European Network of
Transmission System Operators
for Electricity

Requirement for minimum inertia in the Nordic power system

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1. Background

1.1 European regulation

Article 39 (3a) in 'Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation' (EC 2017) requires that all transmission system operators (TSO) shall conduct a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives[1]. All TSOs shall notify their studies to their regulatory authorities. This report describes common Nordic studies, which justify that there is no need for defining the minimum inertia, as such, during the coming two years for the Nordic synchronous system.

This report explains which properties affect the frequency stability and how the Nordic TSOs ensure the stability. The report also describes that the instantaneous frequency minimum after a disturbance is an important criterion for maintaining the stability, and how the Nordic TSOs ensure that the instantaneous frequency minimum after the reference incident will not fall below the defined value, 49.0 Hz.

Several studies regarding the inertia and frequency dynamics are presented at a detailed level in the report 'Future System Inertia 2' (Ørum et al. 2017), prepared and published by Energinet, Fingrid, Svenska kraftnät, and Statnett, i.e. the Nordic TSOs responsible for the Nordic synchronous system.

1.2 Frequency requirements for the Nordic power system

Minimum frequency and automatic low frequency demand disconnection

In the Nordic synchronous system, the instantaneous frequency minimum should be 49.0 Hz or higher after the reference incident, such as the trip of the largest generator or an HVDC link importing power from a neighbouring system. If the system fulfils this requirement, the frequency will be above 49.0 Hz after all other N−1 trips. The motivation for this frequency limit is that massive load shedding for maintaining the system stability will occur when the frequency decreases below 49.0 Hz (indiscriminative load shedding starts at 48.8 Hz).

The reference incident now and in the near future is the trip of 1450 MW, Oskarshamn 3 generator. Olkiluoto 3 generator has a special protection scheme, which automatically disconnects 300 MW load when Olkiluoto 3 trips and therefore the power imbalance after Olkiluoto 3 trip will be 1300 MW and not 1600 MW. (Ørum et al. 2017, p. 107)

System dynamics after a generator trip – the basic features

Figure 1 shows the dynamic response after a generator trip with high and low inertia (high and low kinetic energy) in the system. For both cases, the amount of tripped power and the frequency reserves are the same.

[1] Article 39 is in the Appendix.

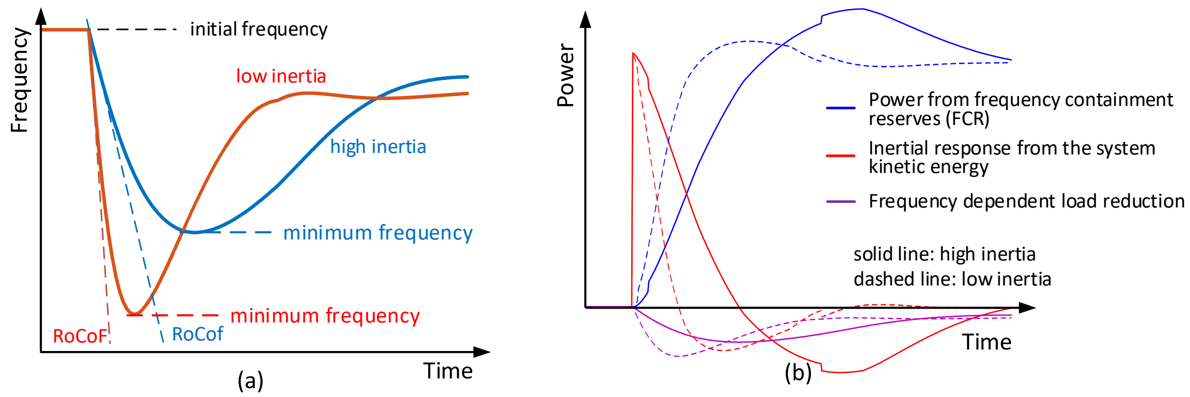

Figure 1. *Frequency and power responses after a generator trip with high and low inertia. a) Initial frequency and the frequency after a generator trip and the corresponding rate of change of frequency (RoCoF) values. b) Power responses from the kinetic energy (inertial response), from frequency containment reserves (FCR), and from the load reduction of the frequency dependent loads. The minor positive step in the power from frequency containment reserves comes from the HVDC FCR, which has an activation delay. (Statnett, Fingrid, Energinet, and Svenska kraftnät 2016 p. 35)*

As Figure 1 shows, the amount of kinetic energy (inertia) affects the rate of change of frequency (RoCoF) after a generator trip. Higher inertia means more kinetic energy in the rotating masses of turbine-generator units. As the system frequency decreases, decelerating masses release their kinetic energy to the system and in this way reduce the power imbalance. Figure 1 also shows that the automatic primary reserves and the load reduction caused by the frequency dependency of the loads affect the frequency response. Tripping more active power leads to a larger frequency change if all the other factors remain the same.

In the Nordic system, the frequency stability and maintaining the minimum frequency are critical. The rate of change of frequency is not a critical aspect since after the reference incident it is not too high and therefore generators remain connected in the system.

2. Maintaining the instantaneous frequency minimum above 49.0 Hz

2.1 Theoretical possibilities

As Figure 1 shows, the amount of system inertia and load dynamics affect the rate of change of frequency and the resulting instantaneous frequency minimum. The amount of tripped generation has an impact too. Reserves have an impact on the rate of change of frequency but this effect depends on how fast the reserves react. If the activation time is e.g. one second, the reserves affect the frequency change roughly after two seconds, not immediately after the disturbance.

Three main factors (inertia, tripped power, and reserves) define the frequency dynamics after a power imbalance. Also load dynamics have an impact but the TSOs cannot set requirements for the load dynamics and the amount of load. The system load and its dynamics being out of control, the remaining possible methods for affecting the initial rate of change of frequency are: 1) the system inertia, and 2) the power imbalance. For the instantaneous frequency minimum, also 3) the speed of the primary reserves comes into play.

Increasing system inertia, i.e. increasing the kinetic energy in the rotating masses of synchronous generators, is a possible solution for maintaining frequency stability. The volume needed to affect the minimum frequency by 0.1 Hz in an 80 GWs system is 20 GWs (Ørum et al. 2017 p. 101). The availability of different possible techniques varies but the costs will be high. Examples of possible techniques are running units as synchronous condensers or starting generators and running them at low output. (Ørum et al. 2017 p. 116)

The 'Future System Inertia 2' report identified several measures for mitigating the low inertia situations, fast frequency reserve (FFR) being one of them. The reduction of the reference incident, a measure already existing today, scores low in terms of cost and can be a "plan B". (Ørum et al. 2017 p. 117).

2.2 Fast frequency reserves

Promising mitigation measures, identified in the 'Future System Inertia 2' report is e.g. load reduction, which can be relay-connected load, converter-connected load, or high voltage direct current emergency power control (HVDC EPC) (Ørum et al. 2017 Section 8.3). These measures can provide FFRs and are associated with low socio-economic costs.

Since several technologies can provide FFRs, the FFR parameters from different sources may be different. For example, the activation time can be instant (relay-connected load) or less than 0.5 seconds (converter-connected load, HVDC EPC) (Ørum et al. 2017 p. 93).

2.3 Limiting the reference incident

An option the transmission system operators have is to limit the power of the largest generators, loads or HVDC links connected to the system. This option does not require investments but has costs and can be a suitable method during exceptional situations, for example, during short periods when sufficient amounts of reserves do not exist or when the system inertia is exceptionally low. However, reducing the power of a nuclear generator may increase the risk of tripping the generator.

2.4 Simulated minimum instantaneous frequencies

Figure 2 shows simulation results on how the amount and parameters of FFRs affect the instantaneous frequency minimum after a power imbalance of 1450 MW in a situation when the Nordic power system post-disturbance kinetic energy is 100 GWs. The 100 GWs kinetic energy is considered a very low inertia situation, and it is used in simulations as a reference case. The figure indicates that it is possible to reach similar minimum instantaneous frequency with different FFR parameters (activation time and frequency).

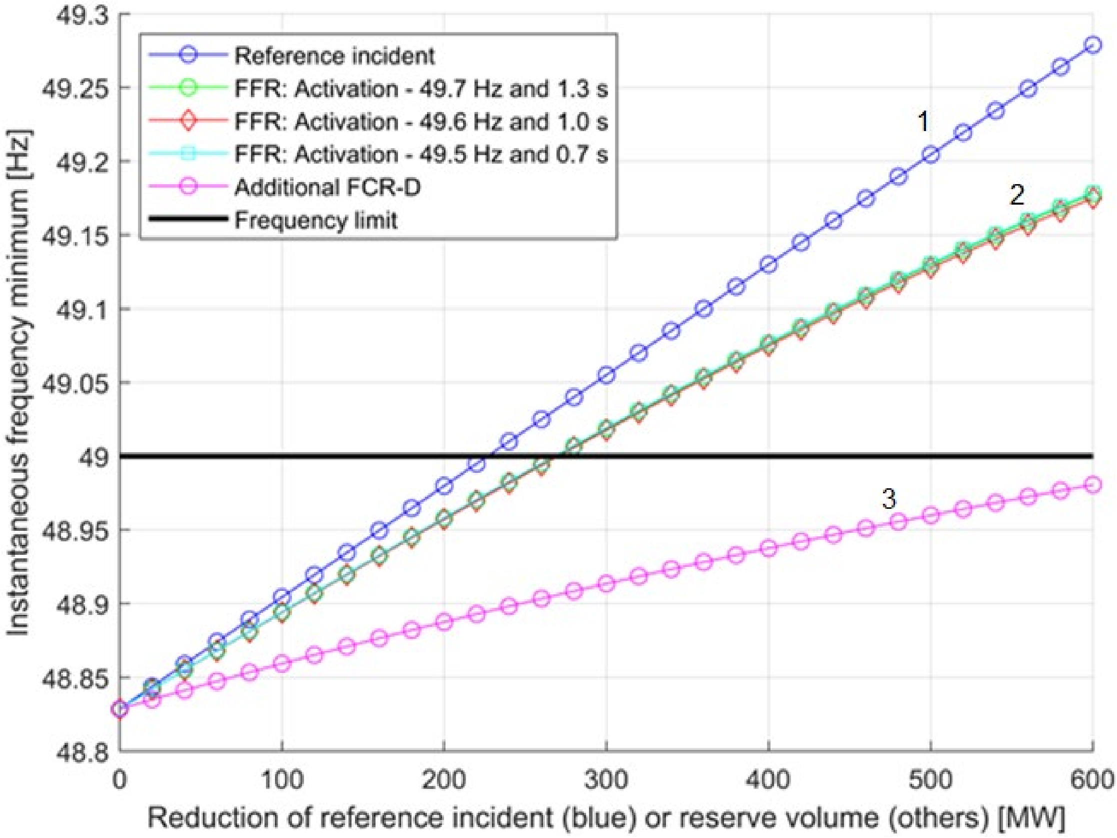

Figure 2. *Simulated instantaneous frequency minimum values for the Nordic power system when the post-disturbance[2] kinetic energy is 100 GWs. The blue curve (1) shows the instantaneous frequency minimum after reference incidents (RI). The reduction of the reference incident $P_{red\text{-}RI}$ is calculated: $P_{red\text{-}RI}$ = 1450 MW – x, where x is the x-axis value (MW). The overlapping green, red and turquoise curves (2) show instantaneous frequency minimum values after a 1450 MW generator trip as a function of the volume of fast frequency reserves (FFR, in the x-axis) with three different activation settings. The purple curve (3) shows the instantaneous frequency minimum values as a function of the volume of additional frequency containment reserves for disturbances (FCR-D) after the trip of 1450 MW.*

Figure 2 shows that in addition to increasing fast frequency reserves, decreasing the reference incident (the amount of tripped generation) is a possibility of preventing too low instantaneous frequency values after a generator trip.

Figure 2 shows that adding the amount of frequency containment reserve for disturbances (FCR-D) by 600 MW is not sufficient for getting the lowest instantaneous frequency above 49.0 Hz. The ‘Future System Inertia 2’ report explains that the current Nordic FCR-D alone is not sufficient to guarantee that the instantaneous frequency minimum remains above 49.0 Hz at all times. (Ørum et al. 2017 p. 110).

[2] Post-disturbance kinetic energy is the kinetic energy value after the reference incident, i.e. the value without the tripped generator.

3. Estimated inertia values for the Nordic system

3.1 Online kinetic energy estimation

The Nordic transmission system operators implemented a real-time kinetic energy estimation in their supervisory control and data acquisition (SCADA) and energy management system in 2015. The pre-fault kinetic energy values received from this online estimation system from the years 2017 and 2018 are well above the very low 100 GWs value as the following figures show. If a generator trip occurred, the kinetic energy would reduce due to the disconnection of the rotating mass and should be considered in any assessment of the frequency stability.

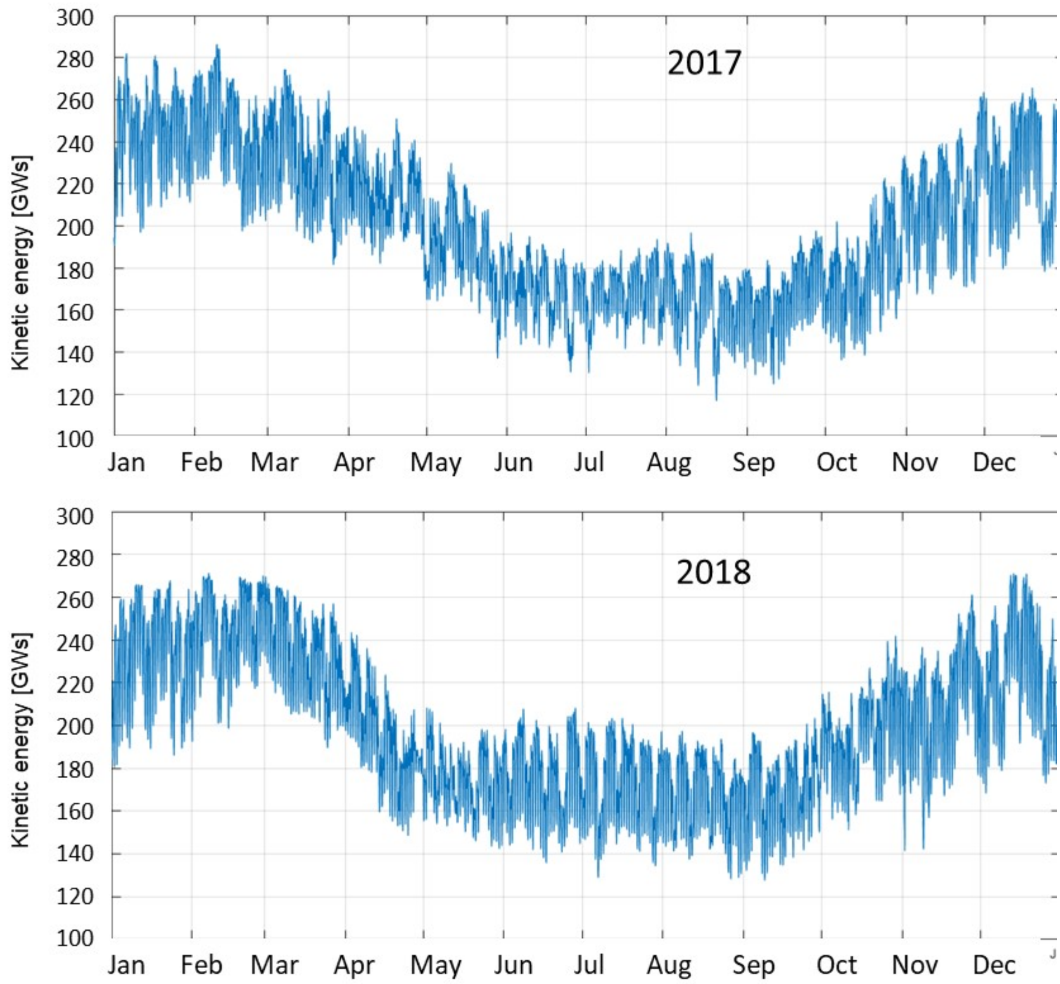

Figure 3. *Estimated kinetic energy values (pre-disturbance values[3]) from the online kinetic energy estimation tool for the Nordic synchronous system in the years 2017 and 2018*

3.2 Estimating future kinetic energy

Future inertia estimations for different future scenarios, presented in the 'Future System Inertia 2' report, show that with 99 % probability, the kinetic energy will be more than 120 GWs or 134 GWs in 2020 and 2025, respectively. These values are presented in the two base case curves in Figure 4.

[3] Pre-disturbance kinetic energy is the kinetic energy value before the possible reference incident, i.e. the value with all the connected generators.

The following duration curves show the future inertia estimates for different future scenarios (Ørum et al. 2017, p. 70 and p. 128).

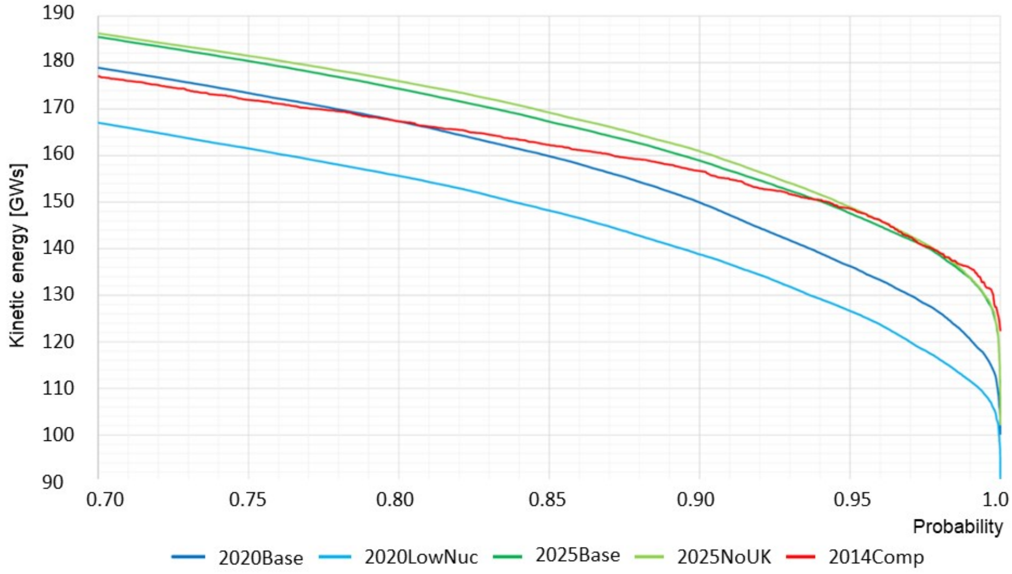

Figure 4. *The kinetic energy pre-disturbance values (y-axis) and the corresponding probability (x-axis) in each scenario show the probability at which the system will have at least the amount of kinetic energy the curve shows. The scenarios are for the year 2014 (2014Comp), 2020 (2020Base), 2025 (2025Base), 2020LowNuc (nuclear generation capacity in Sweden has been further decreased in scenario 2020 by shutting down two units in Ringhals) and 2025NoUK (a new 1400 MW HVDC link to the UK is postponed in the 2025 scenario). Note that the x-axis probabilities are between 0.7 and 1.0, which means that the highest kinetic energy values are not in the figure. (Ørum et al. 2017, p. 70)*

4. Maintaining the frequency stability with fast frequency reserves

There is no need to define and require a minimum inertia (kinetic energy) value for the Nordic power system since other socio-economically efficient mitigation measures can be defined, like providing FFR or limiting the reference incident (Ørum et al. 2017 p. 117).

As Figure 2 shows, with 100 GWs, roughly 300 MW FFRs in the Nordic synchronous system is enough for maintaining the frequency stability and keeping the instantaneous frequency minimum above 49.0 Hz. This is based on a model, describing the frequency response, developed in the project 'Future System Inertia 2' (Ørum et al. 2017). Figure 2 shows that with different activation frequency and full activation time, FFRs provide similar results. This gives flexibility for the reserve service and different technologies and providers will be able to provide FFR for the system. With lower kinetic energy values, the Nordic TSOs can ensure frequency stability by having higher volumes of FFR.

According to the feasibility study by the Nordic Analysis Group (Kuivaniemi, Jansson 2019), FFR is a more cost efficient measure for handling low inertia challenges compared with reducing the size of reference incident. As an additional remedial action to FFR, limiting the reference incident can guarantee the frequency stability during exceptional situations. For example, reducing the power of the largest generator connected to the system is possible, even though reducing nuclear generator output power may increase the risk of tripping the generator.

5. Conclusions

Requiring a minimum inertia value is not needed for the Nordic system in the near future. Considering socio-economic aspects, feasibility and risks, it is efficient to use fast frequency reserves (FFR) as a complement to frequency containment reserves (FCR-D) to keep the instantaneous frequency above 49.0 Hz after a sudden power imbalance. As an additional remedial action to FFR, limiting the reference incident can guarantee the frequency stability during exceptional situations with low inertia.

Abbreviations and definitions

EPC	Emergency power control (of HVDC connections).
FFR	Fast frequency reserve is a system service that delivers a fast power change to mitigate the effect of reduced inertial response, so that frequency stability can be maintained. (Ørum et al. 2017 p. 85).
FCR-D	Frequency containment reserve for disturbances.
HVDC	High voltage direct current.
RI	Reference incident means the maximum positive or negative power deviation occurring instantaneously between generation and demand in a synchronous area (EC 2017 p. 7). (Earlier the concept 'dimensioning incident' was used.)
RoCoF	Rate of change of frequency.
TSO	Transmission system operator.

References

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Appendix

Article 39

Dynamic stability management

1. Where the dynamic stability assessment indicates that there is a violation of stability limits, the TSOs in whose control area the violation has appeared shall design, prepare and activate remedial actions to keep the transmission system stable. Those remedial actions may involve SGUs.

2. Each TSO shall ensure that the fault clearing times for faults that may lead to wide area state transmission system instability are shorter than the critical fault clearing time calculated by the TSO in its dynamic stability assessment carried out in accordance with Article 38.

3. In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level:

   a) all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years;

   b) where the studies referred to in point (a) demonstrate the need to define minimum required inertia, all TSOs from the concerned synchronous area shall jointly develop a methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits. That methodology shall respect the principles of efficiency and proportionality, be developed within 6 months after the completion of the studies referred to in point (a) and shall be updated within 6 months after the studies are updated and become available; and

   c) each TSO shall deploy in real-time operation the minimum inertia in its own control area, according to the methodology defined and the results obtained in accordance with paragraph (b). (EC 2017)