend values, see Figure 4.4. However, no real time trend line will be available for the operators until the final solution will be implemented in the new SCADA. Historical values will also be stored for study purposes.

Figure 4.3 shows the difference between the two different methods; the present implementation and the final solution (breaker status method). The following should be noted:

1. The kinetic energy value calculated with this method fluctuates more compared with the breaker position method due to the use of the actual production level which tends to vary more compared to the number of changes in breaker position.
2. This method tends to give a kinetic energy value which is too low during the night, and too high during daytime. Seen from the "hours of interest" (low load, night time), the deviation gives a more conservative result.
3. The final solution will be improved compared with the presented "breaker position" result, when it comes to the number of units covered, the quality of the inertia constants as well as rated power of the generators.

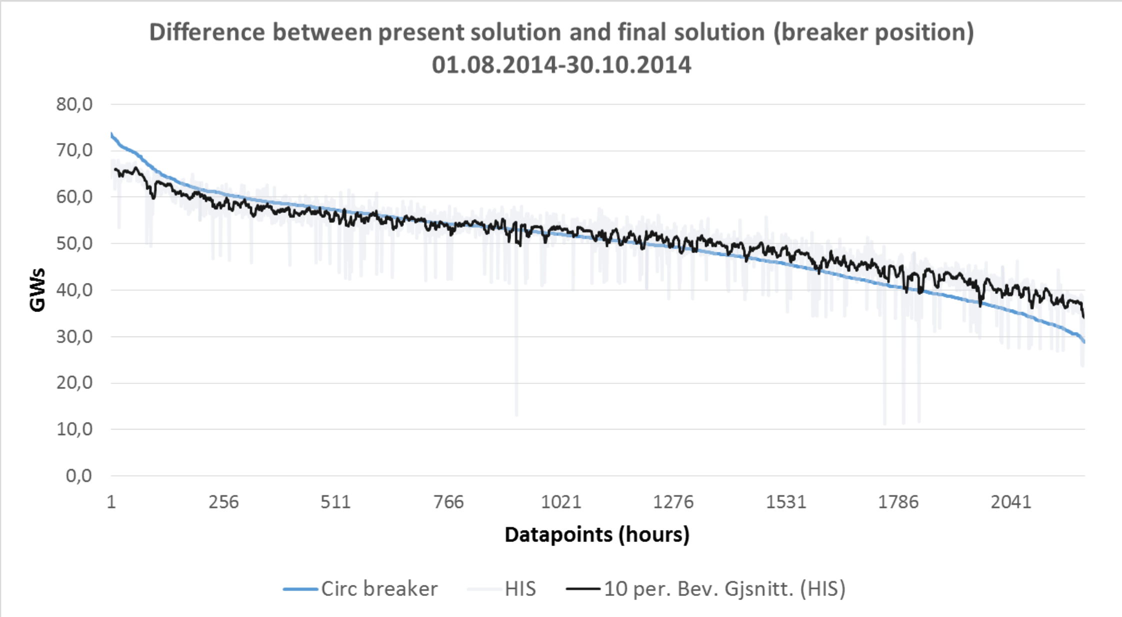

FIGURE 4.3: DIFFERENCE BETWEEN THE PRESENT SOLUTION AND FINAL SOLUTION. "HIS" IS THE DATABASE USED FOR COLLECTING THE HISTORICAL PRODUCTION VALUES USED IN THE STUDY.

FIGURE 4.4: STATNETT SCADA VIEW FOR PRESENT SOLUTION.

The final solution will cover approximately 2000 generating units, of which > 500 can be seen as important for the total kinetic energy. Improvement of inertia values for these units is incorporated in ongoing activities and projects.

4.5 Implementation of online estimation in the Energinet.dk SCADA system

The Danish SCADA system at Energinet.dk includes measurements from all significant (power over 1.5 MW) power plants and these are used to calculate the kinetic energy of DK2 system.

The Danish online inertia estimation tool was implemented in the Danish SCADA system. The estimation tool calculates kinetic energy without any division to different production types.

The kinetic energy of each unit is added to the SCADA in a table, which has to be updated with new units when they are connected to the grid.

Circuit breaker positions and power measurements are used to indicate which machines are synchronised to the system. Circuit breaker positions are preferred but in case such measurement does not exist, generator power measurements are used. If generator power measurement is above 10 % of nominal value, it indicates that the generator is synchronised to the system.

Units smaller than 1.5 MW are not included, but the number and inertia of these units is rather small, so the missing kinetic energy from these units does not influence the total kinetic energy significantly.

Figure 4.5: SCADA screen at Energinet.dk

4.6 Initial results

4.6.1 Online trends

At the moment all Nordic TSOs are exchanging the values of kinetic energy. These values can be followed in real-time and also in trends. For example, Fingrid has a tool where the trend of Nordic kinetic energy can be followed, as shown in Figure 4.6.

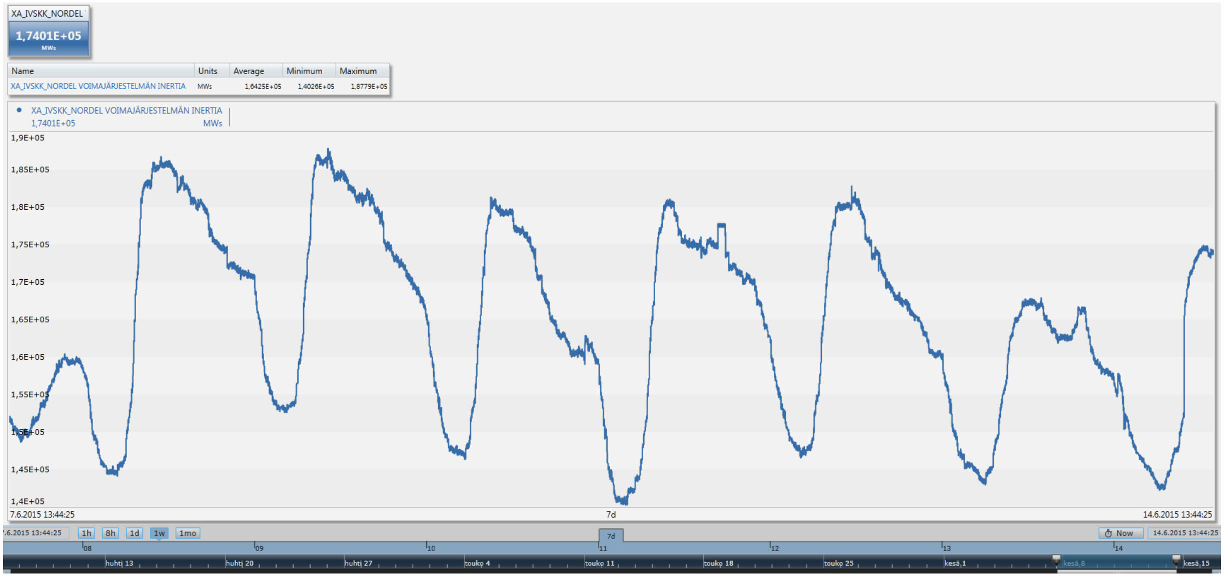

FIGURE 4.6: NORDIC KINETIC ENERGY TREND AT FINGRID

The values of kinetic energy are also saved so that studies can be performed later. An example of kinetic energy in Nordic for week 23 in 2015 is shown in Figure 4.7.

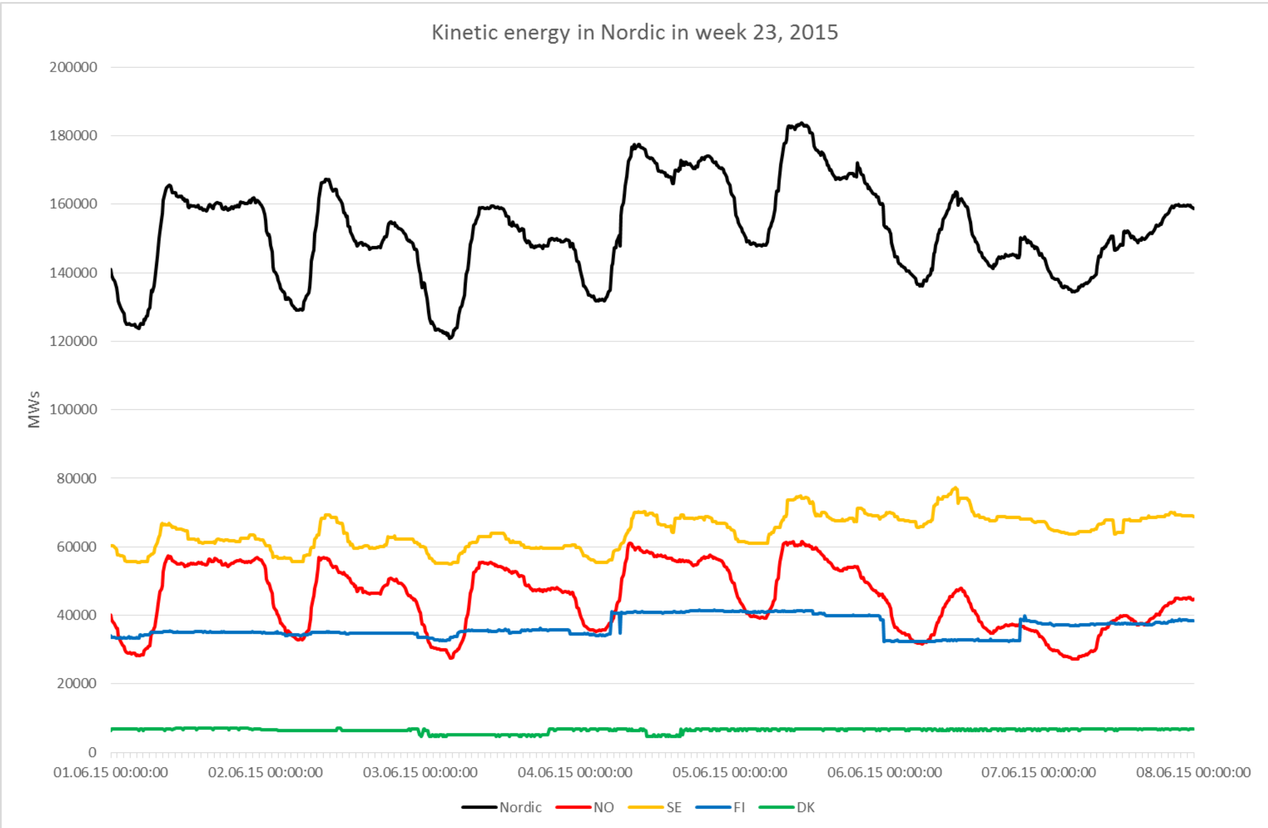

FIGURE 4.7: NORDIC KINETIC ENERGY TRENDS FOR WEEK 23 IN 2015

4.6.2 Retroactive calculation

In order to be able to observe the trend of the kinetic energy development in the Nordic power system, a retroactive calculation using the same method as used in the online inertia estimation tool has been performed. Time period from 2009 to 2015 was chosen for the study.

Kinetic energy is calculated and sampled with intervals of five minutes in Sweden and Finland. Kinetic energy from Norway is sampled every hour and combined for the same time period. There is currently no data from Denmark.

There are uncertainties in this estimation associated with, for example, the accuracy of the inertia constants due to upgrades of generators, especially for older units. Furthermore, more and more active power / circuit breaker status measurements have been introduced during the recent years.

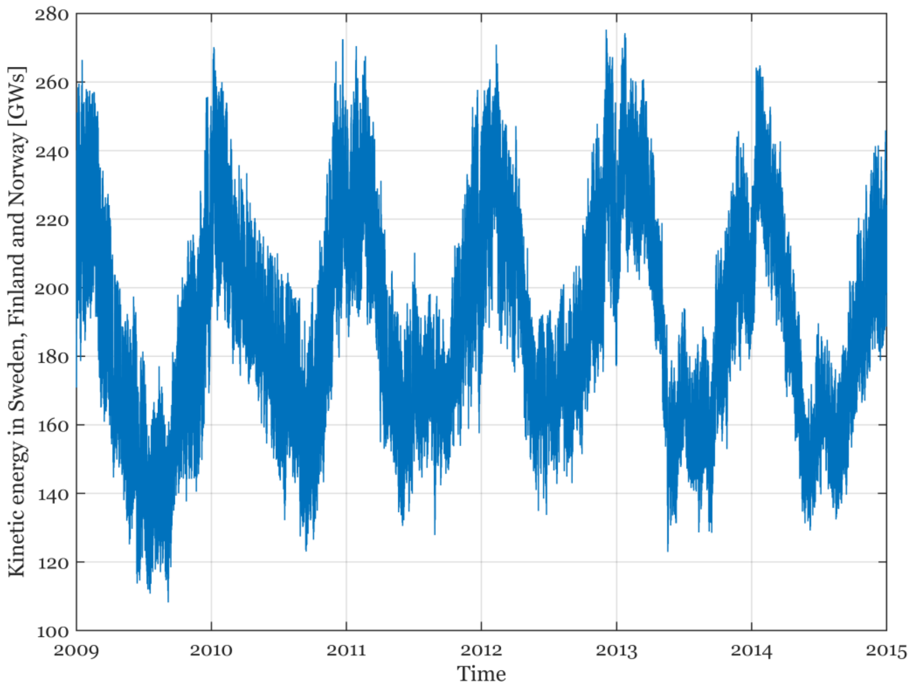

Figure 4.8: Estimated kinetic energy in Sweden, Finland and Norway

Figure 4.8 shows that kinetic energy is higher during winter time with peaks around February and troughs around summer time. The lowest kinetic energy in Sweden, Finland and Norway was 115 GWs during the summer of 2009 and the highest was 275 GWs in the winter of 2012. The low kinetic energy during 2009 can be explained by the fact that nuclear power had a low availability during that year. Duration curves of the kinetic energy are shown in Figure 4.9. The duration curves explain the share of time the kinetic energy was below the current value.

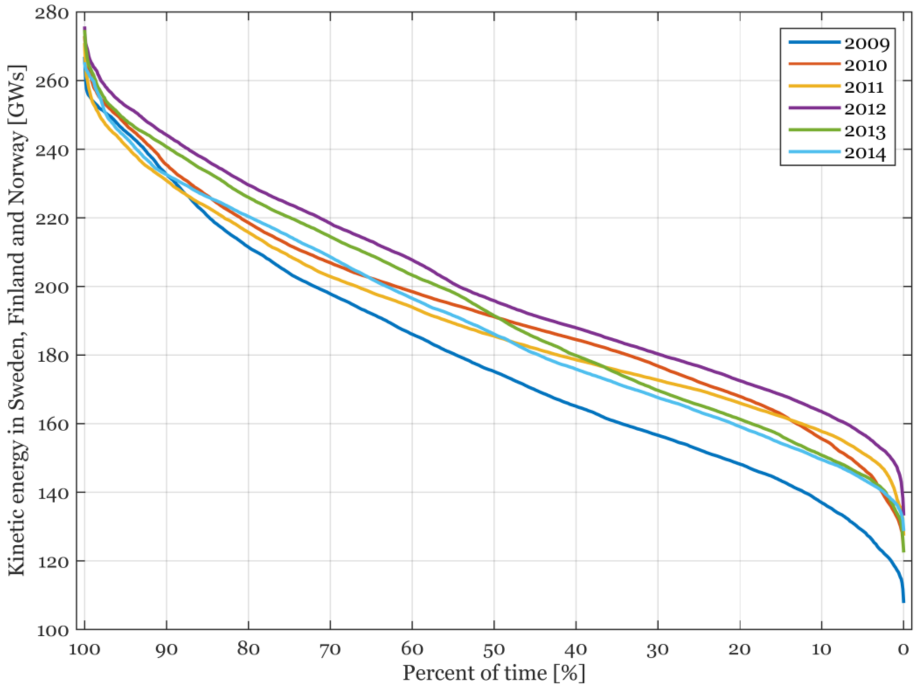

FIGURE 4.9: DURATION CURVES OF THE ESTIMATED KINETIC ENERGY IN SWEDEN, FINLAND AND NORWAY. THE CURVES INDICATE THE PERCENTAGE OF TIME THE KINETIC ENERGY WAS BELOW CURRENT VALUE

4.7 VERIFICATION

There are many uncertainties and inaccuracies related to inertia real-time estimation tool. In order to improve the accuracy of the resulting kinetic energy value from the tool, this value should be compared to the kinetic energy values calculated from the disturbances. For this reason it has been considered if it would be possible to perform test disturbances for this purpose. For example a trip of an HVDC link would cause a frequency change which could be used to calculate the Nordic inertia. Methods for doing this have been considered in Chapter 3, however a reliable method for calculating this has not yet been established.

4.8 CONCLUSION

A working prototype for the real time exchange of kinetic energy data has been implemented. From the prototype it is possible to obtain an estimated value for the total kinetic energy in the Nordic power system, as well as the kinetic energy distribution between the different price zones. This data can be used to track the kinetic energy trend over time, which can be used for future analyses.

The kinetic energy is calculated as a sum of the kinetic energy of generators synchronously connected to the system. There are two ways which are used to identify when a generator is contributing with kinetic energy. One way is to use circuit breaker positions as an indication of whether or not a generator is connected. Another way is to use the generator power measurements. If the output power exceeds a threshold value the generator is assumed to be connected to the system.

The results from the real time estimation tool are impaired by uncertainties which are related to:

- the quality of the inertia constants for single units
- the method used for estimation of kinetic energy by using total production instead of using statuses of individual machines
- the number of production units covered
- the contribution from load

These uncertainties need to be quantified.

Data quality for turbine-generator inertia will be improved by the TSOs and it is suggested that a verification of the obtained kinetic energy shall be performed.

5. Estimation of minimum (maximum) instantaneous frequency

The aim of this activity is to develop a model which can be used to determine the minimum (maximum) instantaneous frequency which can be expected in the Nordic system after a disturbance. By knowing the possible change in frequency due to a disturbance the minimum (maximum) instantaneous frequency can be calculated based on the current frequency. The method is developed by using empirical data. The amounts of reserves are not taken into account with this method.

5.1 Linear regression from frequency disturbances

By investigating the development of frequency during a disturbance and relating the change in frequency to other external factors, a relationship can be found. The maximum frequency deviation Δf is defined in Equation (2.7).

The magnitude of Δf is used because the model assumes the power system behaves similarly independently of the sign of the frequency change.

The quantity Δf is calculated for 69 different frequency disturbances from 2012 to 2014 and correlated to the operational scenario in three different ways, as described in the following sections.

5.1.1 Maximum frequency deviation as a function of power imbalance

Figure 5.1 shows the maximum frequency deviation for the set of studied disturbances related to the power imbalance caused by the disturbance.

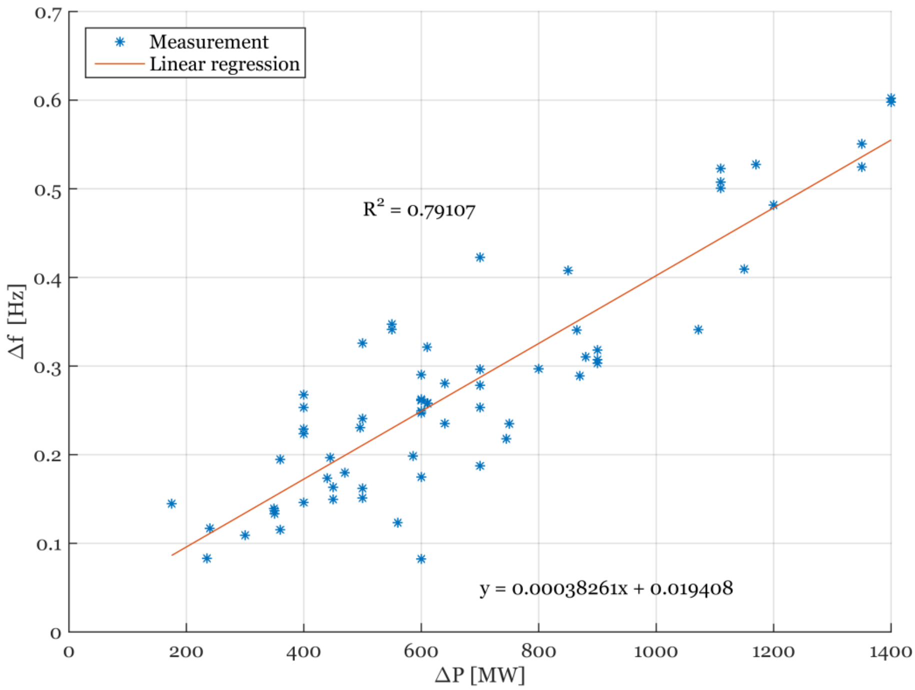

Figure 5.1: Maximum frequency deviation as a function of power imbalance

From the scatter plot a linear regression has been performed. A coefficient of determination R^2 between 0 and 1 has been calculated, where $R^2 = 0$ means that there is no linear correlation between the quantities on the two axes, and $R^2 = 1$ means that there is a perfect correlation between them. In this case the coefficient of determination is $R^2 \approx 0.791$.

5.1.2 Maximum frequency deviation as a function of power imbalance and total production

Figure 5.2 shows the maximum frequency deviation in relation to the power imbalance related to total production, as described by:

$$\frac{\Delta P}{P_{\text{genNordic}}} = \frac{\Delta P}{P_{\text{genSE}} + P_{\text{genNO}} + P_{\text{genFI}} + P_{\text{genDK2}}} \left[\frac{\text{MW}}{\text{MW}}\right] \tag{5.1}$$

where ΔP is the power imbalance caused by the disturbance, like in Figure 5.1. P_{genSE}, P_{genNO}, P_{genFI} and P_{genDK2} are the production values from every Nordic country during the hour when the disturbance occurred. Production data was retrieved from Nord Pool Spot.

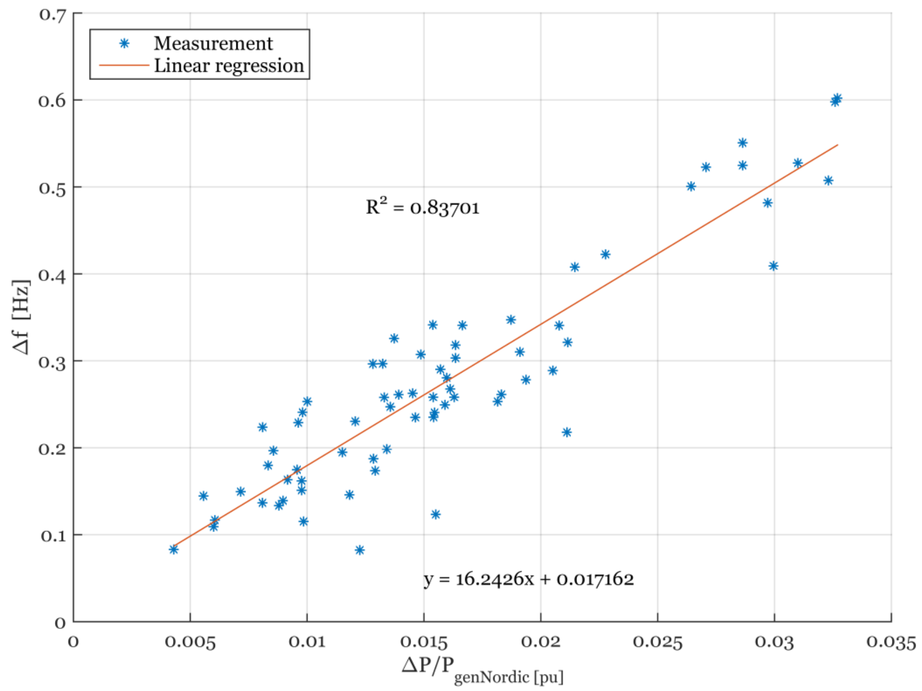

Figure 5.2: Maximum frequency deviation in relation to power imbalance as a fraction of total power production

By relating the maximum frequency deviation to the power imbalance as a fraction of total power production, the loading of the system is taken into account, and therefore indirectly the inertia of the system. The resulting coefficient of determination $R^2 \approx 0{,}837$ is therefore higher than that of the model which only takes into consideration the power imbalance.

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5.1.3 Maximum frequency deviation as a function of power imbalance and estimated kinetic energy

Figure 5.3 shows the maximum frequency deviation in relation to the retroactively estimated kinetic energy in Section 4.6.1. This kinetic energy E_{sys} in the Nordic system is estimated from Swedish, Finnish and Norwegian data. In order to increase the accuracy of the model the kinetic energy in the entire Nordic system should be taken into account.

$$E_{\mathrm{k,sys}} \approx S_{\mathrm{n,SE}}H_{\mathrm{SE}} + S_{\mathrm{n,FI}}H_{\mathrm{FI}} + S_{\mathrm{n,NO}}H_{\mathrm{NO}} - S_{\mathrm{n,dist}}H_{\mathrm{dist}} \;\; [\mathrm{GWs}] \qquad (5.2)$$

where $E_{\mathrm{k,sys}}$ is the estimated kinetic energy which is used in the plot in Figure 4.8, and $S_{\mathrm{n,dist}}H_{\mathrm{dist}}$ is the kinetic energy which is removed from the system as a result of the disturbance. For example, disconnecting a synchronous machine would result in a reduction in the kinetic energy of the system. When the kinetic energy $S_{\mathrm{n,dist}}H_{\mathrm{dist}}$ is unknown for a disconnected generator, it is calculated as:

$$S_{\mathrm{n,dist}}H_{\mathrm{dist}} = \Delta P \frac{E_{\mathrm{k,sys}}}{P_{\mathrm{genNordic}}} \;\; [\mathrm{GWs}] \qquad (5.3)$$

A disturbance caused by a disconnection of a HVDC link will not cause any change to the system kinetic energy and thereby $S_{\mathrm{n,dist}}H_{\mathrm{dist}}$ is equal to zero.

Unfortunately the retroactive inertia values from Denmark are not available at this time so it is assumed that the inertia values for Denmark are zero. The proportion of the maximal kinetic energy in Denmark is only 6.6 % of the maximal kinetic energy in the Nordic countries (Kuivaniemi, Estimation of Generator Inertia in the Nordic Power System, 2014), so this assumption does not affect the results to a large extend. The Danish inertia values can be updated as they become available.

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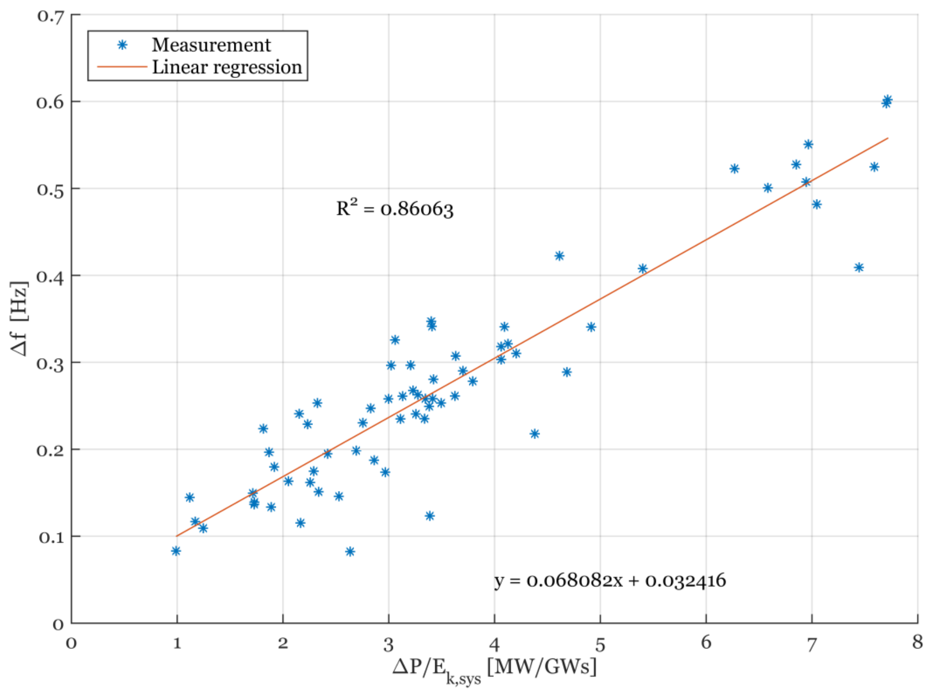

FIGURE 5.3: MAXIMUM FREQUENCY DEVIATION RELATIVE TO POWER IMBALANCE AND ESTIMATED KINETIC ENERGY

The coefficient of determination is in this case $R^2 \approx 0{,}861$, implying that this set of disturbances can be better estimated by a linear relation to the estimated kinetic energy than the total production or power imbalance in the system.

5.2 SIMULATIONS USING THE RAR-MODEL

The Nordic TSOs participated in a common project in which a simple one-bus power system model, called the RAR model, was created. The goal of this model was to emulate the frequency control of the Nordic power system (E-Bridge Consulting GMBH, 2011). The model includes the estimated regulation capabilities and the regulation systems for each Nordic country, as well as the load at the time of the disturbance. The change in power of HVDC links related to emergency power schemes are however not included.

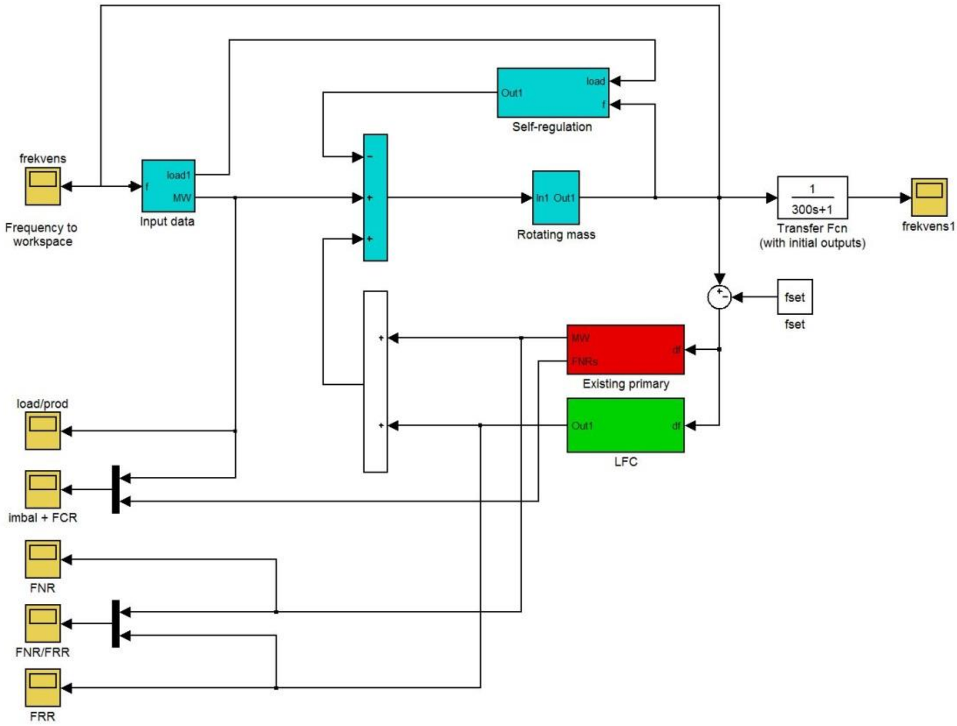

FIGURE 5.4: OVERVIEW OF THE RAR-MODEL BLOCK DIAGRAM, (E-BRIDGE CONSULTING GMBH, 2011)

The inertia at t_{start} for a simulated disturbance is estimated from Figure 4.8 and then used for the simulation. The inertia is then recalculated to take into account the disconnected inertia, as described in Equations (5.2) and (5.3). The load levels and the production levels during a disturbance are retrieved from NordPool Spot.

Figure 5.5 shows a comparison between simulation results from the RAR model and the measured frequency for a disturbance, where the line Hasle–Röd (Norway) was tripped and resulted in a loss of 900 MW after the activation of a system protection scheme (SPS).

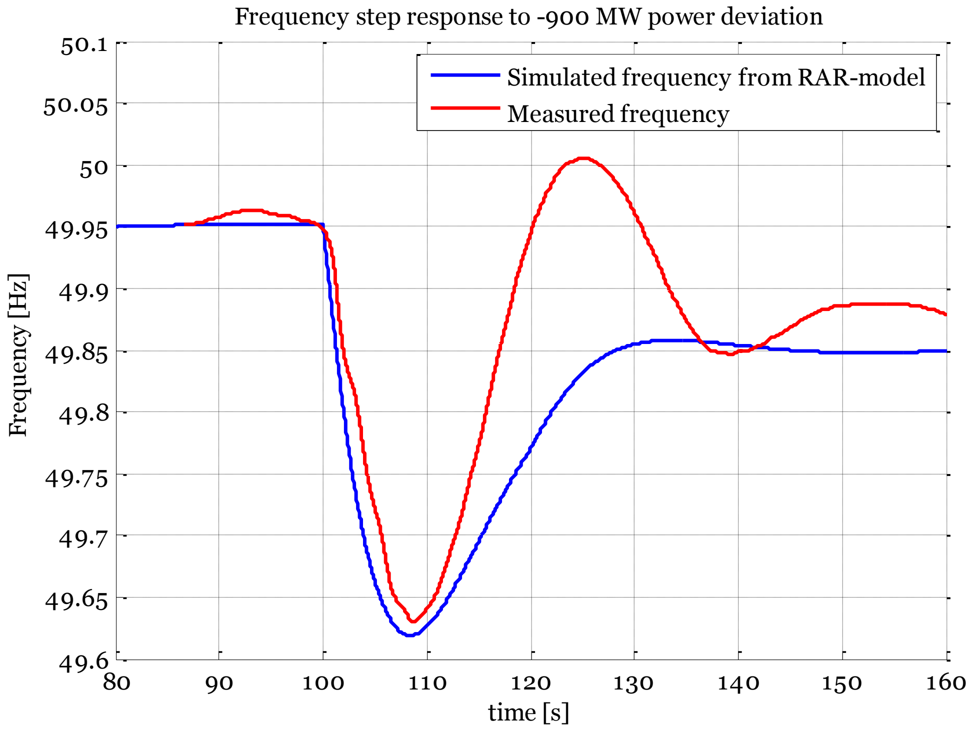

FIGURE 5.5: COMPARISON BETWEEN SIMULATIONS RESULTS FROM THE RAR MODEL AND MEASURED FREQUENCY

For the purpose of this project, the most important feature of these curves is the minimum (maximum) instantaneous frequency. The RAR-model could therefore be used to simulate the change in frequency based on power deviation and kinetic energy.

5.3 VALIDATION OF MODELS

In order to evaluate which of the models described in the previous sections gives the best result, 14 frequency disturbances have been used to compare them. The aim of the models is to estimate the minimum (maximum) instantaneous frequency as accurate as possible. The data from the disturbances from the period 1/4-14 to 2/10-14 and are shown in Table 5.1. None of these disturbances have been used to create the models. The estimated kinetic energy at the time of disturbance is calculated from Equations (5.2) and (5.3).

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TABLE 5.1 FREQUENCY DISTURBANCES WHICH ARE INCLUDED IN THE VALIDATION SERIES

Disturbance number	Tripped component	Power deviation [MW]	Estimated kinetic energy [GWs]	Minimum (Maximum) instantaneous frequency [Hz]	Date and Time
1	Sunndalsöra	460	160.16	50,230	4/5-14 00:35:40
2	Baltic cable	395	158.17	49,824	13/5-14 00:42:54
3	Avedöre	300	162.47	49,765	21/5-14 12:21:25
4	Great belt 1	590	166.22	49,746	10/6-14 11:55:59
5	NorNed	700	187.77	50,346	30/6-14 14:17:01
6	Hasle-Röd (SPS)	800	167.22	49,596	1/7-14 17:36:48
7	Swe-Pol Link	600	162.36	50,332	12/7-14 11:54:02
8	Oskarsham 3	1170	141.89	49,402	13/7-14 08:32:33
9	Ringhals 1	840	155.16	49,713	20/7-14 18:51:21
10	Great Belt 2	350	156.84	49,798	21/7-14 08:00:43
11	Meri-Pori	520	161.78	49,717	22/7-14 22:58:46
12	Konti-Skan 1	350	163.51	49,837	25/8-14 15:14:15
13	Estlink 1	350	173.44	50,177	10/9-14 07:58:31
14	Production in Norway (SPS)	580	197.04	49,750	2/10-14 11:51:10

The mean absolute error from the simulations is shown in Table 5.2 and Figure 5.6.

TABLE 5.2 MEAN ABSOLUTE ERROR OF THE MINIMUM (MAXIMUM) INSTANTANEOUS FREQUENCY, BASED ON 14 DISTURBANCES

Model	Mean Absolute Error [Hz]
Linear model – Power imbalance	0.0363
Linear model – Power imbalance/Total production	0.0260
Linear model – Power imbalance/Kinetic energy	0.0180
RAR-model	0.0393

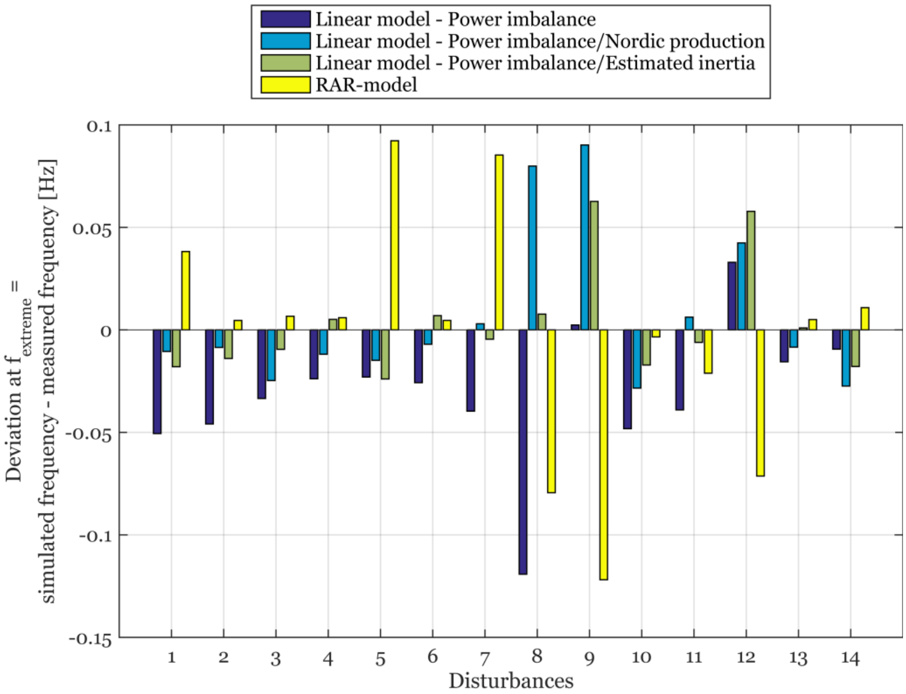

FIGURE 5.6: SIMULATION RESULTS FROM STUDIED MODELS

Figure 5.6 shows that the minimum (maximum) instantaneous frequency for the 14 test disturbances was estimated with a maximum 0.12 Hz error by all of the models. The model which best estimates the change in frequency for the validation series is the linear model which uses both power deviation and inertia. The mean absolute error for this model is 0.0180 Hz and the largest error is 0.0627 Hz.

5.4 RELATIONSHIP BETWEEN MINIMUM INSTANTANEOUS FREQUENCY AND INERTIA

To get a further understanding of how inertia affects frequency behaviour, a sensitivity analysis has been performed on the model which is shown in Figure 5.7 (Saarinen & Lundin, 2014). This model is based on a system comprising of a high share of hydro power generators participating in frequency regulation. The model lumps all generators and represents them as one, which simplifies the model, but neglects oscillations between generators. Emergency Power Control (EPC) functions on HVDC-connections are not modelled here.

Model parameters have been estimated based on the load during the operation scenario to provide a frequency response similar to measurements. The estimation is performed using automatic system identification with upper and lower limitations for the variables.

In Table 5.3 the estimated parameter values are shown and the frequency response can be seen in Figure 5.8. The system values are calculated using the per unit base values $P_{\text{Base}} = 29282$ MW and $f_{\text{Base}} = 50$ Hz.

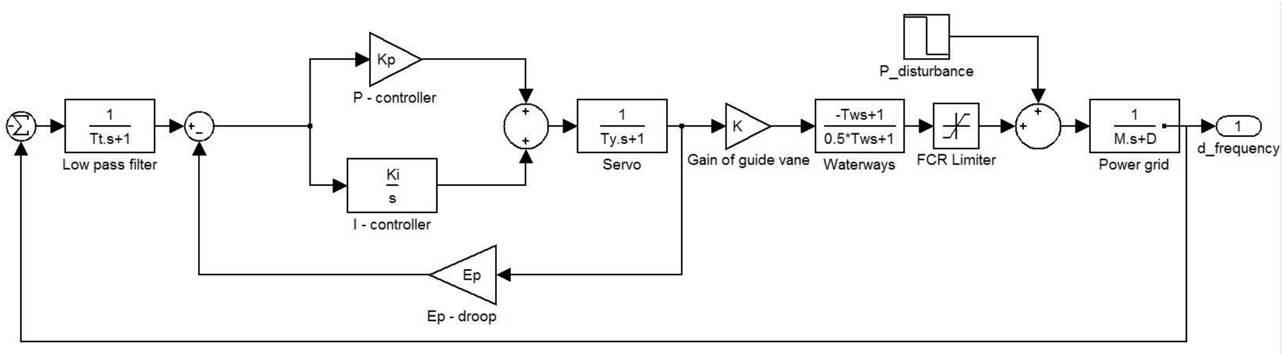

FIGURE 5.7: POWER SYSTEM MODEL BASED ON A SYSTEM WITH HYDRO POWER AS MAIN FREQUENCY REGULATION

TABLE 5.3 ESTIMATED MODEL PARAMETERS

Parameter	Description	Model value	System value
M	Inertia time constant	9.8 s	144 GWs
D	Frequency dependent load	0.9 pu	525 MW/Hz
Kp	Proportional gain	2 pu	-
Ki	Integral gain	0.49 s-1	-
Ty	Servo time constant	0.2 s	-
K	Gain of guide vane	1 pu/pu	-
Tw	Water time constant	0.5 s	-
Tt	Filter time constant	0.55 s	-
Ep	Droop	0.05 pu	-
FCR Limiter	FCR Saturation limit	± 0.062 pu	± 1800 MW
FBF	Frequency Bias Factor	-	11702 MW/Hz

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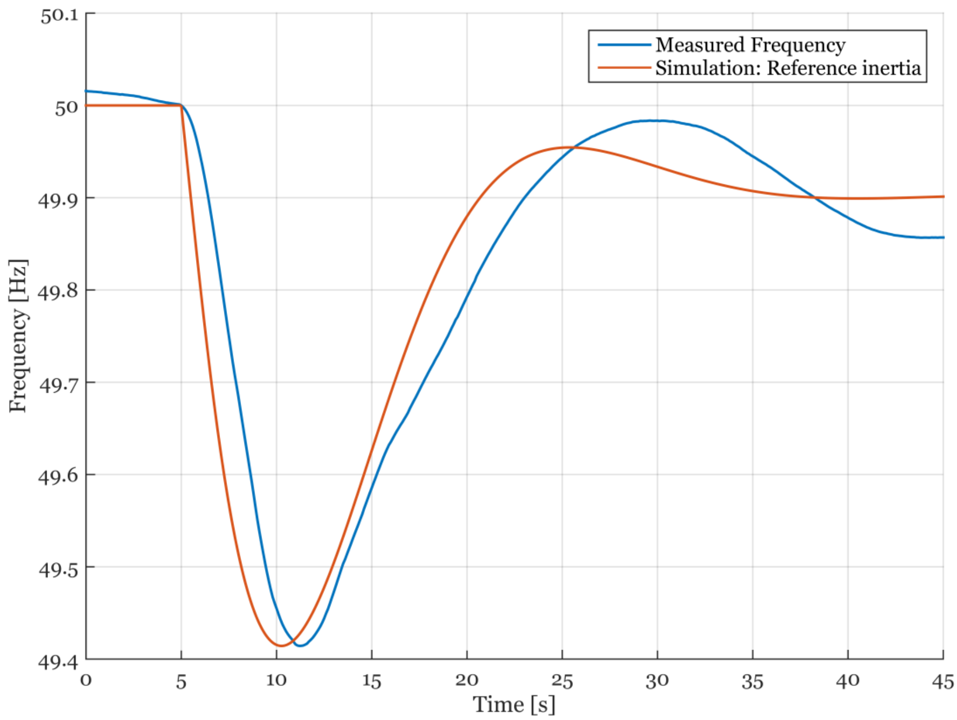

FIGURE 5.8: MEASURED FREQUENCY COMPARED WITH FREQUENCY RESPONSE FROM SIMULATION

The frequency disturbance shown in the figure is the trip of Oskarshamn 3, number 8 in Table 5.1, which results in a loss of 1170 MW. As a note, the estimated inertia (144 GWs) is very similar to the retroactive online estimation (142 GWs).

Figure 5.9 shows the results from six simulations where inertia in the model has been varied from the nominal inertia of the system.

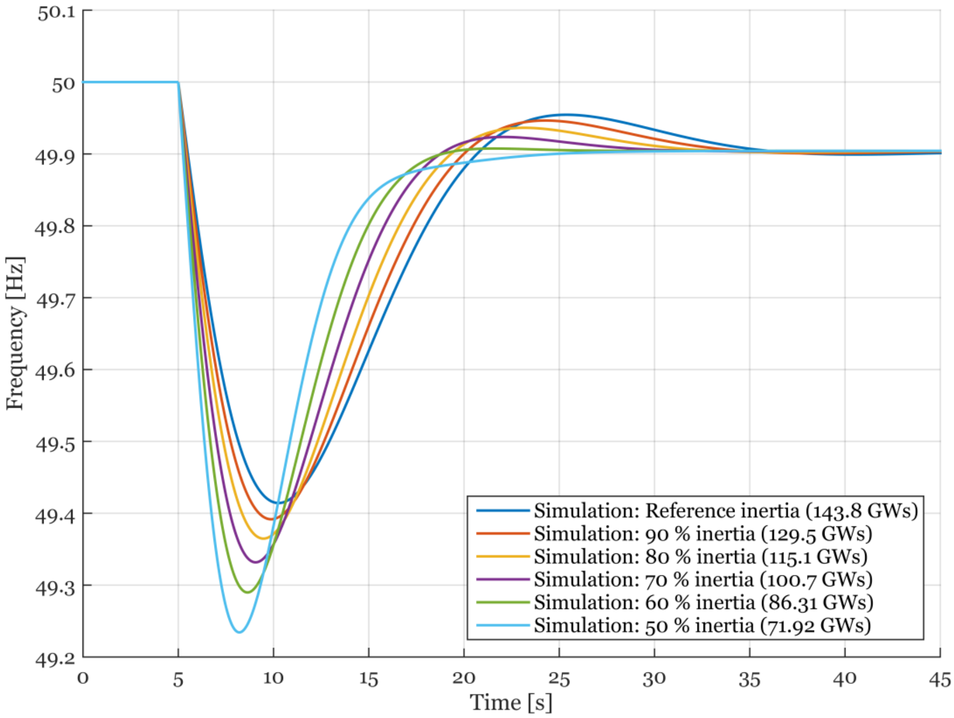

FIGURE 5.9: SIMULATION RESULTS FOR VARYING INERTIA

The results show that when the inertia is reduced the change in frequency becomes larger. This change in frequency does not have a linear relation to the inertia of the system, as shown in Figure 5.10.

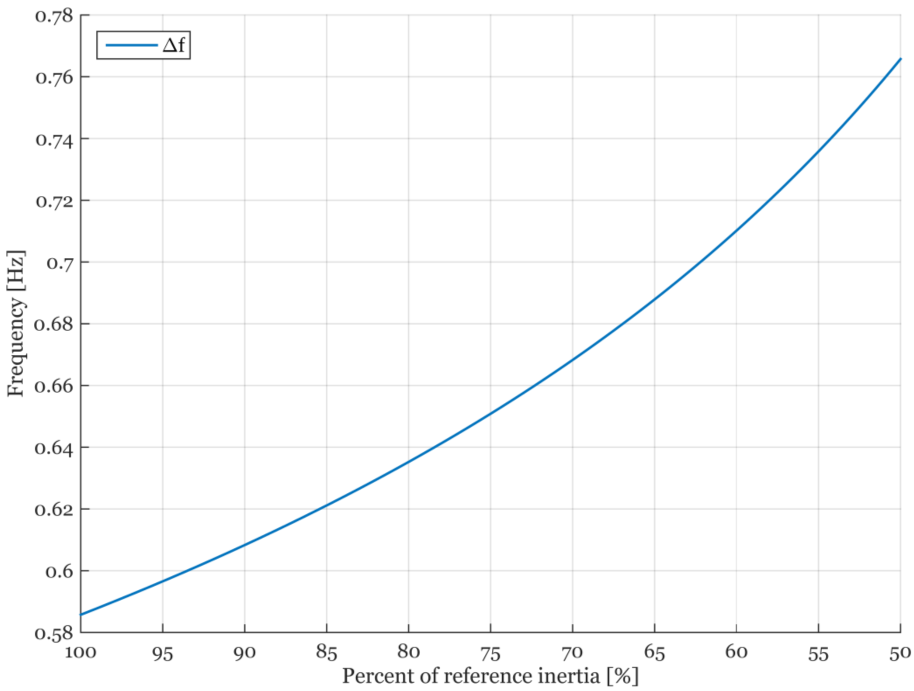

FIGURE 5.10: MAXIMUM FREQUENCY DEVIATION FOR VARYING INERTIA

In the figure, the relationship between the inertia of the system and the maximum frequency deviation has been plotted from 101 simulations between 100 and 50 % of the nominal inertia in the system.

5.5 DISCUSSION AND CONCLUSIONS

The validation results show that the linear model based on the power imbalance in relation to the estimated kinetic energy, described in Chapter 5.1.3, gives the smallest error. This model also has the highest coefficient of determination, R^2 of all the three linear models.

An advantage of the model in Chapter 5.1.2 which uses the relation between frequency deviation and power deviation relative total production is that the prognosis data is available a day ahead on Nord Pool Spot. It is then possible to plan for scenarios with low inertia in advance.

If a model is to be used today to estimate the lowest or highest frequency during a frequency disturbance, a linear model can be used because of the simplicity to implement it into the SCADA-system.

The linear models are limited by the fact that they are based on historical disturbances. If there are any major changes in the power system, for example requirements for the Frequency Containment Reserve, these models needs to be recalculated using new disturbances. In the future it is better to use a multi-node power system model to perform dynamic simulations of the dimensioning fault. This model should automatically update the network model as the operational scenario changes.

There are sources of error for the empirical data, which are used as input to these simulations. These errors make it difficult to create a model which can accurately estimate the largest change in frequency for all types of disturbances. Some of the sources of error are listed here:

- **Size of power imbalance:** The value of the change in produced power is retrieved from the frequency disturbance database at Svenska kraftnät or reports from the general disturbance data base. These values are recorded manually by staff in the control room.

- **Rate of change of power**: In the simulations is assumed that a power imbalance occurs instantaneously, and that a power production follows a step function. This is not the case for a number of disturbances, especially for those, which involve nuclear power units. These units may sometimes decrease their production for a period of up to many seconds, before the generators are disconnected from the network. This means that the maximum frequency deviation which results from a simulation can vary from the measured frequency, more so if the decrease in production occurs slowly.

- **Estimation of inertia:** The estimation of inertia uses standard values for inertia constants for a large number of power plants. The inertia values for Denmark are also not included.

- **Production and load**: The values for production and load are retrieved from Nord Pool Spot, and are therefore only an average value for the hour when the disturbance occurred. This is a source of error for the models, which use this value.

- **Frequency measurements at only one point**: The measured change in frequency during a disturbance depends on where the frequency is measured in the network. This is because power oscillates between generators during a disturbance, which affects the local frequency. For the validation series frequency measurements have been taken from only one point in the power system. A much better way of measuring the frequency is to use several measurements and then calculating the Centre of Inertia (COI) frequency described in Chapter 3.1.1, so as to remove the geographical dependency of the measurement.

- **Emergency power**: Emergency power from HVDC links has not been included in any of the models, which have been used here. In reality, HVDC links provide active power support when certain frequency limits are exceeded.

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6. IMPACT OF FUTURE SYSTEM CHANGES ON INERTIA

In the future there will be more wind, solar and small scale hydropower and the existing condensing power plants may be rarely connected to the network. In addition an increased number of HVDC links will increase import and export capacity. Also the consumption characteristics will change, and rotating motors are more often connected to the grid through frequency converters. All of these changes will have an impact on the system inertia and therefore need to be studied.

In this chapter the impact of production portfolios on inertia is examined. Nordic TSOs have created scenarios for different operational situations in 2020 and 2025 and these have been used to estimate the kinetic energy of Nordic power system in the future.

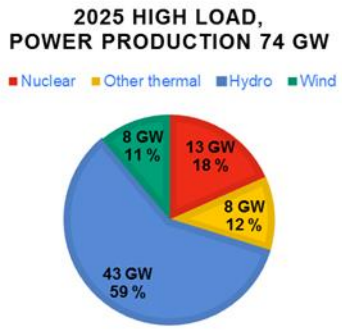
These scenarios have been compiled to address the tasks in the scope of the project, and will be used in further studies in the next stage of this project.

6.1 ESTIMATION OF KINETIC ENERGY IN 2020 AND 2025

Different scenarios have been studied in order to get an estimate of the system kinetic energy in different situations and to see the impact of different levels of hydro power, and the effect of reduced nuclear power. These scenarios were created using market simulation models and comparing these with the historical operational situations.

The scenarios show that the system kinetic energy in 2020 will be between 124 GWs and 305 GWs depending of the amount and type of production. In 2025 the results are similar to 2020 results, but since the production level in 2025 is slightly higher than in 2020, the system kinetic energy is also somewhat higher. System kinetic energy varies between 138 and 313 GWs depending of the situation.

The relation between power production and system kinetic energy with different type of production in high load situation in 2025 can be seen in Figure 6.1. The total production in this case in Nordic is 74 GW.



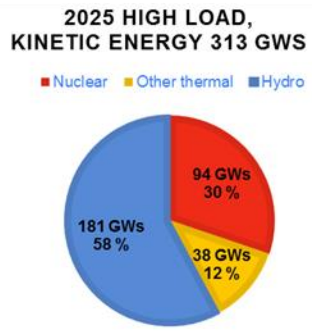


FIGURE 6.1: HIGH LOAD SCENARIO IN 2025. TOTAL PRODUCTION IN NORDIC SYNCHRONOUS AREA IS 74 GW AND SYSTEM KINETIC ENERGY IS 313 GWS.

To estimate the kinetic energy in different scenarios some average values for inertia constants were used. These average inertia constants used are shown in Table 6.1.

TABLE 6.1 AVERAGE INERTIA CONSTANTS USED TO ESTIMATE FUTURE INERTIA IN DIFFERENT PRODUCTION SCENARIOS

Production type	H (s)
Nuclear	6.3
Other thermal	4
Hydro conventional	3
Hydro small-scale	1
Wind	0

In the estimation of kinetic energy it has been assumed that all production has a power factor of 0.9. It has also been assumed that conventional hydro is operated with the power of 80 % of the maximum power and all the other production with full power.

The production scenarios with maximum and minimum kinetic energy for 2020 can be seen in Table 6.2.

TABLE 6.2 PRODUCTION SCENARIOS WITH MAXIMUM AND MINIMUM KINETIC ENERGY FOR 2020

Scenario	Nordic production [MW]					Kinetic energy [GWs]
	Nuclear	Other thermal	Hydro conventional	Wind	Total	
Peak load in winter time	12 288	9 931	41 922	6 868	71 009	305
Midsummer night with high wind	7 664	2 322	14 505	4 510	29 000	124

In order to understand how low the very minimum system kinetic energy can get, cases with very low production with minimum kinetic energy in 2020 and 2025 were studied. In Figure 6.2 one of these cases is presented.

FIGURE 6.2: LOW INERTIA SCENARIO IN 2025. TOTAL PRODUCTION IN NORDIC SYNCHRONOUS AREA IS 27 GW AND SYSTEM KINETIC ENERGY IS 95 GWS.

In this case the total production level in Nordic synchronous area is 27 GW and system kinetic energy 95 MWs. It can be seen that in this low production case the impact of nuclear power to system kinetic energy is significant.

In three of the minimum inertia scenarios, part of the conventional hydro power has been replaced by small-scale hydro power, which has much lower inertia constant.

The production portfolios and kinetic energy of these extreme scenarios are in Table 6.3.

TABLE 6.3 EXTREME PRODUCTION SCENARIOS FOR 2020 AND 2025

Scenario	Production [MW]						Kinetic energy [GWs]
	Nuclear	Other thermal	Hydro conventional	Hydro small-scale	Wind	Total	
2020	7 164	2 322	8 846	0	5 510	23 841	97
2020 part of conventional hydro -> small-scale	7 164	2 322	6 346	2 500	5 510	23 841	90
2025	7 474	2 463	9 383	0	7 182	26 502	102
2025 part of conventional hydro -> small-scale	7 474	2 463	6 883	2 500	7 182	26 502	95
2025 import, less nuclear	5 420	2 463	6 883	2 500	7 182	24 448	80

As shown in the table, the kinetic energy can be as low as 80 GWs if the Nordic system has low load and large part of the production has inertia constant equal to zero or the inertia constant is very low.

6.2 CONCLUSIONS

Different future scenarios with different production levels have been studied. It is possible that the kinetic energy in the Nordic synchronous area can be lower than 100 GWs in the future in scenarios where a large part of conventional production has been replaced with production types with a low inertia constant.

However, in these scenarios, import to Nordic area has been moderate. Nordic TSOs are building more HVDC connections to other synchronous areas, so it can be expected that the import can be quite significant in the future.

These low levels of kinetic energy motivate further studies to investigate the impact of disturbances on frequency excursions, and to develop a plan for dealing with low levels of kinetic energy.

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7. CONCLUSIONS AND FUTURE WORK

7.1 CONCLUSIONS

This report documents the efforts made to analyse historical frequency disturbances and to estimate the consequences of reduced inertia on frequency disturbances.

This work can be seen as an initial attempt to get a better understanding of the variation of kinetic energy in the Nordic power system and how the future changes will impact the inertia values in the system and how real time measurement of kinetic energy can be performed and visualised for operational personnel.

It had been assumed that by looking at a historical frequency trace it would be possible to calculate the system kinetic energy. This was shown not to be the case, and that multiple measurements of frequency from strategic locations are required in order to make a good estimate of the amount of kinetic energy in the system.

Definitions have been made for features of a frequency trace. These include the start of a disturbance, and frequency before and after the disturbance. A list of disturbances has then been extracted from historical data and used to develop a simple model relating minimum instantaneous frequency to the load and kinetic energy present in the Nordic system. This model was shown to correspond well to the historical disturbances used in the validation series. The model using the relation between the power imbalance and kinetic energy provided the best result with a mean absolute error of 0.0180 Hz.

Additionally scenarios for studying future kinetic energy were developed from data provided by the Nordic TSOs. These show that kinetic energy is expected to reach lower levels than today and what we have historically seen. Results from a dynamic analysis show that low amounts of power system kinetic energy are expected to have a significant impact on the minimum instantaneous frequency.

An achievement of this work has been the development of an online tool for estimating kinetic energy in the power system. This is a work in progress, but preliminary results have given good insight into how the operation of generators affects the kinetic energy of the system.

These results can be used as an input to further work to see how low system inertia can be handled.

7.2 FUTURE WORK

Based on the findings and results in this report, recommendations for further work can be made. This work includes making sure the Nordic system will be operated within its operational security limits in the future, with forecasted changes of production and import/export.

A Nordic based approach is required to coordinate the activities of the individual TSOs.

Work is recommended to be continued within the following areas:

1. **System needs/system studies**

It can already now be seen that in some situations the system kinetic energy in the Nordic synchronous area can be quite low. Further studies considering increased number of HVDC connections, and with that, increased import capacity to the Nordic synchronous area, should be performed to evaluate if the kinetic energy in the system can be even lower than estimated in this report. These studies should also study very extreme situations with multiple nuclear power plants being shut down suddenly. This case should reveal the potential challenges for the Nordic system seen from a stability point of view.

ENTSO-E has prepared four visions for 2030 based on common European guidelines. These visions could also be used to study system kinetic energy.

2. **Improvement of inertia estimation tools**

- A more accurate method to estimate the system kinetic energy during disturbances should be established and incorporated into NOIS. This is recommended since the system inertia is a factor that plays a major role in the frequency disturbance characteristic, and it is thereby important to have a good logging of this value during disturbances. It is also important to get this estimation in order to verify the real time estimation of system kinetic energy described in this report.

- In order to establish an accurate estimation method, it is recommended to perform real system tests or utilise planned tests in order to get useful validation data.

- The established online SCADA inertia estimation tool should be improved regarding the accuracy of inertia constants used in the real time estimation. This is supposed to be a TSO-internal work but might be followed on Nordic level regarding harmonisation of accuracy levels etc.

- The possibilities for forecasting system kinetic energy should be studied. Real time estimation is an important tool for handling unforeseen events during periods of low kinetic energy in the system. For planning outages during low load periods, forecasting of kinetic energy could be a measure to ensure an adequate rotating mass in the system ahead of the operating hour.

- As a complement to improving these tools, errors need be quantified to give a better understanding of the results of these tools.

As a short term measure simulations of the disturbance of the dimensioning incident can be performed for different values of kinetic energy to find the expected minimum instantaneous frequency, and a lookup table can be created to find an estimate of the lowest amount of kinetic energy required in order to satisfy the requirements for the lowest allowed instantaneous frequency.

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3. Measures to handle future low kinetic energy situations

Depending on the needs of the system, possible measures to compensate for situations with low system kinetic energy are recommended to be investigated. These measures can for instance be:

- synthetic inertia from frequency converter connected resources, e.g. wind power generators, HVDC connections and non-synchronously connected loads,
- utilising hydro power plants by running on minimum active power or as synchronous compensators,
- reducing the size of the dimensioning incident,
- adjustable FCR parameters for FCR contributing power plants.

Both short term and long term alternatives should be considered.

It is also clear that it is necessary to investigate how to handle these measures from a Nordic market perspective, and who is in charge when a measure needs to be implemented. In this, a benchmarking can be performed to see how other synchronous areas are planning to handle scenarios with low system inertia.

4. Other topics

Other items that are of relevance to bring in to further work are:

- estimation of the amount of system kinetic energy that comes from loads. This topic is of most importance if validation of the inertia online estimation tool shall be performed with full scale system testing, and
- keeping track of ongoing European work and including the inertia-related items in ENTSO-E Guideline on Transmission System Operation, Article 34 (Dynamic Stability Management).

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