Frequency Based Emergency Disconnection Policy Review for the Nordic Region

Report – V 1.0

Nordic Analysis Group (NAG)

14 June 2017

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Executive Summary

The Nordic network has changed significantly in the recent years. It is envisaged that this change will continue over the next decade in order to accommodate an increase in renewable penetration and HVDC interconnections to continental Europe and the UK. As a result of this change, there are other likely eventualities; closure of nuclear units in Sweden, or a reduction in thermal generation units.

These changes in generation profile, inter-country spot trading, and associated network reinforcements have resulted in a need to re-evaluate the policies and settings that maintain and secure network frequency under serious outage events. As a result of this the Nordic Analysis Group (NAG) was engaged to review the Under Frequency Load Shedding (UFLS) philosophy for the Nordics. This report documents the associated review and presents the following initial observations:

- The current SOA agreed UFLS settings are no longer optimal and may increase the risk of frequency instability in the network under severe outage events.
- The current declared UFLS levels are not actually what is implemented within the network; with up significantly less load shedding available than prescribed within the SOA (country specific).
- In reality, the effort to implement a new set of UFLS settings may be no more labour intensive than ensuring that mandated levels of UFLS are implemented in all countries.

Having identified the above salient details, a study was instigated to derive a set of revised UFLS settings that:

- Appropriately distributes shed load between TSOs as well as within a TSO area.
- Provides the same reference for frequency and load shedding stage across the interconnected network.
- Minimises UFLS whilst ensuring frequency stability across the network.
- Avoids over frequency and transients that can lead to an additional loss of generation

Varying UFLS schemes have been assessed through pre-screening studies to evaluate the risk of frequency instability and the risk of exceeding transmission capacity across the wider network. As a result of this, 10 potential schemes were considered against the current network topology and the 2025 network configuration (as set out by each TSO's long term development statement).

The studies enabled each scheme was evaluated against frequency deviation, stability and ultimately the average level of load lost per load shedding event that encompassed over 800 scenarios and dynamic stability studies.

- **The UFLS scheme identified to most efficiently maintain stability whilst minimising total load shed is a 4 stage UFLS scheme shedding 20% of maximum load in 5% stages occurring at 48.8 Hz, 48.6 Hz, 48.4 Hz and 48.2 Hz.**

As a result of this there will be a need to present a set of revised changes to the System Operation Agreement (SOA). It is noted that the recommended changes are generally consistent and compliant with the ENTSO-E Network Code on Emergency and Restoration. The only area that would be necessary to revise would be the mandatory total disconnected load (set at 30% for the Nordics). Given the associated study and the beneficial impact this revision would create, it is likely this revision would be considered favourably.

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1. Introduction

When large generating units or significant parts of the connected network are disconnected, the power system may encounter a swing in frequency of a magnitude relative to the size of loss. Limits are imposed on the magnitude of frequency deviation to prevent plant damage, or in worst case, collapse of the system. Frequency responsive services to recover lost energy are offered in the form of ancillary services such as Frequency Control Reserve (FCR). Likewise, part-load plant, or 'spinning reserve', operates outside of optimal settings, resulting in lower efficiencies, and higher emissions. Under the circumstance of severe disturbance that is not recoverable without the disconnection of load in order to stabilise operating frequency, Under Frequency Load Shedding is employed. The methodology and magnitude is set out in an UFLS policy that is implemented by Transmission System Operators TSO's as part of their licence obligations.

The main scope of this report is to evaluate the existing and alternative UFLS strategies within the Nordics (Norway, Sweden, Eastern Denmark and Finland). Having evaluated suitable options, this report presents a set of recommendations for a coordinated UFLS policy that can be implemented by the relevant TSO's.

The ultimate deliverable of this project is to review and update the UFLS scheme and associated policies based on current and future transmission network and generation development plans for Norway, Sweden, Western Denmark and Finland. In order to provide an appropriate evaluation of these settings varying power systems have been performed in order to provide confidence in the recommendations presented. The structure of this report is presented below.

Chapter 3 provides a context to the current settings, highlighting the current regulatory obligations of each of the TSO's within the System Operation Agreement. The methodology of how each TSO fulfils these obligations is identified.

Chapter 4 sets out the principles and methodology of the study and how UFLS schemes will be evaluated.

Chapters 5 & **6** describe the pre-screening phases of potential UFLS schemes.

Chapter 7 presents the combined findings of the pre-screening and identifies schemes that have been nominated for further study.

Chapter 8 documents the detailed power system studies that were performed in order identify the most technically appropriate UFLS scheme.

Chapter 9 identifies the most technically viable UFLS scheme for the Nordic Operating Area and provides specific commentary on the schemes performance under severe network events.

Chapter 10 documents a high level implementation plan for each TSO/country. This considers the impact of regulation on the study and the regulatory changes required as a result of the recommended scheme.

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2. Current Situation

The existing ULFS philosophy was initially developed and implemented within the 1980's in order to consider the rising interconnectivity of the Nordic system (formerly Nordel). The plan was consistent with "Proposed Recommendation for frequency controlled power conditioner in the synchronous Nordel area".

To this end, the policy set out the following principles:

- HVDC connections out of the Nordel area were used for emergency power within the frequency range from 49.5 to 49.0 Hz. Utilisation (MW/s and MW) was agreed for each individual HVDC connection depending on its capability.
- ULFS within the national power systems was implemented during frequency drops down to 48.7 Hz. Disconnections were made in steps of 0.2 Hz and in a total magnitude of 20-50% of the total load depending on the expected production deficit.
- The individual ULFS policy of the country defined the size, locality and distribution of frequency step whilst having due regard to the requirements of an overall Nordel operation.
- The first ULFS policy steps were implemented in, or near Nordel system load centres.
- ULFS was carried out in such a manner that it minimised the risk of overload due to the changes in power flow around the network.
- Possible localised problems without significant consequences for Nordel network were addressed nationally.

As a result of these principles the following recommendations were adopted within in Nordel system:

- Sweden began load disconnection at 49.0 Hz (time delay 20s) and then used five 0.2 Hz decremented steps.
- Denmark and Norway began load shedding at 48.7 Hz and subsequently over five 0.2 Hz decremented steps.
- Denmark adopted a first stage time delay of twenty seconds, while Norway adopted a relatively small MW level during the first stage.
- Finland began load disconnection at 48.7 Hz (time delay 20 s) and then two 0.2 Hz decremented steps.

These settings have evolved in the intervening years to the settings currently adopted within the SOA. The Current UFLS policy enacted within the SOA is seen in Table 1. It is noted that there are some significant time delays stipulated within the SOA prior to disconnection. Whilst the reason for this has not been fully identified, it has been inferred that this larger duration was to facilitate frequency stabilisation should a significantly severe event cause networks to disconnect and run in islanded sections. Historically this may have been more likely given considerably less network reinforcement and cross border connections but it could be argued is less relevant given the current network topology.

Table 1 identifies the current UFLS policies and obligations that have been adopted within each Nordic country. It is noted that although the SOA prevails over other UFLS policy for each country, there are other procedures that underpin this policy[1]. Although each country has a clear methodology for UFLS activation, the methodology for implementation is different from one country to the next. This is invariably a legacy from the original determination of the settings. The settings together with a summarised methodology of the UFLS application from one country to the next is seen within Appendix C on page 67.

[1] During the process of this study, it has become evident that the quantities of UFLS mandated within the SOA may not be fully available for each Nordic country. An example of this would be the levels of available load to be shed within SE3 and SE4 in Sweden. In these cases the SOA mandates 30% of maximum load should be available for shedding. In reality, it is understood that this level is closer to 20% of load.

Table 1 Current UFLS Policy within the SOA

Country	Locality	Criteria
Denmark	East	10% of consumption f < 48.5 Hz momentary, f < 48.7 Hz at 20 s
		10% of consumption f < 48.3 Hz momentary, f < 48.5 Hz at 20 s
		10% of consumption f < 48.1 Hz momentary, f < 48.3 Hz at 20 s
		10% of consumption f < 47.9 Hz momentary, f < 48.1 Hz at 20 s
		10% of consumption f < 47.7 Hz momentary, f < 47.9 Hz at 20 s
	West	15% of consumption f < 48.7 Hz
		25% of consumption f < 47.7 Hz
Norway		30% of load in stages between 48.7 Hz to 47 Hz
Sweden	South of	Electric Boilers and Heat Pumps
	Constraint	35 MW P ≤ 49.4 Hz in 0.15 s
		25 MW ≤ P <35 MW of 49.3 Hz in 0.15 s
		15 MW ≤ P <25 MW of 49.2 Hz in 0.15 s
		5 MW ≤ P <15 MW of 49.1 Hz in 0.15 s
		At least 30% of Consumption in 5 Stages
		Step 1: 48.8 Hz in 0.15 s
		Step 2: 48.6 Hz in 0.15 s
		Step 3: 48.4 Hz in 0.15 s
		Step 4: 48.2 Hz in 0.15 s at 48.6 Hz for 15 s
		Step 5: 48.0 Hz for 0.15 s, and at 48.4 Hz for 20 s
Finland		10% of consumption f < 48.5 Hz at 0.15 s, f < 48.7 Hz at 20 s
		10% of consumption f < 48.3 Hz at 0.15 s, f < 48.5 Hz at 20 s

3. Study Concept

In this section, the basic principles of how the varying UFLS schemes are to be modelled and evaluated are presented. This is in order that the reader has a clear understanding of how the subsequent sections inform the selection process.

Principles of UFLS

The system frequency of a synchronous AC power system, such as the Nordic transmission grid, varies with the imbalance between generation and load. To maintain system frequency within appropriate limits, a degree of frequency responsive plant is required in order to allow for dynamic adjustment of generated power.

When large generating units or there is a considerable loss of power infeed, the resultant swing in frequency is relative to the size of loss. The Nordic Code imposes on the magnitude of frequency deviation to prevent plant damage, or in worst case, collapse of the system. Frequency responsive services to recover lost energy are offered in the form of ancillary services such as Frequency Control Reserve (FCR). Under the circumstance of severe disturbance that is not recoverable, the disconnection of load is used in order to stabilise operating frequency. The methodology and magnitude is set out in the UFLS policy that is implemented by TSO's as part of their licence obligations.

The UFLS policy as presented in the SOA sets out the criteria by which the Nordic TSO's plan and operate the Nordic transmission system under very low frequency events. The UFLS policy is relevant both to the TSO's, and to Users of the transmission system, namely bulk customers and distribution network operators. For the TSOs, it describes the frequencies under which load is shed as part of a recovery plan to restore system frequency in the event of a severe disturbance that would undermine the transmission networks capacity to operate within the criteria set out by the SOA.

UFLS is applied in a way that provides a compromise between a quasi-linear control target and a rigid fixed pre-set load disconnection. In essence, practical disconnection stages derived from appropriate dynamic studies covering applicable scenarios and realistic operational concerns.

An efficient UFLS scheme is generally planned on the basis of several principles:

- Geographically distributed to effectively shed load between TSOs as well as within a TSO area
- Same reference for frequency and load shedding steps across the interconnected network
- Effective implementation ensures the UFLS has minimal necessary requirement for shedding of load
- Compensate disconnection of dispersed generation at unfavourable frequencies
- Avoid over frequency (overcompensation), overvoltage and power transients that can lead to an additional loss of generation

This review of the current UFLS settings takes the following additional conditions into consideration:

- Utilisation of the current ancillary market mechanisms for frequency support
- Avoidance of splitting of network by intervention of associated protection
- Due consideration of the net effect of losing embedded generation located on the load feeders subject to load shedding
- Account for the operational dispatch of HVDC as part of frequency recovery

Whilst there is an inherent need to review and revise the current settings in order to maintain the high standards of transmission network operation that is currently achieved, it is also necessary to recognise the changing landscape under which transmission networks operate. The transition away from conventional large fossil fuelled or nuclear generating stations having significant inertia, to a higher proportion of embedded or renewable sources has forced TSOs to re-evaluate the way they operate in order to maintain security and quality of supply to Users.

Assumptions

Given the relative complexity of the study it is necessary to quantify the assumptions made during the evaluation. Amongst these assumptions are the below exclusions from the study. These include:

- Operational scenarios based on voltage disturbance.
- Load shedding schemes based on under voltage.
- Load shedding schemes based on Rate of Change of Frequency (ROCOF).
- Pump storage control.
- HVDC frequency support[2]
- Wind turbine synthetic inertia and associated frequency support.

Whilst the study considers the loss of generation, be it conventional thermal or renewable sourced, the study does not consider the relative and seasonal impact of wind patterns on wind generation levels.

In order to stimulate sufficient instability that UFLS is activated, it is necessary to provide severe discrepancy between Generation / Power infeed and associated electrical demand. The associated stages selected to instigate such instability is losses of 1800, 2300, 2800, 3300, 3800, 4300, 4800, 5300, 5800, 6300 and 6900 MW tested with the largest total disconnection (ΔP) being 6900 MW which equates to the loss of all HVDC links to continental Europe at full power (and includes 1400 MW of additional capacity from Nordlink from 2020).

The following frequency ranges are assumed:

The first step of load shedding is fixed at equal to or below 49 Hz.	The reason is to reserve a range between 50 Hz and 49 Hz (1 Hz) where primary reserve is trying to recover the effect from the power deficit. The same range is also usable by TSOs to compensate other effects mainly due to the additional imbalances that could happen in their system. For example, a TSO could choose to shed load (i.e. pumping storage plants or interruptible customers) in order to compensate generator trips due to noncompliant frequency disconnection settings.
The last step is activated at 47.7 Hz	This provides a range of 1.1 Hz to control the under frequency transient by loads shedding. Below this frequency there is a certain margin (around 0.2 Hz) where generating units can operate and hopefully recover without trip.

[2] Outside of the associated levels required by the SOA.

Evaluation Methodology

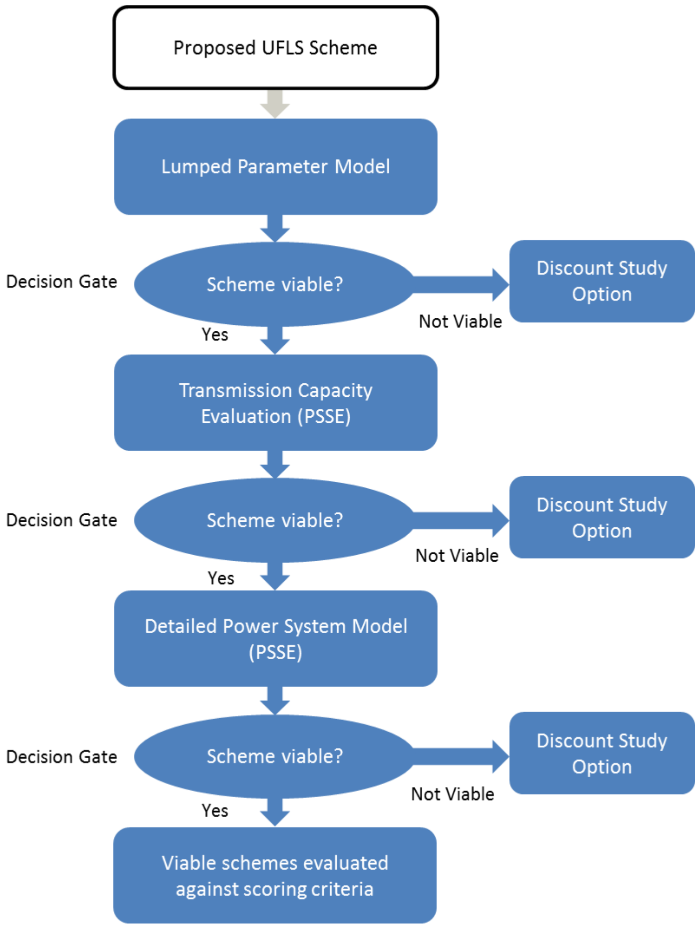
There have been other ENTSO-E studies that have considered the development of harmonised UFLS Schemes for Continental Europe (ENTSO-E, 2014). This approach utilised a simplified representation of frequency control reserves in which each generation technology provides an associated contribution. It also considered the power systems effective inertia to gauge network response to frequency deviation. This concept, whilst fitting for an extended network (where there is less certainty in availability and accuracy of data) has been supplemented with detailed network modelling in this study in order to develop UFLS settings that are more applicable to the Nordics.

To this end, the study is formed with three main stages:

- An initial screening phase utilising a lumped parameter model to characterise dynamic stability.
- A secondary screening phase using a PSSE based model to assess the impact of the UFLS scheme on violation of transmission capacity limits. And finally;
- a detailed power system studies using a comprehensive network model for the Nordics in PSSE in order to verify technical viability of the schemes against identified operational constraints.

This process is characterised in Figure 1 below.

Figure 1 UFLS Evaluation Process



Evaluation of UFLS Scheme

In order to characterize the relative benefits of one load shedding scheme to another; it becomes necessary to adequately characterise the risk of frequency instability. To this end M different load shedding schemes ($S_1...S_M$) are considered. Each load shedding scheme includes a definition of quantity of load lost in the form of percentage of total load per stage, and division of load shedding per bidding zone. Under the evaluation criteria:

- Each load shedding scheme S_k is simulated in N different Nordic load/production levels ($L_1...L_N$) where the risk of losing frequency stability is:

$$R_1(S_k) = R_{1,k} \tag{1}$$

- Each load shedding scheme S_k is simulated in R load flow cases ($C_1...C_R$) where the risk of exceeding transmission capacity:

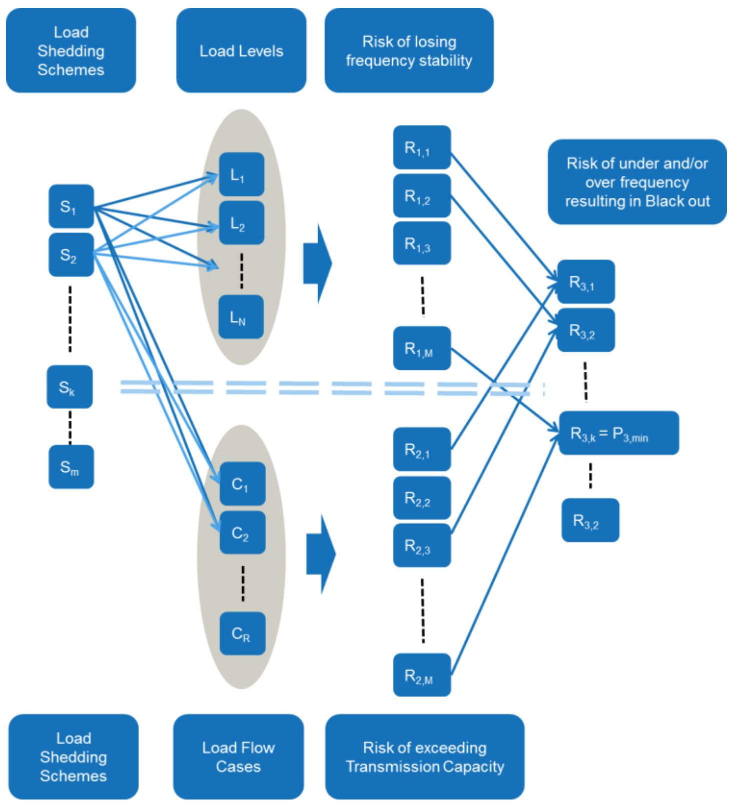
$$R_2(S_k) = R_{2,k} \tag{2}$$

- Thus, the total risk of black out $R_3(S_k)= P_{2,k}$ is calculated for each load shedding scheme[3], where:

$$R_3(S_k) = R_1(S_k) + R_2(S_k) - R_1(S_k)*R_2(S_k) \tag{3}$$

As a result, the load shedding scheme S_k results in the lowest risk of black-out, $R_{3,k}$, and is considered the most viable. The associated scheme is graphically represented below in Figure 2. For clarity, load level evaluation will be performed using the lumped parameter model discussed above. Load flow cases will be evaluated using the Nordic Power System bidding zone PSSE model.

Figure 2 calculating the total risk of black-out as a result of loss of frequency stability or violation of transmission capacity limits



[3] Where (3) is an equation derived to identify the probability of one or both risk criterion occurring

Identified Schemes

In order to determine the recommendations, varying different scenarios have been assessed. As a reference case, the current implemented ULFS is also simulated (cases 1 and 2). The schemes evaluated include varying connotations proposed by the ENTSO-E continental Europe study (ENTSO-E, 2014). As a further benchmark, the study has included varying other UFLS schemes applied internationally by other TSO's in order to include other good practices that could be applied within the Nordics.

The schemes considered are found in the table 2 below. This list is not exhaustive of differing connotations of the same scheme considered with marginally differing values and is included for reference only.

Table 2 Identified potential UFLS schemes considered

Scheme	Country	# Fast Thresholds	Frequency of activating threshold / % of load shed per threshold						
UFLS Plan 1 (SOA defined plan)*	Denmark	n = 5	48.5	48.3	48.1	47.9	47.7	-	Total
			10	10	10	10	10	-	50
	Sweden	n = 5	48.8	48.6	48.4	48.2	48	-	
			6	6	6	6	6	-	30
	Finland	n = 2	48.5	48.3	-	-	-	-	
			10	10				-	20
	Norway	n = 5	48.6	48.2	47.8	47.4	47	-	
			6	6	6	6	6	-	30
UFLS Plan 2 (SOA in reality)*	Denmark	n = 5	48.5	48.3	48.1	47.9	47.7	-	
			10	10	10	10	10	-	50
	Sweden	n = 5	48.8	48.6	48.4	48.2	48	-	
			4	4	4	4	4	-	20
	Finland	n = 2	48.5	48.3	-	-	-	-	
			10	10				-	20
	Norway	n = 10	48.7	48.5	48.3	48.1	>>	47.7	
			2	7	7	11	>>	3	38
ENTSO-E Plan 1 (0.15s delay)	All	n = 6	49	48.8	48.6	48.4	48.2	48	
			2	4	6	8	10	10	40
ENTSO-E Plan 2 (0.15s delay)	All	n = 4	49	48.7	48.4	48.2	-	-	
			5	9	11	15	-	-	40
Plan A (New Zealand)	All	n = 2	48.5 @ 0.4s		48.5 @ 15s		-	-	
			16		16		-	-	32
Plan B (Australia)	All	n = 5	49.5	49	48.85	48.5	48	-	
			10	10	10	10	10	-	50
Plan C (UK)	All	n = 10	48.8	48.75	48.7	48.6	>>	47.8	
			5	5	10	7.5	>>	5	65
Plan D (Ireland)	All	n = 8	48.85	48.8	48.75	48.7	>>	48.5	
			5.9	6.4	5	7.4	>>	10.3	57.2
Plan E (Brazil South)**	All	n = 5	58.5	58.2	57.9	57.7	57.5	-	
			7	7	7	7	7	-	35
Plan F (Brazil North)**	All	n = 5	57.8	57.1	56.5	55.5	55.2	-	
			7	7	7	7	7	-	35
Plan G (Guam)**	All	n = 5	59.2	58.8	58.65	58.5	58.3	-	
			9	9	9	10	10	-	47
Plan I (Western USA)**	All	n = 5	59.5	59.3	59.1	58.9	58.7	-	
			5	5	5	5	5	-	25
Plan J (South Africa)	All	n =7	49.2	49.1	49	48.8	>>	47.9	
			5	5	5	5	>>	10	49.9
Plan K (Libya)	All	n =5	49.4	49.2	49	48.8	48.6	-	
			10.6	8.7	11.1	10.7	13.2	-	54.3

* The scheme is not exhaustively described within this table and does not account for heat pump and electric boiler disconnection.
** Scheme operates on a steady state frequency of 60 Hz, for the purposes of this study 10 Hz has been subtracted

Final Scheme Evaluation Criteria

As seen in the Figure 1; schemes that have been deemed as technically acceptable having been considered against the varying criterion outlined in following chapters are then evaluated based on their ability to maintain wider network integrity whilst minimising disconnection to consumers. These schemes are compared based on their performance and practicality of implementation.

In order to provide a clear metric for the comparison of the reviewed schemes that are deemed feasible the study has considered disconnected load (as a result of UFLS) on a staged and cumulative basis. This allows a robust measure of each viable scheme. This may be used in later works to inform a Value of Lost Load (VOLL) calculation should it be necessary. For clarity this study has not performed this calculation.

4. Screening of Schemes - Frequency Stability

Overview

As stipulated in the study concept, there have been previous ENTSO-E UFLS studies for continental Europe. This approach utilised a 'lumped' model to represent the wider electricity network within mainland Europe. This model has merits, in that it can be used to screen preliminary study schemes prior to progressing to more detailed studies which will use a more comprehensive power systems model.

As a result this study has utilized the Requirements for Automatic Reserves 'RAR' model as a basis for UFLS scheme screening. The model comprises separate models for the Danish (eastern Denmark), Finnish, Norwegian and Swedish governors involved in FNR and FDR. The HVDC connections in Denmark and Finland, used in Frequency Control Normal Operation Reserve (FCR-N) and Frequency Control Disturbance Reserve (FCR-D), are also included. This numerical model enables the characterisation of any non-linearity in performance and assesses the relative risk of the loss of frequency stability to identify viable UFLS schemes.

The risk of loss of frequency stability can be interpreted as the risk of frequency going below 47.5 Hz. This is the point of disconnection of conventional thermal plant that would result in frequency collapse.

It is observed that the NordPool Spot has several bidding zones. As a result load could be shed in zones in differing quantities. It is assumed that an even division is used initially for screening purposes, with further studies informing the most appropriate distribution; the main requirement being to not increase the probability of overload or frequency instability.

Given that RAR model has gone through significant development and evaluation (Nordic Analysis Group, 2011), this study report does not consider its functionality in great detail, more it is recognised as a useful tool in the process. For clarity a schematic view of the lumped parameter model is found within Appendix A.

Methodology

If a generation plant or an HVDC link suddenly trips, the balance between load and power infeed in the Nordic system is disturbed. Immediately after this disturbance, rotating energy of the synchronously rotating machines (both generators and motors) is converted into electrical energy. This leads to a reducing speed of these generators and motors and consequently a decreases frequency in the Nordic system.

Assuming that automatic reserves are not sufficient to stop this trend, frequency would reduce until the imbalance is compensated by the activation of UFLS. If this response is not sufficient, there is a high risk of frequency collapse.

In the existing situation in the Nordic countries, FCR-D attempts to mitigate this frequency drop and stabilize the frequency at steady state.

In order to evaluate the appropriateness of an associated scheme, it becomes necessary to instigate disturbances that are sufficiently onerous that FCR-D is not sufficient to maintain frequency stability and thus activate UFLS. To this end, varying levels of power loss were initiated to assess the UFLS schemes. These losses were of the order of 1800, 2300, 2800, 3300, 3800, 4300, 4800, 5300, 5800, 6300 and 6900 MW with the total loss of production divided into equal three parts, 2nd and 3rd coming 10 and 20 sec after the first one.

The loss of power infeed was separated in stages under the rationale that, should large scale disconnections occur, the likelihood of simultaneous disconnection is remote, thus any form of associated occurrence would occur in a cascaded form, where one disconnection stimulates the next. An example of this is seen in Figure 3 where 6300 MW is disconnected in three 2100 MW blocks at time stamps: 5, 15 and 25s.

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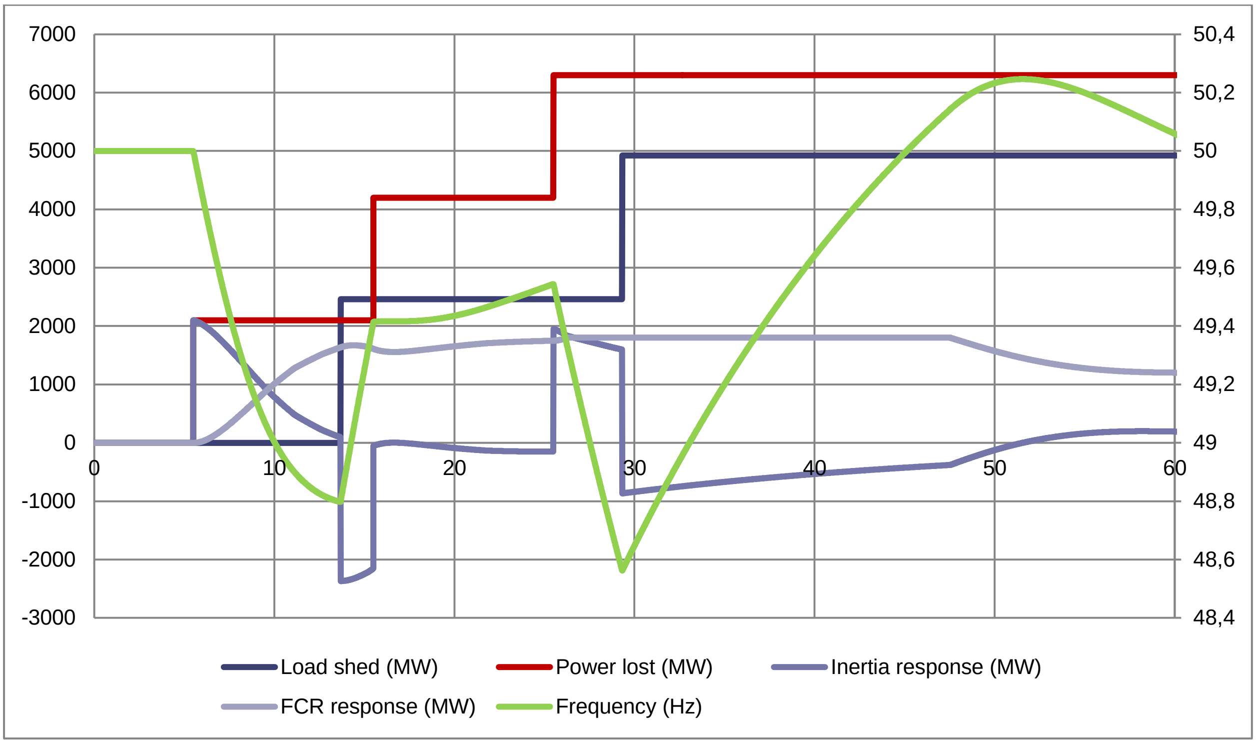
Figure 3 Dynamic response from the loss of 6300 MW disconnected in three 2100 MW blocks at times 5, 15 and 25s



Lumped Parameter Model Modifications and Assumptions

In using the Lumped Parameter (RAR) model for the assessment of the frequency stability element of the screening study; whilst the model and the values have been well proven it is necessary to highlight any specific differences to the model that have been made for completeness. The notable changes or assumptions are:

- A phased disconnection of power infeed as deemed more realistic that in instantaneous common mode failure thus for large scale loss of generation simulations, the disconnection is designed to occur over three equal stages.
- In the initial RAR model, frequency dependence of load was 1%. This study has used the value 0.75% as it equidistant to the values used in sensitivity analysis (the precise value in not known).
- The multi-run component of the model utilizes Samlast market simulation data for year 2025.
- The initial RAR model can be parametrized for 3 different loading/generation levels in the Nordics. The model uses the parameters for load of 30,000 MW (the medium level).
- For a demand of 30,000 MW, inertia is calculated by multiplying the generation by 4 s. This gives the minimum inertia of 90 GWs, average inertia of 170 GWs and maximum inertia of 250 GWs.

Lumped Model Results

In order to provide a clear comparison of each UFLS scheme, key results are presented in the following section. Whilst this information is not exhaustive it provides the pertinent facts that needed to be considered whilst screening for viable schemes. These key aspects are:

- Risk that the scheme will result in under frequency (i.e. less than 48.5 Hz)
- Risk that the scheme will result in over frequency (i.e. higher than 51 Hz)
- Absolute minimum frequency that the scheme reached during the 2860 simulations
- Absolute maximum frequency that the scheme reached during the 2860 simulations
- Average level of load disconnected during the simulations in MW

More detailed information from the simulations can be found in Appendix A.

Table 3 UFLS Cases comparing internationally implemented schemes

Number of simulated cases 2860 for each scheme	A	B	C	D	E	F	G **)	H **)	I **)	J **)	K **)
Risk Index (f<48.5 Hz)	73	0	0	0	73	73	0	0	0	0	0
Risk Index (f>51 Hz)	62	98	9	9	11	12	75	89	0	5	100
fmin, Hz	47.6	48.9	48.6	48.7	48.1	47.1	48.7	48.8	49	48.7	49
fmax, Hz	55.6	57.2	53	51.8	51.9	52.5	52.5	55.5	51	52.2	57
Average LS (MW)	4461	6323	2804	2999	2630	2091	4702	5452	4057	2787	6649

**) Load shedding activates above 49 Hz.

Table 3 Considers the internationally implemented UFLS schemes reviewed in the context of how they would perform when applied to the Nordic Network. The above results assume the levels of FCR in the RAR-model. Table 4 considers the same schemes but with a limited level of FCR contribution to the network (max. 1800 MW[4]).

Of the internationally implemented schemes considered over 2860 simulations, it is clear that there are some schemes that have a significant risk either under frequency, or more commonly, over frequency. Of the schemes that had promising results, there are common themes; the most obvious being that the magnitude of disconnection per stage was not particularly large in the initial stages of disconnection (of the order of 5% per stage).

Schemes C and D had first stage activation at 48.8 and 48.85 Hz respectively which would be realistic levels for this study. I and J had very early level of stage activation (49.5 and 49.2 when adjusted to a 50 Hz network). This level of activation would not be considered realistic within the Nordic network. The schemes with earlier activation do result in a higher level of f_{min} (48.9 and 48.7 Hz), which is expected, though the f_{min} values for schemes C and D are not that much lower than the early activation schemes (48.6 and 48.7 Hz).

The resulting conclusions based on this initial comparison would suggest that the relative size of initial activation should not be more than around 5% of load on the basis that it increases the risk of over frequency. This core principle is reinforced when considering a lower level on frequency support (as seen in Table 4). In this instance schemes C and D also have more pronounced risk of over frequency, though this is measured against the relative point of first stage activation.

[4] This value includes the present obligation volumes of FCR-N and FCR-D specified in the System Operation Agreement of the Nordic TSO's.

Table 4 UFLS Cases comparing internationally implemented schemes with realistic levels of FCR

Number of simulated cases 2860 for each scheme	A	B	C	D	E	F	G **)	H **)	I **)	J **)	K **)
Risk Index (f<48.5 Hz)	91	0	0	0	91	91	0	0	0	0	0
Risk Index (f>51 Hz)	91	98	32	34	47	62	75	90	1	15	100
fmin, Hz	47.5	48.9	48.6	48.7	47.9	46.5	48.7	48.8	48.9	48.7	49
fmax, Hz	*)	*)	*)	53	52.9	54.5	*)	*)	51.6	59.6	*)
Average LS (MW)	6633	7071	3833	3918	3909	3907	4735	5817	4091	3540	7031

*) Frequency in many cases continues to rise to unrealistic values, as no over frequency disconnection of generation was considered.
**) Load shedding activates above 49 Hz.

Graphically the schemes are represented in figure 4. The bracketed 'RAR' suffix can be considered as levels of FCR within the RAR model (optimistic). No suffix denotes levels of FCR consistent with SOA requirements.

Figure 4 Risk of over frequency or under frequency based on international UFLS scheme

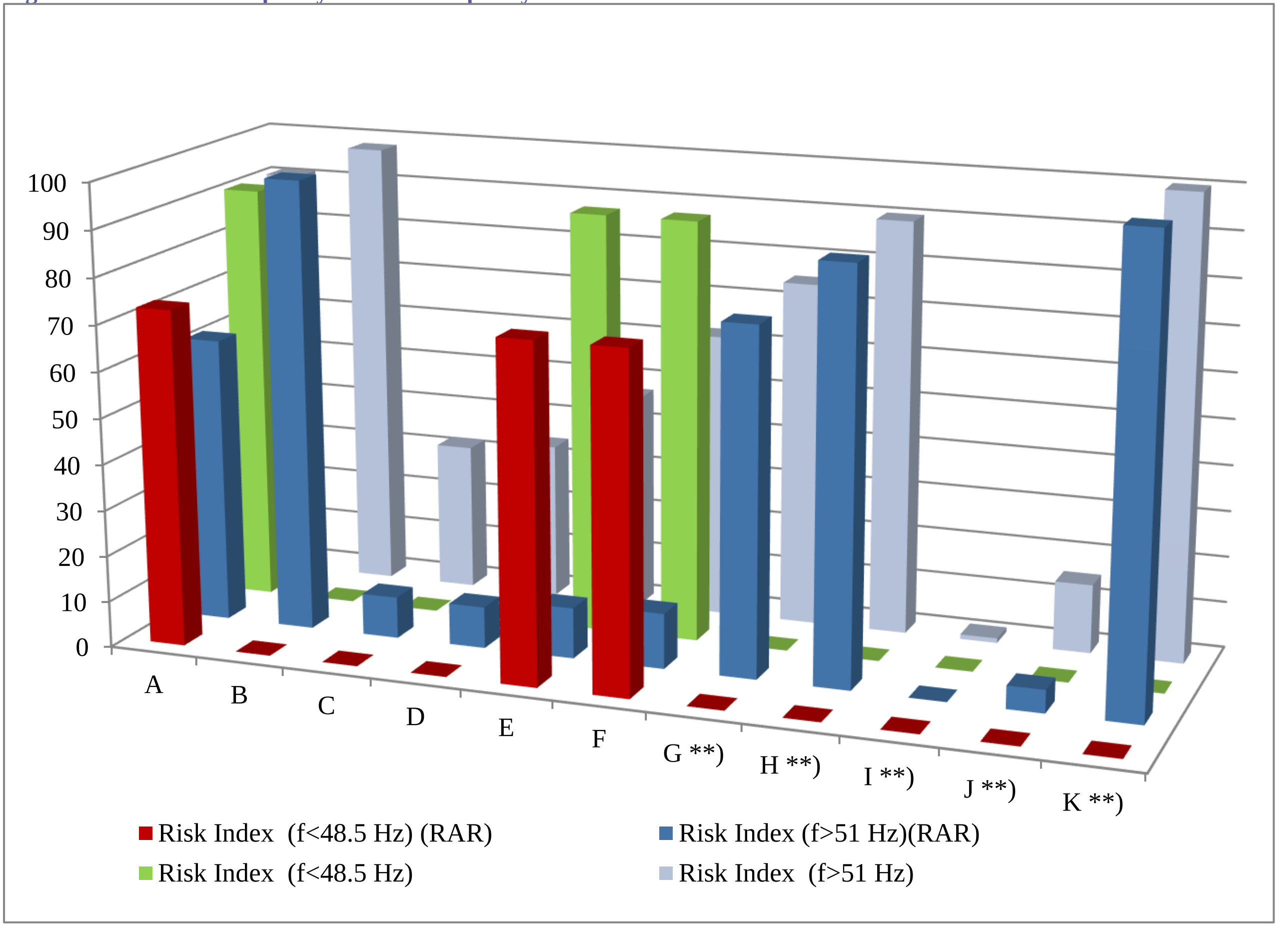


Table 5 presents the simulation results of various schemes considered in other ENTSO-E works (ENTSO-E, 2014) as well as considers the current UFLS scheme prescribed within the SOA. As noted within Chapter 3; there is a difference between the real implemented scheme and the UFLS scheme mandated within the SOA. For completeness both variations are considered within this study.

Table 5 UFLS Cases comparing ENTSO-E proposed schemes

Number of simulated cases 2860 for each scheme	SOA	SOA, "real"	ENTSO-E, Plan 1, 6 stages	ENTSO-E, Plan 2, 4 stages	ENTSO-E, Plan 2, 4 stages, 30%	ENTSO-E, Plan 2, 4 stages, 20%	4 stages 49, 48.8, 48.6, 48.4 Hz (5 % each)	4 stages 48.8, 48.6, 48.4 and 48.2 Hz (5 % each)	4 stages 48.5, 48.3, 48.1 and 47.9 Hz (5 % each)	2 stages 49, 48.8 Hz (5% both)
Risk Index (f<48.5 Hz) (RAR)	32	38	3	0	2	15	0	4	73	3
Risk Index (f>51 Hz) (RAR)	0	0	3	15	7	1	0	0	6	0
fmin, Hz	48.3	48.3	48.4	48.6	48.4	48.3	48.5	48.4	48.1	46.7
fmax, Hz	51.3	50.9	51.5	52.3	51.6	51.2	51	51.1	51.5	51
Average LS (MW)	2142	2882	2407	3183	2744	2302	3371	2496	2044	2641

Table 5 considers the listed ENTSO-E reviewed UFLS schemes in the context of how they would perform when applied to the Nordic Network. The above results consider that levels of FCR are consistent with stated levels within the SOA. As above, Table 6 considers the same schemes, but assumes a more realistic level of FCR contribution to the network (less than 1800 MW[5]).

It is noted that, generally due to inherent characteristics of the Nordics, generally international benchmarked schemes are likely to increase the risk of frequency instability (with the exception of the Western USA) they are discounted from further analysis. It is noted that the 5 stage scheme adopted within the Western States of the United States of America did perform well. Given its characteristics are similar in stage and disconnection level to that of other ENTSO-E plans, this plan is not considered separately.

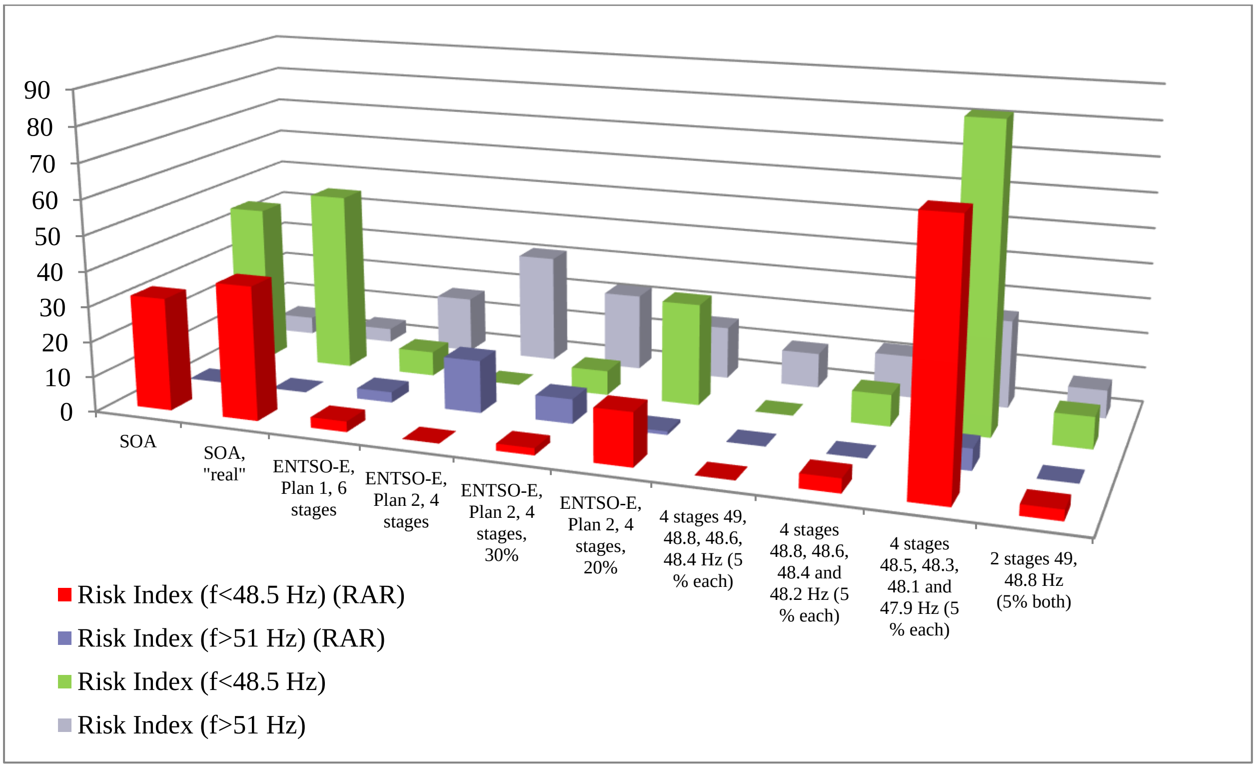
Table 6 UFLS Cases comparing ENTSO-E proposed schemes with FCR limited to mandatory levels of SOA.

Number of simulated cases 2860 for each scheme	SOA	SOA, "real"	ENTSO-E, Plan 1, 6 stages	ENTSO-E, Plan 2, 4 stages	ENTSO-E, Plan 2, 4 stages, 30%	ENTSO-E, Plan 2, 4 stages, 20%	4 stages 49, 48.8, 48.6, 48.4 Hz (5 % each)	4 stages 48.8, 48.6, 48.4 and 48.2 Hz (5 % each)	4 stages 48.5, 48.3, 48.1 and 47.9 Hz (5 % each)	2 stages 49, 48.8 Hz (5% both)
Risk Index (f<48.5 Hz)	45	51	7	0	7	29	0	9	86	9
Risk Index (f>51 Hz)	5	4	16	31	22	15	10	12	25	8
fmin, Hz	48.2	48.2	48.3	48.4	48.3	48.2	48.5	48.3	48.1	42.2
fmax, Hz	51.5	51.4	52.7	53.3	52.9	52.7	51.9	51.9	52.7	51.6
Average LS (MW)	2831	2873	3124	3908	3425	3065	4083	3169	3003	3098

Commentary on the performance of each scheme found in table 5 and 6 is found in the section below.

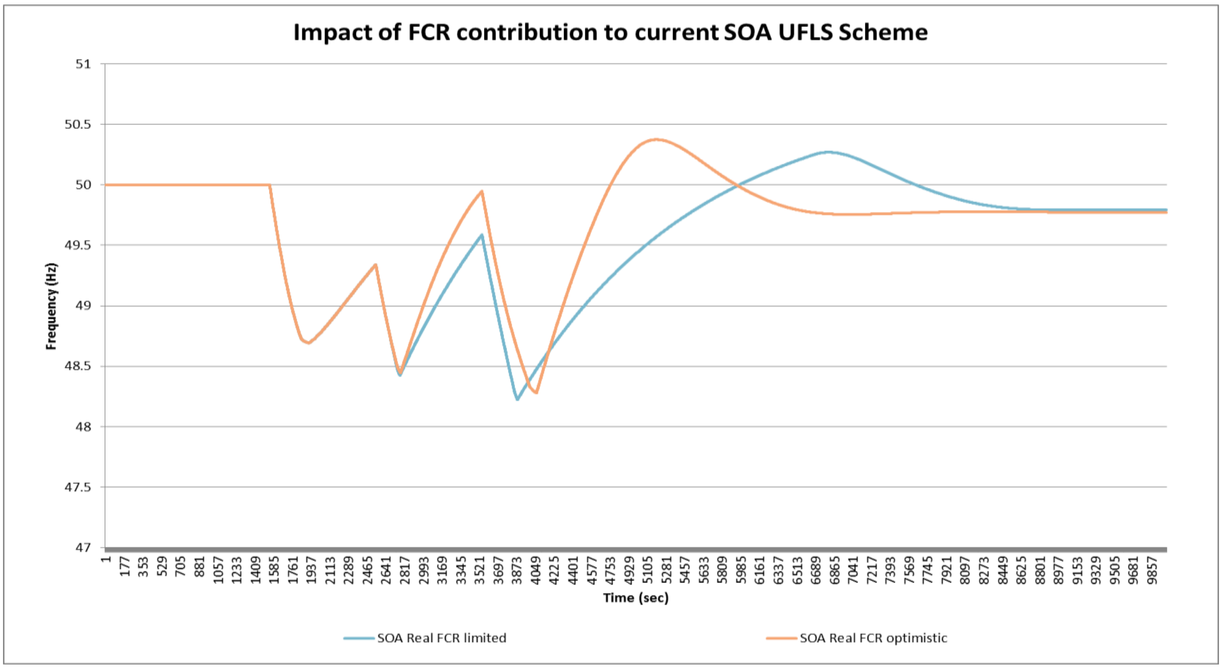
[5] This value has been identified following combined discussions with the all four Nordic TSO's

Figure 5 Percentage risk of over frequency or under frequency based on ENTSO-E UFLS schemes



In Table 5 it is observed that both the UFLS scheme as defined by the SOA and the scheme that is implemented within the Nordics have a reasonable probability of under frequency as a result of UFLS. The associated risk is increased as the level of FCR is decreased as seen in Table 6. This suggests that the scheme does not cut quickly or sufficiently to arrest the loss of system frequency. This is graphically illustrated in figure 5

Figure 6 Impact of FCR Contribution to the SOA frequency performance



In considering Figure 6 further; as can be seen for the currently implemented UFLS, during the initial stages of generation disconnection, the FCR is capable of sustaining frequency stability thus the FCR levels have limited impact. As the level of available FCR reduces in further disconnection stages the schemes performance is not directly comparable as expected. For this reason it becomes necessary to take a pragmatic view on the levels FCR available in the future.

In considering ENTSO-E Plan 1 over 6 stages; it is observed that whilst the risk of frequency instability is low with larger FCR, as the FCR is reduced, the risk of both under and over frequency is increased. It is further noted that the relative level of over frequency reached for this scheme under realistic FCR reserves is around 52.7 Hz. Whilst this is not the highest level reached within the respective schemes, it is still relatively high and any Over Frequency Control (OFC) scheme considered would have to be implemented with such levels considered in order to minimise the risk of UFLS stimulating OFC and vice versa until total loss of network stability is a realistic possibility.

ENTSO-E Plan 2 (over 4 stages) provides similar characteristics to that of Plan 1. The relative risk of over frequency is higher and the level of over frequency is a notable concern (53.3 Hz). It is very likely any OFC scheme implemented would have been activated at such levels. The likely reason for such levels of high frequency is the relative quantity of load shed over the 4 stages; whilst stage 1 of the scheme cuts 5% of load, further stages are considerably higher (9, 11 & 15). This magnitude of disconnection is likely to instigate the high frequency characteristics which results in a total of 3908 MW shed in total. This is the second highest loss of load of any of the schemes considered.

In the further iterations of ENTSO-E Plan 2 considered, three variations of the scheme were tested. The net reductions in load by the schemes were 20%, 30% and 40% respectively. The first stage activation of the schemes was at 49 Hz. It is noted that whilst the risk of under frequency is marginally increased, the risk of over frequency is decreased as total shed load is reduced. Needless to say, as the level of FCR is reduced to realistic levels, the risk of both over and under frequency is marginally increased.

Based on the principle that a 4 stage scheme that has a lower level of total disconnection would appear to produce more advantageous results, 3 additional variations of this scheme were considered. The main difference in the schemes is the point of first stage activation; one at 49 Hz, one at 48.4 Hz and one at 48.5 Hz. Of the three schemes, the first (activated at 49 Hz) had the lowest overall risk of over and under frequency however it disconnects nearly 900 MW in load more in order to achieve this. The primary reason for this is that, with the activation stage at 49 Hz, the scheme cuts early. This doesn’t seem to provide a significant difference in risk when compared to the scheme with first stage activation at 48.8 Hz and 3169 MW total disconnected (Realistic FCR). The scheme with first stage activation at 48.5 Hz has a far higher risk of under and over frequency; this suggests that cutting this late does not present a realistic option.

It is observed in Figure 7 that in reality, one of the largest contributing factors to the risk of frequency deviation is the effective level of FCR available. As FCR decreases the level of frequency deviation inevitably increases. For this reason any identified options have to be evaluated against this rationale, and projected FCR levels. For completeness, the subsequent section on transmission capacity also considers realistic and mandated levels of FCR.

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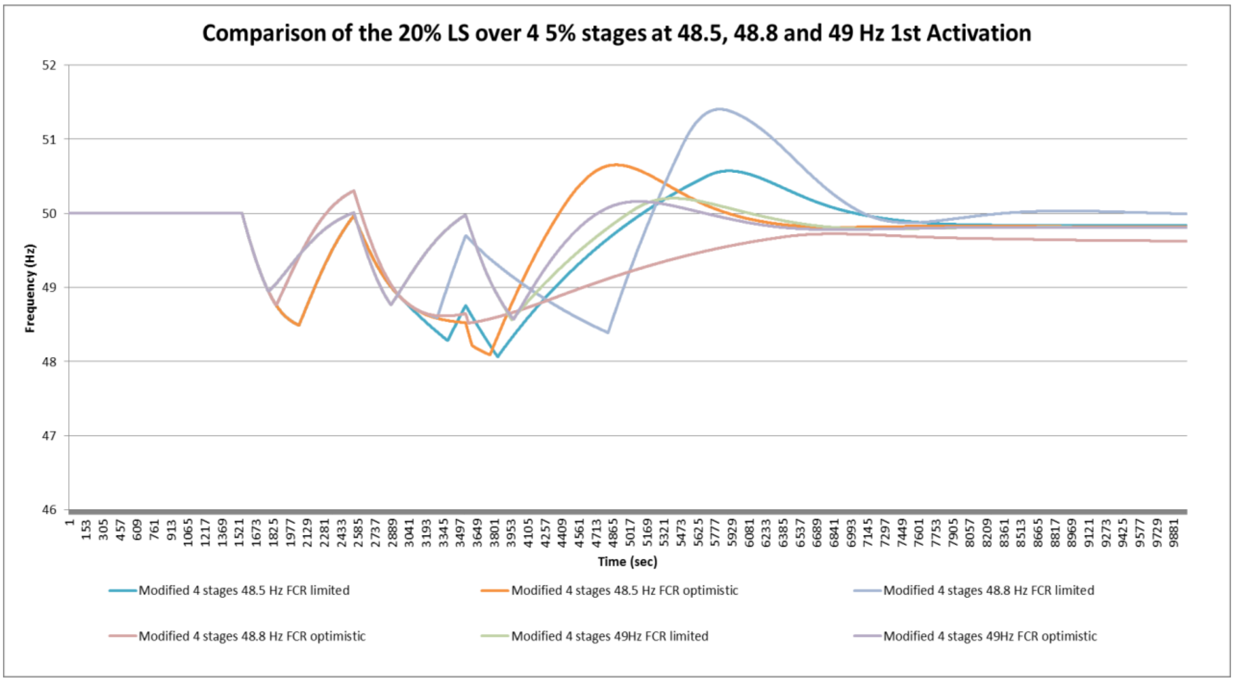
Figure 7 Impact of FCR Contribution to 4 Stage 5% UFLS Schemes frequency performance



Key points derived from the initial screening process can be considered:

- **Schemes that cut in too large increments (more than 5%) have an increased risk of over frequency.**
- **There has to be a balanced approach to first stage activation; too early and the level of total disconnection is high, too late and the risk of frequency instability is increased significantly.**
- **Schemes that have a high level of total disconnection generally seem to have an increased risk of frequency instability.**
- **The level of FCR has a significant impact of frequency deviation.**

5. Screening of Schemes - Transmission Capacity

Overview

A key facet of understanding whether a UFLS scheme is suitable for the network in which it operates is ensuring that, during its activation, the resulting power flows do not exceed the thermal or stability limits of the transmission assets. This could include cables, transformers and overhead lines, or in case of stability issues even a transmission corridor consisting of several parallel AC power lines. In order to assess this, the transmission capacity of the network is modelled. This has been done in the past in a modular format; where zones have been represented, and the total transmission capacity of all interconnections between one zone to the next summated into single value (ENTSO-E, 2014). That approach limits the findings of the screening to a high level view and does not identify individual line loading levels that may be excessive.

In order to assess the impact of UFLS on transmission capacity at a higher level of understanding, network models were developed that considered the intact Nordic transmission network. This is a higher level of resolution than adopted in previous works and builds on the initial findings of the lumped parameter model utilised in the previous chapter.

The 2016 intact network was used as the basis of the model. Based on existing network data held within the TSO's (such as hydrological and zonal trading data), a power system model of the network was developed to reflect the Nordic network and realistic power flows. This stage of the study has not considered the long term development horizon and as a result only current network characteristics are used to identify potentially viable schemes.

Dynamic simulations have been performed for each analysed load shedding scheme, and for each listed scenario that leads to large loss of production (or HVDC import). The assessment is considered in unison with the works seen in chapter 5, and is used to identify an overall value for the risk of blackout (per scheme) as seen in Figure 2.

Methodology

The model developed in PSSE power system software is a collaboratively built network model reflecting the TSO's best understanding of transmission network and its operation.

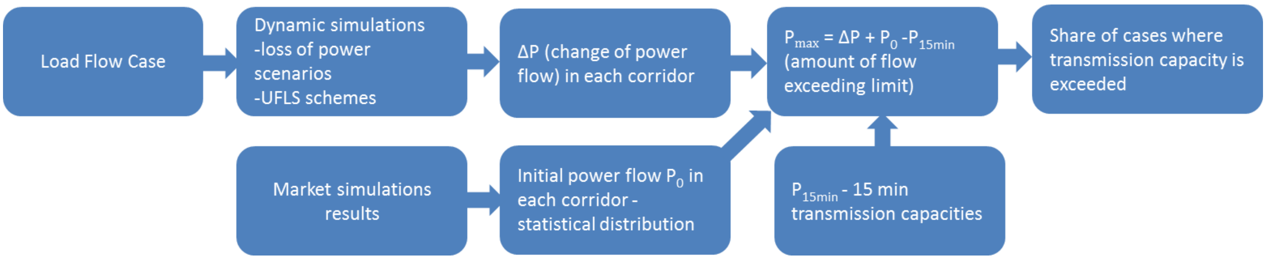
Once initial conditions are set, an event is instigated in the network model simulating a loss of power infeed. Relays are placed on appropriate bus bars around the network configured to the scheme UFLS settings. Once the event is triggered and the necessary load shedding has occurred based on the dynamic response of the network the associated peak line and corridor loading levels are recorded.

Intial conditions of the power system model are partially derived from the Samlast market data in order to provide a more realistic view of the real network power flows prior to an event occurring. The corridor transfer levels are then compared to the 15 minute maximum transmission capacities. If the flow is seen to exceed the 15 minute transmission capacity value in a corridor then the simulation indicates a violation of transmission capacity limits, with the total number of violations per simulation recorded.

Each scenario of outage is considered against the identified load shedding schemes. As a result, the number of violations for each scheme, under each scenario is identified and recorded. This process is graphically represented in Figure 8 below.

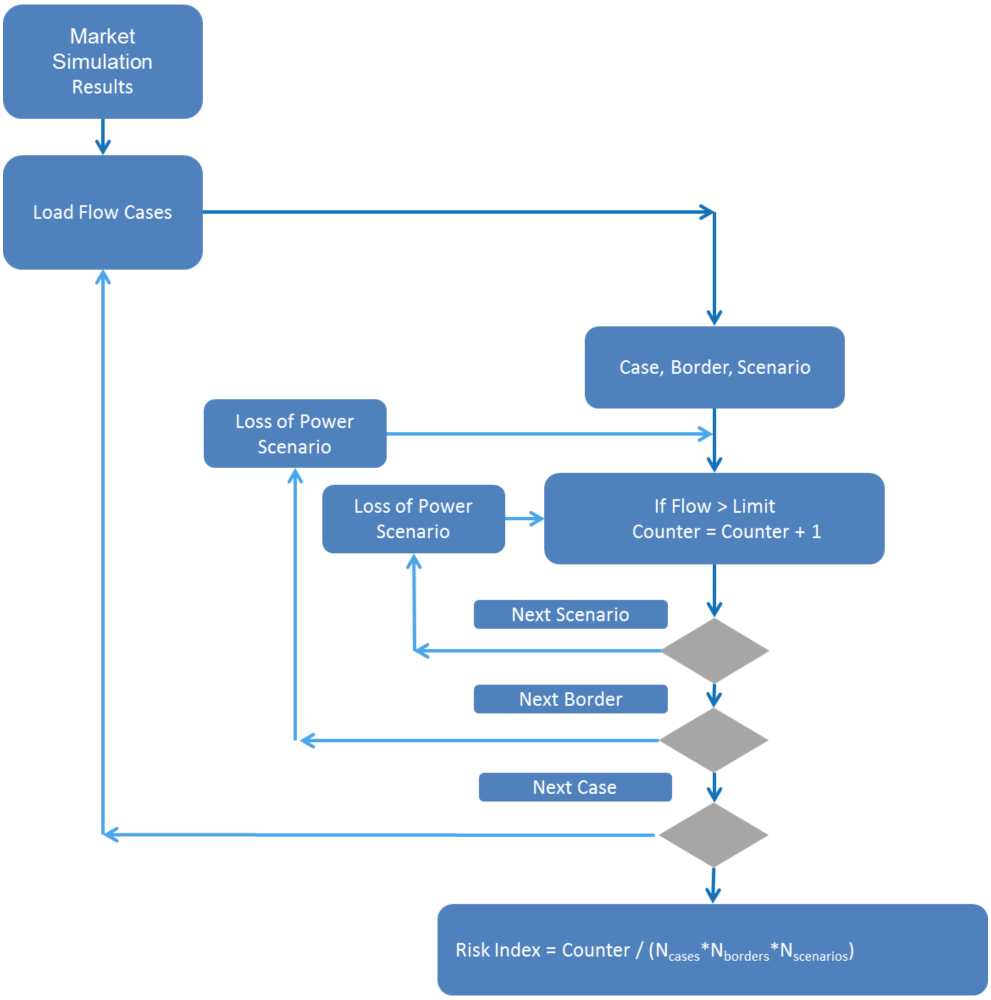
For each simulation the maximum changes of power flow between bidding zones has been recorded. For completeness, the highest instantaneous values of power flow are recorded during the dynamic simulation including FCR responses, frequency and voltage dependence of loads and activation of load shedding schemes).

Figure 8 the basic concept of PSS/E screening



Having identified the relative levels of transmission capacity violation created for each UFLS scheme under varying loss of infeed scenarios, it becomes necessary to then evaluate the scheme as a whole, taking into account its performance under these study scenarios. Figure 9 illustrates the logic of the algorithm utilised for processing the PSSE simulation results into a usable format for evaluation of multiple scenarios and characteristics to identify the UFLS schemes risk of causing instability as a result of significant violation of transmission line thermal capacity.

Figure 9 Evaluating the risk of transmission capacity violation



Modelling Assumptions

It is necessary to identify key assumptions that inform the basis of the PSSE model utilised in the screening process. For simplicity the assumptions are separated in two sections:

- PSSE model specific assumptions that define the mode of operation within PSSE.
- Assumptions that identify the philosophy under which the model was developed.

The assumptions pertaining to the PSSE modelling are found in Appendix B as, whilst important can be considered separately to the body of the report. In the following section, commentary is provided on key aspects that define the principles under which the network model was devised.

Market Modelling

As was discussed in the methodology for this section; transmission capacities are used in conjunction with market simulations to define realistic initial flows around the network prior to loss of infeed / outage. It is been noted that transmission capacities used in the market simulations (Samlast) differ marginally from the present values that are implemented in existing PSSE model in order to accommodate future transmission reinforcement. The study has assumed a constant overload capability of 50% higher than the values used within the Samlast market simulation data. This is in order to capture the reality that values utilised within Samlast are market capacities that consider N-1 reliability margin. It is deemed that this will not have a material impact on the study in this phase of screening but is more applicable in the detailed studies phase of the works.

Generation / Interconnector Modelling

The developed model considers the dynamic behaviour of the Nordic system. As a result it is necessary to represent the varying generating or interconnecting technologies within the system.

Conventional generating plants inter alia, the production from the synchronous generators including thermal, nuclear and hydro power is considered within the model. These to the extent possible, model the dynamic/transient behaviour of the varying units based on the data available. For clarity this generally takes the form of each single generator being connected to the high voltage busbar through generator transformer. Governor and Excitation systems for each generator are modelled based on data available to the TSO's.

Reactive Compensation and Ancillary Services (FCR)

In respect to reactive compensation and associated frequency support provisions:

- Model of MVAr and power factor compensation systems associated with any industrial or commercial customers at transmission level. For clarity this includes reactive compensation found on LV tertiary windings of 400/110/21 kV transformers.
- Ancillary services for frequency support are modelled in accordance with current procurement and regulatory directives.
- FCR levels have been modelled as the previous chapter; the presently realistic levels defined within the RAR-model and a more limited level of FCR based on mandatory volumes stated in the SOA of the TSO's.

During the process of modelling the current network performance characteristics it was identified that a large proportion of Hydro based FCR within Sweden has multiple governor settings to account for differing ancillary market deliverables. This allows the hydro governors to respond to differing levels of frequency deviation. These settings have been modelled in order to provide a realistic view on FCR contribution under frequency deviation. Further details on how this is considered are found in Appendix B.

Relay Activation Time

For all UFLS schemes identified within this body of work there is an assumed 150mS activation time. This accounts for relay sensor activation and break time.

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Data Recorded

In order to provide a clear comparison of each UFLS scheme, key results are presented in the following section. Whilst this information is not exhaustive, it provides the pertinent facts that need to be considered whilst evaluating the schemes. These key aspects are:

- Risk index that the scheme will result in under frequency (i.e. less than 48.5 Hz)
- Risk index that the scheme will result in over frequency (i.e. higher than 51 Hz)
- Risk index that the scheme will result in 120% overload violations
- Risk index that the scheme will result in 150% overload violations
- Risk index that the scheme will result in 200% overload violations
- Average level of load disconnected during the simulations in MW

Each scheme is simulated with high load, low load, and with moderate and low inertia levels.

Cases Evaluated

It is necessary to evaluate any potential scheme under multiple scenarios or cases in order that the schemes are evaluated against current network characteristics and potential future network modes of operation. In order to provide this; three different cases are considered. For simplicity during the screening elements of this work, the 2025 intact network model is utilised. This considers all future declared and approved capital expenditure on all respective country's networks. In order that most eventualities are considered the three base cases are:

- High load assumes network maximum demand based on current projections (winter maximum)
- Low load, intermediate inertia assumes that a reasonable amount of conventional generation and nuclear generation has been taken offline resulting in a network inertia of approximately 160 GWs
- Low load, low inertia assumes that a considerable amount of conventional generation is not in service as a result of low spot pricing. This results in a relative inertia of 120GWs for the Nordic network.

More specific details on production levels and national loads are documented in Table 7 below.

Table 7 Cases considered in screening studies

Year 2025	DK2 prod [MW]	FI prod [MW]	NO prod [MW]	SE prod [MW]	DK2 load [MW]	FI load [MW]	NO load [MW]	SE load [MW]	Σ prod. [MW]	Σ load [MW]	Σ inertia [GWs]
High load	1271	10840	26747	27969	1830	13812	22271	25806	66827	63719	354
Low load modified, "intermediate" inertia	190	5790	14107	16527	1413	6562	11719	12044	36614	31738	161
Low load modified, low inertia	190	6342	11669	14236	1413	6562	11719	12043	32437	31737	120

Schemes Considered

Given the data provided from the initial screening identified certain characteristics, the schemes considered generally adhere to the following basic principles:

- Schemes that cut in too large increments (significantly more than 5%) have an increased risk of over frequency.
- There has to be a balanced approach to first stage activation; too early and the level of total disconnection is high, too late and the risk of frequency instability is increased significantly.
- Schemes that have a high level of total disconnection generally seem to have an increased risk of frequency instability.

It is noted that there some cases which contradict these principles in respect to incremental disconnection. This is necessary in order to provide a degree of sensitivity analysis. The schemes reviewed as part of this screening phase are itemised in the Table 8 below.

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Table 8 Screened UFLS Schemes

Scheme	Fast Threshold		Frequency of activating threshold / % of load shed per threshold						
2 stages 49, 48.8 Hz (10% each)	n = 2		48.8	48.6	-	-	-	-	Total
			10	10	-	-	-	-	20
2 stages 49, 48.8 Hz (5% both)	n = 2		48.8	48.6	-	-	-	-	
			5	5	-	-	-	-	10
4 stages 48.8, 48.6, 48.4 and 48.2 Hz (5 % each)	n = 4		48.8	48.6	48.4	48.2	-	-	
			5	5	5	5	5	-	20
4 stages 48.8, 48.6, 48.4 and 48.2 Hz (7.5 % each)	n =4		48.8	48.6	48.4	48.2	-	-	
			7.5	7.5	7.5	7.5	-	-	30
4 stages 49.0, 48.8, 48.6 and 48.4Hz (5 % each)	n =4		49	48.8	48.6	48.4	-	-	
			5	5	5	5	-	-	20
4 stages 49.0, 48.8, 48.6 and 48.4Hz (7.5 % each)	n = 4		49	48.8	48.6	48.4	-	-	
			7.5	7.5	7.5	7.5	-	-	30
ENTSO-E plan 1, 6 stages (40% Total)	n = 6		49	48.8	48.6	48.4	48.2	48	
			2	4	6	8	10	10	40
ENTSO-E plan 2, 4 stages (40% Total)	n = 4		49	48.7	48.4	48.2	-	-	
			5	9	11	15	-	-	40
ENTSO-E plan 2, 4 stages (20% Total)	n =4		49	48.7	48.4	48.2	-	-	
			3.75	6.75	8.25	11.25	-	-	20
ENTSO-E plan 2, 4 stages (30%total)	n =4		49	48.7	48.4	48.2	-	-	
			2.5	4.5	5.5	7.5	-	-	30
SOA	n = 5	Denmark	48.5	48.3	48.1	47.9	47.7	-	
			10	10	10	10	10	-	50
	n = 5	Sweden	48.8	48.6	48.4	48.2	48	-	
			6	6	6	6	6	-	30
	n = 2	Finland	48.5	48.3	-	-	-	-	
			10	10				-	20
	n = 5	Norway	48.6	48.2	47.8	47.4	47	-	
			6	6	6	6	6	-	30
SOA "Real"	n = 5	Denmark	48.5	48.3	48.1	47.9	47.7	-	
			10	10	10	10	10	-	50
	n = 5	Sweden	48.8	48.6	48.4	48.2	48	-	
			4	4	4	4	4	-	20
	n = 2	Finland	48.5	48.3	-	-	-	-	
			7	5				-	12
	n = 10	Norway	48.7	48.5	48.3	48.1	>>	47.7	
			2	7	7	11	>>	3	38

Events Considered

In order that a comprehensive view of the risk of breaching transmission capacity limits is adequately characterised 11 differing events have been utilised to evaluate each base case. These events are consistent with the loss of infeed simulations found in chapter 5. Given they offer significant meaningful value to the reader; they are included in the detailed studies addendum that supports this report.

Transmission Capacity Results

As a result of the 3 base cases used in the evaluation of transmission capacity limits, the 12 schemes considered and the 11 outage event scenarios, just under 400 simulations were performed to provide a view on the total number of associated capacity violations.

As seen in the previous section; in order that these violations can be graded in respect to severity there are three associated levels:

- Risk index that the scheme will result in 120% overload violations
- Risk index that the scheme will result in 150% overload violations
- Risk index that the scheme will result in 200% overload violations

Generally thermal overload of circuits is an operational risk and may be used safely for short periods in order to maintain security of supply. The scaled level of overload violation enables a more detailed assessment as to the severity of the overload and whether this can be considered operationally acceptable.

The below tables highlight the associated risk of transmission capacity violation for the high, low and low inertia base cases.

Table 9 Risk of transmission capacity violation based on the above identified UFLS scheme whilst operating in high load case inertia ~350 GWs

Load shedding scheme	2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz ->), 5 % each	4 stages (48.8 Hz ->), 7.5 % each	4 stages (49 Hz ->), 5 % each	4 stages (49 Hz ->), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
Cases <48.5 Hz (out of 13)	0	0	0	0	0	0	0	0	0	0	0	2
Cases >51.0 Hz (out of 13)	5	0	0	0	0	0	0	1	0	0	0	0
fmin, Hz	48.7	48.6	48.6	48.7	48.8	48.9	48.6	48.7	48.7	48.7	48.5	48.4
fmax, Hz	51.4	50.4	50.4	50.9	50.5	51.0	50.6	51.3	50.4	50.5	50.0	50.1
P(TC violated 120%), %	8.0	7.3	7.3	7.6	7.2	7.5	7.2	7.4	7.1	7.1	7.4	7.3
P(TC violated 150%), %	4.7	4.2	4.2	4.4	4.1	4.3	4.1	4.2	4.1	4.1	4.2	4.1
P(TC violated 200%), %	2.4	2.2	2.2	2.3	2.1	2.2	2.1	2.1	2.1	2.1	2.2	2.1
Failed cases (out of 10)	0	0	0	0	0	0	0	0	0	0	0	0

Considering the results presented in tables 9, 10 and 11, several aspects become clear. The primary being that with sufficient inertia, there is less likelihood of a perturbation instigating an event that would cause thermal loadings to severe overload limits across the wider network.

With higher levels of inertia, there is inherently more generation to meet demand, thus higher loading of circuits transmitting power to load centres. For this reason; during events that instigate any form of frequency fluctuation on a larger network, there is a proportional risk of reaching line thermal limits. This is supported by table 9, where levels of thermal overload violations of 120, 150 and 200% are seen to be higher than table 10, where the lower levels of demand reduce pressure on thermal limits.

Table 10 Risk of transmission capacity violation based on the above identified UFLS scheme whilst operating in low load case inertia ~160 GWs

Load shedding scheme	2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz ->), 5 % each	4 stages (48.8 Hz ->), 7.5 % each	4 stages (49 Hz ->), 5 % each	4 stages (49 Hz ->), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
f<48.5 Hz (out of 10)	0	1	1	2	0	0	1	0	2	1	2	3
f>51 Hz Hz (out of 10)	2	0	0	1	0	1	0	0	0	0	1	0
fmin, Hz	48.5	48.3	48.3	48.2	48.5	48.7	48.4	48.5	48.4	48.5	48.3	48.2
fmax, Hz	52.3	50.6	50.6	51.4	50.6	51.7	50.6	50.6	50.8	50.6	51.6	50.6
P(TC violated 120%), %	7.7	7.0	7.0	7.8	7.0	7.7	7.0	7.2	7.7	7.0	7.6	7.7
P(TC violated 150%), %	4.0	3.7	3.7	4.1	3.7	4.0	3.7	3.8	4.0	3.7	4.0	4.0
P(TC violated 200%), %	1.9	1.7	1.7	1.8	1.7	1.9	1.7	1.7	1.8	1.7	1.8	1.9
failed cases (out of 10)	2	3	3	2	3	2	3	3	2	3	2	2

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A noticeable difference between the results presented in table 10 and table 11 is the increase in transmission capacity violations across all schemes when load (and associated generation inertia) is reduced. This would suggest that the reduction in the level of inertia level results in a reduction of power system stability around the network in increased; causing short term transient violation of thermal limits.

Whilst this aspect is utilised as a mechanism for screening of potential UFLS schemes it does raise a secondary issue to consider, in that, should inertia levels be reduced to this extent, it may be necessary to take a coordinated approach to the deployment of system protection in order to ensure that activations do not contribute further to system instability.

Table 11 Risk of transmission capacity violation based on the above identified UFLS scheme whilst operating in low load case with low inertia ~120 GWs

Load shedding scheme	2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz ->), 5 % each	4 stages (48.8 Hz ->), 7.5 % each	4 stages (49 Hz ->), 5 % each	4 stages (49 Hz ->), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
f<48.5 Hz (out of 10)	3	3	2	2	0	0	2	3	1	3	3	5
f>51 Hz Hz (out of 10)	3	0	0	1	0	0	0	1	0	1	0	0
fmin, Hz	47.9	48.1	48.3	48.3	48.5	48.8	47.5	47.8	48.3	48.3	47.6	47.6
fmax, Hz	51.9	50.5	50.8	51.3	50.7	50.9	50.9	51.0	50.4	51.1	50.9	50.8
P(TC violated 120%), %	10.1	10.1	8.5	9.6	7.9	7.7	8.5	10.4	8.6	9.6	9.4	9.7
P(TC violated 150%), %	5.6	5.5	4.6	5.3	4.5	4.5	4.6	5.7	4.7	5.2	5.2	5.4
P(TC violated 200%), %	2.5	2.6	2.1	2.5	2.0	2.0	2.1	2.5	2.1	2.3	2.3	2.4
failed cases (out of 10)	1	2	2	2	3	4	2	2	3	1	1	1

Scheme Commentary

1. Two Stages, 10% per Stage

For the two stage, 10 % per stage (scheme 1); even at high load, high inertia levels as seen in table 8, five of the 13 simulations considered reached frequencies in excess of 51 Hz rendering the scheme unfeasible in its current topology. Low load, low inertia cases which were equally unfeasible and recorded very high and very low frequency divergence from nominal.

2. Two Stages, 5% per Stage

The scheme behaves reasonably, in that it does not diverge significantly over the scenarios investigated. It is noted that there were 3 out of 10 occasions when frequency dropped below 48.5, reaching 48.1 Hz which whilst being technically acceptable from a network stability view, would be considered sub optimal when compared against other schemes. In these cases further disconnection stages are deemed advantageous.

3. Four Stages (48.8 Hz>), 5% per Stage

Much like scheme 2, generally the scheme is technically acceptable in that it fulfils its primary function or retaining network stability and frequency stability. Likewise the scheme does not record high levels of frequency deviation in regular occurrence.

4. Four Stages (48.8 Hz >), 7.5% per Stage

Scheme 4, much like the others presented performs reasonably in the wider context. An area of concern would be the impact of the 7.5% disconnection stages which, when considering lower inertia cases, has high swings in over frequency as a result.

5. Four Stages (49 Hz>), 5% per Stage

Scheme 5 generally performs adequately; the main issue in this scheme surrounds the initial activation level, which is unrealistically aggressive to curtail frequency deviation (49 Hz). It seems that the relative characteristics of the network will always result in a frequency that deviates to around a minimum of 48.8 Hz under adverse circumstance, thus a stage at 49 Hz, whilst contributing to restoration of frequency seems to instigate a level of disconnection that has limited real impact on the final resulting deviation.

6. Four Stages (49 Hz >), 7.5% per Stage

Much Like scheme 4, the 7.5% staged disconnection seen in scheme 6 results in an increased level of over frequency. This is prominent in the average inertia, low load case (table 10). It is likely values of over frequency were equally high in the low inertia case (table 11) but with the high level of failed cases it is difficult to conclusively state this.

7. Entso-e Plan 1, 6 Stages

Whilst generally the UFLS schemes seem to operate reasonably; under the scenarios seen in tables 9 and 10, the lowest frequency reached by the scheme was 47.5 Hz. Under these circumstances, it is probable that generation units may begin to actively disconnect which would exasperate the issue further. For this reason this scheme cannot be considered suitable. This is somewhat irregular when considering the relative depth of cut (40%) that would have occurred at that point.

8. Entso-e Plan 2, 4 Stages (40% disconnection)

Whilst the scheme results indicate that as inertia and load is reduced, the level of frequency divergence from nominal is increased. This is somewhat surprising, in that the relative level of cut reached by the lowest recorded frequency (47.8 Hz) would have disconnected 40% of total load, which is considerable. Likewise, as seen in Table 9 the level of over frequency reaches very high levels also, which for such high inertia, is unexpected.

It is noted that the level of violations for the lowest inertia case is higher than any other; this is symptomatic of the degree of instability within the network as a result. It is likely that as a result of lower inertia levels, frequency swings will register faster rates of change resulting in angular instability.

9. Entso-e Plan 2, 4 Stages (20% total disconnection beginning at 49 Hz)Considering Entso-e Plan 2, 4 Stages with a 20% total disconnection results are very similar at high load levels. This is not unexpected as the impact of inertia has been seen to promote power system stability. Comparing this to scheme 5 where there are distinct similarities in performance and scheme structure. Much like scheme 5; the initial stage of disconnection results in an associated loss of load without significant benefit.

10. Entso-e Plan 2, 4 Stages (30% disconnection)

When comparing the varying connotations of Entso-e Plan 2, 4 Stages (i.e. 20, 30 and 40% disconnection); of the three it can be seen that given the three schemes, as the inertia of the network reduces, the best performing scheme is that with the least forced disconnection (20%). This scheme records the least violations across all levels with lower inertia. Interestingly, this is not the case of the high inertia case, in which it's the worst performing scheme. For this reason it becomes critical that a balance between what is appropriate under current and future network topologies is made and that a view is taken considering dynamic stability, transmission capacity, and ultimately, the long term functionality of the network.

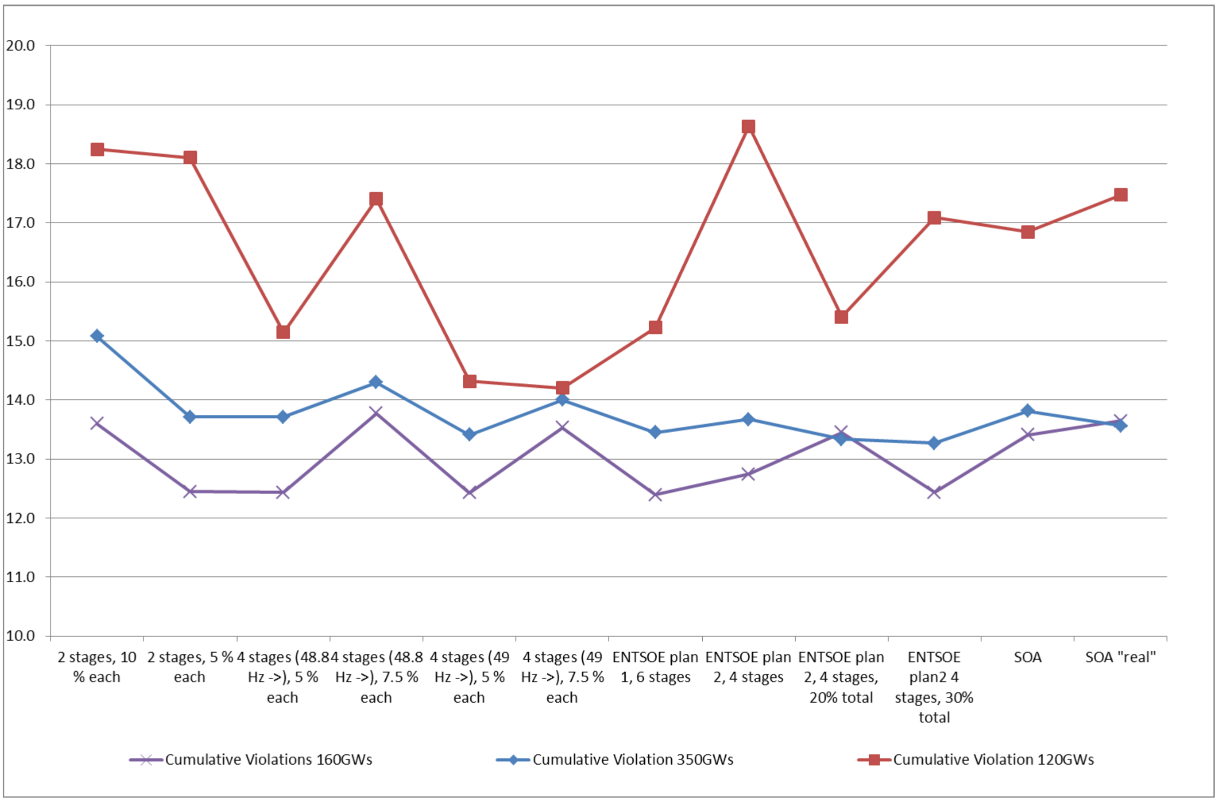
Scheme Summary

Whilst each scheme is considered in greater depth below it can be seen that when comparing the relative levels of transmission capacity violations in cases with moderate to high inertia, the variation between one scheme to the next does not seem to have a significant impact on the results.

When inertia is reduced further to 120 GWs one noticeable outcome does become more prominent. As seen in Figure 10, schemes with either fewer stages or more significant disconnection per stage seem to instigate higher levels of violation. Looking more deeply into this specifically, it can be seen that this is heavily biased toward the 120% violation criteria, thus is of lesser concern. Ultimately logic would dictate that the fewer the stages, or the larger the disconnection, the higher the likelihood of increased transient instability, at least in the short term while flows stabilise to normal levels. Fewer stages (i.e. two stages) would increase risk of instability as, having activated both stages, there would be no remedial mechanism to restore frequency. Larger disconnection stages risk excessive frequency fluctuation, particularly in low inertia networks.

Figure 10 identifies the cumulative number of violations of the transmission capacity (for all overloading levels) in a summated value.

Figure 10 Cumulative violations of each UFLS scheme considered against the operational scenario



6. Combined Screening Results

Risk of Blackout

The findings of the previous two sections are summated to create a total risk of black out per scheme. In order that the context in which these results is understood, it is necessary to highlight the salient issues that form the basis of the study.

It should be reiterated for clarity that the values presented are simulated against the occurrence of a significant loss of power infeed in order that UFLS is activated. The results identify under these circumstances, which scheme has the lowest risk of creating frequency and dynamic instability within the network, should this severe loss of infeed occur.

Based on the results presented, the best candidate schemes move forward to the more comprehensive testing seen in subsequent sections.

Frequency Stability using the RAR model

As previously discussed in chapter 5, notable assumptions in using the RAR model have been:

- A phased disconnection of generation as deemed more realistic that in instantaneous common mode failure thus for large scale loss of generation simulations, the disconnection is designed to occur over three equal stages.
- This study has used the value 0.75% for the frequency dependence of load.
- The multi-run component of the model utilizes Samlast market simulation data for year 2025.
- The initial RAR model uses the parameters for load of 30 000 MW (the medium level).
- In the model the inertia is calculated by multiplying the generation by 4s. This gives the minimum inertia of 90 GWs, average inertia of 170 GWs and maximum inertia of 250 GWs.
- The total loss of production has been divided into equal three parts, 2nd and 3rd coming 10 and 20 sec after the first one.
- Power loss of 1800, 2300, 2800, 3300, 3800, 4300, 4800, 5300, 5800, 6300 and 6900 MWhave bee presented.

Transmission Capacity Assessment

As discussed in chapter 6, there were three cases considered within the screening studies:

- High load assumes network maximum demand based on current projections (winter maximum)
- Low load, intermediate inertia assumes that a reasonable amount of conventional generation and nuclear generation has been taken offline resulting in a network inertia of approximately 160 GWs.
- Low load, low inertia assumes that a considerable amount of conventional generation is not in service as a result of low spot pricing. This results in an inertia of 120 GWs for the Nordic network.

In order that an accurate assessment of transmission capacity violations was undertaken, three categories of violations were recorded:

- Risk index that the scheme will result in 120% overload violations
- Risk index that the scheme will result in 150% overload violations
- Risk index that the scheme will result in 200% overload violations

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Calculation of Total Risk of Blackout

In order that an appropriate understanding of how the statistics presented were formulated an enriched description of this process is seen below.

- Each load shedding scheme S_k is simulated in N different Nordic load/production levels ($L_1 \dots L_N$) where the risk of losing frequency stability:

$$R_1(S_k) = R_{1,k} \tag{1}$$

- Each load shedding scheme S_k is simulated in R load flow cases ($C_1 \dots C_R$) where the risk of exceeding transmission capacity:

$$R_2(S_k) = R_{2,k} \tag{2}$$

- The risk of frequency instability $P_3(S_k)= R_{2,k}$ is calculated for each load shedding scheme, where:

$$R_3(S_k) = R_1(S_k) + R_2(S_k) - R_1(S_k)*R_2(S_k) \tag{3}$$

As a result, the load shedding scheme S_k results in the lowest risk of black-out, $R_{3,k}$, and is considered the most viable.

In order to account for a degree of uncertainty as to the overall level of FCR available; $R_3(S_k)$ for each scheme is presented as two values:

- One in which the levels of FCR are as declared within the RAR model.
- One where the level of FCR is limited to the contractual limits of the SOA.

It should be noted that the variation in FCR is only considered within the frequency stability element for screening purposes.

So that the value of risk of exceeding transmission capacity per scheme is developed in a way that considers all three values of transmission capacity violation, $R_2(S_k)$ is calculated using the summated value of each form of violation per case per scheme. For example the risk of exceeding transmission capacity limits for the '2 stages, 10 % each' scheme in the high load case is the $R_{120\%} + R_{150\%} + R_{200\%}$. This would be R_{Tot} as seen in Table 12.

Table 12 Risk of transmissions capacity violation under the high load case for the 2 stage, 10% load disconnection per stage UFLS Scheme

Load shedding scheme	2 stages, 10 % each
$R_{120\%}$	8.0
$R_{150\%}$	4.7
$R_{200\%}$	2.4
R_{Tot}	15.1

For each of the three cases considered there is an associated R_{Tot} value. These three values are summated to provide total value of risk of exceeding transmission capacity limits for that scheme. Thus, for each scheme the total risk of exceeding transmission capacity limits is seen in Table 13.

Table 13 Cumulative risk exceeding transmission capacity limits per scheme and in total

	2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz ->), 5 % each	4 stages (48.8 Hz ->), 7.5 % each	4 stages (49 Hz ->), 5 % each	4 stages (49 Hz ->), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
Cumulative Violation 350GWs %	15.08	13.71	13.71	14.30	13.41	14.00	13.45	13.68	13.33	13.27	13.81	13.57
Cumulative Violations 160GWs %	13.60	12.45	12.43	13.77	12.43	13.53	12.39	12.75	13.45	12.43	13.41	13.65
Cumulative Violation 120GWs %	18.25	18.11	15.14	17.41	14.32	14.20	15.23	18.64	15.41	17.09	16.85	17.47
Total Violations %	46.93	44.26	41.29	45.48	40.16	41.73	41.07	45.06	42.19	42.79	44.07	44.69

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Having identified Cumulative risk of exceeding transmission capacity limits per scheme the risk that the scheme will result in blackout is calculated using the summated risk of under and over frequency instability for levels of FCR are as declared within the RAR model and for levels of FCR limited to the contractual limits within the SOA.

Table 14 Results of dynamic stability screening

Numer of simulated cases 2860 for each scheme		2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz - >), 5 % each	4 stages (48.8 Hz - >), 7.5 % each	4 stages (49 Hz - >), 5 % each	4 stages (49 Hz - >), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
FCR as in RAR-model	Risk Index (f<48.5 Hz)	0	0	4	0	0	0	3	0	15	2	31	43
	Risk Index (f>51 Hz)	65	0	0	16	0	22	3	15	1	7	1	3
	fmin, Hz	48.5	46.8	48.4	48.5	48.5	48.7	48.4	48.6	48.3	48.4	48.3	48.2
	fmax, Hz	52.6	51.1	51.1	51.8	51	51.6	51.5	52.3	51.2	51.6	51.5	51.3
	Average LS (MW)	3891	2450	2496	3095	3371	3617	2407	3183	2302	2744	2204	2882
FCR limited < 1800 MW	Risk Index (f<48.5 Hz)	0	0	9	0	0	0	7	0	29	7	43	56
	Risk Index (f>51 Hz)	77	12	12	34	10	31	16	31	15	22	8	45
	fmin, Hz	48.5	42.2	48.3	48.5	48.5	48.7	48.3	48.4	48.2	48.3	48.3	48.2
	fmax, Hz	54.1	51.7	51.9	52.7	51.9	52.3	52.7	53.3	52.7	52.9	51.8	52
	Average LS (MW)	4432	3004	3169	3791	4083	3993	3124	3908	3065	3425	2880	3637

Thus, using the values from Table 13 and Table 14, two values of R_3 (S_k) per scheme can be identified using the equation below.

$$R_3(S_k) = [(R_{<48.5\ Hz}+R_{>51\ Hz})+(R_{120\%}+R_{150\%}+R_{200\%})]-[(R_{<48.5\ Hz}+R_{>51\ Hz})*(R_{120\%}+R_{150\%}+R_{200\%})] \qquad (4)$$

Table 15 presents the results of the initial screening process and identifies the cumulative risk of blackout based on dynamic and transmission capacity screening of the associated schemes.

Table 15 Risk index of blackout based on dynamic and transmission capacity screening

	2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz - >), 5 % each	4 stages (48.8 Hz - >), 7.5 % each	4 stages (49 Hz - >), 5 % each	4 stages (49 Hz - >), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
FCR as in RAR-model	81%	44%	44%	54%	40%	55%	45%	53%	51%	48%	62%	70%
FCR limited < 1800 MW	88%	51%	54%	64%	46%	60%	55%	62%	68%	59%	73%	101%

Logically 120% violations will occur be most frequently (in that a 120% violation will need to occur before a 150% violation can etc). However a 120% violation is generally an acceptable level of short term operation. In some very short periods a 150% violation may have limited adverse effect. For this reason consideration has been given to an inverse weighting the transmission capacity violation in order to identify if this has a meaningful impact on the results. In this case 120% violations are multiplied by a factor of 0.5, 150% violations are multiplied by 1 and 200% violation are multiplied by 2. This should 'weight' dangerously high transmission capacity violations more heavily. As a result this should result in a higher risk index value.

Table 16 Risk Indices of blackout based on dynamic and transmission capacity screening and an inversely weighted violation criteria

		2 stages, 10 % each	2 stages, 5 % each	4 stages (48.8 Hz - >), 5 % each	4 stages (48.8 Hz - >), 7.5 % each	4 stages (49 Hz - >), 5 % each	4 stages (49 Hz - >), 7.5 % each	ENTSOE plan 1, 6 stages	ENTSOE plan 2, 4 stages	ENTSOE plan 2, 4 stages, 20% total	ENTSOE plan2 4 stages, 30% total	SOA	SOA "real"
No Weighting	FCR as in RAR-model	0.81	0.44	0.44	0.54	0.40	0.55	0.45	0.53	0.51	0.48	0.62	0.70
	FCR limited < 1800 MW	0.88	0.51	0.54	0.64	0.46	0.60	0.55	0.62	0.68	0.59	0.73	1.01
Weighted Violation	FCR as in RAR-model	0.79	0.38	0.38	0.49	0.35	0.50	0.39	0.48	0.47	0.43	0.58	0.67
	FCR limited < 1800 MW	0.86	0.46	0.49	0.60	0.41	0.56	0.50	0.58	0.64	0.55	0.70	1.01

Selected Schemes

Based on the combined screening results, the schemes that are deemed to justify further investigation are the following:

- No.1 (2 stage 10% each stage)
- No.2 (2 stage 5% each stage)
- No.3 (4 stage 5% each stage activating at 48.8 Hz)
- No.4 (4 stage 7.5% each stage activating at 48.8 Hz)
- No.5 (4 stage 5% each stage activating at 49 Hz)
- No.6 (4 stage 5% each stage activating at 49 Hz)
- No.7 (ENTSOE scheme 1 over 6 stages)
- No.8 (ENTSOE scheme 2 over 4 stages)
- No.9 (ENTSOE scheme 2 over 4 stages cutting 20% load)
- No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)
- No.11 (SOA)*
- No.12 (SOA real)*

*It is noted that the SOA and the SOA “real” schemes have been included without real justification based on the results. This is in order to provide a benchmark against the current settings in order to establish if meaningful improvement has been achieved.

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7. Detailed Evaluation – PSSE Studies

Overview

This section documents the detailed dynamic studies that have been utilised in order to assess the varying UFLS schemes in respect to suitability and identification of a preferred UFLS option.

The performance of the twelve selected UFLS schemes were tested in PSSE on five different power system models (scenarios) representing the Nordic synchronous power system. For each UFLS design and scenario 14 contingency events were simulated. This resulted in 840 simulations (5*12*14) that were evaluated.

This section details the five scenarios used in the PSSE study. This is followed by a description of the contingency events used for testing the UFLS schemes. Finally the main results and conclusions from the PSSE studies are presented.

For completeness a comprehensive set of results from the base cases is provided in a supplementary addendum that is available upon request. More detailed assumptions in respect to dynamic modelling and FCR deployment is found within Appendix B.

Five Scenarios - Base Cases and Extreme Case

The original base cases are 2020 and 2025; with a minimum demand and maximum demand scenario and an 'extreme' low inertia case. The extreme case considers the 2025 minimum demand case in which generation is heavily biased toward low inertia sources. These five scenarios are derived from the original Nordic 2014 planning model[6], which is based on one hour in January (max) and one hour in July (min) year 2014. There is an assumed zero net increase in demand for the derived scenarios.

Table 17 shows a general summary for the five scenarios.

All scenarios are built assuming committed and planned generation and network reinforcements for year 2020 and 2025, which are in line with TYNDP.

The extreme 2025 minimum demand case assumes a low level of effective inertia in order to provide a view on a changing generation profile that may influence network stability in the long term planning horizon.

When studying the scenarios it was found that the HVDC import and export were not suitable to activate UFLS in the PSSE study. The HVDC transfers were relatively low and thus increased in order to get larger impact of the study contingencies. In order to achieve a suitable power balance the production and load have been marginally adjusted in the Nordic countries.

DK1 is not included in the Nordic power system model and hence not considered in this study.

UFLS equipment is installed in all Nordic areas except SE1 and SE2 (as implemented in the system today). For more details please refer to Appendix B.

Table 17 General data for the five different PSSE scenarios used in the study

Scenario	Load[7] in Nordic (MW)	Export from Nordic (MW)	Inertia (GWs)
2020 min	32770	5360	212
2020 max	68850	-5820	325
2025 min	32770	5400	205
2025 max	68960	-6380	318
2025 extreme	26190	-8180	108

[6] The Nordic 2014 planning model is a PSSE power system model (RMS) consisting of approximately 9000 buses, 2100 generators and 6000 lines. The model contains dynamic models for power system stability analysis.
[7] The Nordic synchronous areas (including losses).

Contingency Events

In order to assess the associated schemes that have been selected for further study it becomes necessary to assess these schemes consistently over varying different potentially sever events in order to provide confidence in their functionality.

For completeness the events selected with a brief description of the key events / losses of infeed are characterised in Table 18 below. For clarity the magnitude of loss of infeed for the below events is not constant across all base cases due to load fluctuation and the resulting dispatch.

Table 18 Outage events considered within PSSE detailed studies. Positive value = loss of infeed to the Nordics (or the remaining part of the system after the event).

Event No	Event Description	Delay (seconds)	Resulting power loss in scenario (MW)				
			2020 min	2020 max	2025 min	2025 max	Extreme
1	Loss of Zealand interconnectors	N/A	-1284	-289	-1284	-289	-32
2	Disconnect areas NO1, NO2 and NO5 from the rest of the system	N/A	1044	535	1177	679	3090
3	Loss of NO4 and Porjus area in Sweden, when exporting from this area, separation of surplus north Norway and Sweden	N/A	700	1350	800	1300	-70
4	Loss of interconnectors between Sweden and Finland	N/A	-1835	-1634	-1456	-1124	-1747
5	Loss of Forsmark 1+2+3	1 second delay for each incremental disconnection per unit	3005	3453	3005	3453	0
6	Loss of Olkiluoto 1+2+3	1 second delay for each incremental disconnection per unit	2566	3520	2566	3520	990
7	Loss of Ringhals 3+4	1 second delay for each incremental disconnection per unit	1773	2037	999	1148	0
8	Loss of all units in Forsmark and Ringhals	1 second delay for each incremental disconnection per unit	4778	5490	4004	4601	0
9	Loss of Estonia and Russia, Estlink1, Estlink2 and Nordbalt	N/A	-1041	2098	-776	2700	2288
10	Loss of NorNed, Skagerrak 1-4	1 second delay for each incremental disconnection per HVDC	-2016	800	-2200	800	2200
11	Loss of NorNed, Skagerrak 1-4 and Nordlink	1 second delay for each incremental disconnection per HVDC	-2016	800	-2200	800	3600

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12	Loss of infeed from Germany and Poland	1 second delay for each incremental disconnection per country	-1495	1700	-1495	1815	1622
13	Loss of infeed from Germany, Netherlands, Denmark (DK1)	1 second delay for each incremental disconnection per country	-3738	3190	-3886	3205	5833
14	Loss of all HVDC to continental Europe	3 second delay for each incremental disconnection per country	-4333	3690	-4481	3805	6436

For simplicity the associated waveforms of the above events are presented comprehensively in a separate addendum which will be provided upon request.

Results

2020 Minimum Demand

The 2020 minimum demand case assumes a low level of demand for the Nordic Network. The model represents a summer minimum scenario, with relatively low load and high export. Committed network reinforcements up to 2020 are included in keeping with the TYNDP. Flows between bidding zones and the operation of the nuclear blocks are graphically represented in figure 11.

Notable changes when compared to the 2014 base case are considered to be:

- Nordbalt increased to 400 MW export
- Wind increased in SE
- Some HVDC adjusted slightly due to overloading

Figure 11 Summary of initial power flows for the 2020 minimum base case

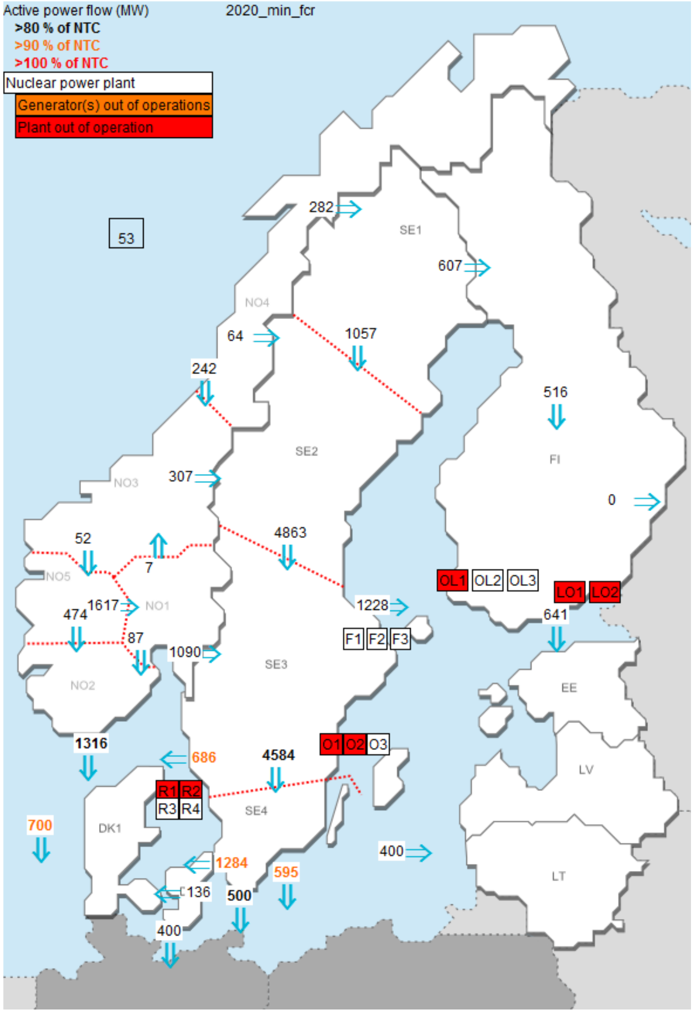


Table 19 Summary of generation and load for the 2020 minimum base case

Summary	Denmark (DK2)	Finland	Norway	Sweden
Total production (MW)	693	5530	15856	16192
Total load (MW)	1417	6573	11719	12171
Total export (MW)	-723	-1043	4136	4021
Inertia (MWs)	4,480	39,567	69,198	99,461

Table 20 Change in quantity of mechanical power available during simulations (2020 Minimum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13	2431.13
Event 2	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82	10834.82
Event 3	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06	2377.06
Event 4												
Event 5	3443.73	2970.10	2970.10	2970.10	2970.10	2970.10	2970.10	2970.10	2970.10	2970.10	2970.10	2970.10
Event 6	3461.04	2575.16	2575.16	2575.16	2575.16	2575.16	2575.16	2575.16	2641.39	2575.16	2575.16	2759.21
Event 7	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39	2274.39
Event 8	6469.89	4387.90	4387.90	4837.81	4387.90	4771.97	4387.90	4460.91	4387.90	4387.90	4387.90	4387.90
Event 9	526.51	526.51	526.51	526.51	526.51	526.51	526.51	526.51	526.51	526.51	526.51	526.51
Event 10	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70	2702.70
Event 11	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84	2702.84
Event 12	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15	1846.15
Event 13												
Event 14	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70	4874.70

Table 21 Change in electrical load from initial steady state conditions to post outage recovery conditions (2020 Minimum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	0	0	0	0	0	0	0	0	0	0	0	0
Event 2**	0	0	0	0	0	0	0	0	0	0	0	0
Event 3	0	0	0	0	0	0	0	0	0	0	0	0
Event 4												
Event 5	-2853	-1427	-1427	-2140	-1427	-2140	-1712	-1427	-1997	-1070	-1259	-1001
Event 6	-2853	-1427	-1427	-2140	-1427	-2140	-1712	-1427	-713	-1070	-1259	-614
Event 7	0	0	0	0	0	0	0	0	0	0	0	0
Event 8	-5637	-2853	-2853	-4280	-3756	-4280	-3424	-3994	-3566	-2996	-3176	-2754
Event 9**	0	0	0	0	0	0	0	0	0	0	0	0
Event 10**	0	0	0	0	0	0	0	0	0	0	0	0
Event 11**	0	0	0	0	0	0	0	0	0	0	0	0
Event 12**	0	0	0	0	0	0	0	0	0	0	0	0
Event 13												
Event 14**	0	0	0	0	0	0	0	0	0	0	0	0

*Greyed out sections denote a lack of convergence of the PSSE base case thus is neglected

** Events resulting in zero net load shed are due to the scenario considering significant export

2020 Maximum Demand

The 2020 maximum demand case assumes a high level of demand for the Nordic Network. The model represents a winter maximum scenario, with relatively high load and import. Committed network reinforcements up to 2020 are included in keeping with the TYNDP. Flows between bidding zones and the operation of the nuclear blocks are graphically represented in figure 12.

Notable changes when compared to the 2014 base case are considered to be:

- Load increased in SE, NO, DK
- Import increased on almost all HVDC
- Production decreased in SE and NO (hydro)

Figure 12 Summary of initial power flows for the 2020 maximum base case

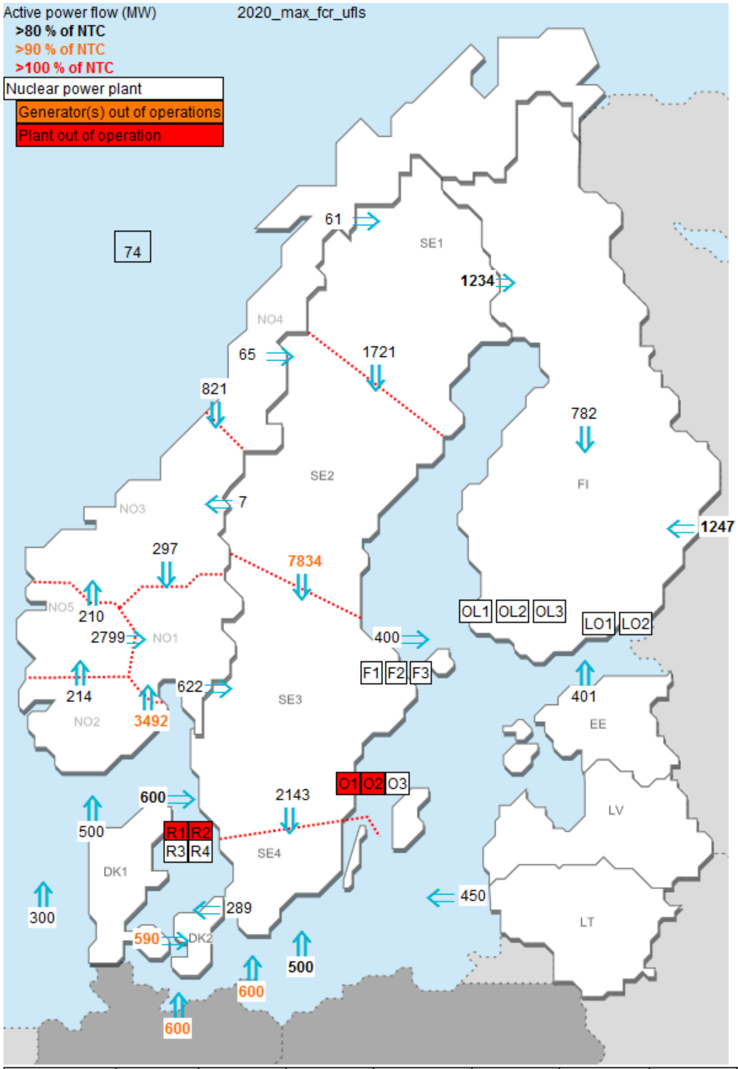


Table 22 Summary of generation and load for the 2020 maximum base case

Summary	Denmark (DK2)	Finland	Norway	Sweden
Total production (MW)	1402	10740	24633	26565
Total load (MW)	2831	13749	24000	26680
Total export (MW)	-1429	-3008	633	-115
Inertia (MWs)	13,253	70,012	104,217	137,715

Table 23 Change in quantity of mechanical power available during simulations (2020 Maximum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	1633	1633	1633	1633	1633	1633	1633	1633	1633	1633	1633	1633
Event 2	17361	17361	17361	17361	17361	17361	17361	17361	17361	17361	17361	17361
Event 3	4378	4378	4378	4378	4378	4378	4378	4378	4378	4378	4378	4378
Event 4	13040	13040	13040	13040	13040	13040	13040		13040	13040	13040	13040
Event 5	4157	4157	4157	4157	4290	6293	3426	4290	3426	3426	4157	4157
Event 6	7309	3844	3844	5945	3657	5710	3519	3657	3519	3519	3809	3881
Event 7	2720	2720	2720	2720	2720	2720	2720	2720	2720	2720	2720	2720
Event 8	7564	5152	5152	5630	5152	5484	5152	5152	5326	5152	5152	5152
Event 9	2911	2911	2911	2911	2911	2911	2911	2911	2911	2911	2911	2911
Event 10	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367
Event 11	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367	1367
Event 12	2337	2337	2337	2337	2337	2337	2337	2337	2337	2337	2337	2337
Event 13	3946	3946	3946	3946	3232	3185	3390	3232	3355	3274	3946	3946
Event 14	4029	3936	3936	3930	3365	5226	3507	3365	3340	3078	3919	4039

Table 24 Change in electrical load from initial steady state conditions to post outage recovery conditions (2020 Maximum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	0	0	0	0	0	0	0	0	0	0	0	0
Event 2**	0	0	0	0	0	0	0	0	0	0	0	0
Event 3	0	0	0	0	0	0	0	0	0	0	0	0
Event 4												
Event 5	0	0	0	0	-3027	-4541	-1211	-3027	-1514	-2270	0	0
Event 6	-5663	-3027	-3027	-4539	-3027	-4541	-1547	-3027	-1514	-2270	-1307	-1306
Event 7	0	0	0	0	0	0	0	0	0	0	0	0
Event 8	-6054	-3027	-3027	-4541	-3591	-4541	-3633	-3027	-4238	-3397	-3728	-3558
Event 9**	0	0	0	0	0	0	0	0	0	0	0	0
Event 10**	0	0	0	0	0	0	0	0	0	0	0	0
Event 11**	0	0	0	0	0	0	0	0	0	0	0	0
Event 12**	0	0	0	0	0	0	0	0	0	0	0	0
Event 13	0	0	0	0	-1599	-1970	-938	-1599	-1056	-1439	0	0
Event 14	-653	-1016	-1017	-945	-3027	-4541	-1211	-3027	-1514	-2270	-1206	-851

*Greyed out sections denote a lack of convergence of the PSSE base case thus is neglected

** Events resulting in zero net load shed are due to the scenario considering significant export

2025 Minimum Demand

The 2025 minimum demand case assumes a low level of demand for the Nordic Network. The model represents a summer minimum scenario, with relatively low load and high export. Committed network reinforcements up to 2025 are included in keeping with the TYNDP. Flows between bidding zones and the operation of the nuclear blocks are graphically represented in figure 13.

The following salient details are considered within the model and within the associated simulations:

- Nordbalt increased to 400 MW export
- Nuclear block R4 disconnected
- Wind increased in SE (circa 600 MW)
- Some HVDCs adjusted slightly due to overloading

Figure 13 Summary of initial power flows for the 2025 minimum base case

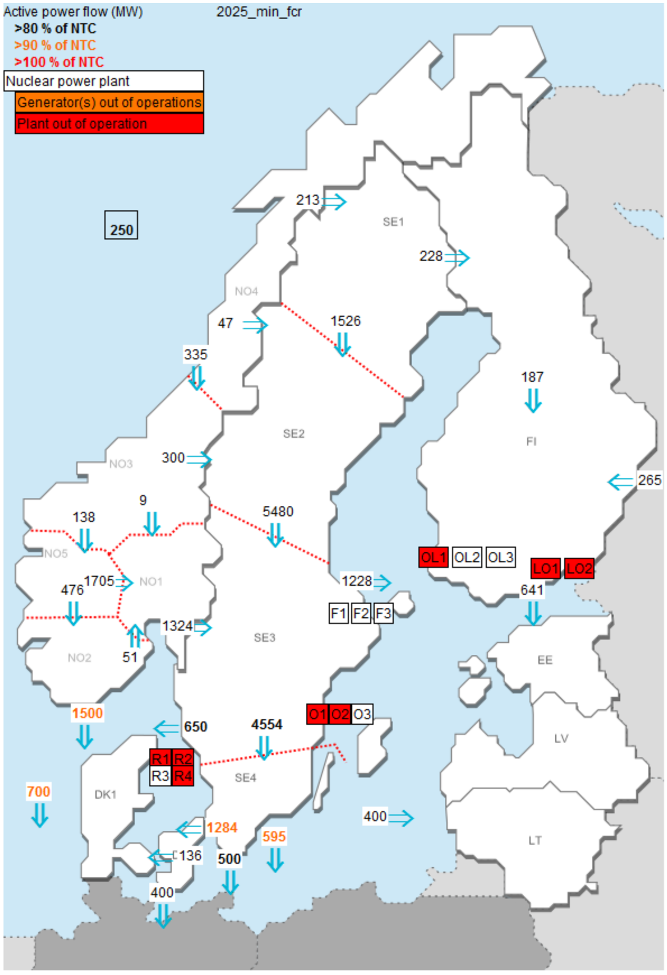


Table 25 Summary of generation and load for the 2025 minimum base case

Summary	Denmark (DK2)	Finland	Norway	Sweden
Total production (MW)	693	5643	16180	15796
Total load (MW)	1417	6571	11719	12294
Total export (MW)	-723	-928	4460	3503
Inertia (MWs)	4,480	39,567	68,846	92,013

Table 26 Change in quantity of mechanical power available during simulations (2025 Minimum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	2292	2292	2292	2292	2292	2292	2292	2292	2292	2292	2292	2292
Event 2	11149	11149	11149	11149	11149	11149	11149	11149	11149	11149	11149	11149
Event 3	2378	2378	2378	2378	2378	2378	2378	2378	2378	2378	2378	2378
Event 4												
Event 5	3404	2986	2986	2986	3273	2986	2986	2986	2986	3633	2986	2986
Event 6	3512	2583	2583	2619	2583	2583	2583	2583	2583	2583	2583	2583
Event 7	1417	1417	1417	1417	1417	1417	1417	1417	1417	1417	1417	1417
Event 8	3941	3897	3897	4976	3897	4910	3925	4592	3897	3897	3897	3897
Event 9	478	478	478	478	478	478	478	478	478	478	478	478
Event 10	1765	1765	1765	1765	1765	1765	1765	1765	1765	1765	1765	1765
Event 11	1765	1765	1765	1765	1765	1765	1765	1765	1765	1765	1765	1765
Event 12	1760	1760	1760	1760	1760	1760	1760	1760	1760	1760	1760	1760
Event 13	1726	1726	1726	1726	1726	1726	1726	1726	1726	1726	1726	1726
Event 14	321											

Table 27 Change in electrical load from initial steady state conditions to post outage recovery conditions (2025 Minimum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	0	0	0	0	0	0	0	0	0	0	0	0
Event 2**	0	0	0	0	0	0	0	0	0	0	0	0
Event 3	0	0	0	0	0	0	0	0	0	0	0	0
Event 4												
Event 5	-2849	-1425	-1425	-2136	-2743	-2136	-1709	-1430	-1994	-2991	-1836	-2356
Event 6	-2849	-1424	-1424	-2136	-1424	-2136	-1709	-1424	-1994	-1068	-1257	-998
Event 7	0	0	0	0	0	0	0	0	0	0	0	0
Event 8	-3495	-2849	-2848	-4273	-2848	-4273	-3418	-3988	-2796	-2991	-2590	-2742
Event 9**	0	0	0	0	0	0	0	0	0	0	0	0
Event 10**	0	0	0	0	0	0	0	0	0	0	0	0
Event 11**	0	0	0	0	0	0	0	0	0	0	0	0
Event 12**	0	0	0	0	0	0	0	0	0	0	0	0
Event 13**	0	0	0	0	0	0	0	0	0	0	0	0
Event 14	-4478											

*Greyed out sections denote a lack of convergence of the PSSE base case thus is neglected

** Events resulting in zero net load shed are due to the scenario considering significant export

2025 Maximum Demand

The 2025 maximum demand case assumes a high level of demand for the Nordic Network. The model represents a winter maximum scenario, with relatively high load and import. Committed network reinforcements up to 2025 are included in keeping with the TYNDP. Flows between bidding zones and the operation of the nuclear blocks are graphically represented in figure 14.

The following salient details are considered within the model and within the associated simulations:

- Load increased in SE, NO, DK
- Import increased on almost all HVDC
- Production decreased in SE and NO (hydro)
- Nuclear block R4 (SE) disconnected

Figure 14 Summary of initial power flows for the 2025 maximum base case

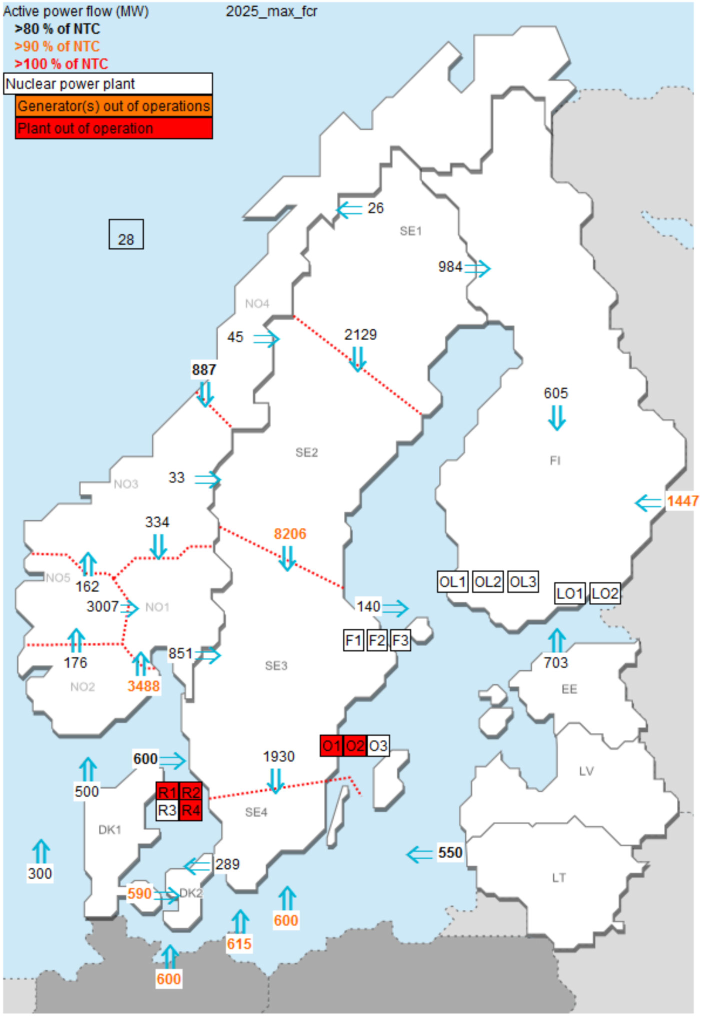


Table 28 Summary of generation and load for the 2025 maximum base case

Summary	Denmark (DK2)	Finland	Norway	Sweden
Total production (MW)	1402	10740	24633	26565
Total load (MW)	2831	13749	24000	26680
Total export (MW)	-1429	-3008	633	-115
Inertia (MWs)	13,253	70,012	104,217	137,715

Table 29 Change in quantity of mechanical power available during simulations (2025 Maximum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	1631	1631	1631	1631	1631	1631	1631	1631	1631	1631	1631	1631
Event 2	17513	17513	17513	17513	17513	17513	17513	17513	17513	17513	17513	17513
Event 3	4330	4330	4330	4330	4330	4330	4330	4330	4330	4330	4330	4330
Event 4	12308	12308	12308	12308	12308	12308	12308	12308	12308	12308	12308	12308
Event 5	8097	4337	4337	6306	4013	5963	3530	4013	3421	3421	3771	3967
Event 6	7133	3964	3964	5519	3837	5863	3621	3837	3510	3510	3730	4029
Event 7	1781	1781	1781	1781	1781	1781	1781	1781	1781	1781	1781	1781
Event 8	7727	4487	4487	5741	4487	5592	4646	4487	4487	4487	4487	4487
Event 9	3652	3652	3652	3652	3652	3652	3652	3652	3652	3652	3652	3652
Event 10	1378	1378	1378	1378	1378	1378	1378	1378	1378	1378	1378	1378
Event 11	1378	1378	1378	1378	1378	1378	1378	1378	1378	1378	1378	1378
Event 12	2449	2449	2449	2449	2449	2449	2449	2449	2449	2449	2449	2449
Event 13	3911	3911	3911	3911	3911	3911	3911	3911	3911	3911	3911	3911
Event 14	3849	4150	4150	3980	3339	4295	3548	3339	3378	3106	3949	4094

Table 30 Change in electrical load from initial steady state conditions to post outage recovery conditions (2025 Maximum Demand)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	0	0	0	0	0	0	0	0	0	0	0	0
Event 2**	0	0	0	0	0	0	0	0	0	0	0	0
Event 3	0	0	0	0	0	0	0	0	0	0	0	0
Event 4												
Event 5	-6070	-3036	-3035	-4553	-3035	-4553	-1214	-3035	-1518	-2276	-1278	-852
Event 6	-5101	-2979	-2979	-4103	-3035	-4553	-1214	-3035	-1518	-2276	-1278	-852
Event 7	0	0	0	0	0	0	0	0	0	0	0	0
Event 8	-6070	-3036	-3035	-4553	-3035	-4553	-3642	-3035	-2434	-2276	-2693	-2151
Event 9**	0	0	0	0	0	0	0	0	0	0	0	0
Event 10**	0	0	0	0	0	0	0	0	0	0	0	0
Event 11**	0	0	0	0	0	0	0	0	0	0	0	0
Event 12**	0	0	0	0	0	0	0	0	0	0	0	0
Event 13**	0	0	0	0	0	0	0	0	0	0	0	0
Event 14	-1058	-536	-536	-801	-3007	-3783	-1214	-3007	-1518	-2274	-1278	-852

*Greyed out sections denote a lack of convergence of the PSSE base case thus is neglected

** Events resulting in zero net load shed are due to the scenario considering significant export

Commentary
In order to provide a purely statistically based view on the benefits of certain schemes the average loss of load for each event, for each base case and for each scheme has been simulated in order to provide a comprehensive view on the performance of each scheme under conventional network operating conditions. This equates to 840 bespoke scenarios under which purely base case performance is considered.

As a result, for each scheme considered an average quantity of disconnected load is calculated. This figure considers the average amount of load lost from UFLS but does not include the average loss of disconnected load that occurs during islanding of sections of network. This average value of all maximum and minimum base cases for 2020 and 2025, where each event specified in Table 18 is then summated and divided by the total number of scenarios, results in a single value of 'average lost load' from UFLS. This allows for a view to be taken on just the functionality of the scheme on the remaining connected network.

It is noted that Events 1 – 4 did not trigger UFLS however they did instigate forced disconnection of sections. This includes NO4 and DK2 bidding zones. Whilst this has no significant bearing on the studies and their associated conclusions, it is included for completeness. For further more detailed information in this respect please refer the studies addendum.

Summated Result

The average lost load as a result of UFLS for all 2020 and 2025 base cases is presented in Table 31 below. It is noted that Schemes No.11 and No.12 were included for comparison only due to the identified risks seen in the screening studies so have not been included within the final results.

The scheme that has the lowest level of forced disconnection as a result of UFLS activation is seen to be Scheme 3. This is 4 stage 5% each stage activating at 48.8 Hz, 48.6 Hz, 48.4 Hz and 48.2 Hz respectively.

It is noted that Scheme No.2 has a matching value of average disconnected load. This is reflective of none of the simulations activating more than 2 stages, thus the results are effectively the same. Of the two, scheme 3 is selected to ensure that further stages are available for load disconnection should it be necessary as well as being closer to full compliance with the ENTSO-E Network Code on Emergency and Restoration[8].

Table 31 Summated Average of UFLS per scheme over maximum and minimum base cases

Scheme	Averaged disconnection per scenario (MW)
No.3 (4 stage 5% each stage activating at 48.8Hz)	-501
No.2 (2 stage 5% each stage)	-501
No.7 (ENTSOE scheme 1 over 6 stages)	-527
No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	-534
No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	-588
No.8 (ENTSOE scheme 2 over 4 stages)	-706
No.5 (4 stage 5% each stage activating at 49Hz)	-714
No.4 (4 stage 7.5% each stage activating at 48.8Hz)	-735
No.6 (4 stage 5% each stage activating at 49Hz)	-976
No.1 (2stage 10% each stage)	-994

[8] As noted in chapter 6 page 30.

Long Term Planning Considerations

In order to consider the behaviour of the varying UFLS under events that are well beyond the required levels of network security (as mandated within the SOA); the events identified in Table 18 have been simulated against an extremely low level of operating inertia base case. This is to provide a degree of clarity as to how the Nordic network may respond should the trend of conventional generation retirement result in a very low operating inertia level in the Nordic network. The simulations are based on a 2025 minimum demand case assuming an extreme low demand for the Nordic network. The model represents a summer minimum scenario, with very low generating inertia (<100 GWs) with committed network reinforcements up to 2025 are included in keeping with the TYNDP.

Given that these circumstances are to be considered outside of what would be considered 'reasonable' when evaluating UFLS this is not included within the body of the report. The associated findings are located in Appendix D, however for completeness are considered consistent with the overall findings of this study, in that scheme 3 is seen to disconnect the lowest level of load whilst maintaining frequency stability.

8. Recommended UFLS Scheme

As a result of the studies performed in the preceding sections, the UFLS scheme that is deemed to technically maintain stability whilst minimising total load shed is seen to be Scheme 3. This is a 4 stage UFLS scheme shedding 20% of maximum load in 5% stages occurring at 48.8 Hz, 48.6 Hz, 48.4 Hz and 48.2 Hz.

Whilst the scheme has been identified to statistically provide the lowest average load shed whilst maintaining frequency stability, it is necessary to conservatively identify 'worst cases' in order to provide context for scheme performance.

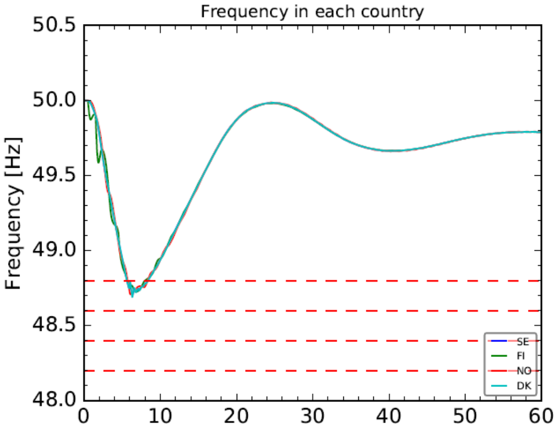
Table 32 identifies the lowest frequency excursion for the defined events considered for the identified scheme. As can be seen, events that on average resulted in load shed had the largest negative frequency deviation. This is particularly identified in Events 5, 6, 8 and 14.

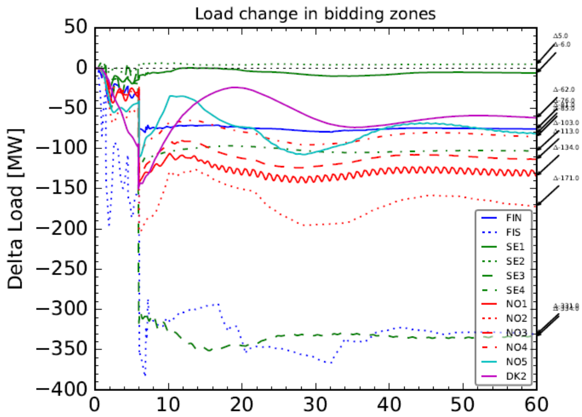
Table 32 Minimum frequency excursion reached as a result of the defined event for 'Scheme 3'

Minimum Frequency	2020 Minimum Load	2020 Maximum Load	2025 Minimum Load	2025 Maximum Load	Avg Load Shed
Event 1	50.00	50.00	50.00	50.00	-
Event 2	49.47	49.81	49.28	49.76	-
Event 3	49.62	49.58	49.57	49.58	-
Event 4		49.95		49.95	-
Event 5	48.70	48.86	48.62	48.78	1472
Event 6	48.73	48.74	48.71	48.76	2214
Event 7	49.10	49.36	49.41	49.63	-
Event 8	48.42	48.66	48.48	48.69	2941
Event 9	50.00	49.29	49.99	49.06	-
Event 10	50.00	49.72	50.00	49.72	-
Event 11	50.00	49.72	50.00	49.72	-
Event 12	50.00	49.49	50.00	49.46	-
Event 13		48.99	50.00	49.00	-
Event 14	50.00	48.80		48.80	388

Figure 15 provides an example of the associated frequency deviation seen under event 6 (Loss of Forsmark units 1, 2 and 3 over a 2 second period), with a total loss of generation equating to 3005 MW. As can be seen the scheme performs favourably to what could be considered a severe network event (well in excess of a dimensioning fault) under 2025 minimum load conditions. In actual fact, only the first stage of load shedding was activated. Load is seen to be shed in a distribution that may be expected; where SE3 and Finland (South) are subjected to the largest loss of load. Other bidding zones are subjected to a loss of load that tends to be between 75 and 125 MW.

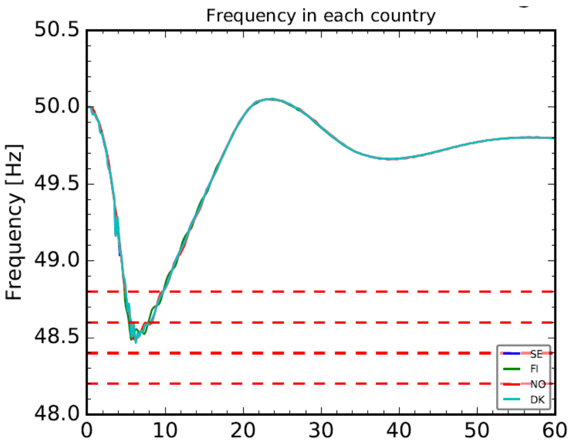
Figure 15 Event 6 data traces for 2025 minimum demand (a) Frequency deviation (b) load lost per bidding zone

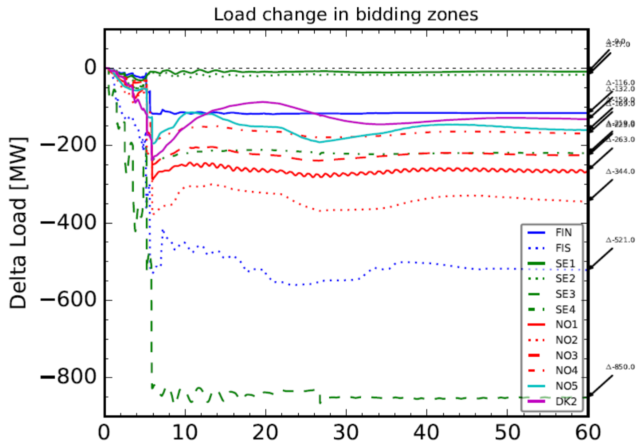




Whilst it is accepted that no UFLS is perfect; in that it is impossible to entirely eradicate loss of load and maintain frequency stability it is recognised that a scheme should disconnect an optimal amount of load in order to return frequency to acceptable levels within an appropriate time. This is supported by Figure 16 which depicts the loss of both Ringhals and Forsmark (all units) with a total loss of just over 4000 MW under minimum load conditions. As can be seen, under this scenario, two load shedding stages are activated resulting in a total loss of load of 2900 MW. It is noted that this, most severe event, is a once in a generation event, and even under these circumstances does not result in a severe loss of load, or require significant network restoration as a result. The major loss of load occurs in SE3 and Finland (South) as in event 6. Whilst it would be expected that SE3 would suffer as a result of the loss it is interesting that Finland (South) suffers approximately 500 MW as a result (given the relative location of the losses).

Figure 16 Event 8 data traces for 2025 minimum demand (a) Frequency deviation (b) load lost per bidding zone





Over Frequency

As a result of network topologies changing, with a rise of HVDC export and high renewable penetration that can be utilised to satisfy international markets; there is a likelihood that over frequency becomes a consideration when assessing the impact of load rejection. Whilst UFLS is not automatically considered as a result of over frequency; there are occasions where an over frequency event may stimulate generation disconnection to the extent that UFLS may be activated as a result. In network terms this is inherently dangerous and invariably results in a high risk of outage. For this reason it is necessary to assess the impact of UFLS on over frequency.

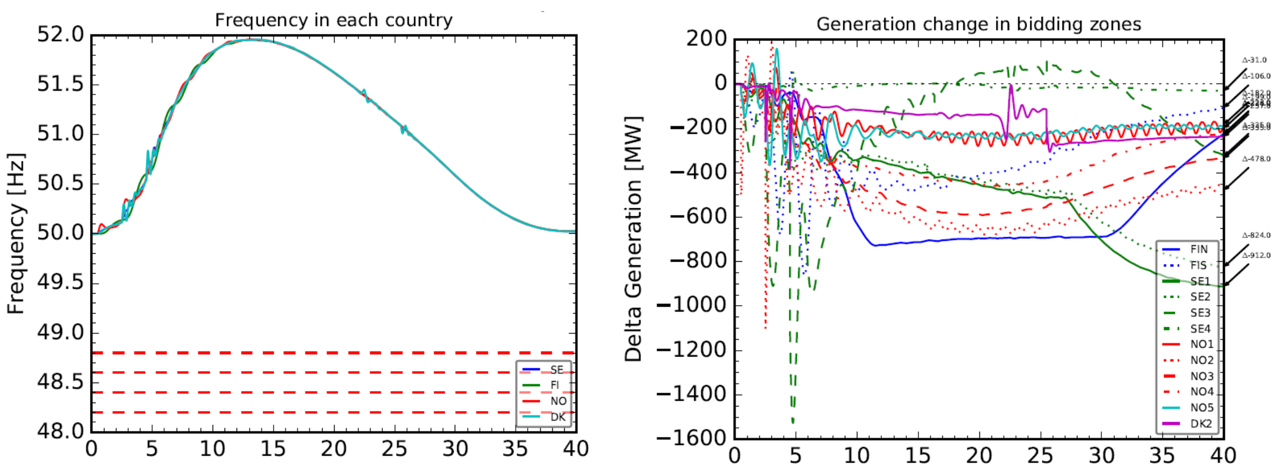
Table 33 Maximum frequency excursion reached as a result of the defined event for 'Scheme 3'

Maximum Frequency	2020 Minimum Load	2020 Maximum Load	2025 Minimum Load	2025 Maximum Load
Event 1*	50.44	50.07	50.42	50.07
Event 2	50.00	50.04	50.00	50.06
Event 3	50.01	50.00	50.00	50.00
Event 4*		50.42		50.30
Event 5	50.00	50.00	50.00	50.52
Event 6	50.01	50.39	50.00	50.42
Event 7	50.00	50.00	50.01	50.01
Event 8	50.00	50.05	50.05	50.22
Event 9*	50.23	50.00	50.09	50.00
Event 10	50.89	50.02	50.78	50.03
Event 11	50.89	50.02	50.78	50.03
Event 12	50.59	50.00	50.51	50.00
Event 13*		50.00	51.04	50.00
Event 14	51.96	50.00		50.00

* Events likely to instigate over frequency events

Table 33 characterises the maximum frequency excursions as a result of the events identified within table 16. Of the events considered Event 14 is seen to have the highest recorded frequency excursion under 2020 minimum load conditions. Event 14 is the loss of all HVDC to continental Europe with 3 second delay for each incremental disconnection per country. This results in a total load rejection of 4,333 MW. As can be seen in the table; under this circumstance the maximum network frequency is reaches 51.96 Hz. The frequency excursion is represented in Figure 17. Of the effective change in generation across trading zones Finland, SE3 and NO2 are forced to curtail more severely.

Figure 17 Event 14 data traces for 2020 minimum demand



Based on the above, it would appear that while 51.96 Hz is high, the network and associated generation is capable of adequate curtailment in order to achieve appropriate frequency reduction. Likewise under such circumstance there has not been any generation forced disconnection which is considered a serious risk in relation to maintaining frequency stability.

Of the events considered 2 event types resulted in a lack of simulation convergence under minimum load base cases. These events are discounted from this study on the basis that it could not be identified if UFLS would have impacted the recovery of frequency stability.

- Event 4: Loss of interconnectors between Sweden and Finland - (3 second delay between incremental disconnection per country)
- Event 13: Loss of infeed from Germany, Netherlands, Denmark (Dk1) - (1 second delay for each incremental disconnection per country)

Ultimately the result of the review of the Nordic UFLS settings is seen to be:

The UFLS scheme that has been identified to technically maintain stability whilst minimising total load shed is seen to be Scheme 3.

This is a 4 stage UFLS scheme shedding 20% of maximum load in 5% stages activating at 48.8 Hz, 48.6 HZ, 48.4 Hz and 48.2 Hz.

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9. Implementation

Overview

In order to provide recommendations that are appropriate and consistent with other Codes and Standards a review of existing regulation is necessary to highlight areas that need to be updated or revised in a consistent way. The purpose of this section is to identify regulatory barriers that may conflict with the recommendations derived from revisions in UFLS schemes.

For clarity this review is not exhaustive, and has not assessed the impact of UFLS and OFC on frequency management during system restoration from complete blackout. This aspect is not within the purview of this study, thus neglected.

Review of Associated Codes, Standards & Agreements

For the purposes of this review, and for simplicity to the reader, the following sections and articles have been reviewed in cognisance of the possibility of changes in the frequency based disconnection of electrical load (UFLS) and generation (OFC). Where there is an aspect of the Code where there will be a direct influence on the results of study; commentary will be provided as to its significance. If there is no material change or influence on the study, the section/article will not receive further comment.

Nordic Grid Code

The Nordic Code is the principle regulation pertaining electricity transmission within the Nordics. It establishes the minimum standards and requirements that the TSO's are required to adhere to. Within the Nordic Code sits the System Operation Agreement that forms the Operations Code that the Nordic TSO's adhere to. The following sections are noted as having a potential impact or will be impacted by the study:

4.1.2 Frequency controlled disturbance reserve paragraph 5:

'Agreed automatic load shedding, e.g. industrial, district heating and electric boiler consumption in the event of frequency drops to 49.5 Hz can be counted as part of the frequency controlled disturbance reserve. The following requirements are applicable, however:

Load shedding can be used as frequency controlled disturbance reserve in the frequency range of 49.9 Hz to 49.5 Hz, when load shedding meets the same technical requirements set below for generators'

- No meaningful impact to study identified

System Operation Agreement (SOA)

As part of the System Operations Agreement, Article 15 pertaining to power shortages specifies that load shedding must be managed in accordance with Appendix 9 of the SOA. In reference to Appendix 9, specifically section 1.4 Critical Power Shortages Paragraph 1 stipulates that:

'When a critical power shortage is approaching, preparations for manual load shedding (15 min) will be ordered in the deficit areas. The Parties will agree on the subsystem(s) where the load shedding will take place and where in the subsystem(s) the load shedding will take place. The consequences for load shift must be assessed.'

- Given the nature of the study in which the main consideration or requirement of UFLS is severe disturbance is the instigator, it would be logical to infer that this stipulation is not applicable and thus can be neglected from the study.

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Section 1.4 Critical Power Shortages Paragraph 4 stipulates that:

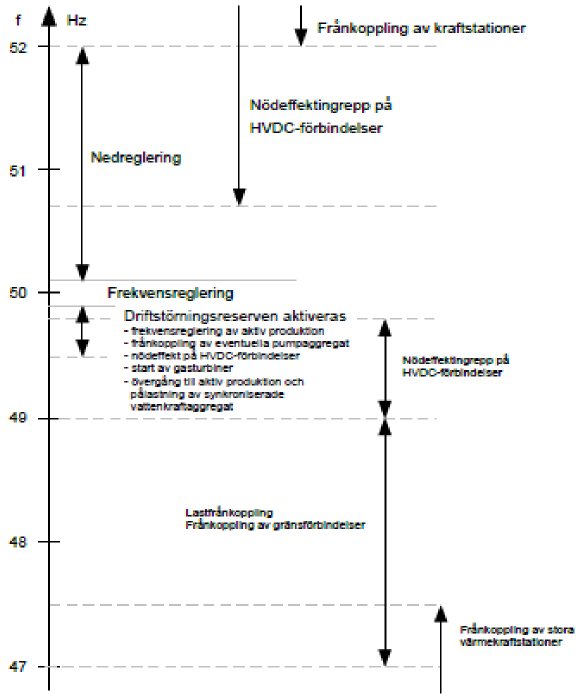
'At the same time, load shedding will be ordered without a commercial agreement. The expected activation time for load shedding has to be weighed into the decision. Load shedding occurs in the subsystem with the greatest physical deficit in its balance. Shedding occurs in stages until the requirement for 600 MW of manual active reserve (15 min) in the synchronous system is met. When load shedding has taken place until two or more subsystems have an equally large deficit, load shedding is distributed thereafter between these subsystems. Attention must be paid to the practical handling; load shedding in stages of 200 – 300 MW at a time is considered a suitable level.'

– Given the inference is that load shedding is ordered rather than automatically activated, this stipulation is assumed to not be applicable to the study in its current format.

APPENDIX 5 - SYSTEM PROTECTION

– 1 General - Paragraph 4

'Automatic system protection is adapted to the combined operational reserves of the interconnected Nordic power system. Frequency controlled functions are shown in Figure 1. A detailed description of the Figure can be found in the Nordel report "Rekommandasjon for frekvens, tidsavvik, regulerstyrke og reserve" from August 1996.'



– It is acknowledged that should the findings of the study may cause this section to require revision; specifically reference to severing cross border connection and reference to activation of UFLS from 49 to 47 Hz.

APPENDIX 5 OF SYSTEM OPERATION AGREEMENT-

– 2.3 Frequency controlled load shedding – table 2

– Revision of table to levels identified within this body of work would be necessary

APPENDIX 6 OF SYSTEM OPERATION AGREEMENT

– 1.2.4 Automatic load shedding – table of values pertaining to stages.

– Revision of table to levels identified within this body of work would be necessary

ENTSO-E Network Code *on Emergency and Restoration* (Awaiting implementation)
Identified Sections

CHAPTER 2 SYSTEM DEFENCE PLAN

- SECTION 1 General Principles

– Article 9 Design of the System Defence Plan

It is noted that Article 9 sub paragraph 3 requires any associated defence plan to follow the following principles:

a) the impact for System Users is minimal;

b) the measures are economically efficient;

c) only the necessary measures are activated; and

d) the measures do not endanger the Operational Security of its Transmission System or of the interconnected Transmission Systems.

– Whilst this does not materially affect the study it is noted that any justification for associated changes must be written in cognisance of these requirements. Based on the envisaged outcome this is not deemed a significant issue.

– Article 10 Implementation of the System Defence Plan

– No material impact

– Article 11 Activation of the System Defence Plan

– No material impact

– Article 12 Inter-TSO assistance and coordination in Emergency State

– No material impact

- SECTION 2 Measures of the System Defence Plan

– Article 13 Frequency Deviation management procedure

5) In case of an under-Frequency event and provided the rate of change of Frequency allows it, each TSO shall activate Demand Side Response from Defence Service Providers providing DSR before activation of the automatic Low Frequency Demand Disconnection scheme described in Article 14.

– Given article 5 refers to the dynamic time domain frequency change which could be managed at a control centre level or via demand side management (DSM). For this reason there is no material impact to this study as the rate of change of any instigated event would be faster than DSM or manual operation could arrest.

6) Each TSO and DSO identified pursuant to Article 9(7) shall manually disconnect Energy Storage acting as load connected to its network before activation of the automatic Low Frequency Demand Disconnection scheme described in Article 14, provided the rate of change of Frequency allows it.

– This assumption has been accounted for within the principles of the study.

– Article 14 Automatic under-Frequency control scheme

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3) Each TSO and DSO identified pursuant to Article 9(7) shall foresee automatic disconnection of Energy Storage acting as load connected to its network before activation of the automatic Low Frequency Demand Disconnection scheme.

– This assumption has been accounted for within the principles of the study.

4) Each TSO shall design the automatic Low Frequency Demand Disconnection scheme with the objective to shed load in real-time according to Table 1. This scheme shall include the disconnection of Demand at different frequencies, from a starting level to a final mandatory level within an implementation range whilst respecting a minimum number and maximum size of steps. The implementation range defines the maximum admissible deviation of Demand to be disconnected from the target Demand to be disconnected at a given Frequency, calculated through linear interpolation between starting and final mandatory levels. The implementation range does not allow disconnection of less Demand than the Demand to be disconnected at the starting mandatory level.

The starting mandatory level, the final mandatory level, the implementation range, the minimum number of steps and the maximum Demand disconnection for each step shall respect the following characteristics:

– This requirement has been considered however may be contradictory to the study findings. There may be a need to propose modifications to table 5 settings based on the conclusions of the study.

Parameter	Continental Europe	Nordic	Great Britain	Ireland	Measuring Unit
Demand disconnection starting mandatory level : Frequency	49	48.7 – 48.8	48.8	48.85	Hz
Demand disconnection starting mandatory level: Demand to be disconnected	5	5	5	6	% of the Total Load at national level
Demand disconnection final mandatory level: Frequency	48	48	48	48.5	Hz
Demand disconnection final mandatory level: Cumulative Demand to be disconnected	45	30	50	60	% of the Total Load at national level
Implementation range	±7	±10	±10	±7	% of the Total Load at national level, for a given Frequency
Minimum number of steps to reach the final mandatory level	6	2	4	6	Number of steps
Maximum Demand disconnection for each step	10	15	10	12	% of the Total Load at national level, for a given step

– Article 15 Automatic over frequency control scheme

2. In consultation with the other TSOs of its synchronous area, each TSO shall define the following parameters of its automatic over-Frequency control scheme:

a) the frequency thresholds for the activation; and

b) the reduction ratio of active power injection.

– No direct impact to this study with findings from the OFC study element informing these requirements.

CHAPTER 6 COMPLIANCE AND REVIEW

– Article 48 Compliance testing and periodic review of System Defence Plan

– No material impact

COMMISSION REGULATION (EU) 2016/631- Network Code on Requirements for Grid Connection of Generators

The Network Code sets out a set of harmonised rules for grid connection for power-generating modules in order to provide a legal framework for grid connections. The Code itself puts an onus on the relative TSO's to identify and stipulate as part of its own national underpinning regulation (i.e. the Nordic Code) requirements for generators wishing to connect. The Code also sets out requirements as to levels of cooperation that become essential in operation of an interconnected network.

Of the articles found within the Code, the classifications of generating unit's sets out minimum operating time requirements under differing frequency levels. These are different per unit size with an example found below in Table 34.

Table 34 Type A generator minimum operating criteria with respect to frequency

Synchronous area	Frequency range	Time period for operation
Nordic	47,5 Hz-48,5 Hz	30 minutes
	48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 30 minutes
	49,0 Hz-51,0 Hz	Unlimited
	51,0 Hz-51,5 Hz	30 minutes

– Although there are requirements for future generators to be compliant in varying minimum standards as set out as part of connection agreements; the reality is that this will have little impact in respect to the time domains under which this study, and emergency disconnection is activated. For this reason the Network Code on Requirements for Grid Connection of Generators can be considered to have no meaningful impact on the results of this UFLS study but will have a meaningful impact on curtailment requirements pertaining to over frequency.

TSO Roll out

In order that each TSO is able to implement the UFLS levels are recommended within this report it is necessary that Each TSO is provided the report and supporting studies addendum in order that UFLS relays are placed in optimal locations so as to maintain frequency stability.

Implementation of UFLS in Eastern Denmark

In Denmark the new demands concerning UFLS are expected to be implemented according to the plan below:

Step	Time frame (estimated)	Issues
0	Time "Zero"	Time "Zero" when the new demands are described in the SOA and signed by the TSO's in NordEL.
1	9 months	The new UFLS demands will be incorporated in an updated Technical Requirement "Automatic and manual Load shedding" and published on Energinet.dk's homepage. Including: 1.1 Working Group formed with a number of DSOs - chaired by Energinet.dk - makes a draft. 1.2 Public hearing of the draft. 1.3 Adjusting the draft. 1.4 Notification to Danish Energy Regulatory Authority (DERA) and publication of the final Technical Requirements on Energinet.dk's homepage.
2	9 months	Timeframe for the practical planning and implementation of the demands described in the published Technical Requirements. In Denmark almost all UFLS will be shed on distribution level (U<110 kV) by the DSO's (Distribution System Operator).
Total	18 months	

Implementation of UFLS in Finland

In Finland the new demands concerning UFLS are expected to be implemented according to the plan below:

Step	Time frame (estimated)	Issues
0	Time "Zero"	Time "Zero" when the new demands are described in the SOA and signed by the Nordic TSOs.
1	9 months	1.1 Fingrid examines the load volumes of the present UFLS and if necessary considers possible new 110 kV power lines owned by Fingrid to be incorporated in the UFLS scheme. 1.2 Fingrid prepares an internal document describing how the present UFLS shall be changed. 1.3 Fingrid prepares a document describing the UFLS methodology on high level and sends it to Finnish Energy Regulatory Authority (EV).
2	9 months	Timeframe for the practical planning and implementation of the upgraded UFLS scheme. In Finland all UFLS will be done on transmission level (U=110 kV) by Fingrid.
Total	18 months	

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Implementation of UFLS in Sweden

In Sweden the new demands concerning UFLS are expected to be implemented according to the plan below:

Step	Time frame (estimated)	Issues
0	Time "Zero"	Time "Zero" when the new demands are described in the SOA and signed by the Nordic TSO's. UFLS demands and equipment requirements needs to be synced with the in grid codes DCC (Demand Connection Code) and ER (Emergency and Restoration).
1	9 months	The new UFLS demands will be incorporated in an updated Regulation (SvKFS 2012:1) for automatic and manual load shedding and published on Svk's homepage. Including: 1.4 Working Group formed - makes a draft. 1.5 Producing an Impact statement. 1.6 Referral of the draft. 1.7 Adjusting the draft. 1.8 Decisions in Svk's board.
2	9 months	Timeframe for the practical planning and implementation of the demands described in the published Regulation. In Sweden almost all UFLS will be shed on distribution level (U<110 kV) by the DSO's (Distribution System Operator).
Total	18 months	

Implementation of UFLS in Norway

In Norway the new demands concerning UFLS are expected to be implemented according to the plan below:

Step	Time frame (estimated)	Issues
0	Time "Zero"	Time "Zero" when the new demands are described in the SOA and signed by the Nordic TSO's.
1	3 months	1.9 Statnett prepares an internal document describing how the present UFLS shall be changed. 1.10 Statnett prepares a document describing the UFSL methodology on high level and sends it to Norwegian Energy Regulatory Authority (NVE).
2	9 months	Timeframe for the practical planning and implementation of the upgraded UFSL scheme. In Norway almost all UFLS will be shed on distribution level (U≤132 kV) by the DSO's (Distribution System Operator).
Total	12 months	

It is noted that whilst there are differing implementation methods of UFLS settings, i.e. by the TSO, or by instruction to associated DSO's; the license obligation ultimately lies with the TSO to comply with the SOA. Thus, where DSO's are responsible for implementation of the associated UFLS settings, a 'compliance' audit by the TSOs could be utilised to ensure and demonstrate adherence to SOA requirements.

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ENTSO-E. (2014). *Technical background for the Low Frequency Demand Disconnection requirments.* Brussels: ENTSO-E.

Nordic Analysis Group. (2011). *Analysis & Review of Requirments for Automatic Reserves in the Nordic Synchronous System - Simulink Model Description.* ENTSO-E.

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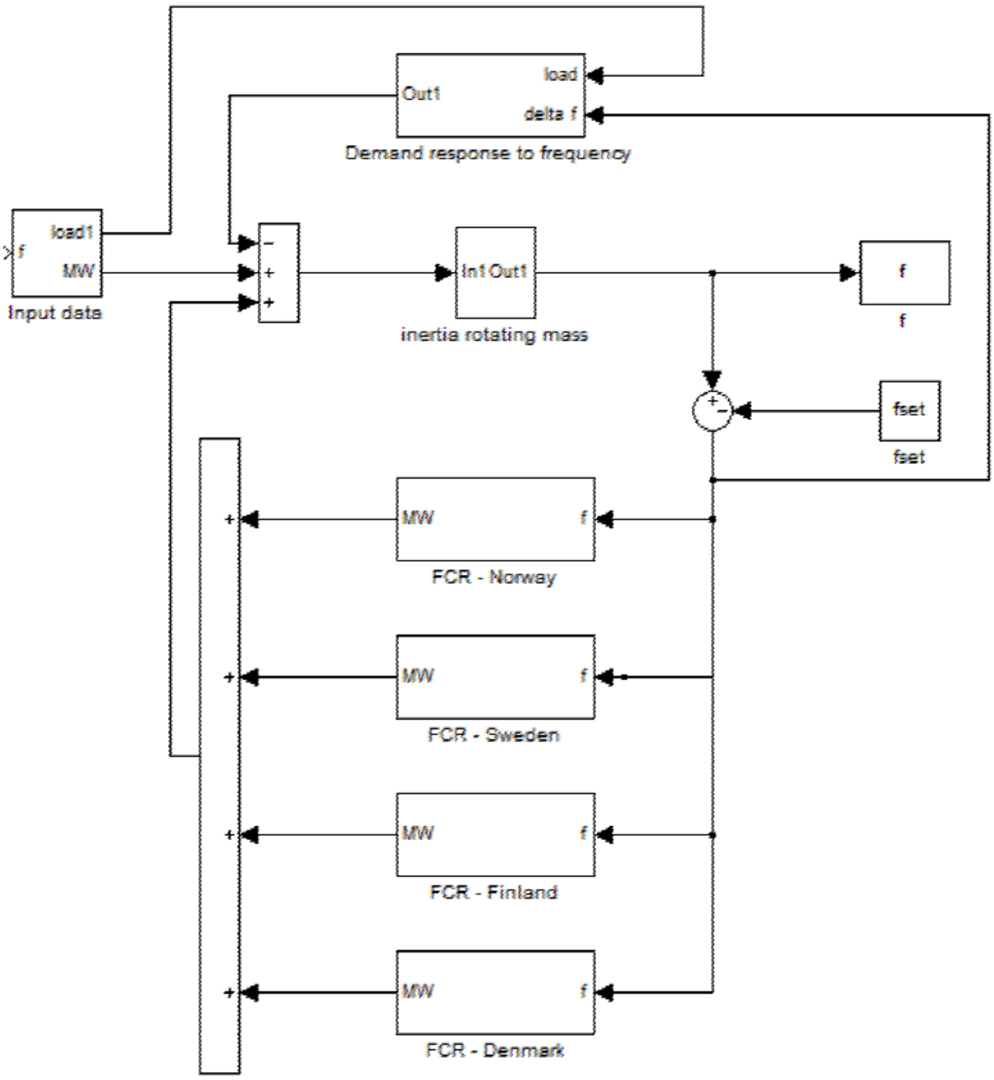
10. Appendix A - RAR Model Structure

The figure below shows the high level overview of the model of the existing automatic reserves in the Nordic system adopted for this project. On the left side, the input of the model is shown. The main input is the imbalance in MW. This imbalance is converted by the 'inertia rotating mass' block in frequency. The Frequency Containment Reserves (FCR) blocks for the different countries respond to this frequency minus the set point frequency (fset). This FCR response is added to the input signal. Also added to the input is the demand response to frequency changes.



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11. Appendix B – PSSE Modelling Assumptions

Modelling Principles

Given the nature of the study, it becomes important to highlight some base principles and assumptions that allow the reader a firmer understanding of how the studies were performed. This includes information like how FCR is deployed, classification of the form of outage considered, the ramping rules under which power can be curtailed or increased and the impact of frequency dependent load.

For clarity this section does not exhaustively consider all facets of the model.

FCR Deployment

In order that the detailed model adheres realistically to outages and associated transient recovery, FCR levels have been deployed to reflect an appropriate geographic distribution and quantities. The targeted levels were 1800 MW (1200 + 600 MW as declared within the SOA) with an activation frequency of 49.5 Hz. The target amount of FCR for each country is stated within SOA.

The division of FCR is characterised as seen below in Table 35.

Table 35 FCR deployment per country

Country	FCR Deployment
Norway	– Bidding zone NO1 10% – Bidding zone NO2 34% – Bidding zone NO3 14% – Bidding zone NO4 18% – Bidding zone NO5 24%
Sweden	FCR volume is set based on historical activation using a merit order.
Finland	– 66% of the FCR capacity is located in northern Finland. – 33% of the FCR capacity is located in southern Finland.
Demark	FCR volume is apportioned to HVDC links

Swedish and Norwegian WEHGOV governor model settings reflect both FCR-N and FCR-D behaviour. Finnish governors are consistent with FCR-D parameters. It is noted that the total reserve contribution in frequency disturbance below 49.5 Hz is approximately 1600 MW, corresponding to 1200 + 600 MW of FCR-D and FCR-N minus 200 MW.

Modelling Assumptions

Given that the scope of this study is to establish an UFLS scheme that will be fit for purpose for a long term transmission planning horizon (year 2025).

Perturbations or transient outages are defined and implemented in a method consistent with the Nordel Grid Disturbance Group definitions in which a grid disturbance is defined as:

Outages, forced or unintended disconnection or failed re-connection as a result of faults in the power grid (STÖRST, 2009).

For the purposes of this study, faults that are seen to instigate grid disturbance would be classified as Primary and Secondary within the auspices of this guide. In this context, and when applied to the Nordic Code, the level of grid disturbance would conform to an FG5 class event within pre fault / fault group planning criteria which is consistent with the likely point of UFLS activation.

Ramping Rules

To avoid imbalances in the Nordic synchronous system, the changes in flow on the HVDC-cables must be followed by corresponding changes in production. With current arrangements for system operation and production control (many manual procedures), it is required that the flow on the cables do not change too quickly.

Consequently, a restriction for flow gradient is set to max 30 MW/min per connection was set in place. With six relevant connections today, this means a total gradient for the synchronous system of 180 MW/min. whilst there is a tangible contribution within the dynamic time domain, when considering the shorter term transient and quasi dynamic time domain this has less relevance and in reality becomes difficult to model coherently in this context. For this reason the associated Ramping Rules are neglected within these studies.

Frequency Dependent Load

It is noted that there is an associated impact of load that is frequency dependent; the magnitude of frequency dependent load and its impact on maximum and minimum base cases is not sufficiently know. Figures 18 and 19 below characterises the impact of frequency dependent load on the network frequency in the Sweden. It is observed that by not considering frequency dependence, the relative divergence of network frequency as a result of the loss of Olkiluoto 3 is the most onerous. Whilst this may not be precisely reflective of reality in this regard, the divergence as a result of the transient can be considered the most onerous outcome. As a result this is considered conservative characteristically, and thus most appropriate in assessing the practicalities of any given UFLS scheme. For this reason frequency dependence of load is not considered as part of this study, with all load modelled conventionally (standard RLC components) within PSSE.

Figure 18 Impact of frequency dependent loads on network frequency

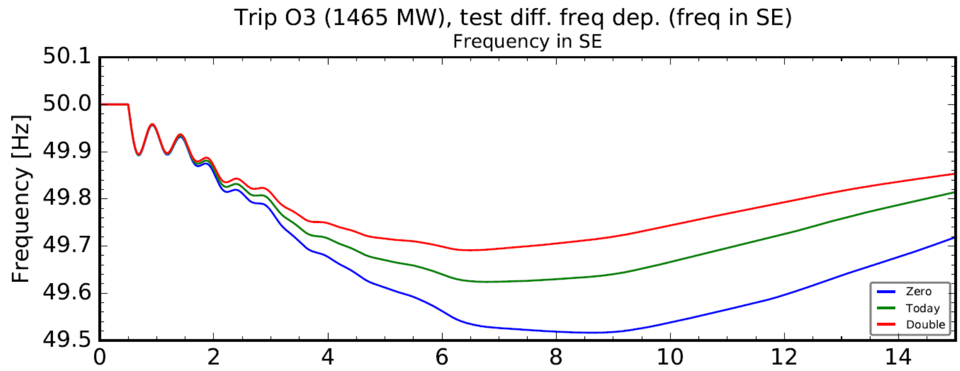
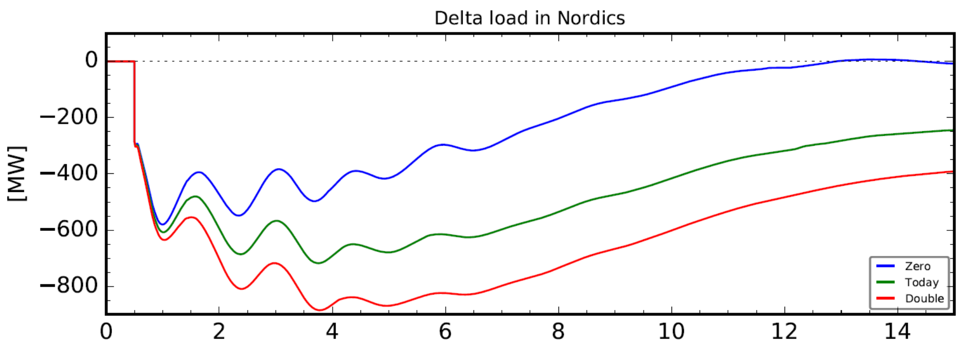


Figure 19 Impact of frequency dependent loads on network demand



Generation / Interconnector Modelling

The developed model considers the dynamic behaviour of the Nordic system it is necessary to represent dynamically, the varying generating or interconnecting technologies within the system. In order to achieve this, the following assumptions and observations are made:

- Conventional generating plants inter alia, the production from the synchronous generators including thermal and hydro power is be considered within the model. These, to the extent possible, model the dynamic/transient behaviour of the varying units based on the data available. For clarity this takes the form of each single generator being connected to the high voltage busbar through step up transformers. New generation is modelled as individual machines rather than lumped machines on an HV busbar based on TYNDP information available.
- Wind turbine generators are represented within the study. The model does not consider inter array cabling though would consider modelling of wind farms based on technology type (i.e. DFIG, SFIG, PMSG) and associated tripping thresholds in under frequency to emulate the particular settings on some TSO's. For future wind farms detailed in the TYNDP, the NAG would assume PMSG equipped with fully rated convertors.
- Whilst we recognize that PV and solar RES have a contribution to the generation profile within the Nordics, its contribution is in the form of embedded generation at distribution voltages. For this reason the model does not consider PV other than recognition of its contribution reduction of local load at a distribution voltage point of connection.
- HVDC interconnections are not modelled in forms consistent with technology type (i.e. LCC and VSC) but do characterise their capacity to deliver a directional flow of electrical power. The model does not consider any bespoke contribution to ancillary service such as voltage or frequency support other than any agreements which are already in place to provide additional electrical power or a change in direction of power flow to system operators. We have modelled staged injection or reduction of electrical power deployed within the scheme where applicable.

Over Frequency Protection

The following settings were implemented in the Nordic power system model:

Sweden: Wind farms with larger generation than 20 MW in steady-state in scenario is modeled with an over-frequency protection model[9]. The tripping point is set to 52.0 Hz, which is the requirement, but also the probable value the relay settings for most of the wind farms in Sweden.

Norway: Wind farms are disconnected at 52.0 Hz, which is the requirement and in this study assumed as the setting for the protection relays.

Denmark (DK2): The required ramping of wind (50.2-52.0 Hz) in DK2 is approximated with the disconnection of wind farms at 51.1 Hz. Wind farms in DK2 is not possible to identify in the model and instead an equivalent amount of generation for the scenario hour was disconnected[10].

Finland: Wind farms are assumed to be disconnected at 53.0 Hz, which also is the requirement in Finland. Since the studied outage events never reach this level no disconnection of generation was observed in the study.

Other generation sources than wind are disconnected at 53.0 Hz, or above, and since the studied outage events never reach this value the protection equipment for these did not needed to be included in the power system model.

The activation time (measuring and tripping) is assumed to be 0.2 seconds.

[9] This simplification results in about 200 MW wind not being modelled with over-frequency protection in Sweden.
[10] The wind generation for the modelled hour in DK2 in the studied scenario is 17 MW. Over-frequency protection equipment was modelled for an equivalent amount of generators in DK2.

Treeing Technique

In PSSE, large scale contingencies have a tendency to fail due calculation issues when the system is separated into one or more islands. To avoid this, a 'treeing technique' is applied in the simulations. For events causing a separate island the isolated part of the model was removed and neglected in the further simulation. For example when NO4 is isolated in event 3 the study only considers how the event affected the UFLS in the remaining Nordic system, and not the isolated area.

Out of Step Model

A generator out-of-step scanning model is applied in the simulations. This model, named STOPG5, disconnects machines at a specified machine angle (>400).

Reactive Compensation and Ancillary Services

In respect to reactive compensation and associated frequency support provisions:

- Model of MVAr and power factor compensation systems associated with any industrial or commercial customers at transmission level. For clarity this may include reactive compensation found on MV tertiary windings of HV transformers. We have not modelled the capability of SVC's to provide frequency support unless a detailed model of that support is available within the NAG.
- Ancillary services for frequency support will be modelled in accordance with current procurement and regulatory directives. We do not propose to model any future alternative ancillary market model.

Modelling of Hydro units in the context of FCR

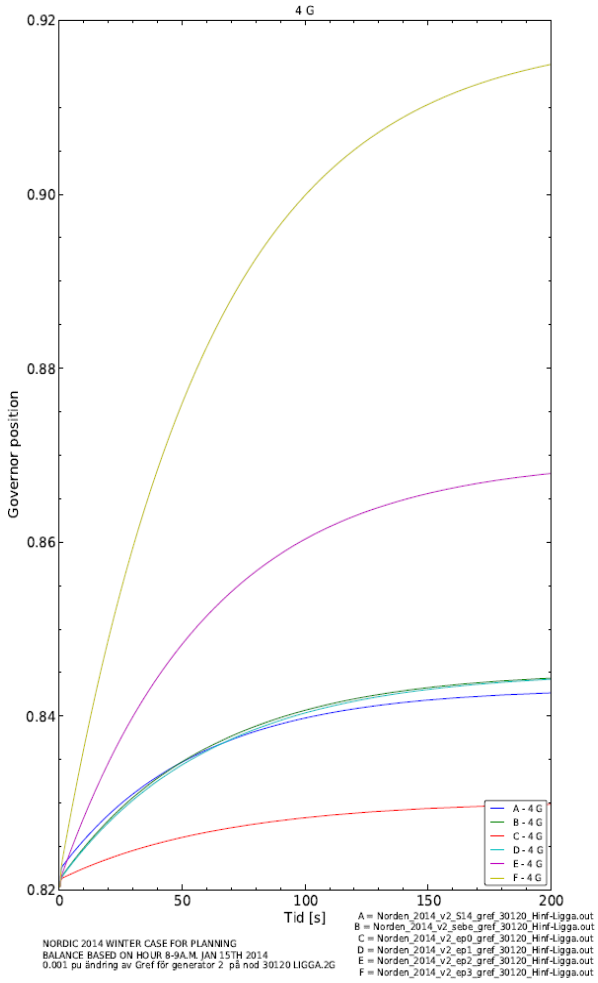
During the process of modelling the current network performance characteristics it became clear that a large proportion of Hydro based FCR within Sweden had up to five differing governor settings (per unit) to characterise the governor performance when responding to differing levels of frequency deviation. To this is end it became necessary to account for these settings in order to provide a realistic view on FCR contribution under frequency deviation.

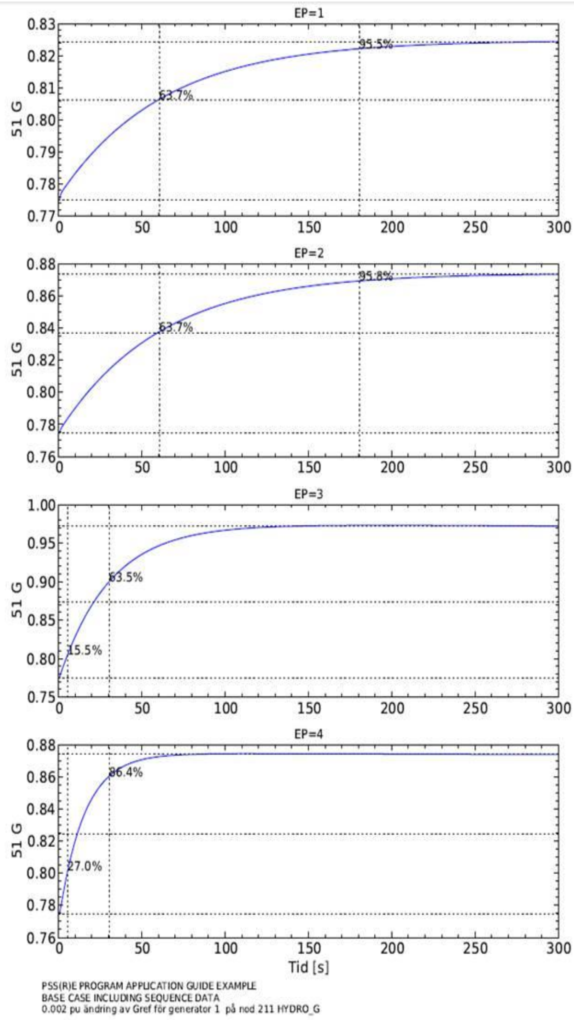
Data provided by the Generator shows the settings of the turbine governors for machines participating in FCR-D. These generators have four or five different modes with different PID settings. Different settings are activated depending on the frequency disturbance. The first modes (ep0, ep1, ep2) are for normal FCR-N. ep3 or ep4 is activated given different condition in the frequency disturbance.

The figure below shows a test with these different settings for a generator in Sweden. The test is essentially a step change of the frequency set point value for the generator.

Current settings are characterised as the blue curve, which correspond well to the ep1 setting in the new data. For this reason, in Sweden all generators are classified to be operating in a FCR-N mode (in our PSSE models), with virtually all generators providing further contribution.

The yellow curve below is the settings seen to be most favourable for FCR-D generators (ep3 setting). The ep4 has even larger response, but this is only available on a small selection of identified units.





It is noted that the power producing entities set the FCR-N (e.g. about 220 MW in Sweden) for the generators. These are then ‘activated’ into FCR-D ep-mode when a frequency dip occurs. The FCR-D volume will always be fulfilled if FCR-N is fulfilled and the FCR-D volume is seen to be higher than currently procured.

12. Appendix C - Current Situation

The existing ULFS philosophy was initially developed and implemented within the 1980's in order to consider the rising interconnectivity of the Nordic system (formerly Nordel). The plan was consistent with "Proposed Recommendation for frequency controlled power conditioner in the synchronous Nordel area".

To this end, the policy set out the following principles:

- HVDC connections out of the Nordel area were used for emergency power within the frequency range from 49.5 to 49.0 Hz. Utilisation (MW/s and MW) was agreed for each individual HVDC connection depending on its capability.
- ULFS within the national power systems was implemented during frequency drops down to 48.7 Hz. Disconnections were made in steps of 0.2 Hz and in a total magnitude of 20-50% of the total load depending on the expected production deficit.
- The individual ULFS policy of the country defined the size, locality and distribution of frequency step whilst having due regard to the requirements of an overall Nordel operation.
- The first ULFS policy steps were implemented in, or near Nordel system load centres.
- ULFS was carried out in such a manner that it minimised the risk of overload due to the changes in power flow around the network.
- Possible localised problems without significant consequences for Nordel network were addressed nationally.

As a result of these principles the following recommendations were adopted within in Nordel system:

- Sweden began load disconnection at 49.0 Hz (time delay 20s) and then used five 0.2 Hz decremented steps.
- Denmark and Norway began Load shedding at 48.7 Hz and subsequently over five 0.2 Hz decremented steps.
- Denmark adopted a first stage time delay of twenty seconds, while Norway adopted a relatively small MW level during the first stage.
- Finland began load disconnection at 48.7 Hz (time delay 20 s) and then two 0.2 Hz decremented steps.

These settings have evolved in the intervening years to the settings currently adopted within the SOA. The Current UFLS policy enacted within the SAO is seen in the main body of this report.

The following section elaborates further on the current UFLS policies adopted within each Nordic country. It is noted that although the SOA prevails over other UFLS policy for each country, there are other procedures that underpin this policy. Although each country has a clear methodology for UFLS activation, the methodology for implementation is different from one country to the next. This is invariably a legacy from the original determination of the settings. The settings together with a summarised methodology of the UFLS application from one country to the next is seen within this section.

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Norway

Description

The Norwegian view of UFLS has been a distributed approach across the country; with each area shedding between 20-50% of total electrical load (depending on seasonal variation). The approach distributes the load shedding across the varying Distribution Network Operator's with an obligation to adequately participate in UFLS, should it be necessary. Each Distribution Network Operator is required to distribute a minimum of 30% of its total load disconnected across the three stages and is coordinated by Statnett. This is characterized in Table 36.

Table 36 UFLS load geographic distribution within Norway

Area	Maximum Load (MW)	Maximum UFLS (MW)	Maximum UFLS as a function of Load
North	1200 MW	300 MW	25 %
East	9700 MW	2900 MW	30 %
South	3000 MW	900 MW	30 %
West	4500 MW	1400 MW	31 %
Central	4500 MW	1500 MW	33 %
Total	22900 MW	7000 MW	31 %

Frequency protection is not installed with the capacity to be deactivated. As a result it is always operational. This has been known to trigger islanded operation locally; instigating voltage collapse. There are, in principle occasions where UFLS is activated resulting in the network no longer being compliant with operational planning standards, which may raise the risk of isolating parts of the network.

Frequency levels for Norway are based on the historical recommendations highlighted in the section above. UFLS has been set such that it will only be activated during serious frequency excursion (which is very rare). There have been occasions where protection mal-operation has resulted in network separation which can create a significant generation to load deficit in the regional network.

Each Distribution Network Operator is assigned three frequency levels unless otherwise specified and a load quantity. It is up to the licensee to distribute the UFLS over these set stages (one third over each frequency level) based on defined guidelines from the Network Operator. The stages and time for UFLS for each regional area is characterized in Table 37.

Table 37 Norway UFLS Implementation

Area	Frequency Area 1 (Hz)	Frequency Area 2 (Hz)	Frequency Area 3 (Hz)	Time (Sec)
North	48.7	48.5	48.3	0.1
East	48.5	48.3	48.1	0.1
South	48.3	48.1	47. 9	0.1
West	48.1	47.9	47.7	0.1
Central	48.1	47.9	47.7	0.1

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Sweden

Description

Transmission planning in Sweden is performed to comply with N-1 intact planning criteria. This is such that the loss of a Principle Component (as named within the SOA) will not result in the need to activate UFLS. Under these circumstances frequency support from ancillary services should be sufficient to resolve the associated frequency excursion. In the case of a Dimensioning Fault it may be necessary to activate UFLS.

The frequency level at which UFLS is activated is determined by the capability of the power generating plants locally to cope with low operating frequencies and disturbances. Presumably this is reference to the large nuclear units which may be sensitive to such disturbances and are exempt from having to provide frequency support to the network.

The relay settings are devised such that disconnection occurs in five approximately equal steps when the frequency falls below the following values:

- Step 1: 48.8 Hz in 0.15 seconds
- Step 2: 48.6 Hz in 0.15 seconds
- Step 3: 48.4 Hz in 0.15 seconds
- Step 4: 48.2 Hz in 0.15 seconds at 48.6 Hz for 15 seconds
- Step 5: 48.0 Hz for 0.15 seconds and at 48.4 Hz for 20 seconds.

The settings are designed such that the disconnection takes place in four stages, depending on the frequency excursion and its associated fall below the following values:

- 35 MW P ≤ 49.4 Hz in 0.15 seconds
- 25 MW ≤ P <35 MW of 49.3 Hz in 0.15 seconds
- 15 MW ≤ P <25 MW of 49.2 Hz in 0.15 seconds
- 5 MW ≤ P <15 MW of 49.1 Hz in 0.15 seconds

Denmark

Description

The Danish approach to UFLS is separated into two specific geographies; these being Eastern and Western Denmark. The scope of this study considers only the East of Denmark. For this reason we focus on this area only within this report.

UFLS is applied on a regional basis characterized as ‘Relief Regions’. A Relief Region is an entire or a portion of a network. This network does not have to be wholly owned by one operator and can be considered in cooperation between grid companies whom collaborate on load shedding as defined by the SOA.

The approach within a specific Relief Region is electrically connected at a voltage level less than 100 kV, meaning that the load shedding occurs at a DSO level with the TSO coordinating and operating the disconnection philosophy.

The largest maximum load within one Relief Region cannot be larger than 600 MW, with the aim of staged disconnection not exceeding 60 MW. For this reason larger Network Operators are separated into several relief regions as appropriate. The stages and time for UFLS for each relief region is characterized in Table 38.

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Table 38 Eastern Denmark UFLS Implementation

Requirements for Automatic Frequency Load Shedding (UFLS) of net Electricity Consumption in Relief Regions					
	% of Load Disconnection	Momentary Criteria for Disconnection		Longer Duration Criteria for Disconnection	
		Frequency (Hz)	Time (Secs)	Frequency (Hz)	Time (Secs)
Step 1	10%	f < 48.5	t = 0.15	f < 48.7	t = 20
Step 2	10%	f < 48.3	t = 0.15	f < 48.5	t = 20
Step 3	10%	f < 48.1	t = 0.15	f < 48.3	t = 20
Step 4	10%	f < 47.9	t = 0.15	f < 48.1	t = 20
Step 5	10%	f < 47.7	t = 0.15	f < 47.9	t = 20
Total	50%				

Finland

Description

Finland's obligations as defined by the SOA are seen below:

- 10% of consumption f < 48.5 Hz at 0.15s f < 48.7 Hz at 20s
- 10% of consumption f < 48.3 Hz at 0.15s f < 48.5 Hz at 20s

Having reviewed this with Fingrid, the likely levels of UFLS are likely to be more realistically characterised by Table 39.

Table 39 A realistic view on UFLS implemented within Finland

Stage	f (Hz)		delay (s)		% of load
	fast	slow	fast	slow	
1	48.5	48.7	0.15	20	7 *
2	48.3	48.5	0.15	20	5 *

*median values in years 2011-2013.

13. Appendix D – High Risk Operational Cases

In order to consider the behaviour of the varying UFLS under events that are well beyond the required levels of network security (as mandated within the SOA); a set of high risk events have been developed to provide a degree of clarity as to how the Nordic network may respond under, what could be considered once in 100 year events.

2025 Extreme Case

The 2025 Minimum demand case assumes an extreme low demand for the Nordic Network. The model represents a summer minimum scenario, with very low generating inertia. Committed network reinforcements up to 2025 are included in keeping with the TYNDP.

The following salient details are considered within the model and within the associated simulations:

- Import increased on almost all HVDC
- Production decreased in SE and NO (hydro)
- Nuclear predominantly offline
- 107 GWs operational inertia

As discussed previously, the main reason for this scenarios inclusion is to account for a changing network topology and a generation profile that may be influenced by spot pricing in ways that facilitate high HVDC injection and low localised generation.

Figure 20 Summary of initial power flows for the 2025 minimum demand extreme base case

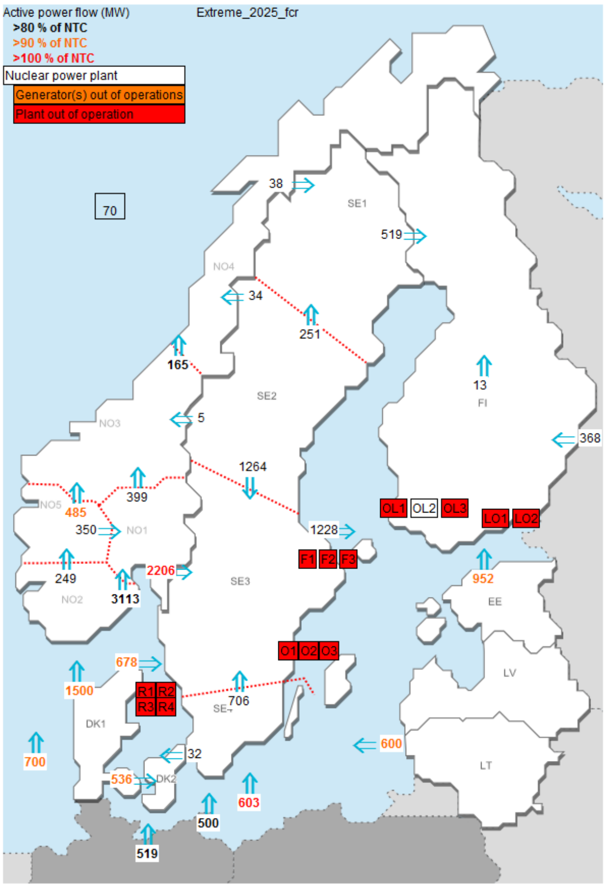

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Table 40 Summary of generation and load for the 2025 minimum demand extreme base case

Summary	Denmark (DK2)	Finland	Norway	Sweden
Total production (MW)	185	3041	9378	5520
Total load (MW)	1253	5970	10427	8106
Total export (MW)	-1068	-2929	-1049	-2586
Inertia (MWs)	1,311	20,561	55,721	30,087

Scenarios Considered

In order to consider the behaviour of the varying UFLS under events that are well beyond the required levels of network security (as mandated within the SOA); a set of high risk events have been developed to provide a degree of clarity as to how the Nordic network may respond under, what could be considered once in 100 year events.

These events are summarised below. Scheme numbers are consistent with the body report.

Scheme	Outage of approximately 2000-2500MW	Outage of approximately 4000MW
1	One large stage (10% load shed) is activated at 48.8 Hz. This instigates overshoot up to 51 Hz. Frequency stability is seen to be acceptable.	Both stages are activated at 48.6 Hz. Frequency stabilizes at 49.7 Hz after 20% load shedding. Frequency drop and overshoot is acceptable.
2	One stage of 5% load shedding is activated. Lowest frequency 48.7 Hz and small overshoot of 50.4 Hz.	Both stages are activated, but a total of 10% load shedding is not sufficient. As a result system frequency drops down to 47 Hz. Stable frequency around 49.2 Hz is also not deemed acceptable.
3	One stage of 5% load shedding is activated. Lowest frequency 48.7 Hz and small overshoot of 50.4 Hz.	All 4 stages are activated at 48.2 Hz. Lowest frequency down to 48.1 Hz might lead to consequential losses. Small overshoot with acceptable frequency stability.
4	One stage of 7.5% load shedding is activated. Overshoot up to 50.6 Hz and stable frequency is 50.0 Hz.	3 of the 4 stages (22% load shedding) are activated at 48.4 Hz in the extreme case. Frequency reaches 48.3 Hz. One stage not activated. No overshoot and acceptable frequency stability (49.7 Hz).
5	One stage of 5% load shedding is activated. Lowest frequency 48.9 Hz and small overshoot of 50.4 Hz.	All 4 stages are activated at 48.4 Hz. Lowest frequency reaches 48.3 Hz. This should not lead to consequential losses. Small overshoot and acceptable frequency stability. Compared to scheme 3, load shedding activation at 49.0 Hz reduces the risk of consequential losses due to the associated frequency drop.
6	One stage of 7.5% load shedding is activated. Overshoot up to 50.6 Hz and stable frequency is 50.0 Hz.	3 of the 4 stages (22% load shedding) are activated at 48.6 Hz in extreme case. Lowest frequency reaches 48.5 Hz with a remaining inactivated stage. No overshoot and acceptable frequency stability slightly under 49.7 Hz. Compared to scheme 4, activation of load shedding at 49.0 Hz does not provide any benefit.

7	Activation of 2 stages (6% load shedding) provides a small overshoot and stable frequency around 49.9 Hz. Stage 2 is not activated. If only the first step of 2% load shedding is activated, the frequency does not stabilize.	4 out of 6 stages (20% load shedding) are activated at 48.4 Hz in extreme case. Lowest frequency down to 48.3 Hz, with remaining inactivated stages. No overshoot and acceptable frequency stability slightly under 49.7 Hz.
8	One stage of 5% load shedding is activated. Lowest frequency 48.9 Hz and small overshoot of 50.4 Hz. Acceptable frequency stability at around 49.9 Hz.	3 of the 4 stages (25% load shedding) are activated at 48.4 Hz in extreme case. Lowest frequency down to 48.3 Hz, with a remaining inactivated stage. Small overshoot and acceptable frequency stability at around 49.8 Hz
9	One stage of 2.5% load shedding is activated. Lowest frequency 48.9 Hz, small overshoot and stable frequency around 49.8 Hz.	All 4 stages (20% load shedding) are activated at 48.2 Hz. Lowest frequency reaches 48.0 Hz which may lead to consequential losses. Small overshoot and acceptable frequency stability at around 49.7 Hz.
10	One stage of 3.75% load shedding is activated. Frequency reaches 48,9 Hz with a small overshoot and acceptable frequency stability over 49.8 Hz.	3 out of the 4 stages (18% load shedding) are activated at 48.4 Hz. Lowest frequency reaches 48.3 Hz, with a remaining inactivated stage. No overshoot and acceptable frequency stability over 49.6 Hz
11	Two stages activated down to 48.7 Hz. This provides a small overshoot and acceptable frequency stability between 49.8-49.9 Hz.	9 stages are activated from 48.8 down to 48.0 Hz. There is a risk that this can lead to consequential losses of generators in the Nordic system. No overshoot and acceptable frequency stability around 49.6 Hz if all generators stay in service.
12	Two stages activated as with scheme 11, but smaller steps (%) will give poorer frequency stability.	Quite similar to scheme 11. 9 stages are activated from 48.8 down to 48.0 Hz. There is a risk that this can lead to consequential losses of generators in the Nordic system. No overshoot and stable frequency around 49.6 Hz if all generators stay in service.

Table 41 Change in quantity of mechanical power available during simulations (2025 Extreme Case)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	164	164	164	164	164	164	164	164	164	164	164	164
Event 2	7149	5984	6424	7185	6431	7202	7214	6789	6702	7042	6874	6487
Event 3	1728	1728	1728	1728	1728	1728	1728	1728	1728	1728	1728	1728
Event 4												
Event 5	5	5	5	5	5	5	5	5	5	5	5	5
Event 6	1563	1563	1563	1563	1563	1563	1563	1563	1563	1563	1563	1563
Event 7	5	5	5	5	5	5	5	5	5	5	5	5
Event 8	5	5	5	5	5	5	5	5	5	5	5	5
Event 9	2544	2139	2139	2115	1957	1749	2051	1957	2429	2203	2368	2616
Event 10	2541	2198	2198	2092	1955	1630	2088	1955	2433	2197	2355	2629
Event 11	2888	2627	2526	2542	2278	2198	2297	2278	2642	2467	2644	2665
Event 12	2083	2238	2238	2219	2004	2120	2317	2482	2578	2074	2516	2569
Event 13	2610	4306	2954	2499	2790	2269	2821	2875	2972	2868	3175	2936
Event 14	2831	4782	3236	3045	3095	2860	3006	2899	3227	3199	3440	3273

Table 42 Change in electrical load from initial steady state conditions to post outage recovery conditions (2025 Extreme Case)

	No.1 (2stage 10% each stage)	No.2 (2 stage 5% each stage)	No.3 (4 stage 5% each stage activating at 48.8Hz)	No.4 (4 stage 7.5% each stage activating at 48.8Hz)	No.5 (4 stage 5% each stage activating at 49Hz)	No.6 (4 stage 5% each stage activating at 49Hz)	No.7 (ENTSOE scheme 1 over 6 stages)	No.8 (ENTSOE scheme 2 over 4 stages)	No.9 (ENTSOE scheme 2 over 4stages cutting 20% load)	No.10(ENTSOE scheme 2 over 4 stages cutting 30% load)	No.11 (SOA)	No.12 (SOA real)
Event 1	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Event 2	-3378.0	-1743.0	-2562.0	-3343.0	-2667.0	-3459.0	-3349.0	-2987.0	-2741.0	-3174.0	-2969.0	-2545.0
Event 3	0	0	0	0	0	0	0	0	0	0	0	0
Event 4												
Event 5	0	0	0	0	0	0	0	0	0	0	0	0
Event 6	0	0	0	0	0	0	0	0	0	0	0	0
Event 7	0	0	0	0	0	0	0	0	0	0	0	0
Event 8	0	0	0	0	0	0	0	0	0	0	0	0
Event 9	-2265.7	-1132.9	-1132.9	-1699.4	-1132.9	-1699.4	-1304.8	-1132.9	-566.4	-849.6	-949.5	-433.7
Event 10	-2265.7	-1132.9	-1132.9	-1699.4	-1132.9	-1699.4	-1249.6	-1132.9	-566.4	-849.6	-946.6	-433.7
Event 11	-3968.7	-2265.7	-2506.3	-3398.6	-2655.4	-3398.6	-2719.8	-3172.0	-2832.0	-2379.2	-2390.5	-2462.1
Event 12	-2265.7	-2265.7	-2265.7	-2228.2	-2265.7	-2917.4	-2154.9	-3053.4	-1586.1	-2379.0	-1868.7	-1879.3
Event 13	-4531.4	-2265.7	-4531.4	-5098.5	-4531.4	-5098.5	-4537.1	-5665.8	-4531.3	-5322.6	-4086.6	-4723.6
Event 14	-4531.4	-2265.7	-4531.4	-4430.1	-4531.4	-4435.4	-4532.4	-4900.1	-4531.3	-4249.7	-4086.6	-4425.5

*Greyed out sections denote a lack of convergence of the PSSE base case thus is neglected.