European Network of
Transmission System Operators
for Electricity

# Operational Limits and Conditions for Mutual Frequency support over HVDC

Published February 2021

## Contents

## List of Figures



## List of Tables

# 1 Executive summary

This paper defines the setting of limits for mutual frequency support over HVDC between Synchronous Areas (SAs) to harmonise the implementation of LFSM for the CE, Nordic and GB synchronous areas and replace some existing EPC services.

The paper focuses on the ways in which current and future mutual frequency support as a defence mechanism can be implemented safely and securely over the HVDC links between SAs. It aims to increase system robustness in preparation for lower levels of inertia due to increases in renewable penetration. Its scope is designed to complement the current internal SA work on inertia[1] and to be compliant with the (EU) 2016/1447[2] Article 13 (3), Article 39 (4) & (7).

The project has modelled the CE, Nordic and GB synchronous areas to recommend a safe, secure and standardised European framework to enable system defence using HVDC links between SAs. The framework limits for mutual frequency support is set out in table 1 and 2 below and are recommended for inclusion in the in the Synchronous Area Operational Agreements (SAOA) in accordance with COMMISSION REGULATION (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (SOGL). The support schemes are intended for *N* – 2 situations and should activate for those incidents that might cause a bigger deviation than the maximum allowed instantaneous frequency deviation. Additionally, these support schemes should be fully deployed before automatic load or generation shedding occurs.

| **Proportional over frequency support scheme** | **GB ->CE** | **Nordic ->CE** | **CE ->GB** | **Nordic ->GB** | **CE ->Nordic** | **GB ->Nordic** |
|---|---|---|---|---|---|---|
| Maximum support (MW) | 600 | 600 | 1000 | 600 | 1000 | 600 |
| Frequency trigger for starting delivery (Hz) | CE : 49.80 | CE : 49.80 | GB : 49.50 | GB : 49.50 | NO : 49.50 | NO : 49.50 |
| Frequency for full delivery (Hz) | CE : 49.20 | CE : 49.20 | GB : 49.0 | GB : 49.0 | NO : 49.00 | NO : 49.00 |
| Frequency level for freezing of delivery (Hz) | GB : 49.75 | NO : 49.75 | CE: 49.90 | NO : 49.75 | CE: 49.90 | GB : 49.75 |

*Table 1: Mutual frequency support between Synchronous Areas for under frequency.*

The framework limits are developed by building validated models of the three SAs (in dialogue with SA technical groups). Simulations are then applied to these models to define dynamic operational security limits. These security limits are then applied in setting the framework limits for mutual frequency support. Worst case scenarios have been considered and modelled assuming a low inertia and low initial frequency at both the receiving and the providing synchronous areas before the event.

[1] As required by SO GL Article 39.3

[2] COMMISSION REGULATION (EU) 2016/1447 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules (HVDC Connection Code).

| **Proportional over frequency support scheme** | **GB ->CE** | **Nordic ->CE** | **CE ->GB** | **Nordic ->GB** | **CE ->Nordic** | **GB ->Nordic** |
|---|---|---|---|---|---|---|
| Maximum support (MW) | 400 | 500 | 1000 | 500 | 1000 | 400 |
| Frequency trigger for starting delivery (Hz) | CE : 50.20 | CE : 50.20 | GB : 50.40 | GB : 50.40 | NO : 50.50 | NO : 50.50 |
| Frequency for full delivery (Hz) | CE : 50.80 | CE : 50.80 | GB : 50.80 | GB : 50.80 | NO : 51.00 | NO : 51.00 |
| Frequency level for freezing of delivery (Hz) | GB : 50.25 | NO : 50.25 | CE: 50.10 | NO : 50.25 | CE: 50.10 | GB : 50.25 |

*Table 2: Mutual frequency support between Synchronous Areas for over frequency.*

There is a limit on the maximum volume of support that each synchronous area can provide to ensure that the synchronous area providing the support remains within a healthy frequency range. These volumes are calculated using the current and future synchronous areas parameters using the developed model in SIMULINK created in the project by ENTSOE. It is evident based on the simulation results that the proposed mutual frequency support schemes are effective in minimising the risk of entering load shedding following the N–2 event on the system. The frequency triggering point for the proposed support schemes are defined to ensure FCR are fully activated in steady state.

This framework is applicable to current operational HVDC links (where technically possible) and all future HVDC links. TSOs that have an HVDC interconnector shall initiate the implementation with the objective of completing the technical adaptations within a period of no longer than 5 years.

# 2 Introduction and motivation for the mutual frequency support report

The report objectives are to investigate inertia management within synchronous areas and arrangements over HVDC to enhance frequency, consolidate existing arrangements and to determine future mutual frequency support arrangements between synchronous areas.

Previous work[3] [16] completed in 2018 defined the dynamic frequency coupling services between synchronous areas and determined operational limits for dynamic Frequency Coupling [1] as required by SO GL Article 172.

As this is a technical paper, commercial market arrangements are out of scope. The focus of this paper is on frequency support in relation to system defence. It details a technical framework and limits for mutual frequency support between SAs to minimize N-2 risks. Such large system failures are not required to be dimensioned under SO GL [1], but do occur.

## 2.1 Operational background

Over the last decade, there has been a large increase in renewable penetration in the power grids of Europe. This increase in renewables has had numerous effects on the European power system including, but not limited to, dynamic behaviour, power flows, inertia changes necessitating adjustment to technical requirements.

As renewable generation sources have lower or no inertia contributions, the resulting decreased system inertia needs new services to ensure operational security at the European level. The erosion in system inertia increases the risk to system security in particular to frequency deviation following a large system loss (N-2) which is not fully dimensioned for under SOGL legislation. The implementation of mutual frequency support as a defence mechanism aims to support the foreseen inertia erosion due to high levels of renewable penetration.

ENTSOE estimates that the renewable penetration will grow from 15% in 2020 to between 37 and 51 % by 2040 in its TYNDP 2018, as shown in Figure 1 below.

[3] Public version available here : https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/Operational_limits_and_conditions_for_frequency_coupling-summary_report.pdf

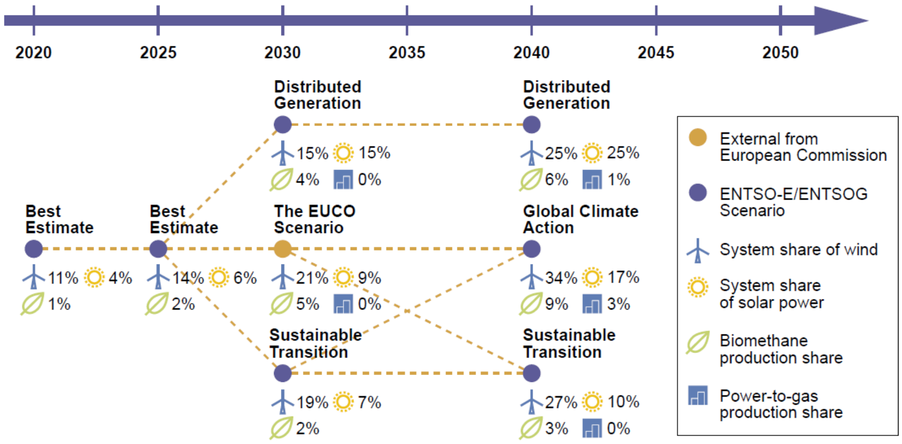


*Figure 1: Scenario building framework indicating Bottom Up and Top Down scenarios[4]*

The European Clean Energy Package legislation focuses on a shift away from carbon production and so conventional power plants will be replaced with renewables (non-synchronous sources of energy), without intrinsic inertia. The resulting loss of inertia from the system means that for the same level of power imbalance between generation and demand experienced by TSOs today, there will be a faster rate of change of frequency (RoCoF) and a greater deviation from 50Hz in the future. This is because power system inertia (the ability of a system to oppose changes in frequency due to resistance provided by kinetic energy of rotating masses in individual turbine-generators) provides time for TSOs reserves to compensate for the power imbalance. Thus, inertia erosion yields higher frequency sensitivity to disturbance incidents; and if the frequency falls below the minimum frequency level (or falls too quickly), the system is likely to have a major system incident and at worst case a blackout could occur. In principle, frequency stability can be maintained by balancing the system inertia, reserves and the size of the disturbances, as shown below in Figure 2.

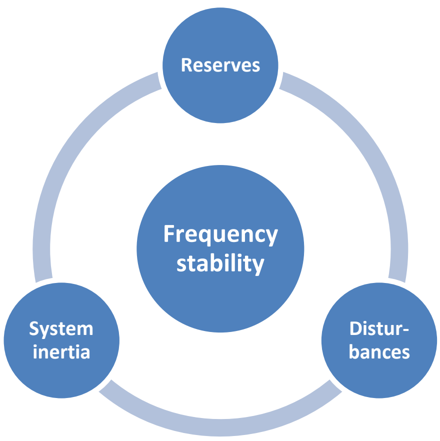


*Figure 2: Relationship that forms frequency stability*

---

[4] European Power System 2040 – Completing the map - The Ten-Year Network Development Plan 2018 System Needs Analysis

Inertia is directly related to the Rate of Change of Frequency (RoCoF). The lower the level of system inertia, the higher the RoCoF will be in the event of system loss. The degree of renewable penetrations and therefore the change in generation mix will have a different impact in the SAs.

In addition to implementing mutual frequency support as a defence mechanism, it also facilitates increasing the level of commercial services over HVDC as discussed in the first report [1] via procurement of new market services.

## 2.2 Focus of the report

The report focuses on the ways in which mutual frequency support as a defence mechanism can be implemented over the HVDC links between SAs. It aims to increase system robustness in preparation for lower levels of inertia due to increases in renewable penetration. This work is designed to complement the current internal SA work on inertia as required by SO GL Article 39.3 and to be compliant with the COMMISSION REGULATION (EU) 2016/1447 Article 13 (3), Article 39 (4), (7) [2]. This report is focused on recommending a safe, secure and standardised European framework to enable system defence using HVDC links between SAs.

## 2.3 Forecasted Inertia reduction in Synchronous Areas

The ENTSOE report "*European power system 2040 Completing the map*" [3] shows clearly that all SAs will see an ever-increasing decline in inertia levels and will be challenged by the resultant consequences for their system security. The impact of this inertia reduction is especially significant in small synchronous areas.

The graph (Figure 3) below illustrates today's generation mix. The aim is to forecast the generation mix with a higher integration of Renewable Energy Sources. It is noted that in all scenarios, all SAs are going to be significantly impacted by the effects of decreasing inertia.

## 2.4 Generation mix and HVDC capacity in 2020

Different types of generation provide different level of inertia and the falling level of inertia in SAs are in direct correlation to the increase of non-inertia providing generation i.e. wind, solar as well as HVDC links infeed. Figure 3 shows the generation mix as a percentage of total installed capacity per SA, and installed HVDC connectivity based on ENTSOE Statistical fact sheet 2018.

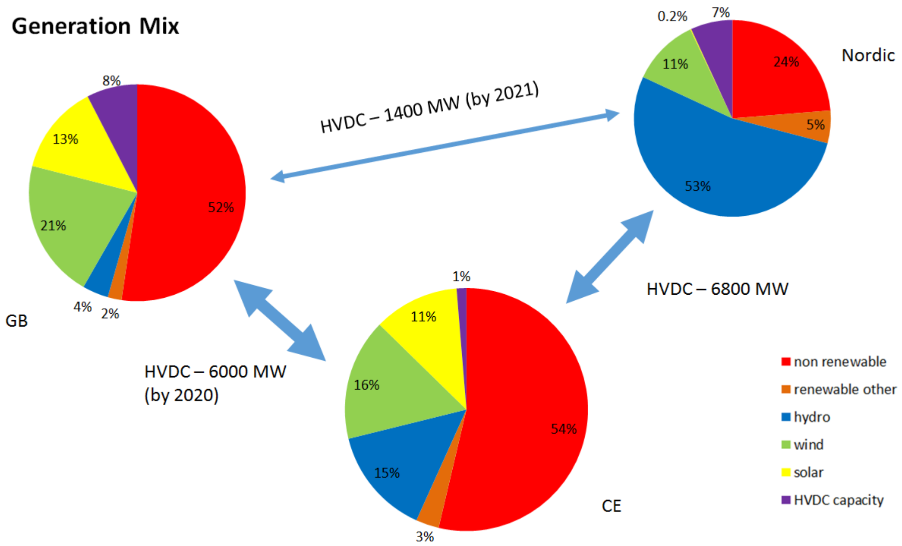


*Figure 3 : Generation Mix*

The pie charts show that the low inertia energy providers (such as wind, solar and HVDC), comprise a large percentage of the total installed generation capacity.

It is important to note that these pie charts show the worst case. However, the de-carbonization targets in response to climate change and current political reforms will continue to provide a motivation for increased renewable energy development. These developments will result in higher levels of wind generation, solar generation and HVDC links coming into operation over the next 5 to 10 years.

# 3 Frequency support

This report is focused on developing a common European defence framework for delivery of frequency support over HVDC links to mitigate the emergency risks at European level. Support is necessary when a SA encounters an event for which it is not dimensioned for and therefore it is in an emergency state.

Frequency support can be generically considered as an exchange of power between TSOs that is activated in real time. The support is provided by a SA or a group of SAs either manually or automatically, to improve the operational situation of the requesting SA. With higher HVDC connectivity between SAs, it enables implementation of mutual frequency support to enhance the system defence at a European level.

## 3.1 Relevant terminology

There are two main terminologies used in this report, they are provided below for clarification.

**Mutual frequency support**: is an obligation when requested by a SA to deliver frequency support up to a defined local frequency freeze threshold (if technically possible[5]), when requested by a SA. Delivery is conditional that the providing SA are not in an alert or emergency system state (so as not to jeopardise secure operation of the providing SA) [3].

**Frequency service**: is a contracted delivery between two SAs or TSOs, which the receiving SA/TSO includes in its dimensioning calculation (N-1). For the providing SA/TSO, it is a binding delivery obligation. The delivery of this service is based on an agreed set of commercial terms between parties (price, volume, duration and conditions).

This report is focused on Mutual frequency support for N-2 operational conditions, and will recommend a framework which includes volume, speed of response, trigger parameters and duration.

[5] i.e.: the control system of the HVDC has the capability of such a service and the providing Synchronous Area is in a system state that allows a support

## 3.2 Generic system state definition

The frequency limits vary for each SA and the values for system operation are defined in Annex III, Table 1 of SOGL [1]. The Figure 4 below shows the definition of system states relating to generic frequency thresholds and event duration in time. Each SA has an equivalent frequency framework for system operation.

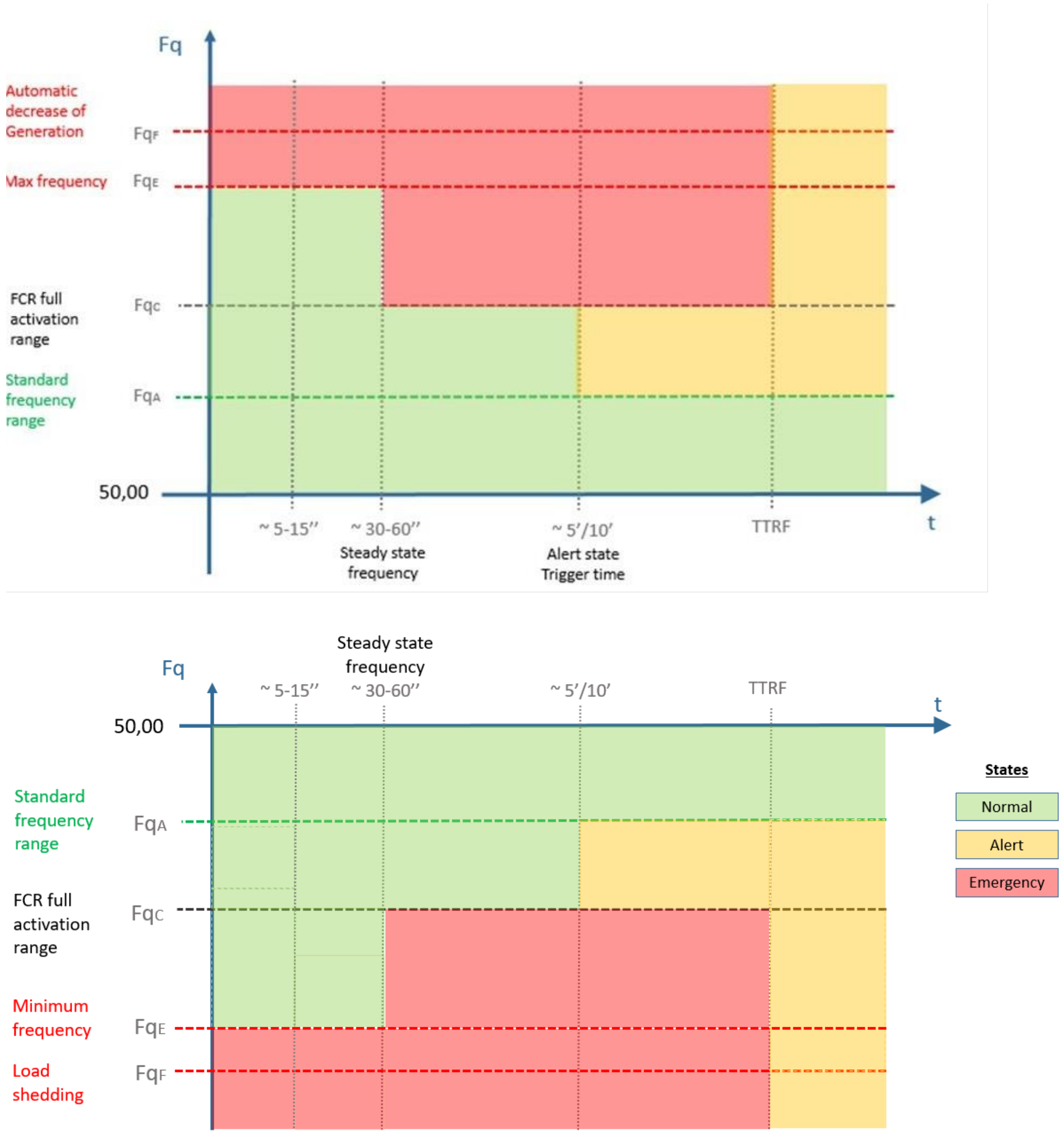


*Figure 4: Generic frequency and time mapping of system state*

The frequency thresholds are shown in the Table 3 below:

| | | CE | GB | IE/NI | Nordic |
|---|---|---|---|---|---|
| **$Fq_A$** | Standard frequency range - lower boundary of standard frequency range; this range is the symmetrical interval around the nominal frequency within which the system frequency of a synchronous area is supposed to be operated. | ± 50 mHz | ± 200 mHz | ± 200 mHz | ± 100 mHz |
| **$Fq_C$** | Maximum steady-state frequency deviation - FCR full activation range; it is the target for maximum steady state frequency deviation after dimensioning incident | 200 mHz | 500 mHz UF<br>500 mHZ OF[6] | 500 mHz | 500 mHz |
| **$Fq_E$** | Maximum instantaneous frequency deviation - minimum frequency; it is defined by the maximum instantaneous frequency deviation after dimensioning incident. | 800 mHz | 800 mHz | 1 000 mHz | 1 000 mHz |
| **$Fq_F$** | Demand disconnection starting mandatory level: - load shedding frequency level; it is specified in the Emergency and Restoration code (E&R | 49.00 Hz | 48.80 Hz | 48.85 Hz | 48.80 Hz |

*Table 3: Frequency quality defining parameters of the synchronous areas from SOGL*

There are four main types of operational needs, namely:

a) Frequency Containment (covered in first report [16])
b) System defence (focus of this report)
c) Frequency Restoration support (out of the scope and specified in EBGL market code) [6]
d) Emergency Restoration support (as specified in ER code [7])

These operational needs are met using various reserve products and services, internally within the SA and also cross-SAs. The speed of response in terms of time for delivery and duration of delivery varies for different SAs, due their system needs and characteristic.

The focus of the report is system defence (b above), however, the report illustrates the interaction with all the operational needs.

Mutual frequency support considers that the receiving Synchronous Area (SA) will be supported when its frequency exceeds the **maximum steady state frequency deviation.** The providing SA will deploy all the support volume when the receiving SA reaches the **maximum allowed instantaneous frequency deviation**. This support will only be given by the providing system while it is in a “healthy” state, which is achieved when its operates inside the boundaries of **nominal frequency** and 50% of the **maximum steady-state frequency deviation,** shown in the **Error! Reference source not found.**3 above. Once the healthy state is surpassed, the supporting area will **freeze** its support to not deteriorate the frequency of the providing supporting area. In the implementation phase the detail control logic for the freeze function will be developed to ensure secure operation and take

[6] LFSM according to the Great Britain Grid Code [18] is required to activate at 50.4Hz for over-frequency

account of potential interaction with commercial services over HVDC. The mutual support will always have priority (as it secures N-2) over bi-lateral commercial services for use of HVDC capacity.

## 3.3 Definition of system defence over HVDC

System defence is initiated to cover N-2 failure (with the combined loss greater than dimensioning incident). An individual SA is required to dimension for N-1 loss, however, there is always a risk of N-2 failure (Figure 5). The report investigates how N-2 can be mitigated with frequency support over HVDC.

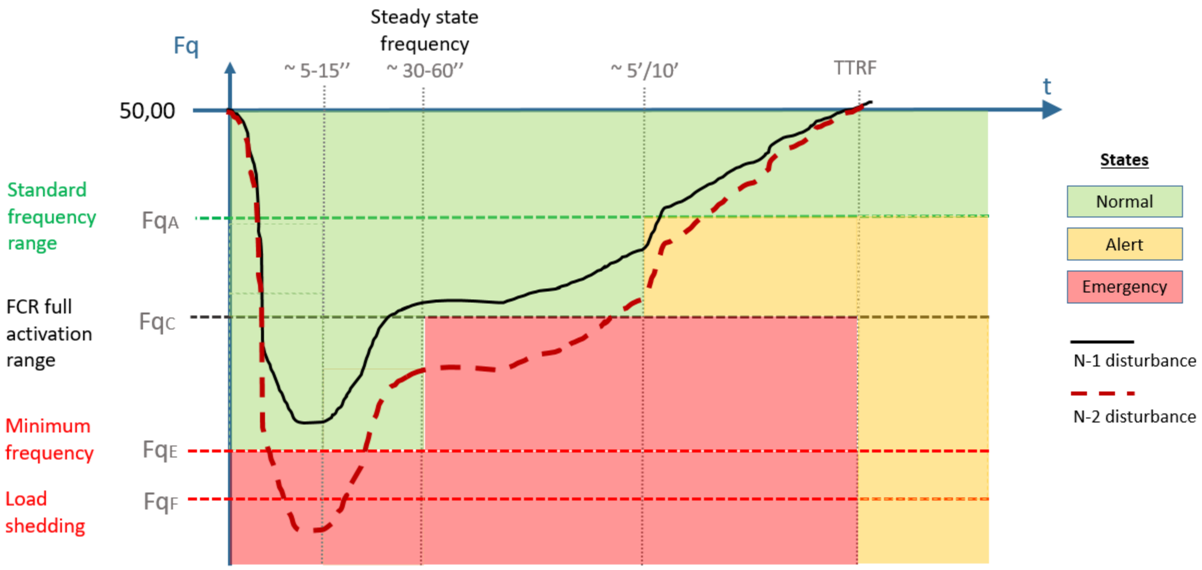


*Figure 5: Frequency behaviour with different disturbances (N-1 or N-2)*

For an N-1 failure, FCR is fully activated by the time that frequency is at $Fq_C$ level. This will ensure that the minimum frequency level $Fq_E$ will not be breached, if local FCR dimensioning is conducted correctly and adjusted for system inertia. This is illustrated in Figure 6 below referred to as condition 1 (❶).

For an N-2 failure, whilst the local FCR is fully activated at $Fq_C$ level (as in Condition 1) it will be insufficient to prevent SA frequency staying above the frequency minimum level $Fq_E$, and there is a risk of reaching an instantaneous frequency minimum that triggers load shedding $Fq_F$.

The report's proposal is to focus on development of the mutual frequency support that is provided over the HVDC to mitigate the risk of local frequency falling below the load shedding trigger level. This is illustrated in Figure 6 below as Condition 2 (❷). This rapid HVDC delivery complements the local FCR response and enhances it as the HVDC has a faster response than FCR.

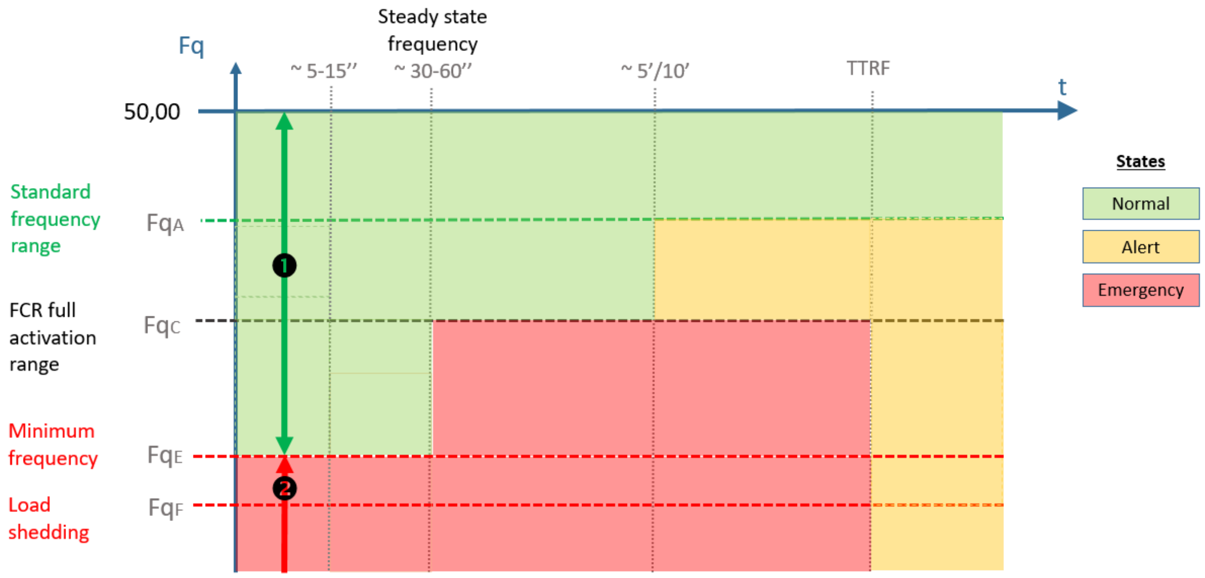


*Figure 6: Frequency support relating to system state of requesting synchronous area*

### 3.3.1 N-1 Defence - Local SA obligation (Condition 1)

SAs are obliged to perform FCR dimensioning in accordance with Article 153 SO GL to ensure that minimum system frequency does not exceed the $Fq_E$ level following an N-1 credible failure. FCR are fully activated and where applicable the Fast Frequency Response (FFR) would complement the FCR with faster response to avoid reaching $Fq_E$. This is shown as condition 1 with green arrow in above Figure 6.

**ACTIVATION**

The activation is automatic, linked to receiving SA frequency value. There are two kinds of responses that will be investigated in the modelling. They are described below:

**Proportional response:** This corresponds to already existing products like Enhanced Frequency Response (EFR).

**Step response:** it is mainly used in existing EPC with frequency threshold defined in the framework limits.

**DEACTIVATION**

A proportional response is automatically deactivated when the frequency goes back within normal range. A step response must be manually deactivated and should require coordination between both SAs to check that the situation of the requesting side is safe again.

### 3.3.2 N-2 Defence - Mutual frequency support (Condition 2)

This mutual frequency support is a system defence measure following an N-2 failure. This support aims to prevent the SAs system frequency breaching the Maximum instantaneous frequency deviation $Fq_E$. It is shown as condition 2 with the red arrow in above Figure 6.

**ACTIVATION**

The activation is automatic, linked to requesting SA frequency value and provides a proportional response. It is the LFSM-O/U [7] [7](Limited Frequency Sensitive Mode Over/Under frequency) triggered at a threshold lower or equal to maximum steady state frequency deviation $Fq_C$ (CE: 49.8 Hz; GB & NO: 49.5 Hz) and fully activated at the frequency limit for demand disconnection starting mandatory level $Fq_F$, laid down in the Annex of E&R network code (CE: 49.0 Hz; NO & GB: 48.8 Hz).

**DEACTIVATION**

A proportional response is automatically deactivated when the frequency goes back within normal range. A step response must be manually deactivated and should require coordination between both SAs to check that the situation of the requesting side is safe again.

**DURATION**

The duration of mutual frequency support impacts the both SAs. For the receiving SA, the duration of the mutual frequency support should not be longer than 15 minutes if the requesting SA respects the Time to Restore Frequency (TTRF) specified in SOGL [1]. The receiving SA always have the possibility to take extreme measure (for example load shedding), therefore 15 minutes is considered sufficient time. For the providing SA, it is important that the level of support (volume in MW) does not cause an alert state. This has been validated in the modelling part based on different levels of provided support and additional blocking and freezing thresholds will be used to ensure a providing SA system remains in normal state.

[7] In accordance with the HVDC connection code (EU) 2016/1447 Article 51

### 3.3.3 Extended mutual frequency support (Condition 3)

This support is a time extension of support in condition 2 defined above. The need for this support occurs when the receiving SA failed to return to $Fq_C$. The aim of the support is to allow more time for the receiving SA to reach steady state frequency $Fq_C$. Local FCR is also acting in the background to deliver the maximum available capacity (it can take up to 30 seconds). It is shown as condition 3 (❸) with the grey arrow in the Figure 7 below.

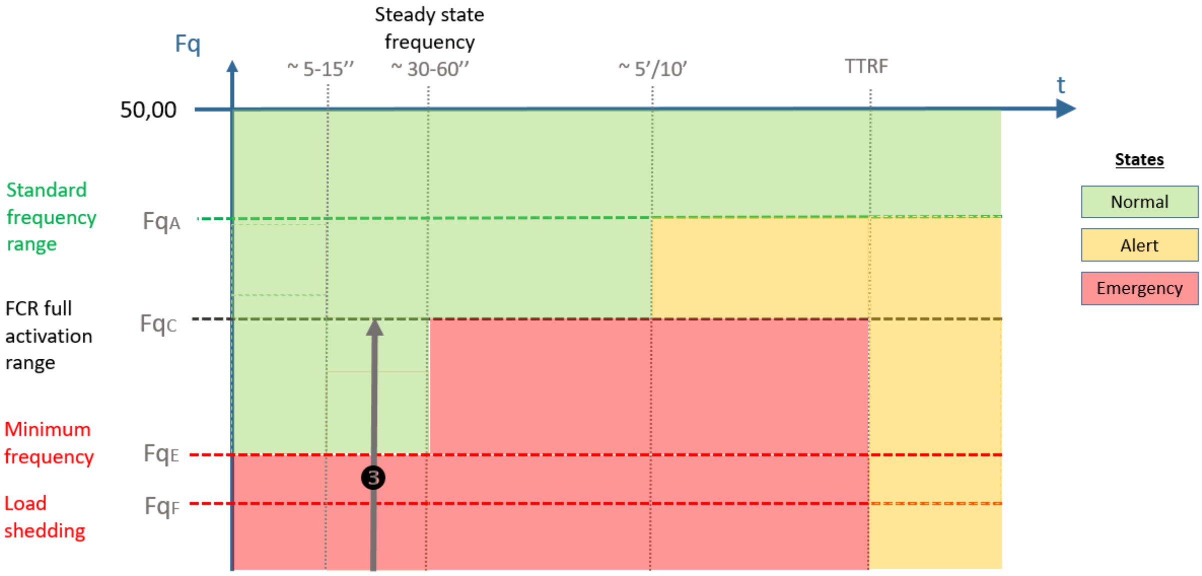


*Figure 7: Frequency support relating to duration of the emergency state of requesting synchronous area*

**ACTIVATION**

There is no activation trigger, only a continued need for support from the receiving SA due to frequency level remaining below $Fq_C$.

**DEACTIVATION**

Deactivation of the support occurs due to two situations. First, when the proportional response is automatically deactivated when the frequency goes back within normal range ($Fq_C$). Secondly, when the time duration of support exceeds 15min and there has been no agreement between the SAs of the need to prolong the support. For this last case, the deactivation is manual, as well as for step frequency support.

**DURATION**

Ideally the duration should not be more than 15 min, however in extreme operational situation, the support can be provided as long as it is necessary and is agreed to by the providing SA.

# 4 HVDC capacity allocation methodology for mutual frequency support delivery

The implementation of frequency support which includes mutual frequency support and frequency reserve[3] over HVDC requires coordination between TSOs, SAs and with the cable owners where applicable.

Alternative methodologies for allocation of HVDC capacity to mutual frequency support have been investigated to ensure frequency defence services can be delivered when necessary.

The requirement for coordination is laid out in articles 15, 16, 17 and 52 of the HVDC connection code [2]. There are different methods as to how capacity is made available for delivery of support to SAs. In any event the volume of the support will be limited by the capacity available on a HVDC interconnector.

Frequency support over HVDC will generate changes in the power flow between two or more synchronous areas. To guarantee delivery of this support capacity needs to be available on the HVDC links. Furthermore, any change in flow between SA can also create additional flows on the connected AC grid[8]. Congestions in the AC grid could limit the availability of the frequency support. This limitation is already included in the calculation of Available Transmission Capacities (ATC)[9] on an interconnector.

The question is to what degree should the capacity be reserved for mutual frequency defence support before the energy market or capacity mechanisms are allocated the capacity by the TSOs. Reservation could guarantee availability for mutual frequency support, which is a non-commercial service. It should be remembered that after day-ahead or intraday gate market closure that the TSO could also allocate remaining capacity for commercial based frequency support without limiting the market.

The report proposes in a pragmatic approach to use the free capacity after the energy market is closed. Therefore, there is no guarantee of delivery of mutual frequency support being delivered.

This solution allows the continuation and coordination of future mutual frequency support over HVDC.

---

[8] In the implementation phase TSO in the SA when allocating mutual support volume to an individual HVDC interconnector should check that the Transmission Reliability Margin on AC borders are sufficient such that the planned maximum mutual support volume can be provided over the HVDC.

[9] According to CACM this can be performed in either with a Flow Based (FB) methodology or a Net Transfer Capacity (NTC) methodology.

# 5 Volume allocation over HVDC

Where multiple HVDC interconnectors between the SAs exist, there is question as how the volume should be allocated to individual interconnectors.

In order to maximise the available mutual frequency support that can be delivered, it is logical to split the delivery between all the interconnectors between SAs. This is relevant because it is proposed to use only available capacity in real time (refer to previous chapter).

It is proposed to split for multiple interconnectors where by the framework limit is allocated proportionally to the nominal capacity of interconnectors.

# 6 Managing multiple SA request for mutual frequency support

As one SA will have obligation to support two SAs, there is a low risk that both SAs will request a support at the same time (two synchronous areas have a N-2 event at the same time).

After evaluating the different options, it is decided that in order to implement mutual frequency support quickly, no prioritisation between SAs is considered. However, a freeze function will be mandatory, set at 50% of the maximum steady state frequency level ($Fq_C$, see section 3.2). This means that a providing SA will not be exposed to a volume delivery that risks its operational security.

# 7 SAs modelling for framework limit definition

To define framework limits, some frequency stability simulations have been performed. Different scenarios were investigated and only a representative number are included in this section as examples. The main results are summarised in tables at the end of this section.

## 7.1 Model of synchronous area frequency responses

Variation in load and generation leads to an imbalance between the load and generation which results in frequency moving from the nominal value. A well-designed frequency control mechanism is required in any power system to maintain the system frequency deviation close to zero and maintaining the frequency fluctuation within the predefined operating limit by regulating the active power output of generators or response provider through their primary governor control system or their supplementary control system. Frequency deviation depends on number of factors such as size of generation or demand loss, system inertia (kinetic energy), and frequency dependency of the load (k). The larger losses result in higher instantaneous frequency deviations especially in system with lower inertia. The rate of change of frequency (RoCoF) is proportional to ratio between the size of the imbalance over Inertia. The transfer function in equation 1 relates power imbalance to frequency deviation. Figure 8 shows an overview of the frequency response model where F(s) is the transfer function of the frequency control model, G(s) the one mass model, a power imbalance entering the system, the output of the closed loop system is the system frequency and s is the Laplace operator.

The one mass model/transfer function of the power system (in Luplas format) is represented by G(s) as follows;

$$G(s) = \frac{f_o}{2E_k s + S_n k f_o} \qquad \textit{Equation 1}$$

$f_o$ = nominal frequency (Hz)
$E_k$ = total kinetic energy (inertia) in the system (MW)
$k$ = frequency dependency of loads (%/Hz of Sn)
$S_n$ = rated apparent power of the power system (MW)

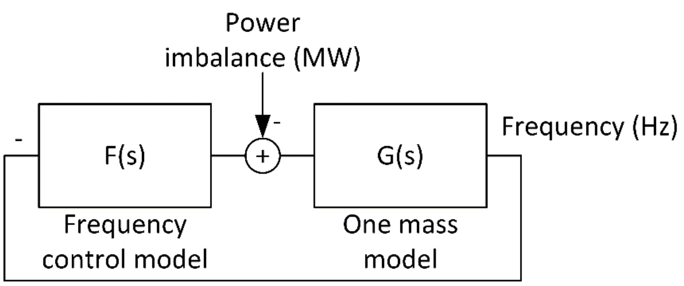


*Figure 8 : Simple illustration of one mass model*

Taking into account penetration of a high level of renewable power in the following years, mainly wind and PV, inertia levels are prone to decrease, as stated in [3].

This decrease of inertia will, in some way, challenge frequency stability. Power system operation at each SA could benefit from mutual frequency support between SA using HVDC interconnectors. The aim of the frequency support between SA is to increase frequency stability by using the supporting capabilities of the SA connected through HVDCs interconnectors. This support should be deployed as a resource to avoid load shedding.

The aim of modelling part of the report was to enable us to investigate various scenarios and assess the performance and effectiveness of mutual frequency support between SAs.

For this purpose, GB, Nordic and CE synchronous area frequency control models have been linked through logic blocks for frequency support between them, as it appears in the following graph:

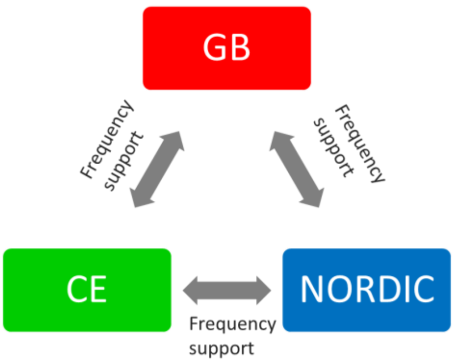


*Figure 9* : GB, CE and Nordic frequency control model connected by HVDC links

These frequency support schemes are based on system frequencies, and, in general, deploy active power from the providing system to the receiving system when it is requested by the receiving system and while the providing system is within the specified frequency limit.

### 7.1.1 Mutual frequency support between synchronous areas

The modelling of the mutual frequency support considers that the receiving system will be supported starting when its frequency exceeds the maximum steady state frequency deviation and the providing system will deploy all the support volume when the receiving system reaches the maximum allowed instantaneous frequency deviation. This support will only be given by the providing system while it is in a "healthy" state, which means, between the boundaries between the nominal frequency and 50% of the maximum steady-state frequency deviation (based on SOGL definition for these parameters).

**Frequency quality defining parameters of the synchronous areas**

| | CE | GB | IE/NI | Nordic |
|---|---|---|---|---|
| standard frequency range | ± 50 mHz | ± 200 mHz | ± 200 mHz | ± 100 mHz |
| maximum instantaneous frequency deviation | 800 mHz | 800 mHz | 1 000 mHz | 1 000 mHz |
| maximum steady-state frequency deviation | 200 mHz | 500 mHz | 500 mHz | 500 mHz |
| time to recover frequency | not used | 1 minute | 1 minute | not used |
| frequency recovery range | not used | ± 500 mHz | ± 500 mHz | not used |
| time to restore frequency | 15 minutes | 15 minutes | 15 minutes | 15 minutes |
| frequency restoration range | not used | ± 200 mHz | ± 200 mHz | ± 100 mHz |
| alert state trigger time | 5 minutes | 10 minutes | 10 minutes | 5 minutes |

Frequency quality target parameters referred to in Article 127:

*Table 4 : SOGL Frequency quality parameters*

Three different support schemes between synchronous areas have been considered:

1) Proportional to frequency deviation support: providing system (e.g. A) will increase or decrease the active power flow provided to the receiving system (e.g. B) proportionally to the frequency deviation on the receiving system including a dead band as shown in Figure 10. Please note throughout this chapter proportional scheme is referred to as proportional to frequency deviation.

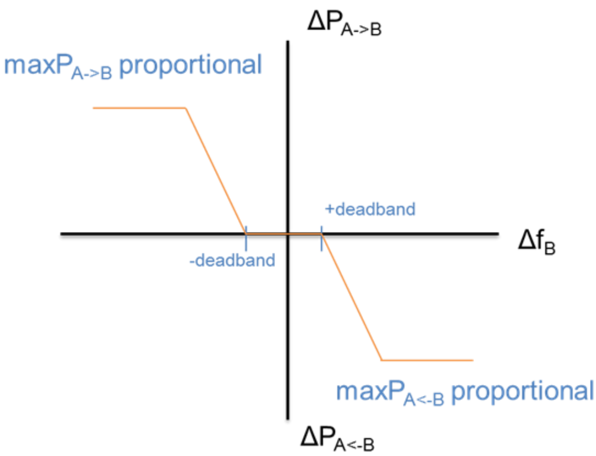


*Figure 10: Proportional support scheme*

In fact, proportional control has been already defined in [2] as LFSM-O and U for HVDC links, which, settles the technical functionality to interchange frequency support based on droop between SAs.

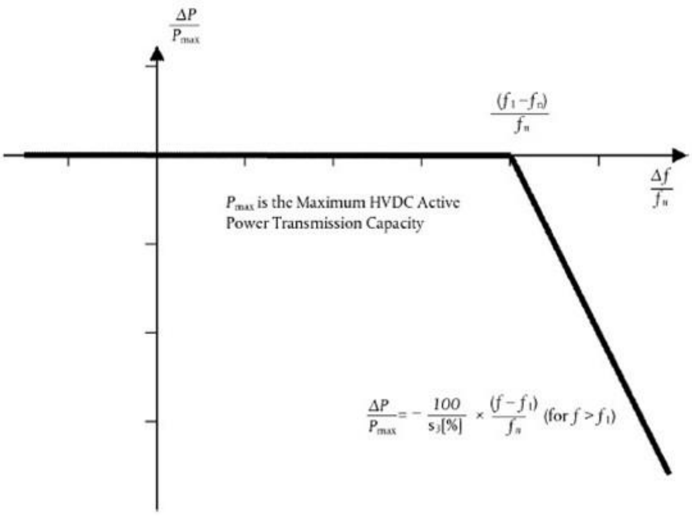


*Figure 11: LFSM-L for low frequency*

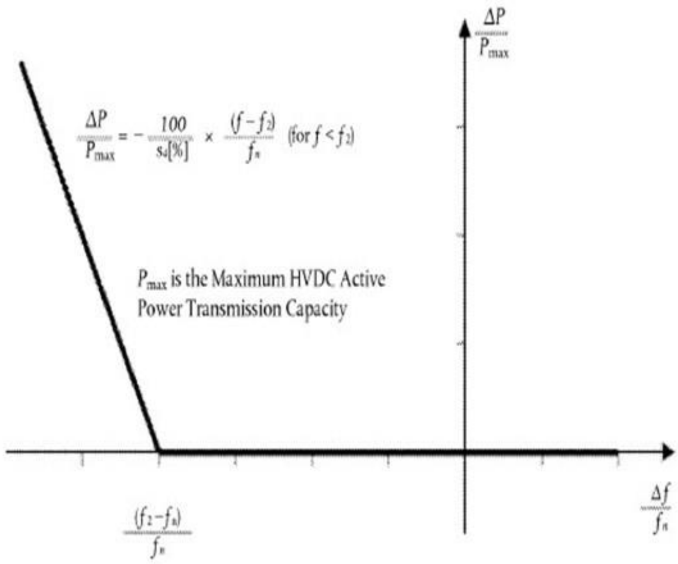


*Figure 12: LFSM-U for over frequency*

2) Step support: different steps of power are deployed when the frequency of receiving area (B) drops below the predefined/agreed frequency thresholds. Three frequency thresholds (in principle) have been defined equally distanced through the frequency range in which the supporting scheme will work and with the same amount of power step in each of them as shown in Figure 13

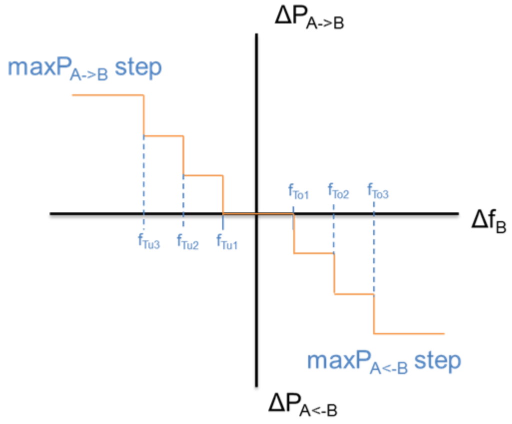


*Figure 13 : Step support scheme*

3) Derivative support (synthetic inertia): the providing system (A) provide active power proportionally to the measured RoCoF at the receiving system (B). RoCoF is measured over a sliding window of 500 ms as shown in Figure 14

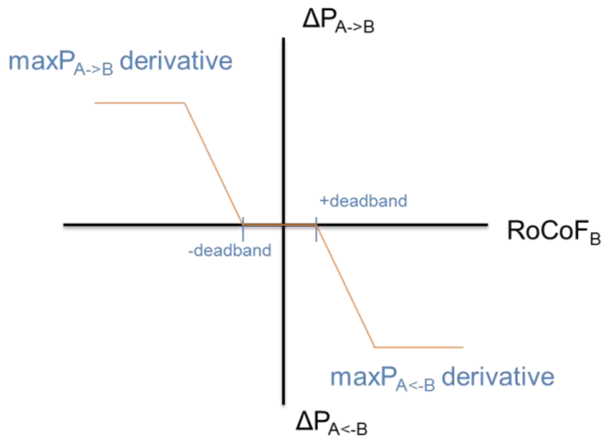


*Figure 14: Derivative support scheme*

The HVDC model considers a first order model with time constant equal to 0.1 s for the deployment of the support. This time constant takes into account the command and control capabilities of the HVDC. The simulations take into account the future HVDC link between UK and Nordic system, so, the supporting schemes considered are CE<->UK, UK<->NORDIC, NORDIC<->CE.

### 7.1.2 Study scenarios

Two main scenarios are investigated using the developed model, the first scenario representing 2020 case and second scenario is representing a future case in 2030. In each scenario the worst case (low inertia case) are studied. In all study cases, to assess the effectiveness of the defined mutual frequency support from each SA, a power imbalance as large as 1.5·RI (150 % time the reference Incident) is simulated and frequency deviation and RoCoF at both ends are monitored. Performance of proportional (droop) support scheme, step support scheme and derivative support scheme response are investigated in all scenarios. In addition, framework limit for each SA is defined based on the simulation results.

## 7.2 Methodology

The objective of performed simulations is to define limits for mutual support between Synchronous Areas for both under and over frequency N-2 conditions. The methodology implemented in this study is the assessment of the following three criteria defined below:

- **Assessment of framework limit**: maximum volume of the support that each synchronous area can provide. To define the maximum volume of the support that each synchronous area can provide, low inertia scenarios in both 2020 and 2030 are used (this is to consider the worst-case scenarios). A step imbalance, (following a generation/demand loss or HVDC trip) at each synchronous area (CE, GB[10] and Nordic) was applied and increased iteratively until it reaches to its LFSM- triggering level (Maximum steady state frequency deviation $Fq_c$). This volume of imbalance at this stage is translated as the maximum volume of support that each providing synchronous area can provide.

- **Assessment of Performance of each supporting scheme**
  Following criteria are implemented to identify the best supporting scheme between proportional, step, derivative scheme.

  Comparison of results by monitoring the RoCoF, instantaneous frequency deviation and steady state frequency at both receiving and providing ends

- **Assessment of Minimum ramp rate limit of the HVDC links**
  Minimum required ramp rate of HVDC interconnectors can be calculated based on the rate of change of frequency at each receiving synchronous area without any support for the given imbalance[11].

## 7.3 Results for under frequency

The support schemes are primary intended for $N-2$ situations and should, in theory, activate for those incidents that might cause a bigger deviation than the maximum allowed instantaneous frequency deviation. Additionally, these support schemes should be fully deployed before automatic load shedding occurs [17].

The supportive frequency control scheme is triggered by monitoring the frequency deviation, or with the derivative support by monitoring the RoCoF, at the receiving end. Maximum allowed instantaneous frequency

[10] Please note that slightly different approach is used for defining the GB framework limit for LFSM-O as the reference incident is relatively small.

[11] The MultiDC project, http://multi-dc.eu

deviation or threshold on RoCoF should be used as triggering points to ensure that the schemes are activated only for *N* – 2 losses. However, higher ramp rate is then required to deliver all the volume of support before frequency reaches to automatic demand disconnection level which becomes a very narrow frequency band. Therefore, aligned to HVDC LFSM defined in [2], in this report, it has been decided that the triggering point for HVDC support based on frequency deviation is the maximum steady state frequency deviation and the full delivery of support is at the maximum instantaneous frequency deviation, which is compatible for its full activation in order to avoid load shedding frequencies. This also allows for a larger frequency range where the support activates and requires lower ramp rates.

### 7.3.1 Assessment of performance of each supporting scheme for under frequency support

In this section the results of the comparison between, no support, step support, proportional support and derivative support (proportional to RoCoF i.e. synthetic inertia), in 2030 scenario with low inertia, are given. The summary of the results are presented in Table 5 and Table 6). To do so, one of the four cases studied is detailled below and an imbalance of 1.5·RI is modelled in each case for each SA, including CE, GB and Nordic. In each case the performance of step support scheme and proportional support scheme is compared. For validation purposes, the performance of the proposed proportional support scheme and step support scheme are compared with the existing schemes between the CE and the Nordic system.

**Case A: Imbalance event in the Nordic system – GB and CE providing support – 2030 low inertia scenario**
The event applied is an *N* – 2 with a loss of 1.5 times the corresponding reference incident in Nordic system. In the Nordic system (case A), following the imbalance event, GB and CE may provide the maximum volume of support (an in a similar manner a case is defined for each SA requiring mutual support below). The frequency of both sides (receiving and providing ends) are monitored to assess the performance of no support and the two SA support scheme including proportional and step support scheme are compared. As can be seen in Figure 15, without support, blue solid line, from other synchronous areas, the Nordic system frequency exceeds their load shedding frequency point (please note that no load shedding is modelled in these studies). Also, in comparison, it is clear that with support (blue dash and dash -dot lines) from GB and CE areas, the Nordic frequency remains within the acceptable limit. Both proportional and step support scheme can be tuned to maintain instantaneous frequency minimum at the same level. However, in case of proportional support scheme, better damping is achieved and with the step support scheme, more oscillatory behaviour and overshooting frequency is observed. In addition, in case of proportional support scheme, steady state frequency is settled at lower value due to the automatic deactivation of scheme. Results also confirmed, that with proportional support scheme, frequency at both providing support sides would not activate the LFSM-U. Also, the impact on CE's frequency is smaller compared to GB frequency and GB frequency system sees over-frequency due to activation of static reserve and automatic deactivation of the proportional scheme support. However, this is not considered as an issue in the GB system.

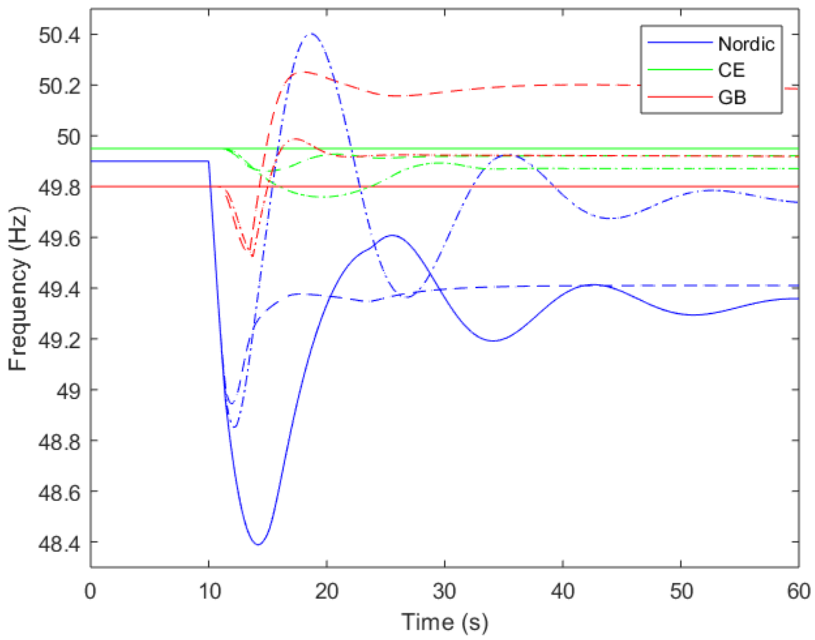


*Figure 15: Power loss of 1.5 times the reference incident in the **Nordic system**, scenario 2030 low inertia (Solid curves: represent no support, - dash: proportional to frequency deviation, dash-dot: step support).*

## Summary of the simulation results for no support, step and proportional schemes in the 2020 and 2030 scenarios for under frequency support:

The 2020 base case is shown in Table 5. It presents the instantaneous frequency minimum at each SAs with 1.5 times the reference incident for the base case.

| Base case 2020 | Instantaneous frequency minimum (Hz) at SAs with 1.5 times the reference incident | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Imbalance in CE (1.5 x 3000 MW) | | | Imbalance in GB (1.5 x 1000 MW) | | | Imbalance in NORDIC (1.5 x 1450 MW) | | |
| | CE | GB | Nordic | CE | GB | Nordic | CE | GB | Nordic |
| No support | 49.41 | - | - | - | 49.4 | - | - | - | 48.71 |
| Step support scheme | 49.52 | 49.72 | 49.79 | 49.9 | 49.49 | 49.79 | 49.91 | 49.68 | 49.06 |
| Proportional support scheme | 49.53 | 49.7 | 49.79 | 49.93 | 49.45 | 49.87 | 49.92 | 49.68 | 49.15 |

*Table 5*: instantaneous frequency minimum in Base case 2020 for under frequency support.

Similarly, Table 6 presents the instantaneous frequency minimum at each SAs with 1.5 times the reference incident for low inertia in 2030 scenario.

| Low inertia 2030 | Instantaneous frequency minimum (Hz) at SAs with 1.5 times the reference incident | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Imbalance in CE (1.5 x 3000 MW) | | | Imbalance in GB (1.5 x 1400 MW) | | | Imbalance in NORDIC (1.5 x 1450 MW) | | |
| | CE | GB | Nordic | CE | GB | Nordic | CE | GB | Nordic |
| No support | 48.19 | - | - | - | 48.70 | - | - | - | 48.39 |
| Step support scheme | 48.74 | 49.61 | 49.46 | 49.84 | 49.07 | 49.48 | 49.76 | 49.52 | 48.85 |
| Proportional support scheme | 48.75 | 49.57 | 49.47 | 49.89 | 49.07 | 49.68 | 49.86 | 49.54 | 48.94 |

*Table 6: instantaneous frequency minimum in low inertia 2030 for under frequency support.*

### 7.3.2 Simulation results conclusions for under frequency support

In all studies, worst case scenarios have been considered assuming a low inertia and low initial frequency at both the receiving and the providing synchronous area before the event. It is evident based on the simulation results that, the proposed mutual frequency support schemes are effective in minimising the risk of entering load shedding following the *N*–2 event on the system. The studies therefore are proposing calculated limits that ensure the providing synchronous area(s) will not deviate outside their regulatory limits. However, it has been agreed to add an additional freeze function on the level of mutual support such that when the providing synchronous area system frequency reaches 50% of the maximum steady state frequency deviation the MW level of support is frozen and does not therefore increase even if the receiving SA frequency deteriorates further. In addition, the frequency triggering point for the proposed support schemes are defined to ensure FCR are fully activated in steady state in the receiving SA.

There is a limit on maximum volume of support that each synchronous area can provide to ensure that the providing synchronous area remains within a healthy frequency range. These volumes are calculated using the current and future synchronous areas parameters using the developed model in SIMULINK. However, these calculations are required to be revised in the future on the regular basis to include any system changes. Between the support schemes studied, a scheme proportional to the frequency deviation at the receiving side is recommended for better frequency stability at the receiving side and lower impact on the providing side. In addition, to have an effective support scheme, a selection of secure ramp rates on the HVDC links are critical which can be found using the RoCoF value at the receiving side following the *N*–2 event. This calculated ramp rate at the providing end is a combined ramp rate which means if there are number of interconnectors between two areas, this ramp rate can be shared between interconnectors. In the case that a higher proportion of the total volume (not equally shared) is allocated to a specific link due to higher capacity being available on that link then the combined ramp rate should be shared between links with the same proportion. Also, depending on the size of the considered *N–2* event, the ramp rate could be different which should be considered at the design stage. In the studies, we used 1.5 times the reference incident as our *N*–2 event which is considered as a reasonable *N-2* loss.

## 7.4 Results for over frequency

The support schemes are primary intended for N – 2 situations and should, in theory, activate for those incidents that might cause a bigger deviation than the maximum allowed instantaneous frequency deviation. Additionally, these support schemes should be fully deployed before automatic generation shedding occurs.

The supportive frequency control scheme is triggered by monitoring the frequency deviation, or with the derivative support by monitoring the RoCoF, at the receiving end. Maximum allowed instantaneous frequency deviation or threshold on RoCoF should be used as triggering points to ensure that the schemes are activated only for N – 2 losses. However, higher ramp rate is then required to deliver all the volume of support before frequency reaches to automatic generation disconnection level which becomes a very narrow frequency band. Therefore, aligned to HVDC LFSM defined in [3], in this report, it has been decided that the triggering point for HVDC support based on frequency deviation is the maximum steady state frequency deviation and the full delivery of support is at the maximum instantaneous frequency deviation, which is compatible for its full activation in order to avoid generation shedding frequencies. This also allows for a larger frequency range where the support activates and requires lower ramp rates. The support schemes are primary intended for $N-2$ situations and should, in theory, activate for those incidents that might cause a bigger deviation than the maximum allowed instantaneous frequency deviation. Additionally, these support schemes should be fully deployed before automatic generation shedding occurs.

### 7.4.1 Assessment of framework limit for over frequency support

A minimum combined ramp rate required to ensure high frequency support scheme is fast enough to be effective in fully delivering the maximum volume of support before automatic generation shedding occurs. To calculate the minimum ramp rate required for each support providing SA, the RoCoF was monitored in each receiving SA following an imbalance of 1.5 times the corresponding reference incident. The maximum observed RoCoF value was used in the calculation of the required ramp rate.

Four cases which are defined in section 5.4.3 are investigated and an imbalance of 1.5·RI (demand loss/disturbance) is modelled in each case for each SA, including CE, GB and Nordic. In each case the performance of step support scheme and proportional support scheme are compared. One case is detailed below.

**Case A: Imbalance event in the GB system – Nordic and CE providing support – 2030 low inertia scenario over frequency support:**

The event applied is an $N-2$ with a loss of 1.5 times the corresponding reference incident in GB system, following the imbalance event, CE and Nordic provide support. The performance of proportional support and step support scheme compared to no support are depicted in Figure 16. This shows that with mutual support the GB system remains within their operational limit, whereas without support, large frequency deviation is observed. As shown in Figure 16, the steady state frequency in GB has a lower frequency deviation using the step support scheme compared to the proportional support scheme. However, with implementing proportional support scheme, Instantaneous frequency maximum at the GB system is lower and impact on the resulting instantaneous frequency maximum in both CE and the Nordic are less.

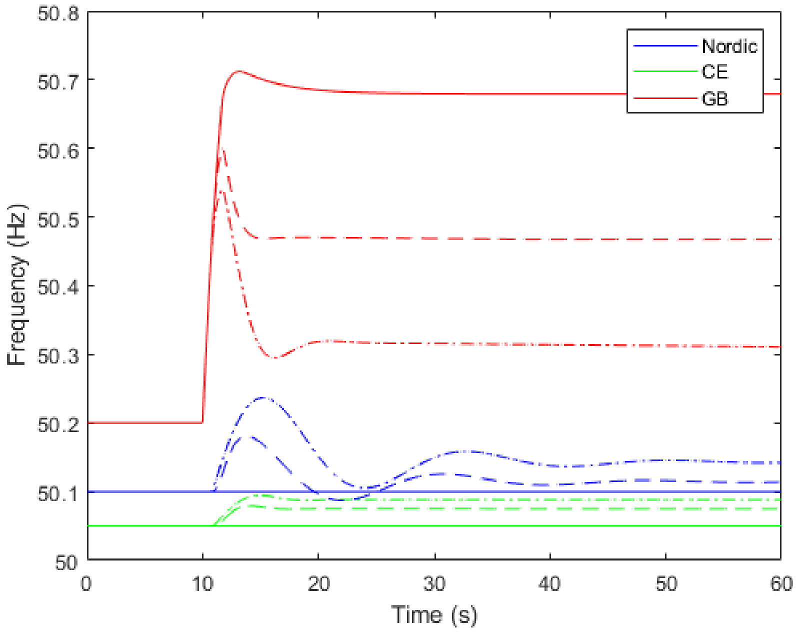


*Figure 16: Demand loss of 1.5 times the reference incident **in the GB system**, scenario 2030 low inertia for over frequency support (Solid curves: represent no support, - dash: proportional to frequency deviation, dash-dot: step support)*

## Summary of the simulation results for no support, step and proportional schemes in the 2020 and 2030 scenarios for over frequency support:

Table 7 presents the instantaneous frequency maximum at each SAs following an imbalance of 1.5 * the reference incident (demand loss or trip of HVDC when exporting) in 2020 and Table 8**Error! Reference source not found.** with low inertia in 2030 accordingly.

| Base case 2020 | Instantaneous frequency minimum (Hz) at SAs with 1.5 times the reference incident | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Imbalance in CE (1.5 x 3000 MW) | | | Imbalance in GB (1.5 x 1000 MW) | | | Imbalance in NORDIC (1.5 x 1400 MW) | | |
| | CE | GB | Nordic | CE | GB | Nordic | CE | GB | Nordic |
| No support | 50,59 | - | - | - | 51.05 | - | - | - | 51.19 |
| Step support scheme | 50,50 | 50.31 | 50.20 | 50.10 | 50.46 | 50.19 | 50.09 | 50.31 | 50,92 |
| Proportional support scheme | 50,50 | 50.29 | 50.20 | 50.08 | 50.51 | 50.15 | 50.08 | 50.28 | 50.85 |

*Table 7: Instantaneous frequency minimum in Base case 2020 for over frequency.*

| Low inertia 2030 | Instantaneous frequency minimum (Hz) at SAs with 1.5 times the reference incident | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Imbalance in CE (1.5 x 3000 MW) | | | Imbalance in GB (1.5 x 700 MW) | | | Imbalance in NORDIC (1.5 x 1400 MW) | | |
| | CE | GB | Nordic | CE | GB | Nordic | CE | GB | Nordic |
| No support | 51.81 | - | - | - | 50.71 | - | - | - | 51.51 |
| Step support scheme | 51.39 | 50.46 | 50.47 | 50.10 | 50.54 | 50.24 | 50.24 | 50.40 | 51.13 |
| Proportional support scheme | 51.39 | 50.38 | 50.49 | 50.08 | 50.61 | 50.18 | 50.15 | 50.39 | 51.03 |

*Table 8: Instantaneous frequency maximum in low inertia 2030 for over frequency support*

### 7.4.2 Simulation results conclusions for over frequency support

In all studies (for both under and over frequency support), worst case scenarios have been considered assuming a low inertia and low initial frequency at both the receiving and the providing synchronous area before the event. It is evident based on the simulation results that; the proposed mutual frequency support schemes are effective in minimising the risk of entering load/generation shedding following the *N*–2 event on the system. The studies therefore are proposing calculated limits that ensure the providing synchronous area(s) will not deviate outside their regulatory limits. However, it has been agreed to add an additional freeze function on the level of mutual support such that when the providing synchronous area system frequency reaches 50% of the maximum steady state frequency deviation the MW level of support is frozen and does not therefore increase even if the receiving SA frequency deteriorates further. In addition, the frequency triggering point for the proposed support schemes are defined to ensure FCR are fully activated in steady state in the receiving SA.

There is a limit on maximum volume of support that each synchronous area can provide to ensure that the providing synchronous area remains within a healthy frequency range. These volumes are calculated using the current and future synchronous areas parameters using the developed model in SIMULINK. However, these calculations are required to be revised in the future on the regular basis to include any system changes. Between the support schemes studied, a scheme proportional to the frequency deviation at the receiving side is recommended for better frequency stability at the receiving side and lower impact on the providing side. In addition, to have an effective support scheme, a selection of secure ramp rates on the HVDC links are critical which can be found using the RoCoF value at the receiving side following the *N*–2 event. This calculated ramp rate at the providing end is a combined ramp rate which means if there are number of interconnectors between two areas, this ramp rate can be shared between interconnectors. In the case that a higher proportion of the total volume (not equally shared) is allocated to a specific link due to higher capacity being available on that link then the combined ramp rate should be shared between links with the same proportion. Also, depending on the size of the considered N–2 event, the ramp rate could be different which should be considered at the design stage. In the studies, we used 1.5 times the reference incident as our *N*–2 event which is considered as a reasonable N-2 loss.

# 8 Conclusions

The report objective was to investigate the possibility for implementing mutual frequency support over HVDC interconnectors to mitigate the system risk of N-2 incidents, in Synchronous Areas.

The report concludes that N-2 incidents can be mitigated by implementation of mutual frequency support within a set of framework limits which include the volume of support, the way the frequency triggers for support and the droop settings. With the right framework limits, the overall system security and frequency quality can improve without creating an additional security risk for the providing SAs. The conclusions are in accordance with the HVDC connection code (EU) 2016/1447 Article 51. An automatic activation linked to requesting SA frequency value with support provided on a proportional response scheme basis. The limits for support are defined hereafter.

## 8.1 Framework limits

The following tables summarises the maximum Synchronous Area obligation, and settings, based on the modelling studies using a proportional response for low frequency (LFSM-u) modelling of over frequency is ongoing (LFSM-o) as this both minimises the impact on the providing SA and eases implementation.

| **Proportional support scheme** | **GB ->CE** | **Nordic ->CE** | **CE ->GB** | **Nordic ->GB** | **CE ->Nordic** | **GB ->Nordic** |
|---|---|---|---|---|---|---|
| Maximum support (MW) | 600 | 600 | 1000 | 600 | 1000 | 600 |
| Frequency trigger for starting delivery (Hz) | CE : 49.80 | CE : 49.80 | GB : 49.50 | GB : 49.50 | NO : 49.50 | NO : 49.50 |
| Frequency for full delivery (Hz) | CE : 49.20 | CE : 49.20 | GB : 49.00 | GB : 49.00 | NO : 49.00 | NO : 49.00 |
| Frequency level for freezing of delivery (Hz) | GB : 49.75 | NO : 49.75 | CE: 49.90 | NO : 49.75 | CE: 49.90 | GB : 49.75 |
| Support scheme droop (MW/Hz) | 1000 | 1000 | 2000 | 1200 | 2000 | 1200 |
| Ramp rate (MW/s) | 200 | 200 | 1400 | 840 | 1400 | 840 |

*Table 9: Limits for mutual under frequency support with frequency characteristics parameters consistent with HVDC code requirements and modelling results.*

| Proportional support scheme | GB ->CE | Nordic ->CE | CE ->GB | Nordic ->GB | CE ->Nordic | GB ->Nordic |
|---|---|---|---|---|---|---|
| Maximum support (MW) | 400 | 500 | 1000 | 500 | 1000 | 400 |
| Frequency trigger for starting delivery (Hz) | CE: 50.20 | CE: 50.20 | GB: 50.40 | GB: 50.40 | NO: 50.50 | NO: 50.50 |
| Frequency for full delivery (Hz) | CE: 50.80 | CE: 50.80 | GB: 50.80 | GB: 50.80 | NO: 51.00 | NO: 51.00 |
| Frequency level for freezing of delivery (Hz) | GB: 50.25 | NO: 50.25 | CE: 50.10 | NO: 50.25 | CE: 50.10 | GB: 50.25 |
| Support scheme droop (MW/Hz) | 667 | 833 | 2500 | 1250 | 2000 | 800 |
| Ramp rate (MW/s) | 133 | 167 | 500 | 250 | 1400 | 560 |

*Table 10: Limits for mutual over frequency support with frequency characteristics parameters consistent with HVDC code requirements and modelling results.*

## 8.2 Principles

In order to minimise the N-2 risk, the mutual frequency support should be implemented as soon as practically possible. Therefore, as a first step, the focus will be on a process which requires low coordination in real time and few technical arrangements with the HVDC control systems. This is the basis of the recommendations for CE, Nordic and GB SAs below:

- Frequency support should be restricted to the frequency containment process for N-2 incidents and be provided for a period of a minimum of 15 minutes and a longer period if agreed between the coordinating entities.
- Frequency support between SAs should be a mandatory delivery as long as the providing SA is within its system security criteria as modelled by the report.
- Frequency support should use the free capacity after the energy market gate closure. If there is no free capacity, there is no support, unless an overload capability can be utilised.
- Each providing SA has a fixed mutual frequency support volume obligation which is the sum of all mutual frequency support as defined in Table 9 and Table 10.
- A freeze limit on support is set to minimise the risk to the providing Synchronous Area, such that support provided will be frozen if the providing synchronous area reaches this frequency limit. The limits are defined in Table 9 for under frequency support and Table 10 for over frequency support.
- As a principle, the SA obligation should be allocated between all interconnectors as this increases the probability of the service being delivered.
- Already existing service arrangement parameters should be adapted to be compliant with the recommendations made in this report.
- To minimise the impact on the providing SA and achieving the same level of frequency stability, a support scheme proportional to frequency deviation is recommended (LFSM). TSOs can arrange

additional bi-lateral commercial services such as exchange of FCR or EPC (to cover N-1), as long as they comply with the requirements of their SAOAs' and ensure there is no negative interaction with the proposed mutual support (N-2).

## 8.3 Implementation approach

The principles above have been selected to enable timely implementation of mutual frequency support. However, implementation requires that adaptions are made to all HVDC interconnectors control systems between SAs which are technically capable. This will also require testing before an individual interconnector can actively deliver frequency support which may need to align with a maintenance outage.

The implementation of individual interconnectors will be monitored through an annual statement of the status of implementation. A maximum period of 5 years is given post ENTSO-E SOC approval[12] to implement the recommendations.

[12] Formal approval by System Operations Committee on September 30th, 2020.

# 9 Next steps

The report proposes actions to ensure that existing mutual frequency support is consolidated, and future support is coordinated between synchronous areas:

1. Monitor the implementation of the operational HVDC framework recommended above and to report bi-annually on activations. This will enable the ENTSO-E Steering Group Operations to evaluate the performance and benefit of mutual frequency support as inertia is eroding in all SAs.
2. Extension of framework to include other synchronous areas.

# 10 References

Documents used in the study:

[1] European Commission, EU 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation.

[2] "(EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules".

[3] ENTSO-E, European Power System 2040. Completing the map. The Ten-Year Network Development Plan 2018. System Needs Analysis, Brussels, 2018.

[4] N. Modig, R. Eriksson and M. Kuivaniemi, "Online Tool to Predict the Maximum Instantaneous Frequency Deviation during Incidents," *IEEE Power & Energy Society General Meeting (PESGM), Portland, OR, 2018, pp. 1-5. doi: 10.1109/PESGM.2018.8586442,* 2018.

[5] Not used.

[6] COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guide line on Electricity Balancing.

[7] "(EU) 2017/2196 of 24 November 2017 establishing a network code on electricity emergency and restoration".

[8] COMMISSION REGULATION (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

[9] ENTSO-E, Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe – Requirements and impacting factors., Brussels, 2016.

[10] ENTSO-E, Dispersed Generation Impact on CE Region Security, Brussels, 2014.

[11] ENTSO-E, "Power System Inertia - Future Challenges and Requirements, RG-CE System Protection & Dynamics Sub Group, 24 September 2014. Internal report140924_Inertia_TF_v7.docx".

[12] ENTSO-E, "Requirements for UFLS settings v22, RG-CE System Protection & Dynamics Sub Group, 06 November 2014, ENTSO-E internal report".

[13] M. Kuivaniemi, N. Modig and R. Eriksson, "FCR-D design of requirements," *ENTSO-E,* 2017.

[14] N. Modig and et al., "Technical requirements for Fast frequency reserve provision in the Nordic synchronous area," *ENTSO-E,* 2019.

[15] ENTSO-E, Technical background for the Low Frequency Demand Disconnection requirements, Brussels, 2014.

[16] ENTSOE SOC ad'hoc Group Frequency Coupling, Operational Limits and Conditions for Frequency Coupling March 2018.

[17] D. Obradovic, M. Ghandhari, R. Eriksson. "Assessment and Design of Frequency Containment Reserves with HVDC Interconnections," NAPS 2018.

[18] National Grid Electricity System Operator Limited. "The Grid Code Issue 5 Revision 47," February 2020.