IMPACT OF OVER-FREQUENCY EVENTS ON NORDIC NPPS

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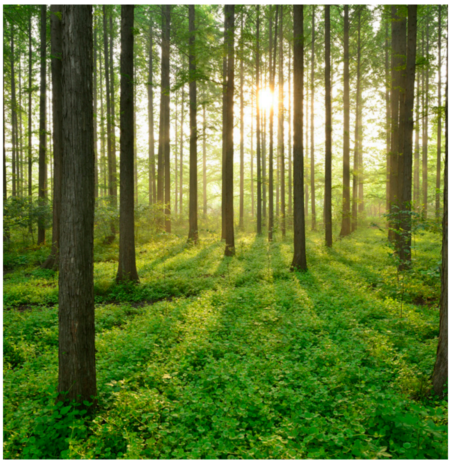

GRID INTERACTION ON NUCLEAR POWER PLANT OPERATIONS, GINO

Energiforsk

Impact of over-frequency events on Nordic NPPs

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Foreword

This report forms the results of a project performed within the Energiforsk Grid Interaction with Nuclear power plant Operations (GINO) Program. The GINO Program aims to increase the knowledge of aspects of the interactions between the external grid and the Nordic nuclear power plants. Part of this is to investigate technical issues.

The increasing occurrence of over-frequency events in the Nordic power system poses significant challenges for nuclear power plants, as these events can cause stress on the power plant systems, potentially impacting their safe and reliable operation.

This study aims to provide a comprehensive analysis of the impact of over-frequency events on Nordic nuclear power plants. It uses a simulation model to quantify these events and assess their potential effects under various operating conditions.

The findings indicate that while the Nordic nuclear power plants are generally robust, extreme scenarios could exceed their capabilities. Recommendations include continuous monitoring, increased consideration of HVDC links, and collaboration with other stakeholders to ensure secure and reliable operation.

The study was carried out by Matilda Arvidsson, Andreas Benjaminsson, Lucas Finati Thomée and Daniel Karlsson, DNV. The study was performed within the Energiforsk GINO Program, which is financed by Vattenfall, Uniper, Fortum, TVO, Skellefteå Kraft, Karlstads Energi, the Swedish Radiation Safety Authority and Svenska Kraftnät.

These are the results and conclusions of a project, which is part of a research Program run by Energiforsk. The author/authors are responsible for the content.

Summary

The Nordic power system is currently undergoing significant changes, which are expected to continue for a long time, to reach climate goals through the electrification of industries and society. As part of these changes, the HVDC interconnectors between the Nordic synchronous system and other synchronous systems are increasing, both in terms of the number of interconnectors and their capacity (MW). In connection with this, analysis of the trends of frequency deviation in the Nordic power system over the past 20 years indicates a recent increased occurrence of over-frequency events.

This report quantifies over-frequency events by using a simulation model of the Nordic synchronous system and simulating different faults related to the HVDC links, in combination with operating conditions of high and low inertia. The following faults are considered:

- Disconnection of HVDC link
- Reverse power flow of HVDC link
- Disconnection of several HVDC links
- System split

Using the simulation model the resulting frequency change are calculated. For HVDC link faults, RoCoF of up to 0.82 Hz/s; and frequency deviation up to 51.1 Hz. For the System split scenario, RoCoF of up to 1.7 Hz/s and frequency deviation of up to 52 Hz.

The findings of the study indicate that the NPPs should be robust to most of the studied cases related to large disturbances related to HVDC links. This is further highlighted from the experience of the NPPs, as there has been no significant impact on the recent historical over-frequency events on the operation of the NPPs. However, the most extreme system split scenario, might result in extreme over-frequency deviations beyond the system and NPPs capabilities. Reference is made to the 1983 historical event where over-frequency of 54.0 Hz after 5 seconds was reached.

Measures undertaken to limit the impact of over-frequency events in other synchronous areas have also been reviewed. This includes the introduction of market mechanisms, such as Fast Frequency Response/Reserve, and technical requirements, such as provision of synthetic inertia.

From the perspective of the Nordic NPPs, the over-frequency domain is still viewed as a relatively new and unexplored territory. Recommendations are put forward to ensure the continued secure and reliable operation of the Nordic NPPs, including: Continuous monitoring and analysis of frequency deviations and impact assessments to determine the need for implementing further countermeasures; Encourage the Grid Committee and the Operations council to increase the consideration of HVDC links in worst-case scenarios and in anticipating future over-frequency events; and, Collaboration and experience exchange between stakeholders and with NPPs in other synchronous areas to gain valuable insights and best practices.

Keywords

HVDC interconnectors, Over-/under-frequency events, System split, Rate-of-Change-of-Frequency (RoCoF), Synthetic inertia

Sammanfattning

Vårt nordiska elsystemet genomgår för närvarande stora förändringar, som förväntas fortsätta under längre tid för att nå klimatmålen genom elektrifiering av industrier och samhället. Som en del av dessa förändringar ökar HVDC förbindelserna mellan det nordiska synkrona systemet och andra synkrona system, både i antal och kapacitet (MW). Analys av frekvensavvikelsens trender i det nordiska elsystemet under de senaste 20 åren visar också på en ökad förekomst av överfrekvensevent, särskilt de senaste åren.

Denna rapport kvantifierar överfrekvensevent genom att använda en simuleringsmodell av det nordiska synkrona systemet och simulera olika fel relaterade till HVDC förbindelser, i kombination med olika driftförhållanden med hög och låg tröghet. Följande fall beaktas:

- Bortkoppling av HVDC länk
- Omvänd kraftflöde av HVDC länk
- Bortkoppling av flera HVDC länkar
- Systemdelning

Med hjälp av simuleringsmodellen beräknas de resulterande frekvensavvikelserna. För fel med HVDC-länkar, beräknas RoCoF till 0,82 Hz/s; och maximal frekvensavvikelse till 51,1 Hz. För scenariot med systemdelning, beräknas RoCoF till 1,7 Hz/s och maximal frekvensavvikelse till 52 Hz.

Resultaten av studien indikerar att kärnkraftverken bör vara robusta mot de flesta av de studerade fallen som rör stora störningar relaterade till HVDC länkar. Detta understryks till viss mån ytterligare av erfarenheter från kärnkraftverken, då de senaste historiska händelserna med överfrekvens inte har haft någon betydande inverkan på driften. Dock kan det mest extrema scenariot med systemdelning leda till extrema överfrekvensavvikelser som ligger utanför systemets och kärnkraftverkens förmåga att klara av. Hänvisning görs till den historiska händelsen 1983 då en överfrekvens på 54,0 Hz uppnåddes efter 5 sekunder.

Åtgärder som vidtagits för att begränsa påverkan av överfrekvenshändelser i andra synkrona områden har också granskats. Detta inkluderar införandet av marknadsmekanismer såsom Fast Frequency Response/Reserve och fastställande av tekniska krav, såsom tillhandahållande av syntetisk tröghet.

Ur de nordiska kärnkraftverkens perspektiv ses överfrekvensevent fortfarande som ett relativt nytt och outforskat område. Rekommendationer läggs fram för att säkerställa den fortsatta säkra och tillförlitliga driften av de nordiska kärnkraftverken, inklusive: Kontinuerlig övervakning och analys av frekvensavvikelser samt konsekvensbedömningar för att fastställa behovet av att genomföra ytterligare motåtgärder; Uppmuntra nätkommittén och Driftrådet att i högre grad beakta HVDC-länkar i värsta tänkbara scenarier och för att förutspå framtida överfrekvenshändelser; och, Samarbete och erfarenhetsutbyte mellan olika aktörer i Norden och med kärnkraftverk i andra synkrona områden för att få värdefulla insikter och dela bästa praxis.

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1 Context of over-frequency events in the Nordic Power System

Significant changes in the power system are underway and are expected to continue for the foreseeable future to enable continued electrification of industries and society and thereby achieve set climate goals. As a result of this, an extensive expansion of the power system's generation capacity is underway and planned, large offshore wind farms, medium-sized solar farms on land, and possibly new nuclear generation. It is expected that there will also be significant changes on the load side in the future energy system.

Furthermore, transmission networks and distribution systems must be expanded and strengthened to cope with increased transmission of electricity, partly as a result of increased generation and electricity use, and partly because of increased volatility in the power flows.

The interconnectors between the Nordic synchronous area and other synchronous areas have been increased both in terms of numbers and in terms of capacity (MW). Recently, HVDC interconnectors have been commissioned with a capacity above 1 GW. This development is expected to continue for the coming years and in some respects, the future power system has few similarities with the system that existed when many of the Nordic nuclear power plants were introduced.

The existing HVDC interconnectors are shown in Figure 1-1 and further information of the existing HVDC interconnectors is provided in Table 1-1.

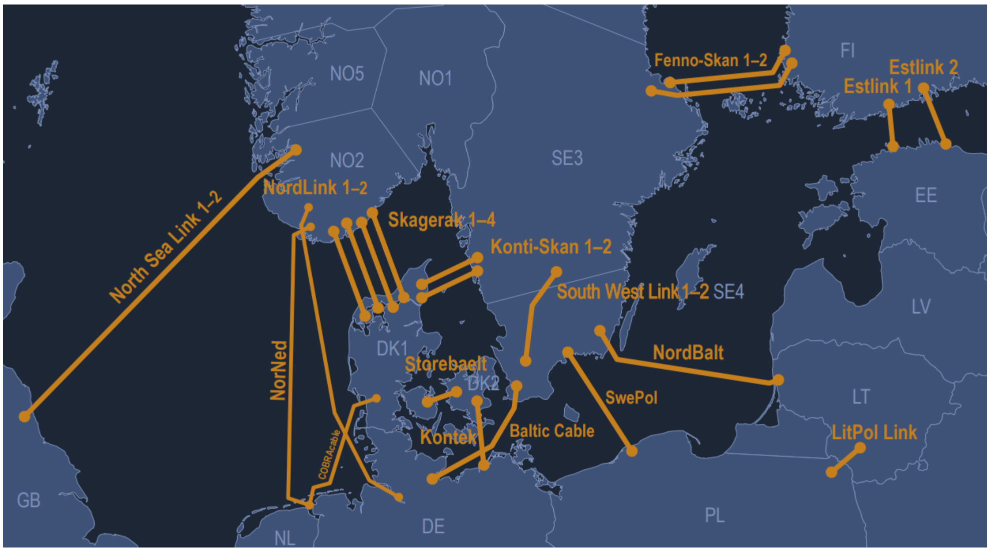

Figure 1-1 HVDC links in the Nordic synchronous system [2]. Note that the HVDC links LitPol Link and COBRA cable shown in the figure are not within the Nordic synchronous system.

Table 1-1 HVDC links in the Nordic synchronous system [2]

HVDC link	Country connections	Interconnected zones	Capacity (total link capacity) [MW]	Converter technology
Baltic Cable	Sweden – Germany	SE4 – DE	600	LCC
EstLink 1	Finland – Estonia	FI – EE	350	VSC
EstLink 2	Finland – Estonia	FI – EE	650 (1000)	LCC
Fenno-Skan 1	Sweden – Finland	SE3 – FI	400	LCC
Fenno-Skan 2	Sweden – Finland	SE3 – FI	800 (1200)	LCC
KontiSkan 1	Sweden – Denmark	SE3 – DK1	357.5	LCC
KontiSkan 2	Sweden – Denmark	SE3 – DK1	357.5 (715)	LCC
NordBalt	Sweden – Lithuania	SE4 – LT	700	VSC
NordLink 1	Norway – Germany	NO2 – DE	700	VSC
NordLink 2	Norway – Germany	NO2 – DE	700 (1400)	VSC
NorNed	Norway – Netherlands	NO2 – NL	700	LCC
North Sea Link 1	Norway – England	NO2 – GB	700	VSC
North Sea Link 2	Norway – England	NO2 – GB	700 (1400)	VSC
Skagerrak 1	Norway – Denmark	NO2 – DK1	236	LCC
Skagerrak 2	Norway – Denmark	NO2 – DK1	236	LCC
Skagerrak 3	Norway – Denmark	NO2 – DK1	478 (1000)	LCC
Skagerrak 4	Norway – Denmark	NO2 – DK1	682	LCC
South West Link 1	Sweden – Sweden	SE3 – SE4	600	VSC
South West Link 2	Sweden – Sweden	SE3 – SE4	600 (1200)	VSC
Stroebel	Denmark – Denmark	DK1 – DK2	600	LCC
SwePol	Sweden – Poland	SE4 – PL	600	LCC

The Nordic power system is in a net exporting state to the surrounding regions most of the time during normal operation. Especially Sweden and Norway reach operational states of high export where the HVDC links are heavily utilized. Tripping of an exporting HVDC link will, from the exporting side, results in a fast load reduction. This causes a power imbalance where the overall system generation exceeds the total system loading, thus resulting in an increase in the system frequency. The severity, in terms of over-frequency, Rate-of-Change-of-Frequency (RoCoF), etc., of such an event is determined by the magnitude of the power trip and the system characteristics in terms of inertia and frequency containment resources.

The swing equation can be used to calculate a theoretical RoCoF (df/dt) as per the following equation:

$$RoCoF = \frac{\Delta P * f_0}{2 * E_k}$$

using the total kinetic energy in the system, E_k, the base frequency, f_0, and the size of the system disturbance, ΔP [3].

The frequency in a synchronous system is an indicator of the overall system power balance. In a "healthy" system, the frequency magnitude remains close to the nominal system frequency, in the Nordic synchronous system 50 Hz, with only small variations. The backbone of today's power system consists of heavy synchronous machines which offer stability to the system frequency, governed by the swing equation, where the angular momentum of the machines is determined by the difference in generated electrical and mechanical power. During a system disturbance, the electrical power generated by the synchronous machines is rapidly affected. The mechanical power, on the other hand, does not change as rapidly due to the mass of the machines. This causes an imbalance between the mechanical power and electrical power, which results in an angular momentum of the machine, depending on the type and severity of the disturbance, hence resulting in an over- or under-frequency observed in the synchronous system.

Historically, there have been several over-frequency disturbances in the Nordic synchronous system. DNV has in a GINO project conducted in 2022 characterized, in detail, significant grid events ("big events"), including over-frequency disturbances, while also noting significant events that have been observed in the past [4]. Such "big events", characterized as over-frequency events include:

- Tripping of exporting HVDC links
- Tripping of significant loads
- System split

Examples of such events, which caused severe over-frequencies in the Nordic synchronous system, are:

- Hamra 1983 – System Split
    - On the 27th December 1983, a disconnector overheated and fell to the ground in the substation Hamra and created a busbar fault. The substation was equipped with a common section and a replacement breaker and when this breaker was used to disconnect the fault, the busbars were split, and two busbars were disconnected instead of only one. This disconnection led to a cascade of other disconnections of high voltage links, and the south of Sweden lost connection to the north, to Norway and Denmark, and some parts were without power for up to 6 hours. The north part of Sweden and Finland survived the disturbance with a significant frequency overshoot. The generation surplus in this part of the system was about 6000 MW, which accelerated the system to a temporary over-frequency of 54.0 Hz after 5 seconds.

- Trip of the North Sea Link – Tripping of exporting HVDC links
    - On October 8th, 2024, a trip of the North Sea Link HVDC connection occurred. The power flow of the HVDC link rapidly changed from the pre-fault condition of exporting 1400 MW from Norway to the United Kingdom, to a 0 MW exchange following the tripping of the HVDC link. Because of the tripping, the frequency in the Nordic synchronous system reached a frequency peak of 50.42 Hz.

Recent disturbances related to the HVDC interconnectors during the last years have shown that the worst-case scenario in terms of over-frequency event is not limited to the trip of an HVDC interconnector operating at full export (load). Instead of "instantaneous" trip, a change of power flow direction could occur, which in terms of magnitude (MW) is worse than tripping while operating at full export (load). This could lead to a significant over-frequency, which could affect the turbine governors in the Nordic NPPs, or in worst case cause overspeed or acceleration protection (if applicable) to trip.

- Reverse power flow Nordlink [5] – Change of power flow on HVDC link
    - On February 17th, 2023, the Nordlink HVDC link between Norway and Germany was importing 1372 MW to Norway, when the link suddenly changed direction to 348 MW in export. The total fault was 1720 MW, which is larger than the dimensioning fault of 1450 MW, for which the Nordic electricity system is currently designed.

In order to maintain secure and reliable operation of the Nordic NPPs, the maximum over-frequency and the maximum df/dt that can occur due to different faults in HVDC links has been studied. The faults are also studied during different operating conditions. The results from the calculation are then used to review possible impact on the secure and reliable operation of existing Nordic NPPs.

1.1 AIM

The aim of this project is to deliver a well-founded report that the nuclear power plant stakeholders, mainly the nuclear power plant operators and the transmission system operators, can use to increase their knowledge regarding the topic of impact of over-frequency events on Nordic NPPs and use as a guidance in their continuous work to ensure the power system operational security and reliability.

1.2 SCOPE OF WORK

The assignment has been carried out in close collaboration with the reference group consisting of the Nordic nuclear power plant stakeholders. It has been conducted completed in three main parts.

As a **first** part, the open source power system model Nordic 44 was set up in DIgSILENT PowerFactory to represent the current Nordic synchronous power system including the HVDC interconnectors. The behavior of the model was compared and benchmarked to over- and under-frequency events from disturbances during recent years. The DIgSILENT PowerFactory model was then used to calculate the RoCoF and maximum over-frequency deviation, which could occur for different extreme faults and operating conditions in the system, including

- Disconnection of HVDC link
- Reverse power flow of HVDC link
- Disconnection of several HVDC links
- System split

in combination with different operating conditions of the Nordic system, such as high or low inertia. The faults and operating conditions were agreed upon with the reference group. Answers to relevant questions such as "what is the maximum over-frequency", "what is the maximum df/dt that could occur", and "what kind of faults and operating conditions are causing such a disturbance" was sought out.

The **second** part of the project, measures taken in other synchronous areas to limit the impact of over-frequency on the system and where applicable, specifically on NPPs, were reviewed.

In the **third** part, the results from the calculations were used to assess any possible impact on the Nordic NPPs. Countermeasures, based on identified impact and input from the second part, are suggested.

1.3 LIMITATIONS

The assignment is limited to over-frequency events in the Nordic synchronous area and their possible impact on existing Nordic nuclear power plants. Only system frequency behavior is considered. Grid voltage disturbances are not included in the scope.

Review of impact is related to different sorts of protection or control actions.

Possible impact on the reactor- or turbine due to deviating pump speeds is not included in the scope of work.

2 Nordic power system simulation model

In this study, the Nordic synchronous power system was modeled using the Nordic 44 representation in DIgSILENT PowerFactory version 2023. The Nordic 44 model is a representation of the Nordic synchronous power system used for simulation and analysis purposes which was initially developed by the Norwegian University of Science and Technology (NTNU) but it has since gone through many iterations. The model is designed to replicate the behavior of the Nordic power system during various disturbances and operational scenarios [6].

The model used in this study was updated and tuned to replicate the behavior of the Nordic power system during two recent grid disturbances:

- On October 8, 2024, the North Sea Link HVDC interconnector between NO2 (Norway) and Great Britain experienced an unexpected disconnection while transferring 1400 MW from Norway to Great Britain. This incident led to a loss of 1400 MW in the Nordic synchronous system, triggering an over-frequency with a peak frequency of 50.42 Hz.
- On February 17, 2023, NordLink, connecting NO2 in Norway to Germany, suddenly reversed its power flow from 1372 MW import to 348 MW export, comparable to a sudden loss of 1720 MW generation.

To benchmark the simulation model and its frequency response, the operational scenarios during the faults were reproduced, to the extent possible in the model, and the same fault conditions were applied.

Details regarding the adjustments made to the model and its benchmarking are presented in the following sections.

2.1 ADJUSTMENTS MADE TO NORDIC 44 SIMULATION MODEL

Several updates were made to the model to better align it with the current grid configuration:

- Inclusion of missing HVDC connections: The HVDC connections, previously absent from the model, were added and represented as static loads.
- Addition of wind and "other production" generators: Generators for wind and other production types were incorporated into each bidding zone. Additionally, the installed capacities of hydro and nuclear generation were adjusted to reflect actual installed capacities.
- Representation of DK2: DK2 was added to the model and represented as a load, sized to match the power flow between SE4 and DK2.
- Update of generator inertia constants: The inertia constants for different generation types were standardized, with nuclear set to 7 s, other production to 3 s, and hydropower to 2 s.
- Adding generic dynamic models for the wind generation units and setting the LFSM-O and LFSM-U response of these according to an 8% droop setting.
- LFSM-O (Limited Frequency Sensitive Mode – Over-frequency) and LFSM-U (Limited Frequency Sensitive Mode – Under-frequency) are control modes

defined in European grid codes to support frequency stability. In LFSM-O, generators reduce their active power output when the system frequency rises above a certain threshold, while in LFSM-U, they increase output when the frequency drops below a defined limit.

These changes were implemented to replicate the grid's configuration accurately. Furthermore, additional modifications were made to simulate the operating conditions during the over-frequency event that occurred on October 8 at 9:47 AM. These included:

- Setting the generation output per bidding zone and type according to the actual production data from that hour.
- Adjusting the installed capacities of each generation type to ensure the system inertia matched that of the benchmarking over-frequency event, which had a total system inertia of 186 GWs and represents a high inertia scenario.
- A separate low inertia scenario was also considered, with a total system inertia of 131 GWs which represents the hour of the lowest inertia observed in the Nordic synchronous system during 2023–2024, which occurred on July 7 at 10:40 AM.
- Tuning the parameters of the hydropower plant governors (HYGOV) to reflect their behavior during the over-frequency event.

These refinements ensured that the model closely represented the actual grid conditions and dynamics during the event.

The overall updated Nordic 44 model is shown in Figure 2-1.

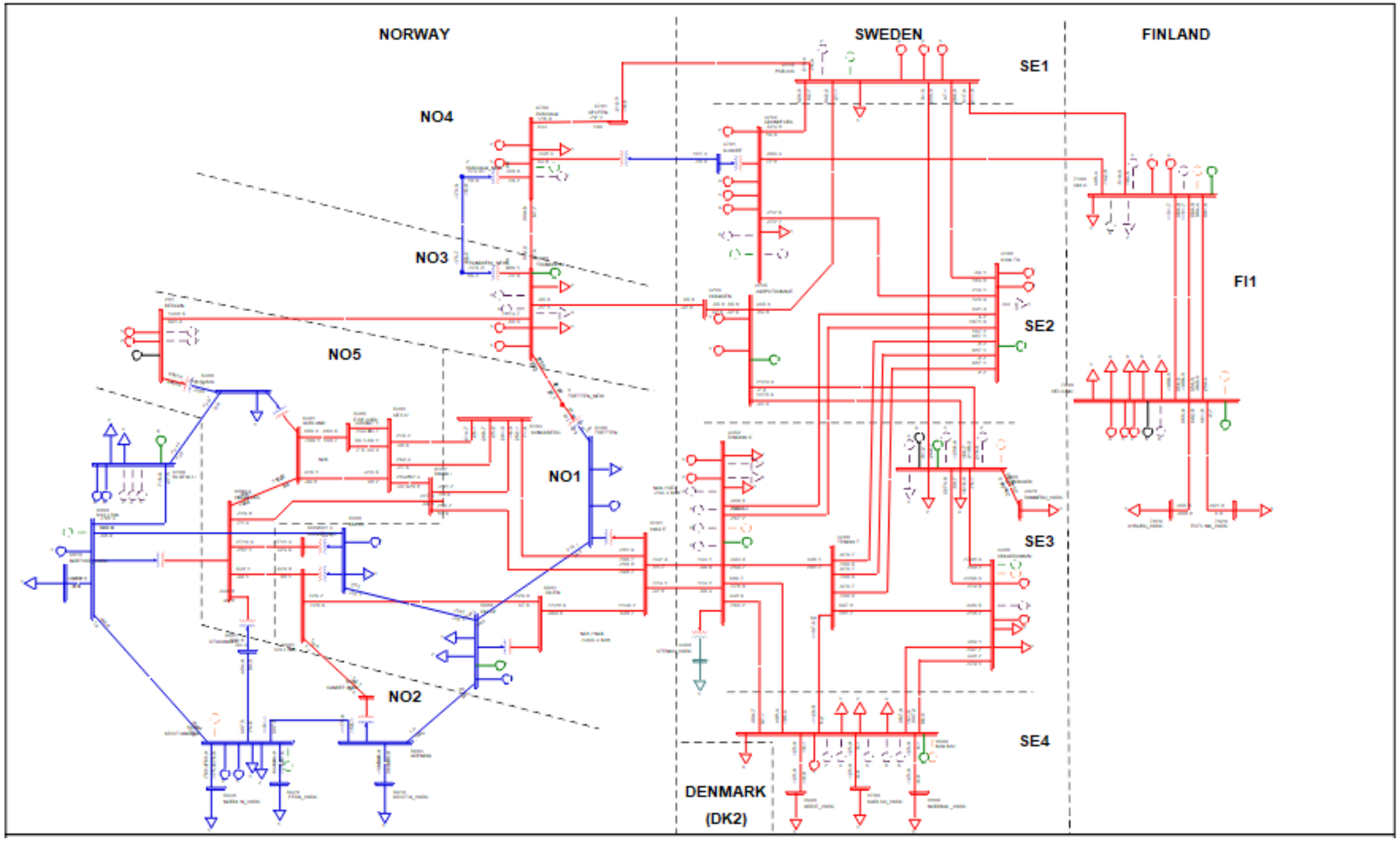

Figure 2-1 Overview of the Nordic 44 updated model

2.2 OPERATIONAL SCENARIOS

The operational scenarios used for the cases in this report are all taken from actual operational scenarios in the grid.

This report uses two different benchmarking scenarios where significant frequency deviations have occurred, the tuning and benchmarking is done for one over-frequency event and one under-frequency event. In addition to this a third operational scenario is also used to compare the impact of frequency disturbances when the inertia in the grid is low.

During October 8, 2024, and the North Sea Link event, the total inertia in the system was 186 GWs. Similarly, during the under-frequency event that occurred on the 17th of February 2023, with NordLink, the inertia in the system was 182 GWs. As a first step, the installed capacity of the different generation types was adjusted to match the installed capacity per generation type and bidding zone according to available data from ENTSO-E transparency platform [7] and SCB in Sweden [8].

Table 2-1 Total installed capacity in the Nordic synchronous system 2024

Bidding zone	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]
SE1	5357	-	3000	266
SE2	8083	-	3969	964
SE3	-*	5589	6823	9871
SE4	-*	-	2431	3568
NO1	2552	-	406	49
NO2	5524	-	1447	45
NO3	2222	-	2120	72
NO4	3133	-	1160	329
NO5	4657	-	-	224
FI	1830	3640	3322	7896

*Hydro power in SE3 and SE4 are represented in the 'Other' category

When the system is in operation, not all the installed capacity in the grid is connected at all times. As previously mentioned, the rated capacity of the hydro power plants and generators in the 'Other' category were adjusted to align the system's total inertia with that of the operational scenario. Wind power was not considered to contribute to system inertia. Nuclear power plants were either connected at full capacity or disconnected entirely, depending on their production status based on data from the ENTSO-E Transparency Platform.

The total installed capacity, the total production, and the total connected capacity of each generation type for the different scenarios are presented in Table 2-2 - Table 2-4.. In Table 2-2 the operational scenario on October 8, 2024, is presented, this is the operational scenario used in the base case simulations. This operational scenario had a total system inertia of 186 GWs, with a lot of nuclear and hydro power connected. In Table 2-3, the operational scenario on the 17th of February is presented, which was used during the under-frequency event and is similar to the operational scenario on the 8th of October having a total inertia of 182 GWs. In Table 2-4 the operational scenario of the low inertia scenario is presented which has a total inertia of 132 GWs and is characterized by a lot of wind generation, and less hydro power.

Table 2-2 Recalculation of connected capacity – High inertia scenario – October 8th, 2024, 8-9 am

	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]
Total installed capacity	54120	11314	24678	20817
Total production	27180	9229	3634	3634
Total connected capacity	45300	11314 - (data on production per unit available)	24678 - (assumed not to contribute to total inertia)	18170

In Table 2-3, the operational scenario on the 17th of February 2023 is presented, this operational scenario is similar to the operational scenario on October 8th, but with a bit less hydro and nuclear and a bit more generation in the other category.

Table 2-3 Recalculation of connected capacity – High inertia scenario – February 17th, 2023, 15-16 pm

	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]
Total installed capacity	54120	9714	24678	20817
Total production	23070	8565	4629	4629
Total connected capacity	38450	9714 - (data on production per unit available)	24678 - (assumed not to contribute to total inertia)	11572

In the low inertia operational scenario from July 7th, 2024, the generation from wind is higher and the generation from the hydro, nuclear and other categories are lower, especially the hydro power which is producing less than a third of the power in the low inertia scenario compared to the high inertia scenarios. The total generation is also lower in the low inertia scenario than in the high inertia scenarios. It is assumed that in the low inertia scenario, each hydro power unit is loaded less than in the high inertia scenario, thus the Assumed power output ratio is 0.35 for the hydro power in the low inertia scenario.

Table 2-4 Recalculation of connected capacity – Low inertia scenario – July 7th, 2024, 10-11 am

	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]
Total installed capacity	54120	11314	24678 - (assumed not to contribute to total inertia)	20817
Total production	9481	6883	9151	2250
Total connected capacity	27088	7632 - (data on production per unit available)	24678	9000

Moreover, the active power generated, and the loads are also set according to the operational conditions at the relevant hours. Data on the generation is available per type and bidding zone. The input data for the three different operational scenarios are presented in Table 2-5-Table 2-7. The data presented in the tables are the reported production and consumption values for each hour, in reality these varies within the hour.

Table 2-5 Active power setpoints October 8th, 2024, 8-9 am – over-frequency benchmarking scenario and high inertia scenario

Bidding zone	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]	Load [MW]
SE1	2283	-	873	8	1203
SE2	4979	-	1965	23	2120
SE3	- *	5589	661	1804	10333
SE4	- *	-	325	250	2736
NO1	2552	-	90	11	3887
NO2	5524	-	631	14	4104
NO3	2222	-	583	25	3481
NO4	3133	-	567	158	2789
NO5	4657	-	-	21	1992
FI	1830	3640	3322	1320	9701
DK2 (represented as load)	-	-	-	-	1763

Bidding zone	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]	Load [MW]
Total	27180	9229	9017	3634	44109

*The hydro power in SE3 and SE4 is represented in the 'Other' category

Table 2-6 Active power setpoint February 17th, 2023, 15-16 pm – under-frequency benchmarking scenario

Bidding zone	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]	Load [MW]
SE1	2769	-	410	33	1527
SE2	4999	-	1359	178	1770
SE3	- *	5790	2282	2013	11360
SE4	- *	-	1733	470	3008
NO1	1384	-	187	3	5083
NO2	4358	-	593	-	5135
NO3	1860	-	412	13	3617
NO4	3718	-	371	220	2731
NO5	1994	-	-	22	2201
FI	1988	2775	1804	1677	10106
DK2 (represented as load)	-	-	-	-	-250
Total	23070	8565	9151	4629	46288

*The hydro power in SE3 and SE4 is represented in the 'Other' category

Table 2-7 Active power setpoint July 7th, 2024, 10-11 am – low inertia scenario.

Bidding zone	Hydro [MW]	Nuclear [MW]	Wind [MW]	Other [MW]	Load [MW]
SE1	499	-	266	9	973
SE2	1132	-	1275	160	1239
SE3	- *	3221	2697	1529	7384
SE4	- *	-	1563	520	1712
NO1	1995	-	45	320	2469
NO2	1295	-	758	-	3378
NO3	1536	-	160	15	2712
NO4	964	-	185	189	1823
NO5	1250	-	0	17	1681
FI	781	3648	3000	9	8127
DK2 (represented as load)	-	-	-	-	-124
Total	9452	6869	9949	4010	31374

*The hydro power in SE3 and SE4 is represented in the 'Other' category

The simulation scenarios on October 8th and February 17th are comparable in terms of system inertia, with values of 186 GWs and 182 GWs, respectively. Although more power is generated on October 8th, the most significant difference lies in hydro power generation. In contrast, the overall system load is higher on February 17th.

In the low inertia scenario from July 7th, the system load is considerably lower than in the other cases—31 GW compared to 44 GW and 46 GW. Generation from both hydro and nuclear sources is also reduced in this scenario, with hydro power output particularly affected: only 9.5 GW is produced, compared to 27 GW on October 8th and 23 GW on February 17th.

2.3 BENCHMARKING OF SIMULATION MODEL

To benchmark the model's behavior, it is tested using two known frequency events: an over-frequency event on October 8, 2024, and an under-frequency event on February 17, 2023. The operational scenarios are presented in Section 2.2.

The over-frequency event is chosen for initial tuning as the primary purpose of this report is to study the response in the grid during over-frequency events. The under-frequency event, characterized by different regulatory conditions, is then used to verify that the chosen settings and methods remain robust across the scenarios.

2.3.1 Tuning of hydropower and wind generation

To adapt and tune the frequency response of the model, the parameters of the hydro power governors, HYGOV, are tuned. Due to the physical properties of hydropower turbine regulation, the response to frequency disturbances is inherently asymmetric as there is a difference in closing and opening the gates.

To replicate this behavior in the model, the temporary droop parameter of the HYGOV is adjusted differently for the under-frequency event compared to the over-frequency event, while keeping all other parameters constant. Temporary droop represents the proportional relationship between changes in turbine speed (frequency) and the governor's transient response. A higher value of temporary droop causes a slower response to frequency disturbances, whereas a lower value results in a faster response. This adjustment allows the model to represent the asymmetrical dynamics observed in real-world hydropower systems.

The hydropower plant's governor is modeled using HYGOV standard model, with the temporary droop parameter, *r*, set to 0.75 p.u. for the over-frequency event and 1.6 p.u. for the under-frequency event. The discrepancy in the values is necessary to correctly mimic the difference in speed of the down versus up regulation of power depending on if it is an over- or under-frequency event that has occurred. These values reflect the faster response required to address over-frequency and the slower response characteristic of under-frequency regulation. By setting *r* low for the over-frequency event and high for the under-frequency event, the model effectively captures the differing transient behaviors of the hydropower system during these events. In Figure 2-2, the block diagram of the HYGOV is presented.

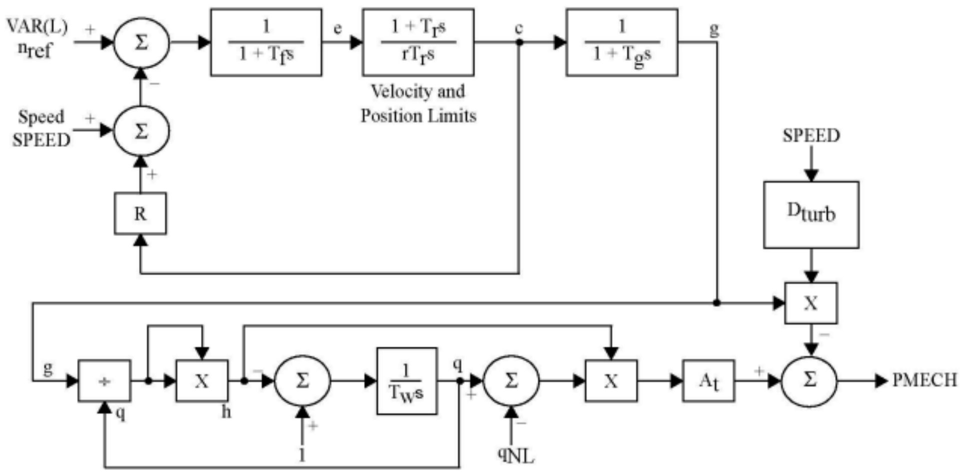

Figure 2-2 HYGOV block diagram with among other parameters for Droop, R, and temporary droop, r. [9]

In the simulation, it is assumed that all wind power is contributing with LFSM-O and LFSM-U with a droop, R, setting of 8%, as recommended by the Swedish grid code [10].

2.3.2 Conformity of over-frequency response (North Sea Link trip on October 8, 2024)

To assess the frequency response behavior of the simulation model in comparison to the Nordic synchronous system, a PMU recording of the frequency in Malmö was overlaid with the simulation model's frequency response. To make sure the inertia in the model matches that of the system at the time of the disturbance, the size of the generators was adjusted.

Figure 2-3 and Figure 2-4 illustrate a comparison between the model's frequency response and the recorded frequency response. Specifically, the frequency measurements, taken from Bara (a location outside of Malmö), are compared to the simulated frequency response at the corresponding main bus in the model in SE4 (see Figure 2-1). This model frequency measurement point applies to all simulations apart from the system split events, where frequency is measured at the Helsinki and Forsmark corresponding buses.

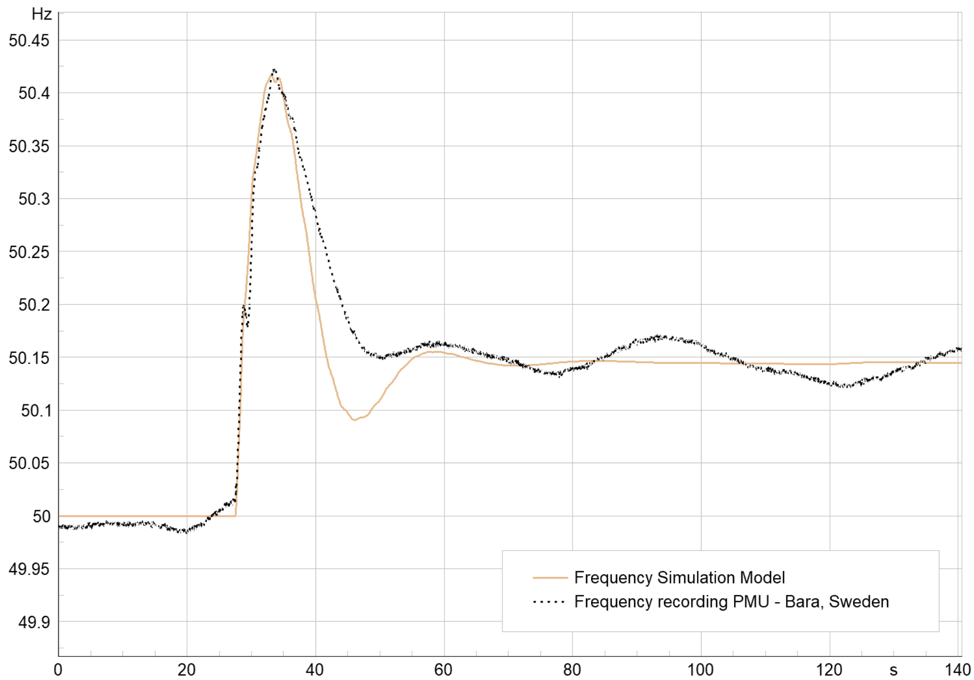

Figure 2-3 Frequency response of simulation model overlayed over actual frequency response from a PMU in Malmö for the over-frequency event on October 8th, 2024

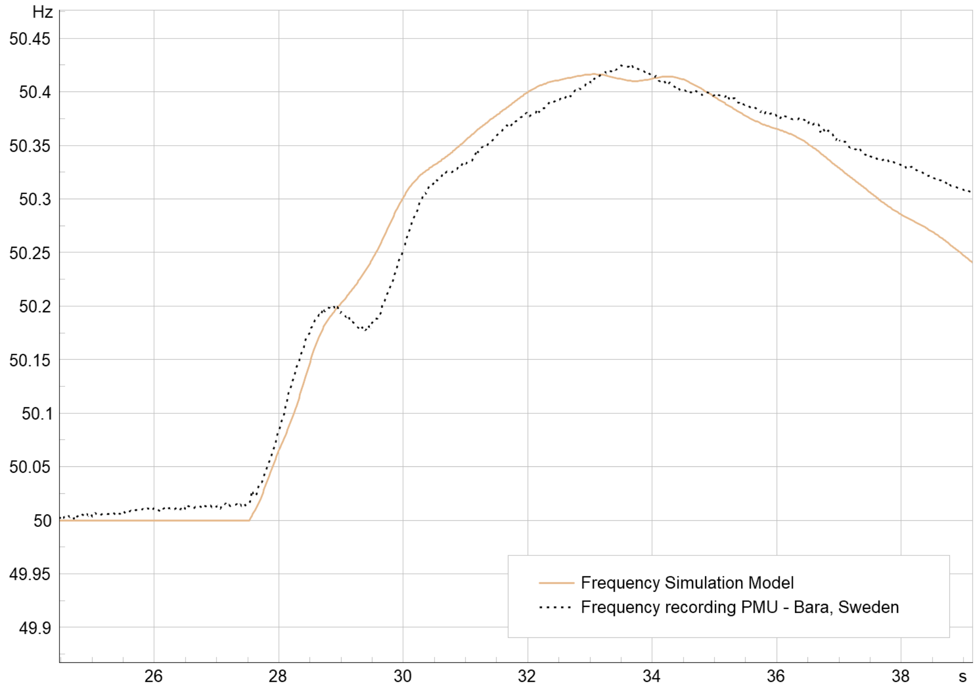

Figure 2-4 Frequency response of simulation model overlayed over actual frequency response from a PMU in Malmö for the over-frequency event on October 8th, 2024, zoomed in

As can be seen in Figure 2-3 and Figure 2-4, the simulated and recorded frequency responses align closely until the maximum frequency is reached. The steady-state frequency values also match well. Some discrepancies are observed in the speed of the frequency recovery. Additionally, the model exhibits a more pronounced overshoot during recovery compared to the actual grid response.

The parameter governing both the slope of the frequency recovery and the steady-state frequency is the permanent droop, R. A lower value of R results in a lower steady-state frequency and a steeper, faster frequency recovery slope. To ensure accurate representation, R was adjusted so that the steady-state frequency in the model aligns closely with the steady-state frequency of the actual grid.

2.3.3 Conformity of under-frequency response (NordLink power reversal on February 17, 2023)

To further validate the accuracy of the simulation model, its performance was evaluated for the under-frequency event on February 17th, 2023. After tuning the parameter for the temporary droop, r, the simulated frequency response was compared to a PMU recording from Malmö. Except for the parameter r, temporary droop, all settings in the dynamic models are the same between the over- and under-frequency simulations. In addition to this, the same method as described in Section 2.2, for deciding the connected capacity of the different generation types, is used. The comparison of the actual frequency response and the frequency response in the model to the 1720 MW disturbance on the 17th of February is shown in Figure 2-5 and Figure 2-6.

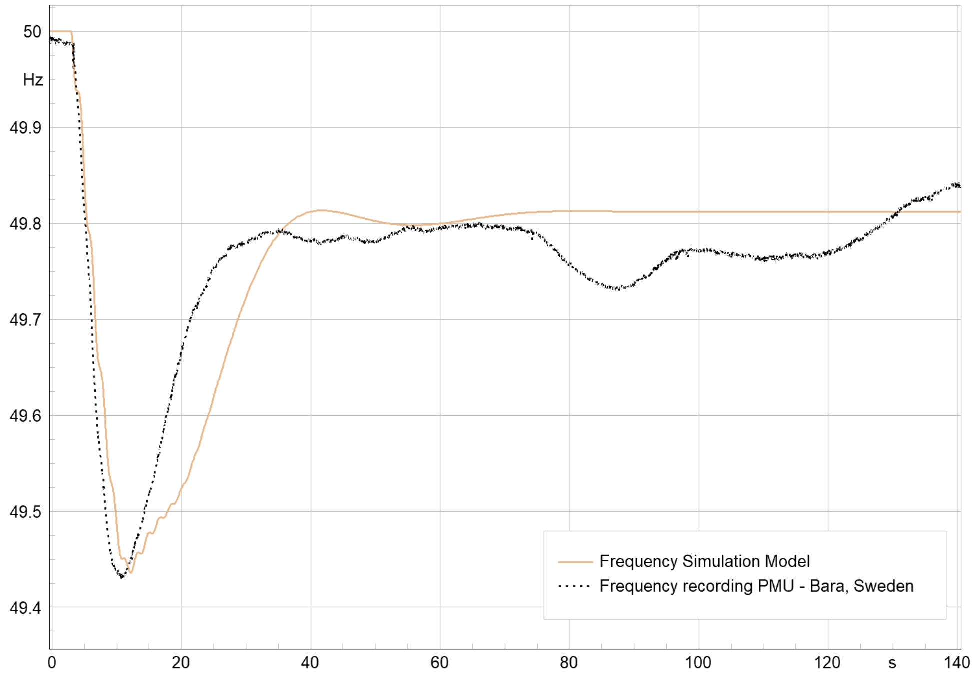

Figure 2-5 Frequency response of simulation model overlayed over actual frequency response from a PMU in Malmö for the under-frequency event on February 17th, 2023

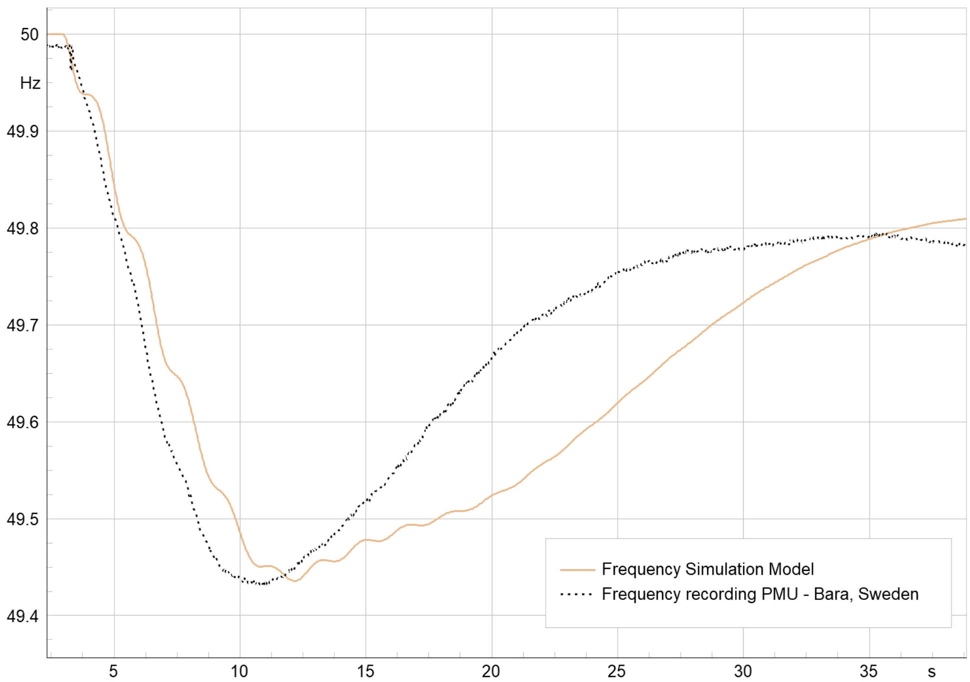

Figure 2-6 Frequency response of simulation model overlayed over actual frequency response from a PMU in Malmö for the under-frequency event on February 17th, 2023, zoomed in

The comparison in Figure 2-5 and Figure 2-6 demonstrates that the simulated and actual responses align well down to the nadir (lowest frequency). However, the nadir in the simulation is reached approximately 2 seconds later than in the actual event, although the initial RoCoF matches closely. After reaching nadir, the initial recovery phase of the simulation oscillates and is slightly slower than the actual frequency response. Once those oscillations stop, the frequency recovery of the simulation model is similar to the actual response. The steady-state frequency level aligns well with the observed response.

2.3.4 Discussion on overall conformity and limitations of the simulation model

The simulation model demonstrates a behavior similar to the actual Nordic system in terms of the initial RoCoF and the frequency response from disturbance to minimum or maximum frequency. Additionally, the model successfully stabilizes the frequency after the disturbance at a steady state level close to that observed in the actual system.

Discrepancies are noted in the speed of frequency recovery. The simulation model recovers faster than the actual system in the over-frequency response and it exhibits a frequency overshoot during over-frequency recovery, that is not observed in the actual system. On the other hand, for the under-frequency response, the frequency recovery is slightly slower than the actual response, but with no overshoot and a good matching of the steady state frequency level. These differences may arise from simplified turbine dynamics or governor settings in the simulation model which may not fully represent the physical constraints of the real system, and/or slight misalignment with the volume of frequency response and regulating power deployed in the model compared to the real system.

The model did not include any frequency support services provided by the HVDC links. In reality HVDC links provide Emergency Power Control (EPC) services in case of over- and under-frequency conditions, consuming or supplying power as a response to larger frequency deviations using a droop characteristic. On the other hand, it is assumed that all the installed wind power plants can provide LFSM-O and LFSM-U, which is not likely for older wind turbines. To some extent, it can be estimated that the missing frequency support from EPC is accounted for from the wind power instead.

All wind turbines are modeled as type 4. However, in the Nordics a large share of the older turbines are type 3 turbines, which exhibit some natural inertial response due to their partial mechanical coupling with the grid. This may have some impact on the overall frequency dynamics which are not captured by the simplified model.

The consumption loads are modeled as static loads with a power factor of 0.98, with no frequency dependence. The loads used to represent the HVDC connections have a power factor of 1, and are also static with no frequency dependence. Omitting the frequency dependence of loads may contribute to underestimation of system damping and frequency stabilization. On the other hand, it could be considered a conservative and relevant approach as this type of phenomena is not that straight forward to capture accurately in a modelling environment and may consequently lead to overestimation of the system frequency stability.

In general, as the overall frequency behavior of the model aligns with the system behavior for the reference frequency events, any frequency contribution present in the real system during the reference events, including EPC, FFR, synthetic inertia, and frequency dependencies from e.g. type 3 wind turbines and loads, is implicitly captured in aggregate within the model, even if the individual functionalities are not modelled separately.

These above mentioned assumptions and simplifications should be considered when interpreting the results depicted using this simplified model.

Despite these model discrepancies, the strong alignment in RoCoF, minimum and maximum frequency, and steady-state stabilization indicates that the simulation model provides a reasonable approximation of the actual Nordic system frequency behavior. This suggests that the model can be used for analyzing and replicating key system dynamics during frequency disturbance scenarios.

The modelling approach is summarized in Table 2-8 and the overall model performance as indicated by the provided test cases is presented in Table 2-9.

Table 2-8 Modelling approach

Modelling approach	Comment
Adding HVDC links	All HVDC links in the Nordic 44 model are modelled as constant loads. While this causes a limitation in the dynamic behavior of the HVDC links, it is assumed that the inherent nature of the inverter-based technology allows the HVDC links to operate continuously for the observed frequency events.
Frequency regulation	Most of the frequency containment regulation is assumed to originate from the hydropower plants which were tuned to achieve a similar response to the benchmarking disturbances.
Addition of wind farms	Wind farms are added to the model using the standard type 4 WECC model. The frequency regulation (LFSM) is activated for all wind turbines in the model, using a droop setting of 8 %.
Load flow modelling	The static pre-disturbance load flow is tuned against the available data for the pre-disturbance operation of the selected benchmark cases. This is done by tuning the cross-zone power flows for active power. The tuning of voltage levels and reactive power flows is limited and only benchmarked to remain within reasonable limits.
Benchmarking	The model is benchmarked for only one over-frequency and one under-frequency event. It is assumed that the model performance is valid for the selected operational scenario of the grid. Other operating scenarios might require re-tuning of system characteristics such as frequency regulation.
aFRR and mFRR	Automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR) are not modeled separately in this study. The Frequency Restoration Reserve markets are activated to restore the frequency back to 50 Hz after a disturbance. These are assumed too slow to have an impact on the maximum frequency and the initial RoCoF, which is the focus of this report.

Table 2-9: Model performance for frequency events

Performance characteristic	Comment
RoCoF	RoCoF is calculated through the derivative function in PowerFactory over approximately 100 ms and at least 300 ms after the fault is applied, to avoid including transients. The model performance in terms of initial ROCOF is similar to that of the benchmarking scenarios, both for over- and under-frequency events, suggesting that the model inertia is within reasonable limits compared to the true system inertia. When comparing the RoCoF of the simulation and the theoretical value calculated using the swing equation, the RoCoF from the swing equation also aligns well for most cases. For example, using the swing equation, in a system with 186 GWs inertia, the RoCoF for a 1400 MW loss of load would theoretically mean a RoCoF of 0.19 Hz/s. This aligns well with the 0.20 Hz/s, which was simulated using the model in the over-frequency event. Some deviations are noted for the larger events, which may be explained by the fact that the theoretical RoCoF value assumes essentially fully idealized conditions such as uniform inertia distribution, linear generation and load behavior, etc. There are similar assumptions in the model, however, the model also considers certain non-ideal conditions which we expect to have in the real system, primarily those related to the generation frequency response. That could explain the deviation from the theoretical value.
Maximum frequency	The maximum frequency for the benchmarked over-frequency event is similar in the model to that of the true frequency.
Frequency nadir	The frequency nadir for the benchmark under-frequency event is similar in the model to that of the true frequency.
Second frequency swing	The simulation model accurately replicates the initial frequency swing but overestimates the second frequency swing, due to limitations in capturing later-stage dynamics. Additionally, the frequency restoration occurs more rapidly in the over-frequency and slower in the under-frequency simulation. However, as the focus is primarily on the maximum frequency deviation and RoCoF additional efforts to reach further alignment with the measurements was not undertaken.
Frequency recovery and stabilization	The simulation model recovers to a constant frequency level quicker than the true frequency during the over-frequency event, but slower for the under-frequency event. The stabilized frequency level is similar in the simulation model compared to the real measurements.

3 Simulations of large disturbances causing over-frequency events

This study aims to investigate and evaluate the impact of various large disturbances on the frequency dynamics of the Nordic synchronous system. To achieve this, multiple simulation cases were discussed and agreed with the reference group to establish a list of "extreme" but not "unrealistic" and distinct over-frequency events, including the disconnection of different combinations of HVDC links under varying loading conditions. Simulations were conducted across different operational scenarios with normal/high and low inertia.

For the over-frequency benchmarking scenario, the system's total inertia was set to 186 GWs, corresponding to the inertia in the grid at the time of the disturbance. Additionally, a low inertia scenario was modelled with a total inertia of 131 GWs, representing the hour of the lowest inertia observed in the Nordic synchronous system during 2023–2024, which occurred on July 7 at 10:40 AM.

Table 3-1 Presentation of applied disturbances in the simulations performed in this study

Event	Simulation name	Applied changes	Total change in active power	System characteristics
HVDV link trip	Base case simulation	North Sea Link: 1400 MW export to 0 MW import	1400 MW reduced load	Normal/high (186 GWs) and low (131 GWs) inertia
Reverse power flow	Case A1	North Sea Link: 1400 MW export to 700 MW import	2100 MW reduced load	Normal/high (186 GWs) and low (131 GWs) inertia
	Case A2	North Sea Link: 1400 MW export to 700 MW import Nordbalt link: 700 MW reduction in load	2800 MW reduced load	Normal/high (186 GWs) and low (131 GWs) inertia
Disconnection of several HVDC links	Case B1	Changes on multiple lines	2900 MW reduced load	Normal/high (186 GWs) and low (131 GWs) inertia
	Case B2	Changes on multiple lines	3950 MW reduced load	Normal/high (186 GWs) and low (131 GWs) inertia
System split	System split	Disconnection of lines that connects the northern and south part of the system	4428 MW load reduction in northern part	Normal/high (186 GWs) inertia (104 GWs in the northern part)

3.1 HVDC LINK TRIP AND REVERSE POWER FLOW

In this section, trip and power flow reversals in the North Sea HVDC link under conditions that lead to over-frequency events are presented.

3.1.1 North Sea Link trip and reversing power flow – normal/high inertia

In the base case simulation, the power flow changes from 1400 MW to 0 MW, this case is the same as presented for the benchmarking, thus the frequency recording of this event is also included in the figures.

Additionally, two more simulations are conducted: one where the power flow shifts from 1400 MW export to 700 MW import, and another where it transitions from 1400 MW export to 1400 MW import. These scenarios and the frequency response are presented in Figure 3-1 and Figure 3-2. Key takeaways from the figures are summarized in Table 3-2.

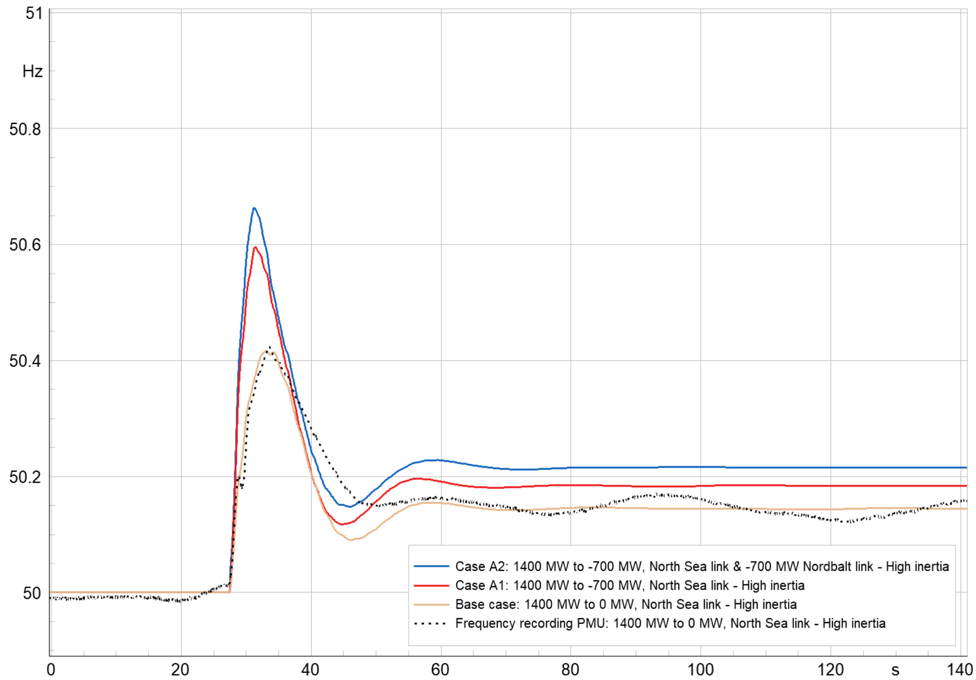

Figure 3-1 Over-frequency simulation responses of different disturbances, including reversions of power flow, on the North Sea HVDC cable, and disconnection of the Nordbalt HVDC cable, as well as the frequency recording from the 1400 MW to 0 MW load event, normal/high inertia scenario

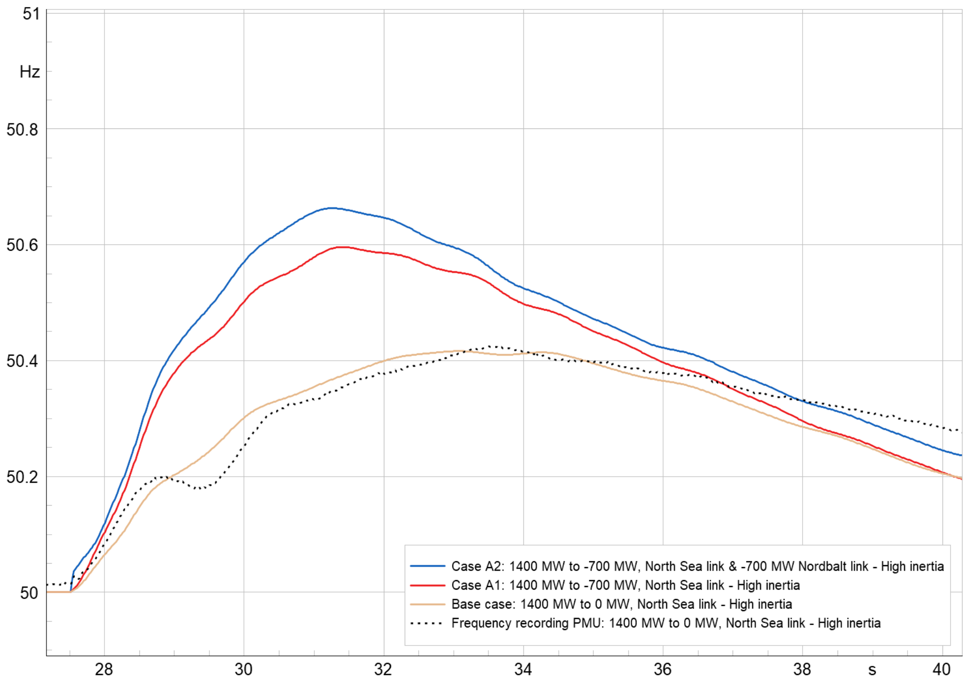

Figure 3-2 Over-frequency simulation responses of different disturbances, including reversions of power flow, on the North Sea HVDC cable, and disconnection of the Nordbalt HVDC cable, as well as the frequency recording from the 1400 MW to 0 MW load event, normal/high inertia scenario, zoomed in

Figure 3-1 and Figure 3-2 show how the frequency response varies for disturbances of different sizes. When the frequency disturbance becomes more significant, the maximum frequency increases, and with the more significant frequency disturbances, the maximum frequency is reached earlier. For both Case A1 and Case A2, the frequency increases beyond 50.5 Hz, the limit for LFSM-O activation. It can also be seen that the RoCoF is increasing when the size of the disturbance increases. In simulation Case A1 and Case A2, the RoCoF reaches 0.36 Hz/s and 0.39 Hz/s respectively.

However, even for a disturbance twice the size of the dimensioning fault (1400 MW) —specifically, a transition from a 1400 MW export to a 1400 MW import, resulting in a net change of 2800 MW—the frequency deviation does not exceed 51 Hz. Table 3-2 provides detailed metrics for frequency deviation, RoCoF, and steady state frequency across all scenarios.

Table 3-2 Maximum frequency, maximum and minimum ROCOF and steady state frequency measured during simulation of different HVDC disturbances – normal/high inertia

	Change in active power	Maximum frequency [Hz]	Maximum RoCoF [Hz/s]	RoCoF according to swing equation [Hz/s]	Steady state frequency [Hz]
Frequency recording PMU	1400 MW export to 0 MW (NO2)	50.42	0.20	0.19	50.12 - 50.17
Base case simulation	1400 MW export to 0 MW (NO2)	50.42	0.19	0.19	50.14
Simulation A1	1400 MW export to 700 MW import (NO2)	50.60	0.32	0.28	50.18
Simulation A2	1400 MW export to 700 MW import (NO2) + loss of 700 MW export (SE4)	50.66	0.34	0.38	50.22

From the data presented in Table 3-2, the model indicates that, for all tested disturbances, the frequency remains within a 1 Hz deviation from the nominal frequency, and that the RoCoF does not exceed 0.4 Hz/s. With a larger disturbance, the maximum frequency and the RoCoF increases.

3.1.2 North Sea Link trip and reversing power flow – low inertia simulation

The disturbance test cases conducted in Section 3.1.1 are repeated here but in this simulation they are performed in an operational scenario where the system's inertia is lower. The total system inertia is set to 131 GWs, the lowest recorded inertia in the Nordic synchronous system between 2023 and 2024. The simulations are performed to assess the impact of a large HVDC disturbance under these more sensitive conditions. Figure 3-3 and Figure 3-4 illustrates the simulated frequency response when the North Sea link power flow shifts under low inertia conditions: from a 1400 MW export to 0 MW, from a 1400 MW export to a 700 MW import, and from a 1400 MW export to a 700 MW import with a simultaneous reduction of 700 MW in the Nordbalt link.

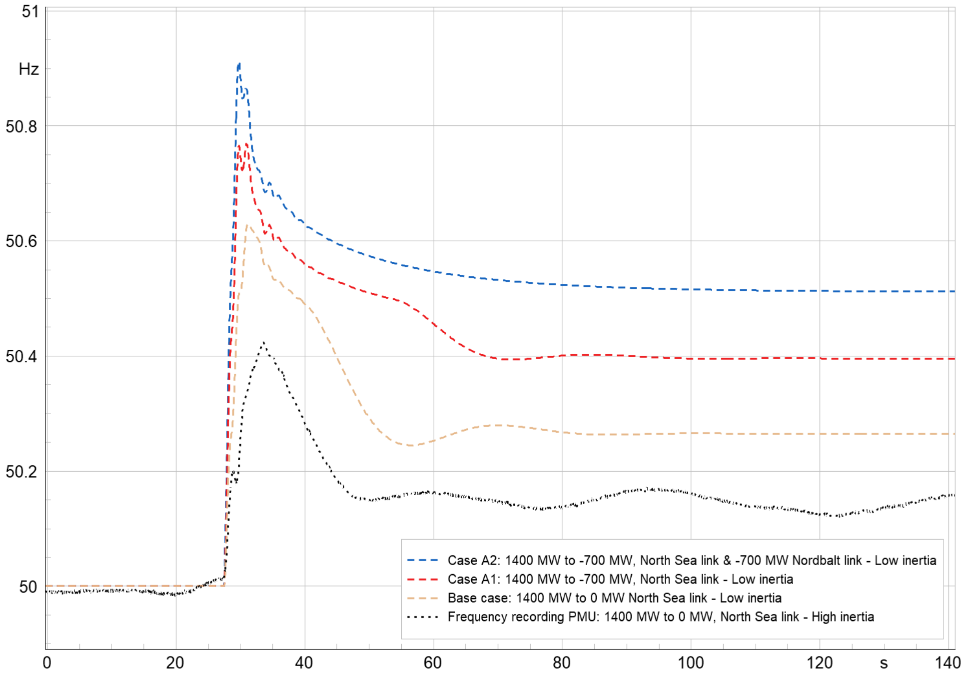

Figure 3-3 Over-frequency simulation responses of different disturbances, including reversions of power flow, on the North Sea HVDC cable, and disconnection of the Nordbalt HVDC cable, as well as the frequency recording from the 1400 MW to 0 MW load event, low inertia scenario

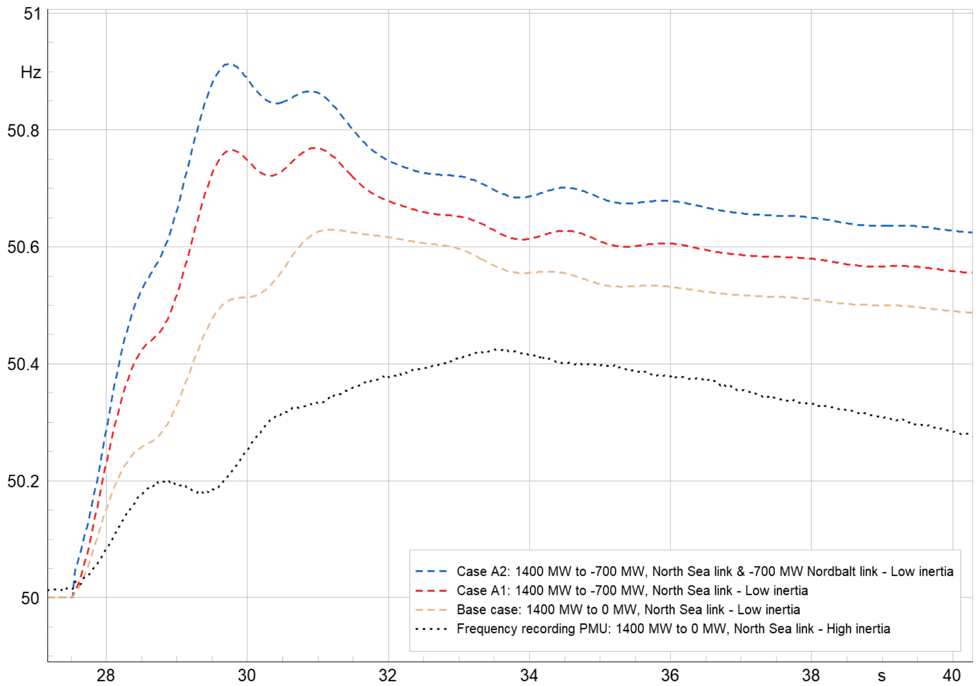

Figure 3-4 Over-frequency simulation responses of different disturbances, including reversions of power flow, on the North Sea HVDC cable, and disconnection of the Nordbalt HVDC cable, as well as the frequency recording from the 1400 MW to 0 MW load event, low inertia scenario, zoomed in

The figure clearly demonstrates that the size of the disturbance influences the maximum frequency, with a larger disturbance resulting in a higher maximum frequency. The ROCOF also increases as the disturbance size grows. Additionally, when compared to the frequency recordings from the normal/high inertia scenario, it is evident that the maximum frequency is higher in the low inertia simulation.

In the low inertia scenario, the frequency curve is narrower at the peak for the two more severe disturbances. However, the descent to the steady-state frequency is more gradual, with no overshoot. This behavior is likely due to the high level of wind generation and reduced hydro generation in the low inertia scenario.

In this simulation model, the frequency response from wind power is limited to the LFSM-O response, which activates at 50.5 Hz. This threshold is exceeded in cases A1 and A2, causing wind power units to reduce their output. Simultaneously, most of the frequency regulation required to restore normal frequency is managed by hydro power plants. Since there is less hydro capacity connected to the grid in this scenario, the recovery to steady-state frequency takes longer. In the simulation for Case A2, where the net active power change is 2800 MW, the frequency does not exceed 51 Hz, but deviates to about 50.9 Hz. Table 3-3, summarizes key metrics, including frequency deviation, RoCoF, and steady-state frequency for each scenario, as well as theoretical RoCoF calculated using the swing equation.

Table 3-3 Maximum frequency, maximum and minimum RoCoF and steady state frequency measured during simulation of different HVDC disturbances – low inertia

	Change in active power	Maximum frequency [Hz]	Maximum RoCoF [Hz/s]	RoCoF according to swing equation [Hz/s]	Steady state frequency [Hz]
Frequency recording PMU	1400 MW export to 0 MW	50.42	0.20	0.19	50.12 - 50.17
Base case simulation	1400 MW export to 0 MW	50.63	0.39	0.27	50.26
Simulation A1	1400 MW export to 700 MW import	50.77	0.59	0.40	50.40
Simulation A2	1400 MW export to 700 MW import + loss of 700 MW export	50.91	0.68	0.53	50.51

From Table 3-3 it can be observed that the simulation model indicate that the maximum RoCoF reached for a 2800 MW disturbance is 0.68 Hz/s, and that the maximum frequency does not exceed 51 Hz but is limited to 50.91 Hz for the worst disturbance.

In addition to this, in this scenario, the model indicates that the base case disturbance, from 1400 MW export to 0 MW, would make the maximum frequency exceed 50.5 Hz, which is the limit where LFSM-O response should be activated.

3.1.3 Comparison of over-frequency response with normal/high respectively low system inertia

In Figure 3-5 the simulations performed in Sections 3.1.1 and 3.1.2 are plotted together to more easily compare the normal/high and low inertia scenarios with each other. In Figure 3-5 and Figure 3-6 the comparison of the "Base case" is displayed with when the North Sea link went from 1400 MW export to 0 MW. In Figure 3-7 and Figure 3-8 "Case A1" is displayed with a total load change of 2100 MW. Lastly, in Figure 3-9 and Figure 3-10 "Case A2", a total load change of 2800 MW, is compared in normal/high and low inertia conditions.

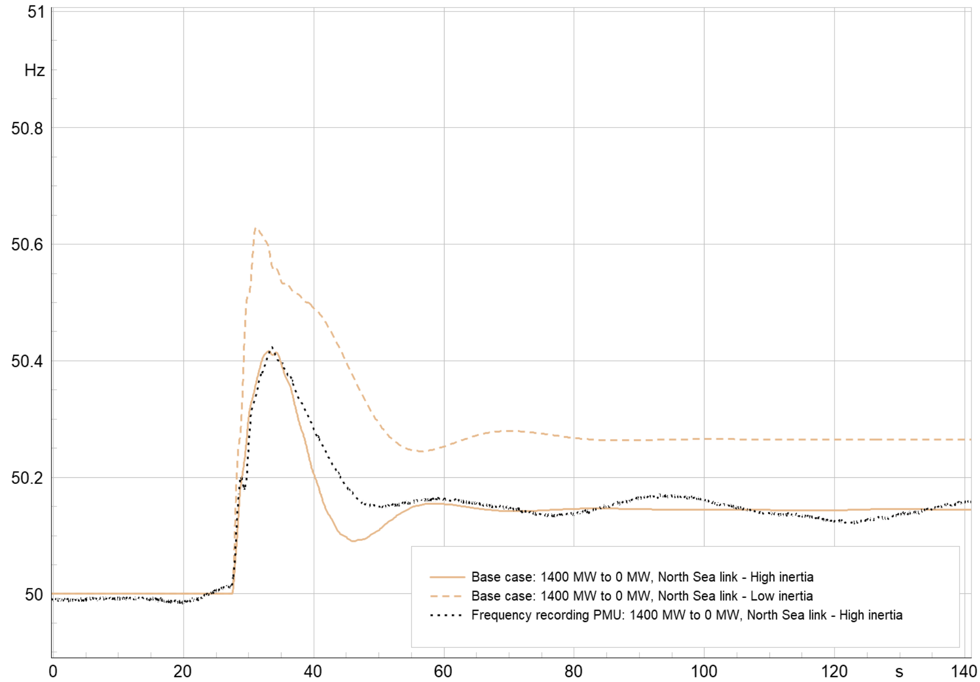

Figure 3-5 Comparison of frequency response of normal/high and low inertia scenarios, 1400 MW to 0 MW North Sea link

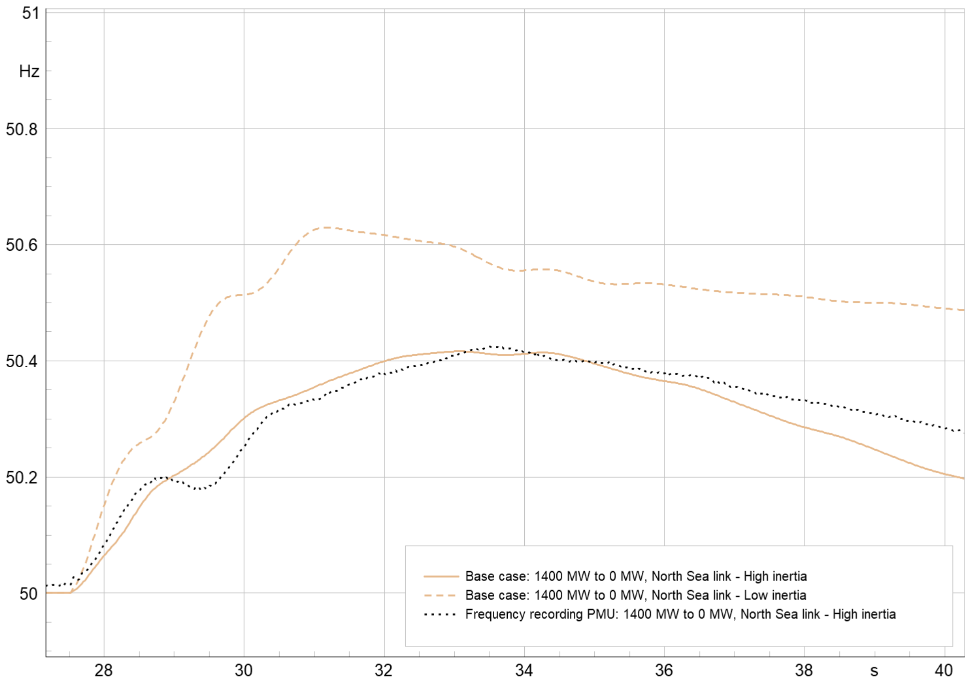

Figure 3-6 Comparison of frequency response of normal/high and low inertia scenarios, 1400 MW to 0 MW North Sea link, zoomed in

As can be observed from Figure 3-5 and Figure 3-6, when a loss of load is applied in a low inertia system both the initial inertia and the maximum frequency increases. In the simulation with lower inertia the maximum frequency exceeds 50.6 Hz. At frequencies over 50.5 Hz, the LFSM-O response is activated.

In this model, overall market mechanisms such as aFRR and mFRR, which are frequency services with longer activation times with the purpose of bringing back frequency to 50.0 Hz, are not modeled separately. The model is tuned to reflect the overall short term frequency support in the response from the generators. As a result of that approximation, the steady state frequency post fault recovery is in the model not going back to the same levels for the normal/high and low inertia cases.

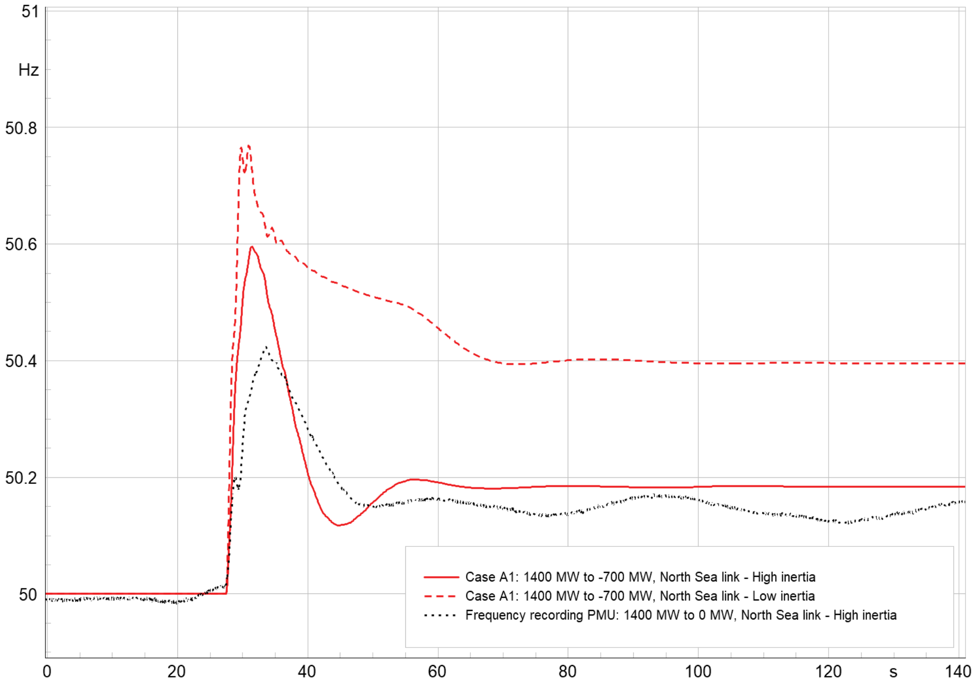

Figure 3-7 Comparison of frequency response of normal/high and low inertia scenarios, 1400 MW to -700 MW North Sea link

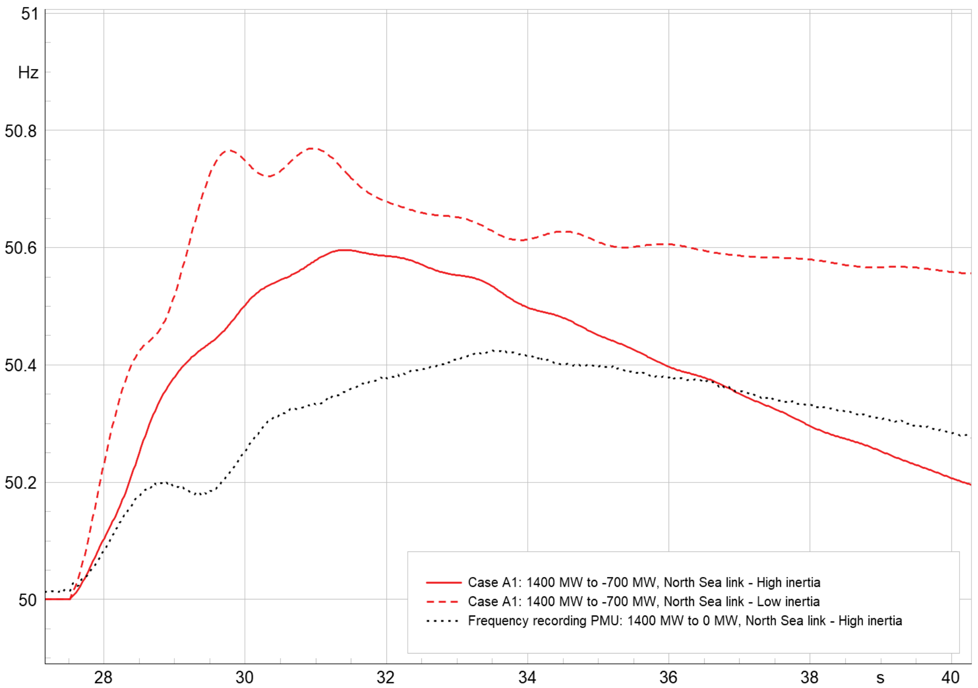

Figure 3-8 Comparison of frequency response of normal/high and low inertia scenarios, 1400 MW to -700 MW North Sea link, zoomed in

In Figure 3-7 and Figure 3-8 similar differences between the frequency behavior under the normal/high and low inertia scenarios can be observed as in the base case presented before. The initial RoCoF and the maximum frequency is higher for the low inertia case. The recovery down to the steady state frequency is also slower in the low inertia case.

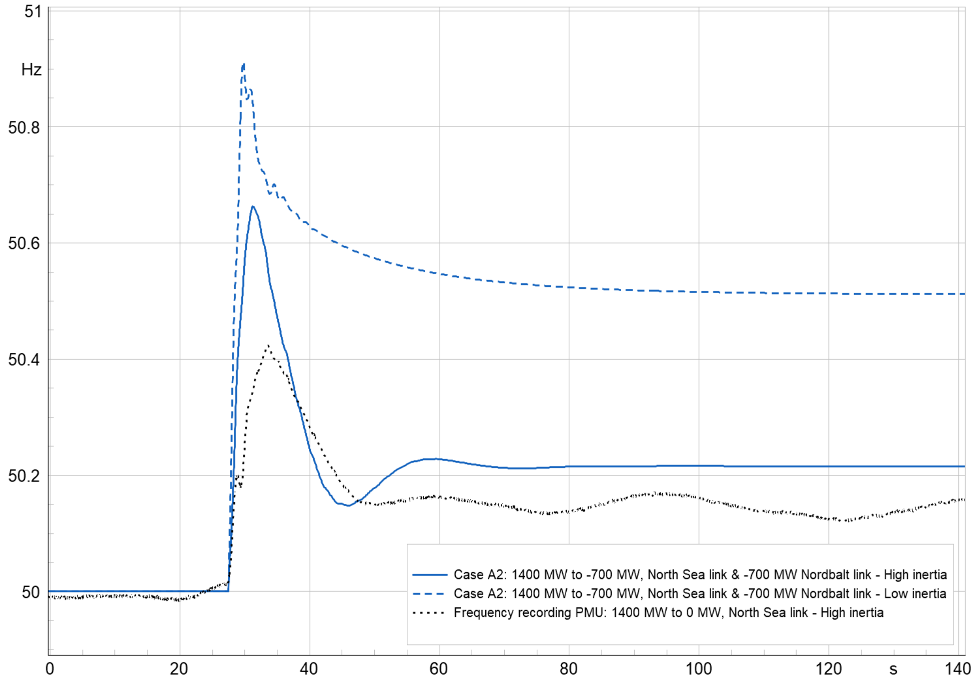

Figure 3-9 Comparison of frequency response of normal/high and low inertia scenarios, 1400 MW to - 700 MW North Sea link, 700 MW to 0 MW, Nordbalt

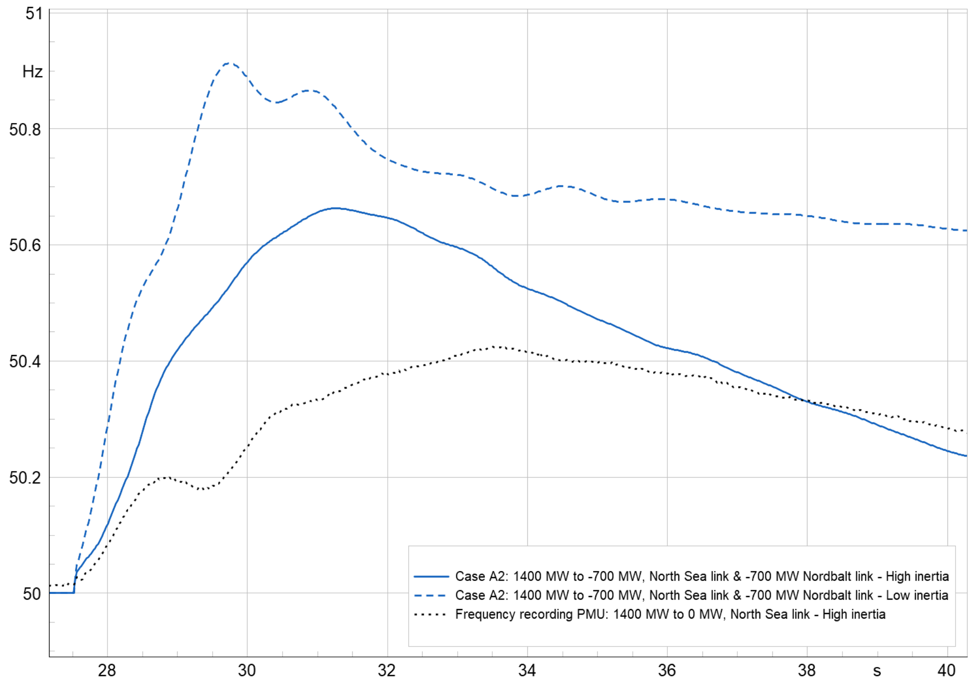

Figure 3-10 Comparison of frequency response of normal/high and low inertia scenarios, 1400 MW to - 700 MW North Sea link, 700 MW to 0 MW, Nordbalt, zoomed in

When comparing the normal/high and low inertia scenarios for Case A2 disturbance displayed in Figure 3-9 and Figure 3-10, it becomes clear that a high system inertia helps to limit the disturbance, both in terms of maximum frequency deviation, and to limit the initial RoCoF. However, the simulations indicate that the initial frequency recovery is faster in the normal/high inertia scenario, and the simulations reaches a lower steady state frequency deviation in the normal/high inertia scenario.

Since the low inertia scenario also corresponds to a low load scenario, both the active power production and the installed capacity of hydro power are lower than in the normal/high inertia scenario. As a result, the system has less regulating power available, leading to a higher steady-state frequency in the low inertia case.

This difference in steady-state frequency is also influenced by the distinct frequency response characteristics of hydro power and wind power. In the low inertia simulation, most of the frequency response comes from the droop-based LFSM-O control of wind power, which activates only at frequencies above 50.5 Hz. Consequently, it does not restore frequency in the same way as hydro power does in scenarios where its share is higher.

3.2 DISTURBANCES ON SEVERAL HVDC LINKS

To assess the impact of even larger disturbances, simulations were conducted involving scenarios where multiple cables are disconnected. Although this scenario is considered less likely, it could lead to significantly greater disruptions. The simulations presented in this section investigate the impact of larger system disturbances including several HVDC links. Two larger disturbance events, one where the change in load is reduced by 2900 MW in total, and the second where the change in load is 3950 MW. The simulations are run for both the normal/high and low inertia scenario.

3.2.1 Disturbances on multiple HVDC links – normal/high inertia scenario

In this section two different sized disturbances, a reduction of 2900 MW (Case B1) and a reduction of 3950 MW (Case B2) are simulated in the model. The simulations are performed under the conditions in the grid on the 8th of October 2024, when the inertia in the grid was 186 GWs. These are the same conditions as during the base case, when North Sea link disconnected and went from 1400 MW export to 0 MW.

In Case B1, North Sea link (NO2) is reduced from 1400 MW to 0 MW, Nordbalt is reduced from 730 to 0 MW(SE4), and Estlink (FI) is reduced from 930 MW to 130 MW.

In Case B2 North Sea link (NO2) is reduced from 1400 MW to 0 MW, Nordbalt is reverses its power flow from 700 MW export to 700 MW import (SE4), Baltic cable (SE4) is reducing its power flow from 360 MW export to 0 MW import and Estlink (FI) is changing its power flow from 930 export to 140 MW.

In Figure 3-11 and Figure 3-12, the frequency response of simulation Case B1 and Case B2 during normal/high inertia conditions are presented along with the recorded frequency response of the disturbance on the 8th of October 2024.

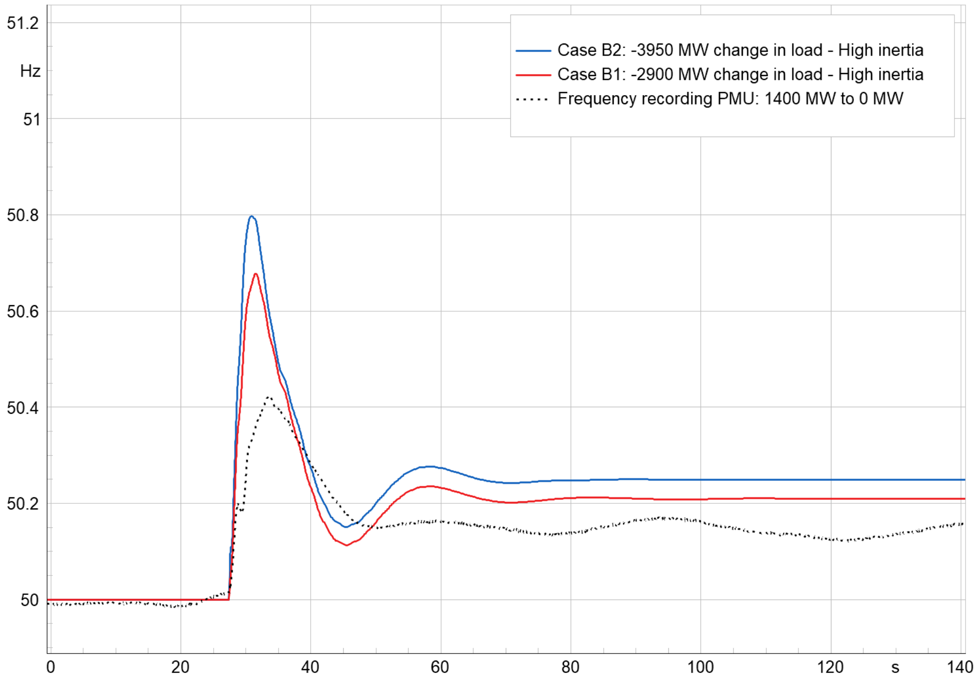

Figure 3-11 Over-frequency simulation responses of different large disturbances on several HVDC links – normal/high inertia scenario

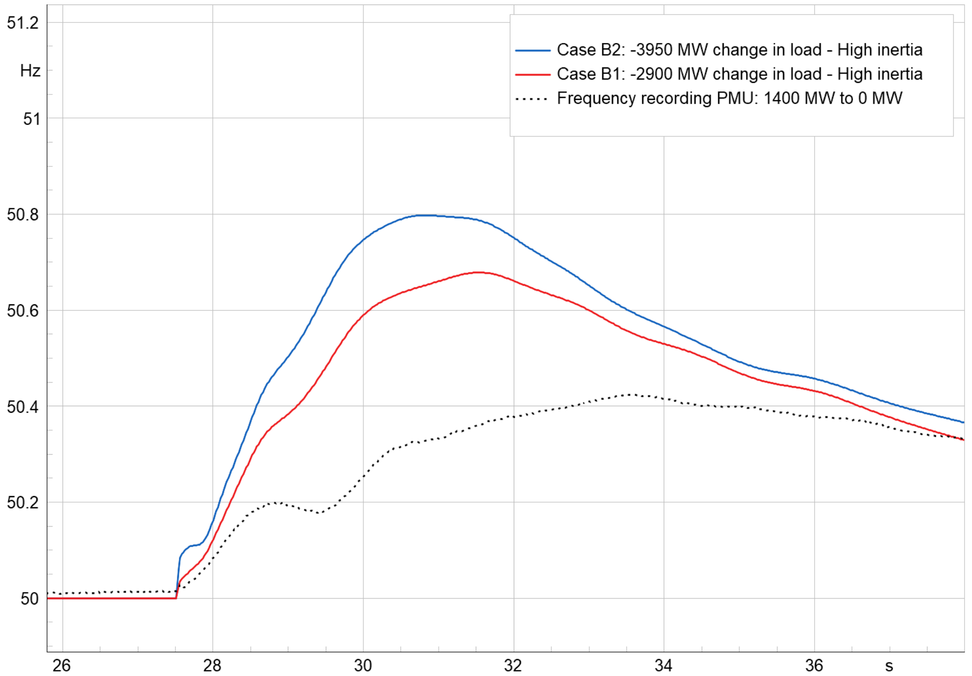

Figure 3-12 Over-frequency simulation responses of different large disturbances on several HVDC links – normal/high inertia scenario, zoomed in

Figure 3-11 and Figure 3-12 show that the frequency response of both the disturbances exceed 50.5 Hz, the limit of the LFSM-O response, but staying below

51.0 Hz. For case B1, the 2900 MW disturbance, the frequency peaks at 50.68 Hz, and for Case B2, the 3950 MW disturbance, the frequency peaks at 50.80 Hz. In Table 3-4 key take aways from the simulations are presented, for example maximum frequency and maximum RoCoF, and theoretical RoCoF calculated according to the swing equation.

Table 3-4 Maximum frequency, maximum and minimum RoCoF and steady state frequency measured during simulation of different large HVDC link disturbances – normal/high inertia

	Change in active power	Maximum frequency [Hz]	Maximum RoCoF [Hz/s]	RoCoF according to swing equation [Hz/s]	Steady state frequency [Hz]
Frequency recording PMU	1400 MW export to 0 MW	50.42	0.20	0.19	50.12 - 50.17
Simulation B1	2900 MW reduction in load	50.68	0.35	0.39	50.21
Simulation B2	3950 MW reduction in load	50.80	0.46	0.55	50.25

From the data presented Table 3-4 the maximum frequency for a disturbance of 3950 MW, in normal/high inertia conditions, is not exceeding 51 Hz. In the simulation, RoCoF is not exceeding 0.5 Hz/s, but what can also be seen from the table is that according to the swing equation, the RoCoF would theoretically be slightly higher than what was simulated for the same inertia and disturbance. There is 0.09 Hz/s difference between the simulation and the calculated RoCoF for Case B2. This could mean that the maximum frequency in this simulation might also be slightly higher than what reached in the simulation.

3.2.2 Disturbances on multiple HVDC links – low inertia scenario

Two disturbances of the same size as applied in the previous section was also applied in the low inertia scenario. The disturbances of size 2900 MW (Case B1) and 3950 MW (Case B2) were applied by changing HVDC loads. The faults were applied in low inertia conditions corresponding to the generation and load on the 7th of July 2024.

In Case B1, North Sea link (NO2) is reduced from 1400 MW to 0 MW, Nordbalt is reduced from 730 to 0 MW(SE4), SWEPOL (SE4) is reduced from 570 MW to 0 MW and Estlink (FI) is reduced 340 to 140 MW. In Case B2 North Sea link (NO2) is reduced from 1400 MW to 0 MW, Nordbalt is reduced from 730 to 0 MW(SE4), SWEPOL (SE4) is changing its power flow from 570 MW export to 570 MW import and Estlink (FI) is changing its power flow from 340 export to 340 MW import.

The frequency response simulated is presented in Figure 3-13 and Figure 3-14. For reference the actual frequency response to the 1400 MW trip of North Sea link on the 8th of October is included in the figures as well.

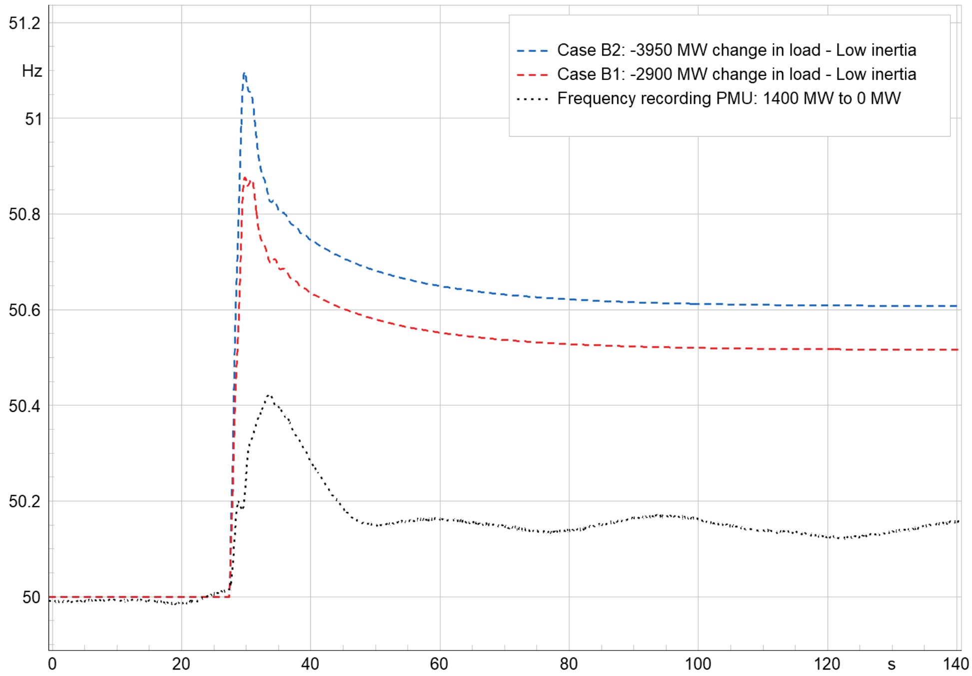

Figure 3-13 Over-frequency simulation responses of different large disturbances on several HVDC links – low inertia scenario

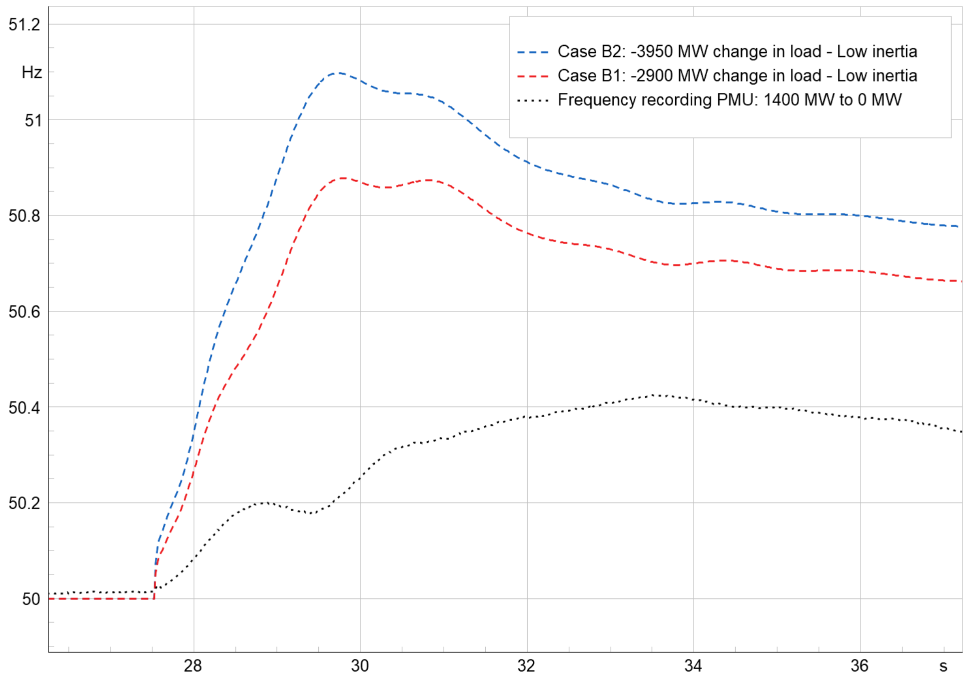

Figure 3-14 Over-frequency simulation responses of different large disturbances on several HVDC links - low inertia scenario, zoomed in

Figure 3-13 and Figure 3-14 demonstrate that the frequency response to the applied disturbances have a much higher RoCoF compared to the recorded frequency response, and that the maximum frequency is higher as well. In this simulation, for case B2, the frequency is reaching above 51 Hz. The frequency response is also stabilizing at a higher frequency after the initial recovery. The shape of the frequency responses of both Case B1 and Case B2 are very similar, there is a deviation in amplitude, and the amplitude difference is the biggest when both frequency responses are at their maximum, which happens very close in time. Table 3-5 present key metrics from the simulations presented.

Table 3-5 Maximum frequency, maximum and minimum ROCOF and steady state frequency measured during simulation of different large HVDC link disturbances – low inertia

	Change in active power	Maximum frequency [Hz]	Maximum ROCOF [Hz/s]	RoCoF according to swing equation [Hz/s]	Steady state frequency [Hz]
Frequency recording PMU	1400 MW export to 0 MW	50.42	0.20	0.19	50.12 - 50.17
Simulation B1	2900 MW reduction in load	50.88	0.60	0.55	50.61
Simulation B2	3950 MW reduction in load	51.10	0.82	0.78	50.52

From the data presented in Table 3-5 maximum frequency for the 3950 MW disturbance in Case B2 is exceeding 51 Hz, reaching 51.10 Hz, with a maximum RoCoF of 0.82 Hz/s. The RoCoF in the simulation is slightly higher than what, for the same disturbance and system inertia, is calculated using the swing equation.

3.2.3 Comparison of over-frequency response with normal/high and low system inertia

In this section, the same simulations as were presented in Sections 3.2.1 and 3.2.2 is presented again, but here the disturbances in normal/high and low inertia scenarios are compared. Case B1, when a 2900 MW load change is simulated, is presented in Figure 3-15 and Figure 3-16, along with the recoded frequency response of the 1400 MW disturbance on the 8th of October 2024. Case B2, when a 3950 MW load change is simulated, is presented in Figure 3-17 and Figure 3-18, also with the recoded frequency response of the 1400 MW disturbance on the 8th of October 2024.

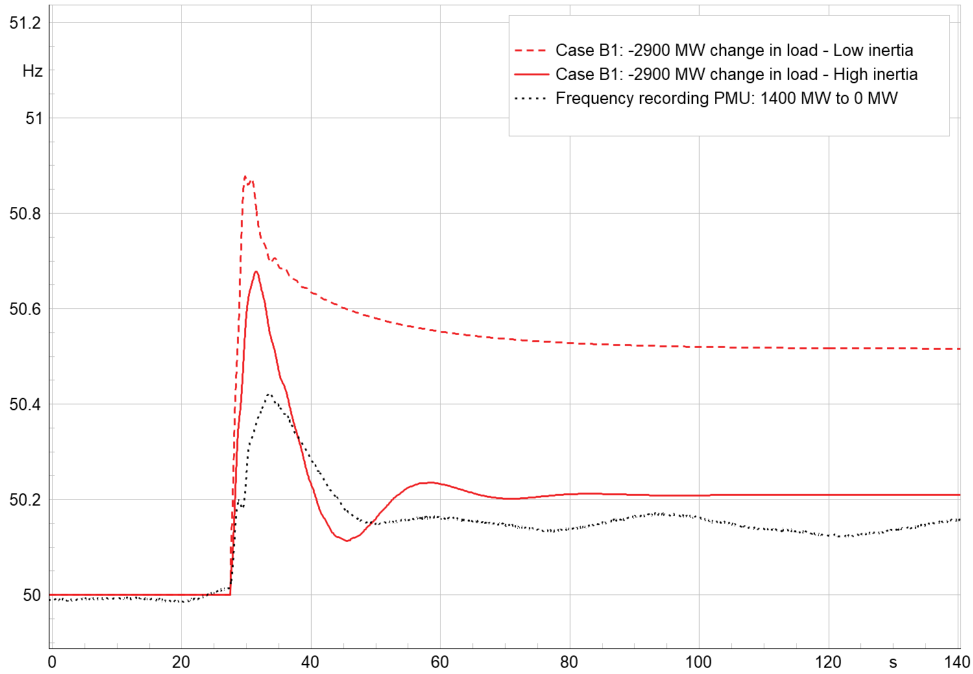

Figure 3-15 Comparison of Case B1 – a 2900 MW load change, simulated in normal/high and low inertia scenario

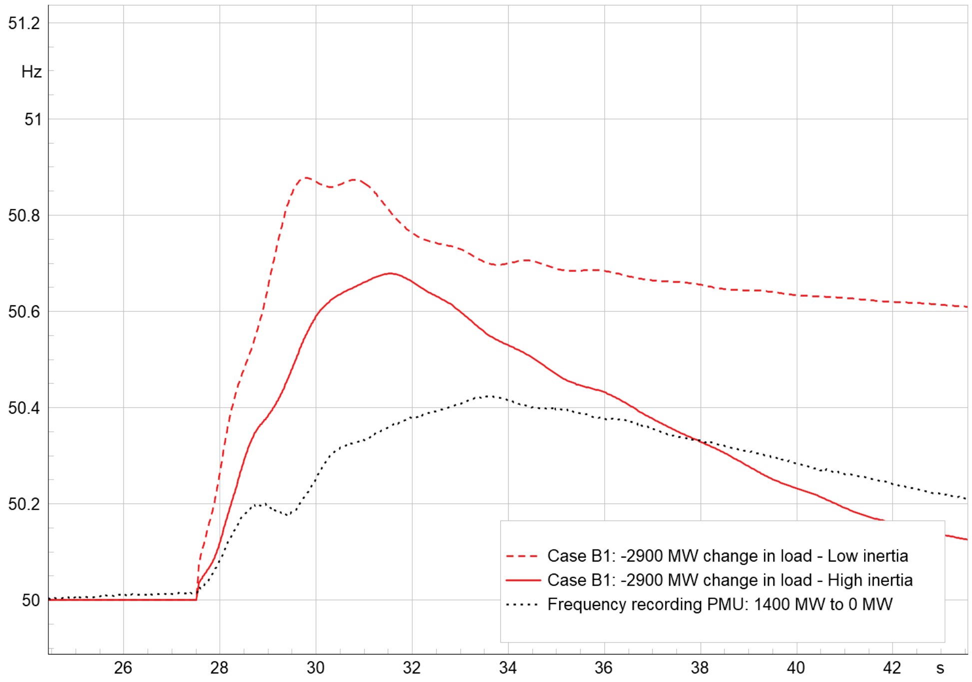

Figure 3-16 Comparison of Case B1 – a 2900 MW load change, simulated in normal/high and low inertia scenario, zoomed in

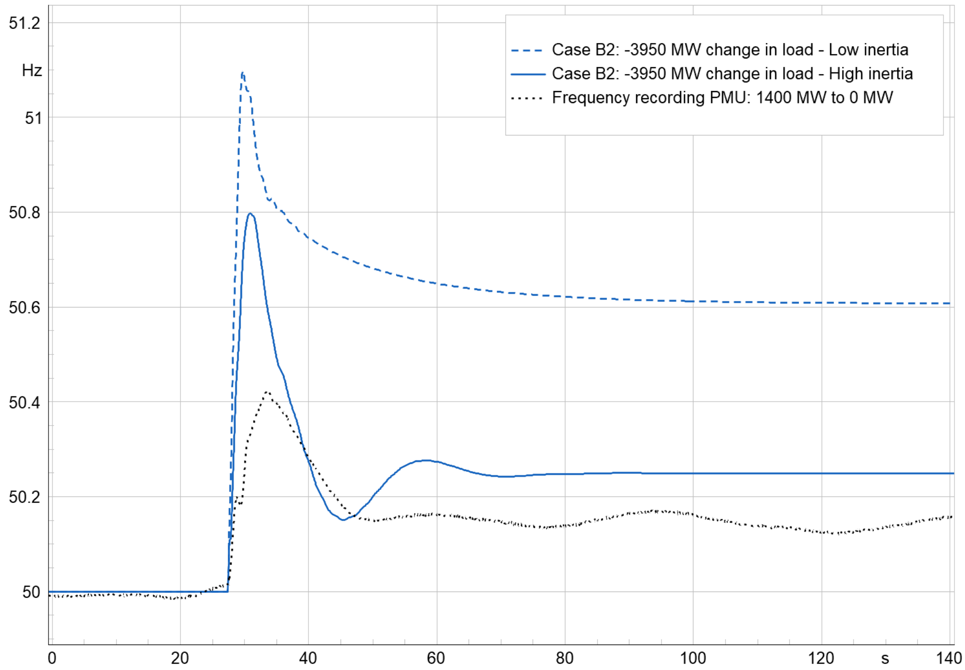

Figure 3-17 Comparison of Case B2 – a 3950 MW load change, simulated in normal/high and low inertia scenario

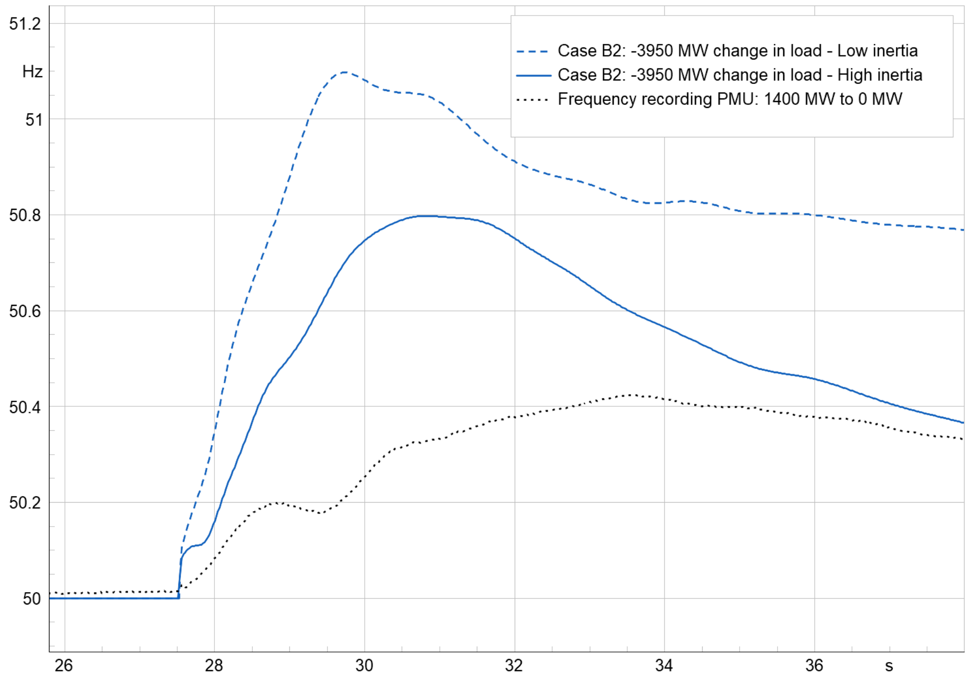

Figure 3-18 Comparison of Case B2 – a 3950 MW load change, simulated in normal/high and low inertia scenario, zoomed in

From Figure 3-15-Figure 3-18 some clear differences between the normal/high and the low inertia can be observed. What is most significant is the difference in the steady state frequency of the frequency response, but there are also expected differences in the RoCoF and maximum frequencies during the disturbances.

3.3 SYSTEM SPLIT

A more severe scenario would involve a disturbance that causes the power system to separate into two or more distinct areas. Within the Nordic synchronous system, one such possibility is a loss of synchronism between the northern and southern regions. In this case, the northern parts of the grid—including Finland—would likely form a subsystem with surplus generation, resulting in significant over-frequency conditions. In contrast, the southern section would experience a power deficit, leading to an under-frequency event.

As this report focuses on the impact of over-frequency events on nuclear power plants, the system split scenario assumes that the system separation occurs just south of Forsmark. Consequently, Forsmark and the nuclear power plants in Finland are located within the power-surplus northern region.

The simulated operational scenario mirrors the conditions on October 8, 2024, with total system inertia equal to 186 GWs. The disturbance initiating the system separation is the same as on that date—disconnection of the North Sea interconnector while exporting 1400 MW. However, in this simulation, a system split is introduced 2.5 seconds after North Sea link is disconnected. The split is modeled by disconnecting the transmission lines connecting southern Sweden (south of Forsmark) and Norwegian bidding zones NO1, NO2, and NO5 from northern Sweden and Norwegian bidding zones NO3 and NO4.

The Fenno-Skan interconnection between Finland and SE3 is assumed to belong entirely to the northern region. At the time of the split, the export of the areas that are disconnected is 4428 MW, causing a very severe disturbance. How the system is split is shown in Figure 3-19.

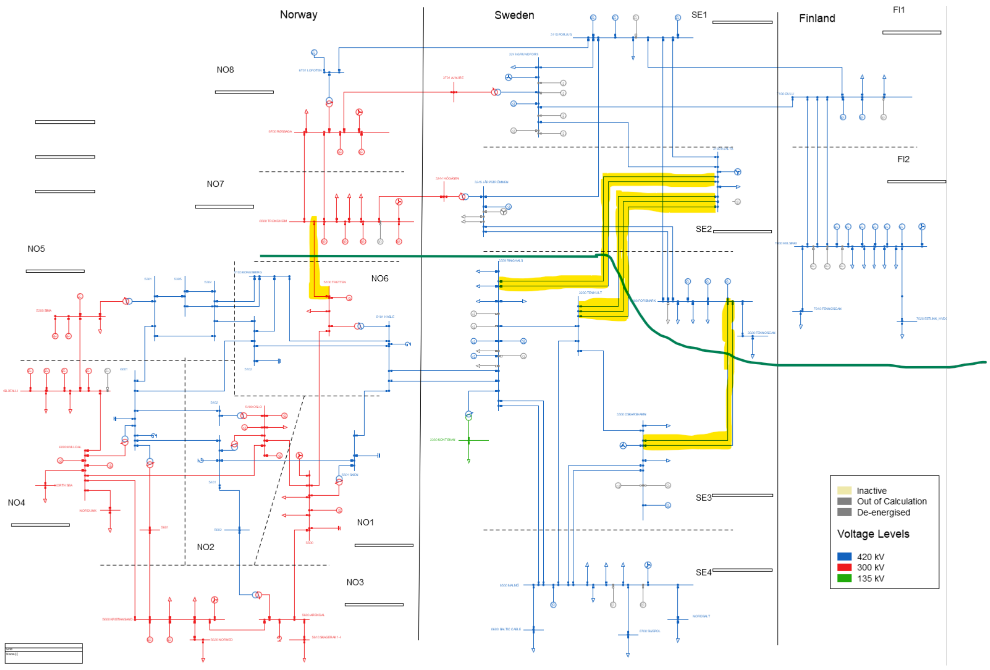

Figure 3-19 SLD from PowerFactory with disconnected lines marked in yellow, dividing the Nordic synchronous system in a northern and southern part.

The frequency response when this disturbance is applied is shown in Figure 3-20 and Figure 3-21.

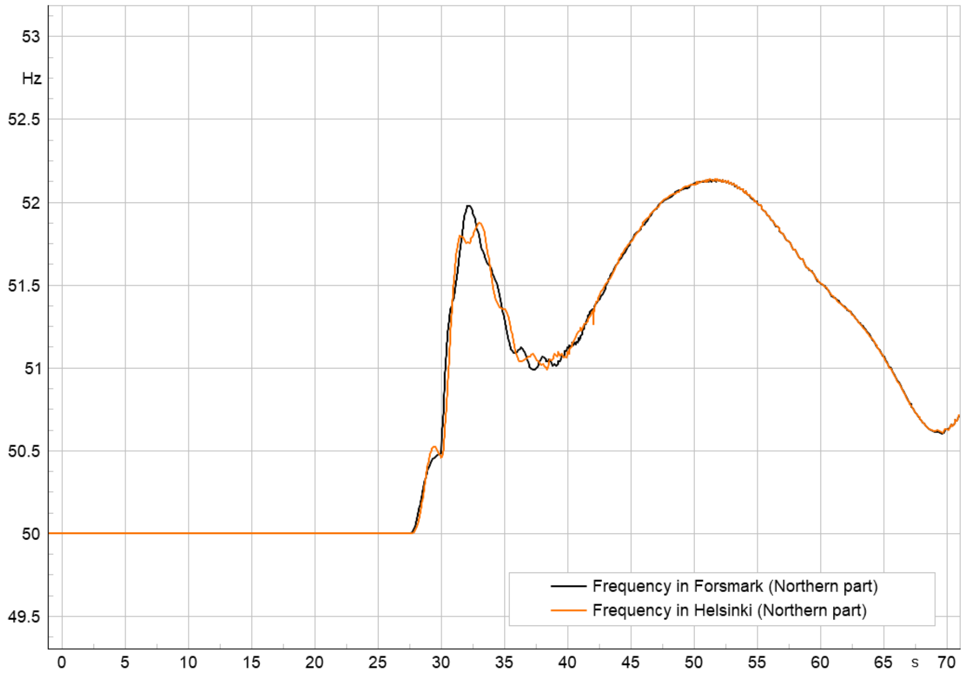

Figure 3-20 Over-frequency response on the Helsinki bus belonging to the norther part when a system split has occurred

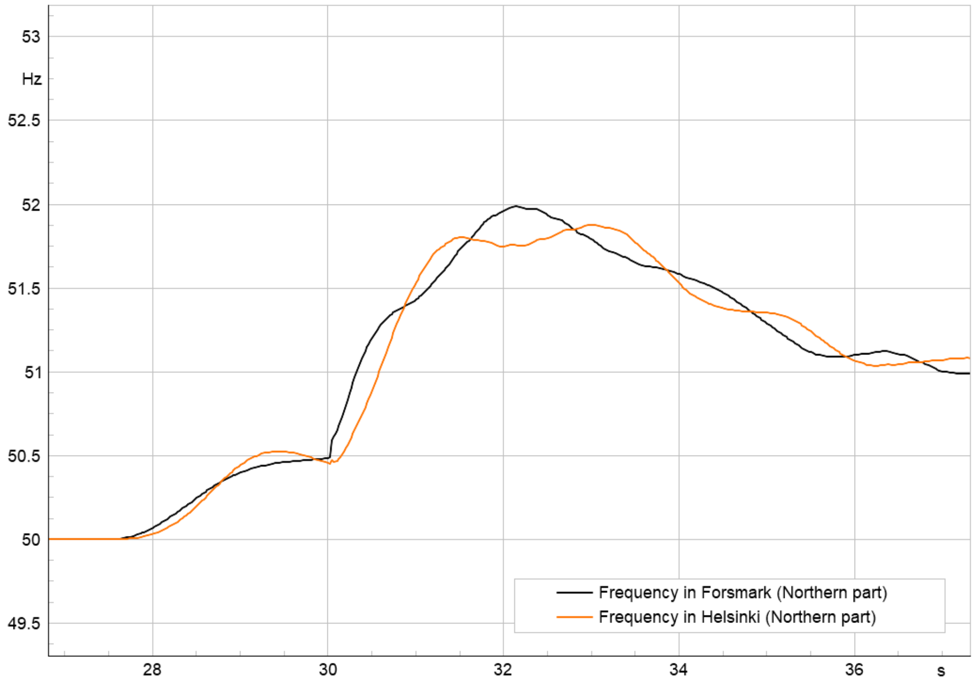

Figure 3-21 Over-frequency response on the Helsinki bus belonging to the norther part when a system split has occurred, zoomed in

Figure 3-20 and Figure 3-21 illustrates how the disturbance leads to a significant over-frequency event in the northern section of the grid. The maximum frequency during the initial transient reaches 52 Hz. However, following the initial frequency recovery, the system fails to stabilize and does not return to 50 Hz in a controlled manner. Given the severity of the event and the limitations of the model, the accuracy of the simulated system behavior in this scenario is uncertain. Nevertheless, it is evident that the initial RoCoF immediately after the system split reaches approximately 1.7 Hz/s, which is considerably higher than in the previous simulations.

4 Review of measures taken in other synchronous systems

The increased integration of renewable energy sources presents certain challenges to TSOs, with low inertia production becoming a large part of the power mix at certain hours. This chapter provides an overview and insights of various measures implemented in different synchronous systems to mitigate the impact of over-frequency events on the system.

4.1 FAST FREQUENCY RESERVE VS SYNTHETIC INERTIA

To counteract the reduction in inertia traditionally provided by heavy synchronous machines, two different products that can be supplied from inverter-based sources are often discussed, Fast Frequency Reserve (FFR) and synthetic inertia.

Today in the Nordic synchronous system, when the inertia is low, FFR is secured to compensate for the lack of inertia [11]. But the effect of FFR and synthetic inertia is not the same. The main difference between synthetic inertia and FFR is that synthetic inertia is released based on RoCoF, whereas FFR is activated based on absolute frequency. Synthetic inertia is intended to provide a response that is mimicking the release of kinetic energy from a rotating mass in case of frequency deviations.

The study “Synthetic inertia versus fast frequency response: a definition” [12], compares the impact on the frequency response of synthetic inertia and FFR and uses the following definitions.

The definition of synthetic inertia: *synthetic inertia is defined as the controlled contribution of electrical torque from a unit that is proportional to the RoCoF at the terminals of the unit* [12].

The definition of FFR: *fast frequency response is the controlled contribution of electrical torque from a unit which responds quickly to changes in frequency in order to counteract the effect of reduced inertial response* [12].

The study examined the system's frequency response under three scenarios:

1. without any frequency support from inverter-connected wind power;
2. with FFR; and,
3. with synthetic inertia provided by the inverter-connected wind power.

The results indicated that improving RoCoF requires the provision of synthetic inertia that responds directly to changes in RoCoF. Furthermore, the study demonstrated that both synthetic inertia and FFR contributed to limiting the frequency nadir, compared to a scenario in which inverter-connected wind power provided no frequency support. In addition to this it was also shown that the frequency quality was improved when FFR was provided, but not when synthetic inertia was provided. In this case, frequency quality refers to how well the frequency is kept around the nominal 50 Hz level. The reason for this being that synthetic inertia reacts to fast frequency changes, whereas the FFR reacts to larger frequency deviations [12].

4.2 ENTSO-E ON ROCOF IN CONTINENTAL EUROPE

The Continental European synchronous system, due to its large size, is generally less sensitive to disturbances—such as the disconnection of loads or generators—in terms of frequency deviations and RoCoF. Nevertheless, the system has experienced several instances of separation, where it has split into two or more independent subsystems [13]. As a result, ENTSO-E has highlighted the critical importance of maintaining sufficient system redundancy to withstand disturbances that could cause the RoCoF to exceed 1 Hz/s in certain regions [14].

Since system splits can result in both over-frequency and under-frequency conditions, any measures implemented to limit the RoCoF are expected to positively impact both the maximum and minimum frequency deviations. In a presentation by ENTSO-E addressing strategies to manage RoCoF, several recommendations were proposed to mitigate the challenges associated with low system inertia. These included the provision of additional inertia from grid-forming renewable generators, battery energy storage systems, synchronous condensers, or STATCOMs equipped with energy storage. Other suggested measures involved enhancing the frequency withstand capabilities of power generating units, implementing strategies to prevent system splits, developing countermeasures to reduce the impact of such splits, and introducing market-based restrictions aimed at maintaining system stability [15].

ENTSO-E is expecting to release the new version of the RfG, which should include requirements on generators to be able to withstand different RoCoF. Today, there are not specific requirements on RoCoF withstand capability in the RfG. Different requirements are suggested for synchronous generators compared to power park modules. Early drafts suggest that inverter-connected power park modules of all sizes should be able to withstand [13]:

- 4 Hz/s for 0.25 s
- 2 Hz/s for 0.5 s
- 1.5 Hz/s for 1 s
- 1.25 Hz/s for 2 s

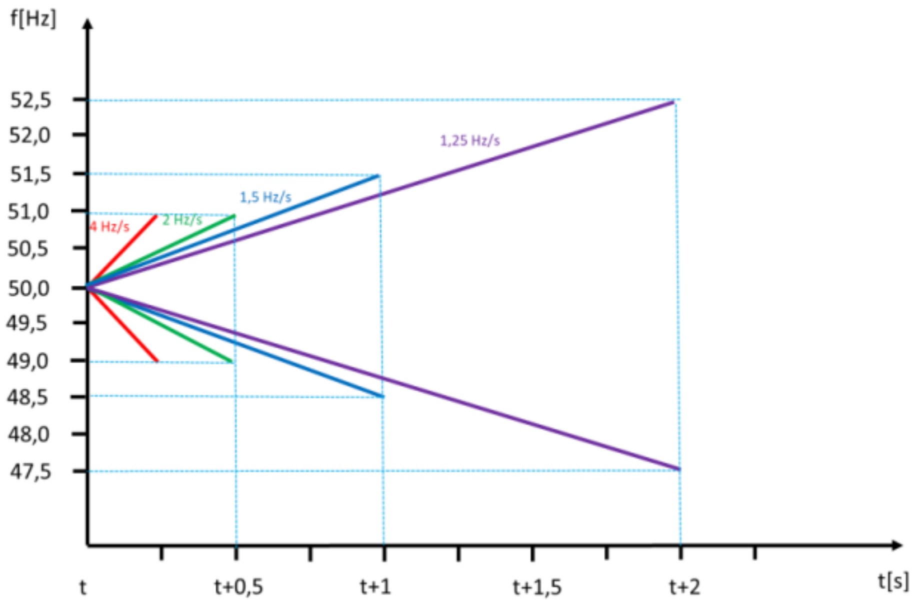

Figure 4-1 Illustration of suggested frequency and RoCoF withstand requirements for inverter-connected generation [13]

As for synchronous power generating modules (SPGM) it has been suggested that the requirements should be that the synchronous generators should be able to withstand [16]:

- 2 Hz/s for 0.5 s
- 1.5 Hz/s for 1 s
- 1.25 Hz/s for 2 s

However, these proposed requirements have been met with opposition from EUTurbines. The organization argues that withstanding a RoCoF greater than 1 Hz/s over a 0.5-second duration is technically challenging for large synchronous generators and may risk loss of synchronism. EUTurbines recommends that Type D synchronous generators should be required to withstand RoCoF levels up to 1 Hz/s for 0.5 seconds. Conversely, they acknowledge that smaller synchronous generators are generally more capable and could be expected to tolerate RoCoF levels up to 2 Hz/s over the same duration [17].

4.3 STUDIES PERFOMED IN COUNTRIES WITH LOW INERTIA SYSTEMS

In this section studies performed, and measures taken in countries with low inertia power systems, are presented. Australia and Ireland are two countries with relatively small power systems with different characteristics, but that both are challenged by increasing levels of inverter-based power park modules feeding the grid with power.

The learnings and mitigation measures that have been deployed in these systems can be used as valuable insights and inspiration for the Nordic synchronous system. For example, increasing the technical requirements and grid codes while still considering the system conditions and considerations such as nuclear safety.

4.3.1 Australia

Australia's power grid is transitioning towards renewable energy sources like solar PV and wind, which presents challenges in maintaining grid stability, voltage, and frequency control. The reduction of natural inertia due to the shift from traditional synchronous generators complicates frequency stability management. Additionally, the growing prevalence of distributed energy resources (DER), such as rooftop solar, affects the effectiveness of existing emergency frequency control schemes [18]. Australian Energy Market Operator (AEMO) has predicted a large increase in installed capacity in the coming years, using two different scenarios, a large part of the increase is distributed PV, but also other inverter-connected sources [19].

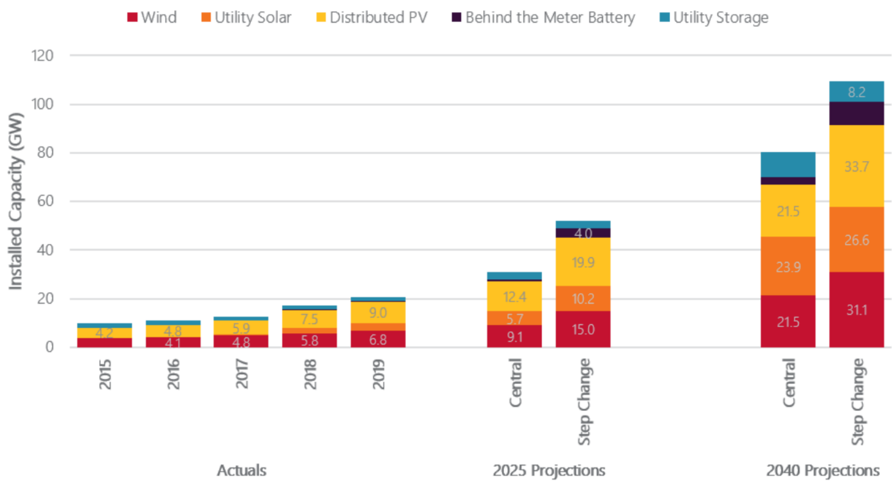

Figure 4-2 Prediction of installed generation capacity in the Australian grid [19]

The AEMO is actively addressing these challenges by exploring and implementing a range of measures. AEMO conducts studies to determine the available, minimum threshold, and secure operating levels of inertia across different sub-systems of the Australian grid. This approach ensures that each potential islanded section of the grid maintains sufficient inertia, given that subsystem islanding for some areas in Australia is not unlikely [18].

Measurement taken by AEMO to asses risks associated with low inertia include continuing to monitor high RoCoF events and review over-frequency generation shedding and under-frequency load shedding settings as necessary and performing sensitivity studies with inverter-based frequency control disabled are being conducted to assess the risk of over-frequency [20].

Over-Frequency Generation Shedding (OFGS) and Under-Frequency Load Shedding (UFLS) are two key mechanisms employed by AEMO to manage major system disturbances. However, the effectiveness of traditional UFLS schemes has diminished with the increasing integration of distributed energy resources (DER). The presence of significant distributed generation can reduce the net load in certain areas, meaning larger geographical regions may need to be disconnected to achieve the required load reduction during under-frequency events. In response, AEMO is implementing new special protection schemes tailored to specific contingencies. Additionally, AEMO recommends dynamic arming of UFLS relays to be introduced to prevent unintended operation under reverse power flow conditions, thereby enhancing the reliability and precision of frequency control strategies in a DER-rich environment [20].

These measures aim to enhance the resilience of the power system while increasing renewable energy penetration and the associated challenges in maintaining frequency stability and managing RoCoF.

4.3.2 Ireland

EirGrid, the transmission system operator for Ireland and SONI, the transmission system operator in Northern Ireland, has implemented several measures to manage the RoCoF and ensure system stability with high penetrations of inverter-connected generation like wind and solar PV [21].

To manage the challenges posed by high renewable penetration, EirGrid initially instituted a 50 % cap on System Non-Synchronous Penetration to limit the amount of non-synchronous generation, by curtailing inverter-connected generation. This 50 % cap has been gradually increased through the Delivering a Secure Sustainable Electricity System (DS3) program, which aims to raise it to 75 % [21]. Introducing a cap on a specific generation source means restricting its contribution to total active power output, ensuring it does not exceed a predefined share of the total power supplied to the grid.

Additionally, EirGrid introduced seven new system services to incentivize the provision of essential reliability services. These services include synchronous inertial response, which rewards units with high inertia and low minimum generation levels, thereby reducing RoCoF [21].

EirGrid ensures that sufficient synchronous generators remain online to provide inertia and maintain system stability. This includes revising market incentives to encourage lower minimum generation levels for thermal plants. Thermal plants are good for the grid but are emitting more carbon dioxide the more power they are producing. Furthermore, EirGrid has developed new market products like Fast Frequency Response (FFR) to provide rapid response to frequency deviations [21]. The regular response time for FFR is two seconds, but they also have ultra-fast services with response times as fast as 0.15 seconds. These services are more suitable for BESS, and units providing these services can be paid more for these extra fast responses [22].

When necessary, EirGrid curtails inverter-connected wind generation to maintain stability and manage RoCoF. This is particularly important during periods of high wind output and low demand. These measures collectively help EirGrid manage RoCoF and maintain grid stability as the penetration of renewable energy sources continues to increase [21].

To ensure that the RoCoF is not exceeded with a higher share of renewable generation, several steps are being taken in Ireland:

1. **Enhanced Grid Codes**: Grid codes are being updated to require that all generating units, including renewable sources, can withstand higher

RoCoF values. This ensures that these units remain connected and contribute to system stability during frequency disturbances.

2. **Increased System Inertia**: Adding synchronous condensers and other inertia-providing devices helps to increase the overall system inertia, which reduces the RoCoF during disturbances.
3. **Advanced Control Systems**: Implementing fast-acting control systems and frequency response mechanisms in renewable generation units helps to quickly counteract frequency changes.
4. **Improved Forecasting and Management**: Better forecasting of renewable generation and demand, along with more sophisticated energy management systems, helps to anticipate and mitigate potential frequency issues.
5. **Grid Reinforcement**: Strengthening the grid infrastructure, including upgrading transmission lines and interconnections, helps to better manage power flows and maintain frequency stability.
6. **Regulatory and Market Mechanisms**: Introducing market mechanisms that incentivize frequency support services from both conventional and renewable generators ensures that there are adequate resources available to manage frequency.

These measures collectively help to ensure that the grid can handle higher levels of renewable generation without exceeding RoCoF limits [21].

Study on Ireland RoCoF withstand capabilities

A study performed by DNV/KEMA for EirGrid [23] investigated limitations of the power system's ability to withstand RoCoF values up to 2 Hz/s. The study found that RoCoF values of 1.5 Hz/s and 2 Hz/s could cause instability in the system. This means that synchronous generators are at risk of experiencing pole slip, which can lead to mechanical stress on the equipment and potential disconnection from the grid. For a RoCoF of 1 Hz/s all generators could stay synchronized and comply, for all operational scenarios tested except for when they were operating with a leading power factor. Smaller gas turbines and hydro units performed better at higher RoCoF and could withstand RoCoF of up to 2 Hz/s [23].

5 Potential impact on NPPs in the Nordic synchronous system

To ensure continued safe and reliable operation of the Nordic synchronous system it is important to understand and monitor the potential impact of over-frequency events on the NPPs.

As the Nordics NPPs are designed to operate within specific frequency ranges, over-frequency events can cause significant stress on the plant's systems and components. It can also accelerate wear and tear on critical components such as turbines, generators, and auxiliary systems, which can reduce the overall lifespan and challenging the continued safe and reliable operation of the plants.

Therefore, it is necessary that the potential risks related to over-frequency events and that historical disturbances are utilized to understand the impact on the NPPs.

5.1 EXPERIENCE OF NPPS WITH IMPACT FROM OVER-FREQUENCY EVENTS

The primary concern of the NPPs, which is also raised in the recently published GINO report "Trends and Frequency Deviations" [1] which partly covers the topic of over-frequency events and impact on the Nordic NPPs, is that a future, more complex power system might be more susceptible to frequency deviations that exceed the applicable grid regulations and design criteria. Consequently, this might result in increased tripping of NPPs to preserve NPP integrity in the case of severe over-frequencies.

Based on discussion with the reference group in this project, and with reference to the report "Trends of Frequency Deviations", we arrive in the overall conclusion that the NPP operators have not yet reported any significant impact due to over-frequency events. Also, the impact on wear and tear of NPP equipment due to increased over-frequency tendencies is still unknown as it cannot be distinguished from other sources of wear and tear.

The significant impact on the NPPs from external events is more often reported to be related to other power system parameters and characteristics, such as voltage deviations and incorrect operation of system protection.

5.2 POSSIBLE OVER-FREQUENCY SYSTEM EVENTS

Within this report, several system events which pose the risk of causing significant over-frequencies within the synchronous system are identified and simulated. Due to the probabilistic nature of disturbances and faults, it is not unreasonable to assume that any of said disturbances may occur or eventually will occur.

[1] Trends of Frequency Deviations

Energiforsk

Disconnection of HVDC link

- Due to the significant power flow across the various HVDC links, disconnection, or tripping of such a link, will cause a significant power imbalance, which might result in severe over- or under-frequencies depending on the power flow direction.

Reverse power flow of HVDC link

- Historical events show that HVDC links can not only trip but can also suddenly experience disturbances in rapid changes in power flow direction. This presents a new challenge where even more significant power imbalances caused by HVDC links may occur.

Disconnection of several HVDC links

- It is not unreasonable that several HVDC links experience cascaded disconnection following a disturbance on one HVDC link. This results in a challenging operational situation of the synchronous system.

System split

- System split may cause the most significant over-frequencies depending on the system characteristics. If system split occurs in such a way that an area with high generation and low loading, such as northern Sweden, becomes isolated, the frequency will rapidly rise due to the excess generation in the isolated network.

The simulations performed in this report indicate that resulting frequency deviations for the HVDC link faults can amount to: RoCoF of up to 0.82 Hz/s; and maximum frequency deviation up to 51.1 Hz.

With the more extreme System split scenario, RoCoF of up to 1.7 Hz/s and maximum frequency deviation of 52 Hz are calculated through the simulations. Experience from the historic 1983 event, where frequency reached up to 54 Hz within 5 seconds, provides additional indication of the most extreme system fault conditions that could potentially occur. In that case, Forsmark and the nuclear power plants in Finland, which were located within the power-surplus northern region, were most exposed. With changing system dynamics and with increased load demand in the northern part of the system, it is not unreasonable to consider that similar scenarios could occur for the other NPPs as well.

Note, as the simulation model used in this report is a generic representation of the Nordic synchronous system, the values mentioned above should be used as an indication of the possible frequency deviations and investigation of the robustness of the system.

5.3 DESIGN AND OPERATIONAL STRATEGIES OF THE NPPS

NPPs in the Nordics are designed with several measures to withstand over-frequency events in the grid. These measures are intended to ensure the safe and reliable operation of the plants even during significant frequency deviations. These include:

- Over-frequency relays or limits:

  - If applied and functionality is activated, these are normally aligned with the applicable regulations at the time of the larger modernizations or change of significant equipment of the plants. For example, such changes that would result in the applicability of RfG requirements.
  - For the older plants in the Nordic system, e.g. in Sweden, the plants are allowed and designed to operate with reduced power output for frequencies between 50.3-51.0 Hz for minimum 30 minutes, within 51.0 – 52.5 Hz for up to 3 minutes, and above 52.5 Hz the plants are allowed to disconnect instantaneously (normally set at 5 s).
- Turbine over-speed protection, both mechanical and electrical to avoid turbines in the event of a fault, from going into overspeed.
  - This is normally set to minimum 110 %. With regards to frequency this would correspond to 55 Hz.
- RoCoF design considerations.
  - RoCoF outside of 2 Hz/s is outside of design parameters for the system.

All the above mentioned design measures and protection apply to the overall NPP including protection and control equipment, and auxiliary systems in the case of motor-driven devices, such as pumps and fans that have frequency-dependent speeds.

6 Conclusion

To ensure the safe and reliable operation of the Nordic synchronous system, it is crucial to understand and monitor the impact of over-frequency events on Nuclear Power Plants (NPPs). Such events can potentially cause significant stress on the plants' systems, leading to unreliable conditions and accelerated wear and tear on critical components.

The results of this report indicate that disconnection or reverse power flow of HVDC links, and system splits, can cause severe over-frequency deviations. Seemingly, the NPPs are designed with measures like over-frequency relays, turbine over-speed protection, and RoCoF considerations to withstand these events and ensure safe operation.

However, due to lack of actual testing and experience with over-frequency events there are still many unknowns and from the perspective of the Nordic NPPs, the over-frequency domain is still viewed as mostly unexplored territory.

Recommendations are put forward to ensure the continued secure and reliable operation of the Nordic NPPs, including:

- Continuous monitoring and analysis of frequency deviations and impact assessments to determine the need for implementing further countermeasures.
- Encourage the Grid Committee and the Operations council to increase the consideration of HVDC links in worst-case scenarios and in anticipating future over-frequency events and share the findings with the NPPs and other relevant stakeholders.
    - Furthermore, it might be relevant to consider setting a limit to the maximum capacity of future HVDC-links to avoid them reaching installed capacities beyond the system stability capabilities. It might also be relevant to challenge the current system dimensioning fault, which is currently 1450 MW for the trip of Oskarshamn 3, and take into consideration the HVDC links and the possibility of reverse power flow scenarios.
- Collaboration and experience exchange with NPPs in other synchronous areas to gain valuable insights and best practices both within and outside of the Nordics.

6.1 FUTURE WORK

This project primarily focused on the existing Nordic power system and utilized a generic open-source model for simulations of “extreme” but not “unrealistic” over-frequency events. While this approach provided valuable insights, it is recommended that future work should consider more detailed and realistic scenarios. Specifically, the actual Nordic power system model supplied by the Nordic TSOs and the NPPs should be used to achieve a closer match with the actual system behavior. This would enable more accurate predictions and assessments of the impact of over-frequency events on the Nordic NPPs.

Additionally, exploring future scenarios with increased renewable energy integration and the changing and varying system conditions could provide a more comprehensive understanding of potential challenges and solutions.

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IMPACT OF OVER-FREQUENCY EVENTS ON NORDIC NPPS

This report quantifies over-frequency events by using a simulation model of the Nordic synchronous system and simulating different faults related to the HVDC links, in combination with operating conditions of high and low inertia. The following faults are considered:

- Disconnection of HVDC link
- Reverse power flow of HVDC link
- Disconnection of several HVDC links
- System split

Using the simulation model the resulting frequency change are calculated. For HVDC link faults, RoCoF of up to 0.82 Hz/s; and frequency deviation up to 51.1 Hz. For the System split scenario, RoCoF of up to 1.7 Hz/s and frequency deviation of up to 52 Hz.
The findings of the study indicate that the NPPs should be robust to most of the studied cases related to large disturbances related to HVDC links. This is further highlighted from the experience of the NPPs, as there has been no significant impact on the recent historical over-frequency events on the operation of the NPPs. The most extreme system split scenario might result in extreme over-frequency deviations beyond the system and NPPs capabilities. Reference is made to the 1983 historical event where over-frequency of 54.0 Hz after 5 seconds was reached.

Measures undertaken to limit the impact of over-frequency events in other synchronous areas have also been reviewed. This includes the introduction of market mechanisms, such as Fast Frequency Response/Reserve, and technical requirements, such as provision of synthetic inertia.

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