European Network of
Transmission System Operators
for Electricity

Report on Deterministic Frequency Deviations

4 November 2019

Contents

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List of Abbreviations

aFRR	automatic Frequency Restoration Reserve
FRCE	Frequency Restoration Control Error
CE	Continental Europe
DACF	Day-ahead Congestion Forecast
DFD	Deterministic Frequency Deviation
EAS	ENTSO-E Awareness System
EFR	Enhanced Frequency Response
FCR	Frequency Containment Reserve
FFR	Firm Frequency Response
IDCF	Intraday Congestion Forecast
IBS	Imbalance Settlement Period
LFC	Load Frequency Controller
MFR	Mandatory Frequency Response
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
PLR	Part Loaded Response
SA	Synchronous Area
STOR	Short Term Operating Reserve
TSOs	Transmission System Operators
XBID	Cross Border Intraday Market

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Executive Summary

From 9 to 11 January, the Continental Europe (CE) Synchronous Area faced an extraordinary frequency and time deviation due to the convergence of the following two main events:

- The Deterministic Frequency Deviation (DFD) during the evening peak-load at the hourly schedule transition;
- A long-lasting frequency deviation (average -30 mHz) caused by a technical failure given by a frozen measurement on four tie lines between TenneT Germany and APG grids, which affected the Load Frequency Controller (LFC) of both the TenneT Germany Control Area and the Germany Control Block.

The cumulative effect of the permanent frequency deviation due to the frozen measurement, in addition to the large evening DFD, culminated on 10 January at 21:02 when the steady-state frequency in the CE system reached 49.808 Hz. This low frequency value triggered the automatic activation of the RTE Industrial Interruptible Service (decreasing the French load by 1250 MW within 5 seconds and up to 1700 MW in 30 seconds), which quickly returned the frequency to within the normal frequency range.

A Task Force was approved on 6 February by the ENTSO-E System Operations Committee (SOC) to investigate the events during 9 and 11 January 2019 and to identify the Causal Factors and mitigating actions to prevent a re-occurrence of this type of event. The Task Force consists of representatives from 15 transmission system operators (TSOs) and ENTSO-E Secretariat. The technical report published (here) investigating the events during 9 and 11 January 2019 has already been approved by ENTSOE System Operations Committee.

This DFD report developed by the Task Force elaborates on the general approach for mitigating and alleviating the DFDs in CE. The task force is proposing to set common DFD targets for the Synchronous Area of CE. The solutions for mitigating the DFDs can be different from TSO to TSO, depending on the technical and market preconditions, but the final objective is to commonly reduce the individual contribution of the LFC Blocks to an acceptable level of DFDs.

Proposed Solutions

Working Package 3 of the Task Force Significant Frequency Deviations' preferred solution is moving towards a 15-minute Imbalance Settlement Period (ISP) and Market Time Unit (MTU) in a stepwise manner, at the national and international level and for any or all relevant timeframes. This proposal is in line with existing or upcoming legislation (Network Codes, Guidelines and Clean Energy Package) and is described in more detail in section 4.3.1 of this report.

In addition, as permanent or intermediate measures, the following solutions can reduce the impact of the DFDs:

1. ramping imposed on generation units on a national level (section 4.3.3)
2. include a provision for ramping on load and generation schedules at the national level (section 4.3.2)
3. increase the volume of Frequency Containment Reserve (FCR) available to control the DFDs (section 4.4.1) as a temporary measure, awaiting the implementation of other solutions.

Other solutions which have been discussed and which could be investigated for particular control blocks could include:

(a) Introduction of a limit of change in net position of a market area / bidding zone between two successive market periods;
(b) Introduce Spot Power Balancing, also known as Residual Central dispatch

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(c) Use changes between ISP for BRPs as market based automatic frequency restoration reserves (aFRRs) bids;
(d) Additional Very Fast Reserves from Battery Storage
(e) Additional aFRRs;
(f) K-factor adaptation
(g) Introduction of a Dynamic Frequency Setpoint in Control Areas / Blocks

National implementation

Given the market situation and that the production mix (shares of units with considerable ramping capabilities) may differ in different market areas of Member States within the CE Synchronous Area, the Task Force also recommends a possible hybrid solution whereby different mitigation measures are implemented at the national level, depending on the specifics of each country. The goal of the hybrid solution is to reduce the level of DFDs to an acceptable level, while supporting flexibility in terms of the selection of cost-effective measures within the local context.

ENTSO-E proposes to leave the decision on which solutions to mitigate the DFDs to be implemented in each LFC block, and at the national level to the national TSOs and regulators. The proposed solutions in this report are not-exhaustive and any other local solutions can be proposed.

Each LFC Block must set up and follow an action plan to implement the chosen solution(s). Each LFC Block will report to ENTSO-E periodically regarding the implementation of the measures.

Setting the targets

Each LFC block needs to respect the quality target as proposed in this report, Chapter 3 – acceptable DFD level of 75 mHz. Once the targets are accepted, they will be integrated into the SAFA to cover:

- The establishment of the quality targets values per LFC block;
- The measurement of the targets compliance by following instantaneous or average FRCE values;
- The mechanism by which the targets' compliance is monitored;
- The TSOs consequences for non-compliance.

Monitoring and Enforcement

ENTSO-E Regional Group Continental Europe will set up a process for monitoring the DFDs and report on a quarterly basis on all LFC Blocks' compliance level. The observed DFDs during the monitoring process are those which violate the frequency quality target, as defined in Chapter 3 of this report.

The DFD monitoring process will formally start in 2021, allowing time for all LFC Blocks to implement the selected mitigation measures. A status report should be available during 2020, to follow the evolution of DFDs and FRCE quality targets before the actual start of the monitoring process.

Action Plan

The recommendations of the final report will require the implementation of at least one of the suggested solutions by 2021, with the aim of meeting the quality targets set for each LFC block of CE.

Recognising the ongoing challenges in managing the system frequency, both across the hourly schedule change and during steady state operation, it is prudent to implement a comprehensive action plan to address

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these challenges. The proposed solutions are to be implemented progressively with all actions completed by 2021.

Each LFC Block not yet complying with the FRCE target will be required to deliver its implementation plan to the ENTSO-E relevant body.

If no solutions are implemented by some LFC Blocks and the DFDs are still too high according to the targets established by the Task Force, the ENTSO-E relevant body could decide that these Control Blocks acquire additional FCR to assist in reducing DFDs until the necessary solutions are in place.

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The Task Force recommends the following decisions be taken:

1. **Set Frequency Quality Targets which define acceptable levels of DFD.**

   Details are set out in Chapter 3.1

2. **Set Quality Targets per LFC Block (based on FRCE values) which define acceptable levels of DFD.**

   Details are set out in Chapter 3.2

3. **Determine how much additional FCR would be required to reduce DFDs to the agreed frequency quality target in case no other solutions are implemented.**

   Details are set out in Chapter 4.4.1

4. **Conclude on the Way Forward presented in this report, that each LFC block will determine which solution(s) it will implement to reduce its contribution to DFDs to the agreed FRCE Quality Target.**

   Details are set out in Chapter 5

5. **Adapt the SAFA in order to include the conclusions of this Report (as stated in the Way Forward).**

   Details are set out in Chapter 5.3

6. **Organise the follow-up of the local implementation of solutions to reduce DFDs.**

   Date: February 2020, followed by a continuous monitoring process

1 Definition of the Problem

1.1 Introduction and Approach

Given the events that occurred on 10 January 2019 and the evidence of DFDs occurring in CE since 2003, the System Operations committee and the Market Committee of ENTSO-E have decided to set up a task force to examine the circumstances giving rise to the DFDs and implement an Action Plan to definitively manage DFDs and thus avoid any further deterioration in frequency quality.

The task force is comprised of experts from System Operations and from Markets who have studied the question of DFDs extensively and are ready to achieve a common view on the proposed way forward.

This document elaborates on the general approach for the mitigation and alleviation of DFDs. The foundation of this approach is the definition of common DFD targets for the Synchronous Area and quality targets per LFC Block that form the basis for the assessment of the necessity to take mitigation and alleviation measures within the responsibility of the LFC Blocks. The chosen mitigation and alleviation measures might be different from TSO to TSO depending on the technical and market preconditions but have the aim in common of reducing the individual contribution of the LFC Blocks to an acceptable level. The reader will find an explanation for why the approach proposed cannot be a 'one-size-fits-all' proposal with the aim of unifying the approaches for the mitigation of DFDs across the Synchronous Area.

In addition, this document presents historic trends and analysis of market based DFDs. Possible mitigation measures and next steps to resolve DFDs are discussed.

This document will provide an answer to the following questions:

(1) Why is it a problem to have large DFDs at the change of the hour in the morning and in the evening?
(2) Where are the DFDs coming from?
(3) What does ENTSO-E consider to be acceptable as frequency deviations from a System Security point of view for the Synchronous grid of CE?
(4) Which solutions can be envisaged to reduce the size of the DFDs?
(5) Which set of solutions is practically implementable and will solve the deviations?
(6) What is the action plan to ensure these solutions are implemented in reality?

1.2 Deterministic Frequency Deviation Historic Trends Analysis

The quality of frequency in the CE Synchronous Area has decreased during the last few years. More precisely, continuous measurements of the frequency show that the value is deviating more often, and for longer periods from the average value of 50 Hertz. Figures 1 and 2 show, over the last 5 years, and per month, the number of frequency deviations which were higher than 75 mHz and higher than 100 mHz. These graphs clearly show that, especially the very large DFDs above 100 mHz, have recently increased considerably in number, and the 75 mHz variations have already been high in number for some time.
Note that these graphs show the variation 'peak to peak' from maximal to minimal frequency or minimal to maximal frequency during the DFD. So, for instance, a DFD which has a variation from 50.04 to 49.94 Hz will be reported in these graphs as a variation of 100 mHz (50.04 – 49.94).

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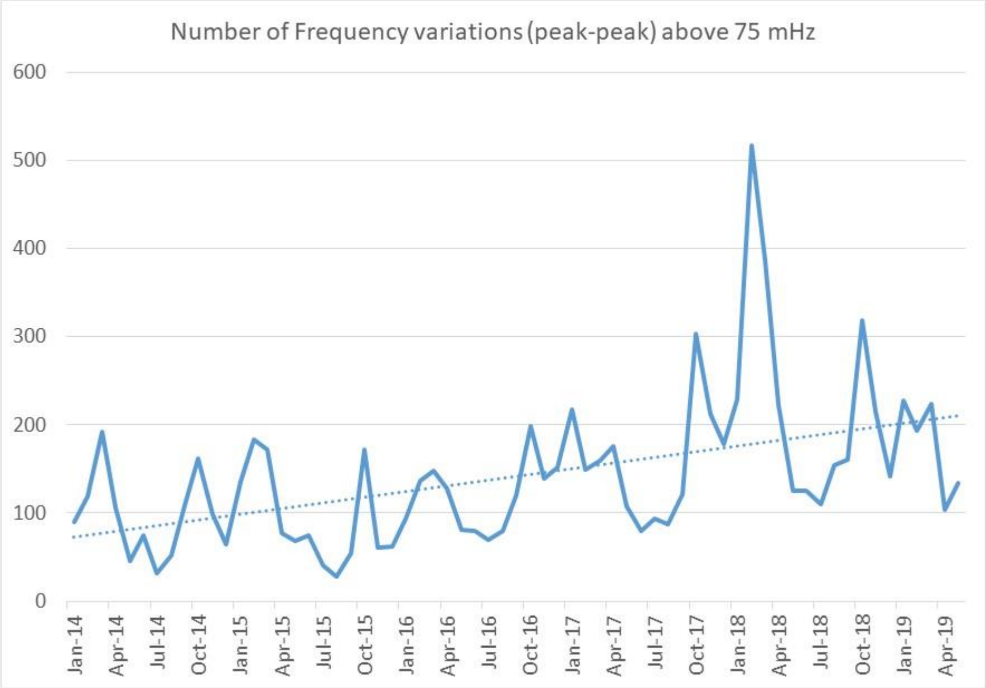


Fig. 1 – Number of +/- 75 mHz criteria violations

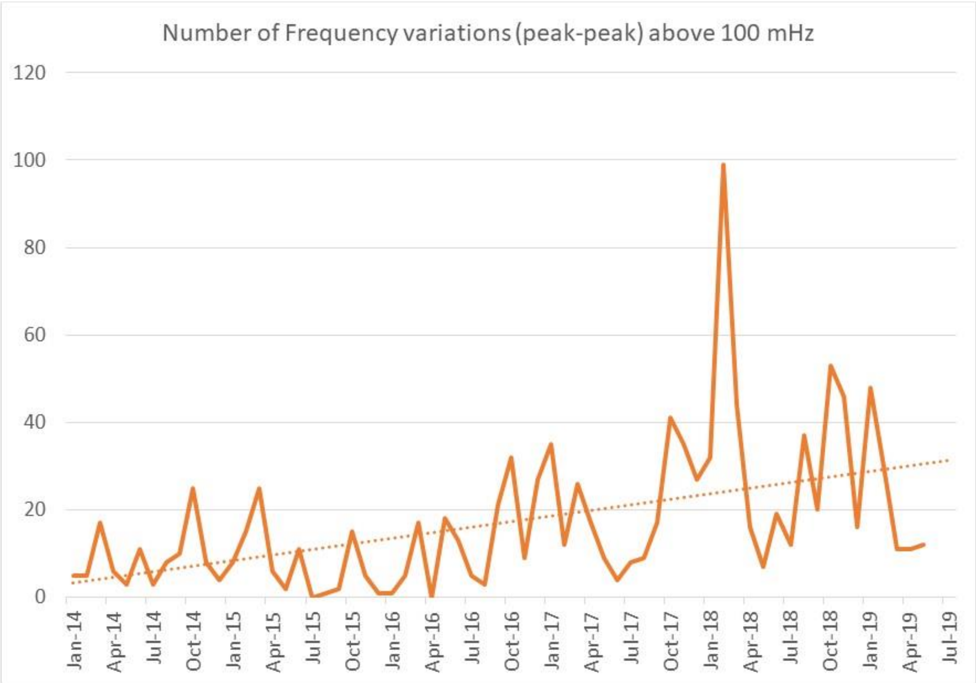


Fig. 2 – Number of +/- 100 mHz criteria violations

Figure 3 shows over the last 18 years, and per month, the number and duration of periods when frequency deviation was greater than 75 mHz. It can be clearly seen that the number and intensity of deviations increases during the winter period.

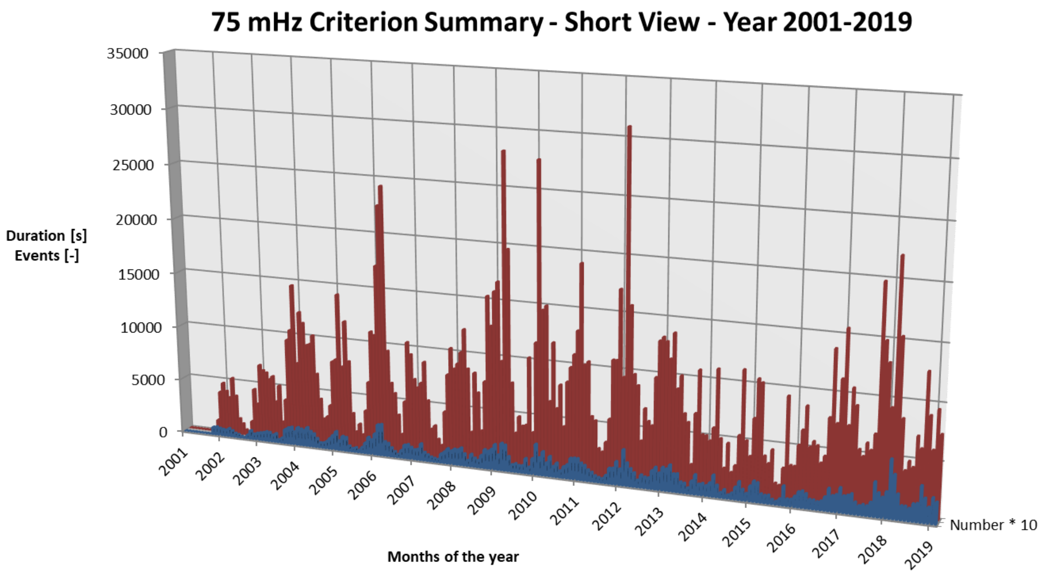


Fig. 3 – Number and duration of +/- 75 mHz criteria violation

A very high percentage of the frequency deviations are caused by DFDs. Figures 4 to 7 illustrate the total number and period of duration in the frequency deviations higher than 75 mHz and 100 mHz within the last two years and the participation of frequency deviations caused by DFDs in those values. Approximately 85% of the deviations are deterministic with respect to the 75 mHz limit and more than 90% with respect to the 100 mHz limit. In addition, the size of the absolute frequency deviations has been permanently increasing during the last few years. For instance, on 24 January 2019 at 06:00, the CE Synchronous system experienced its largest positive DFD of +173 mHz.

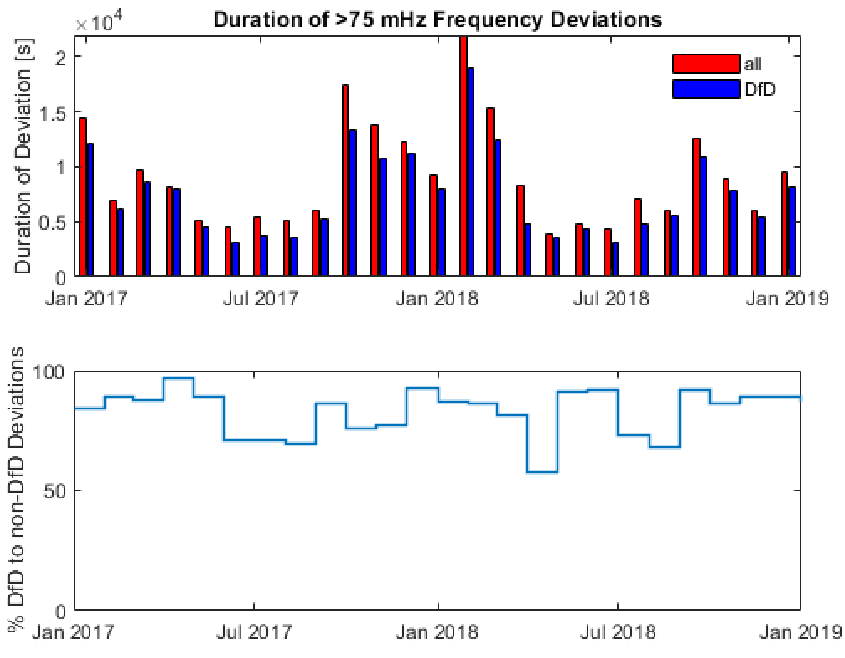


Fig. 4 – Duration of DFDs and % of DFD compared to all deviations in the last 2 years (>75 mHz)

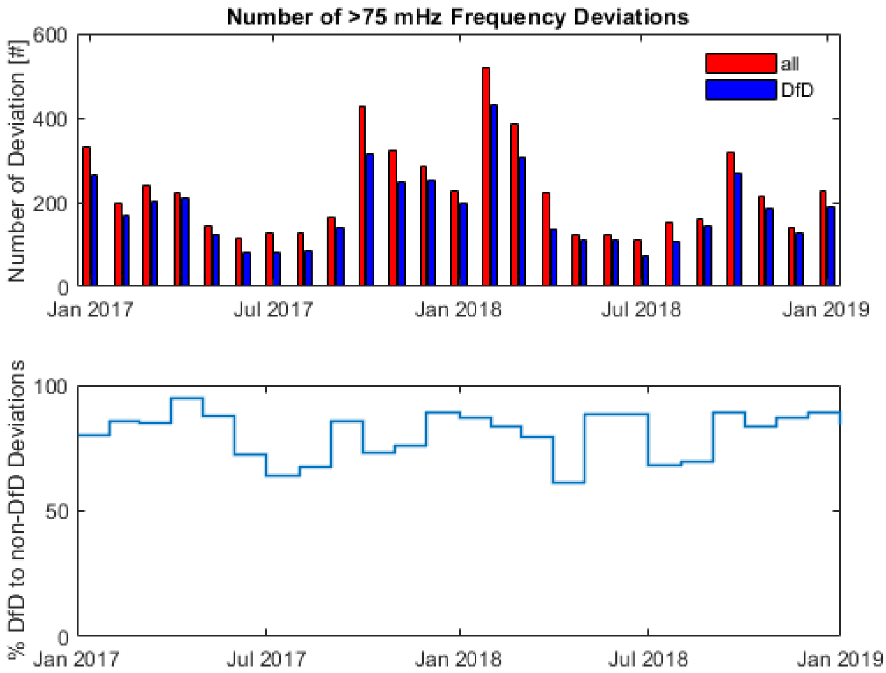
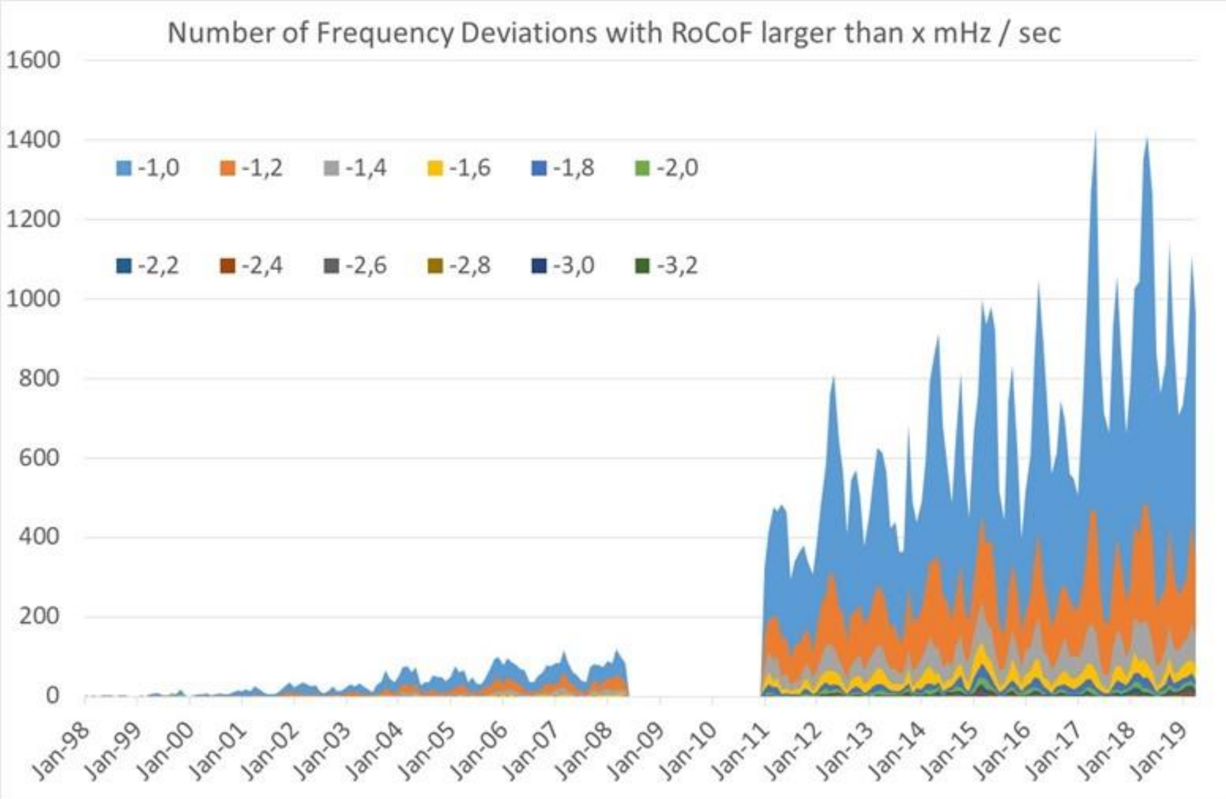


Fig. 5 – Number of DFDs and % of DFD compared to all deviations in the last 2 years (>75 mHz)

Analysis has also been carried out on the rate of change of frequency (RoCoF) during the DFD. It has been observed from regular sampling of the DFD over the past few years that the speed at which the frequency changes is increasing from values which were always smaller than 1.5 mHz per second about 10 years ago to values which now reach regularly a value of 3 mHz per second, and sometimes reach critical values of 5 mHz per second. This RoCoF is already the same as during forced unit outages, with a size of approx. 600–800 MW. This is getting close to the maximum speed at which FCR is expected to react (and for which it was designed). Further increases in the coming years could result in more serious DFDs and lower frequency values

The following statistics involve the largest negative frequency deviations over a 30 second period during a DFD. The 30 seconds mark is important, as this is equal to the activation time of the FCR. Fig 6a shows the evolution of the RoCoF of the observed DFDs since 1998. Where ten years ago a RoCoF of 2 mHz / sec did not exist, we currently regularly face RoCoF of above 3 mHz / sec.



The higher levels of RoCoF above 2.2 mHz / sec are magnified in the graph below, as these are most relevant to observe the amplitude of the problem.

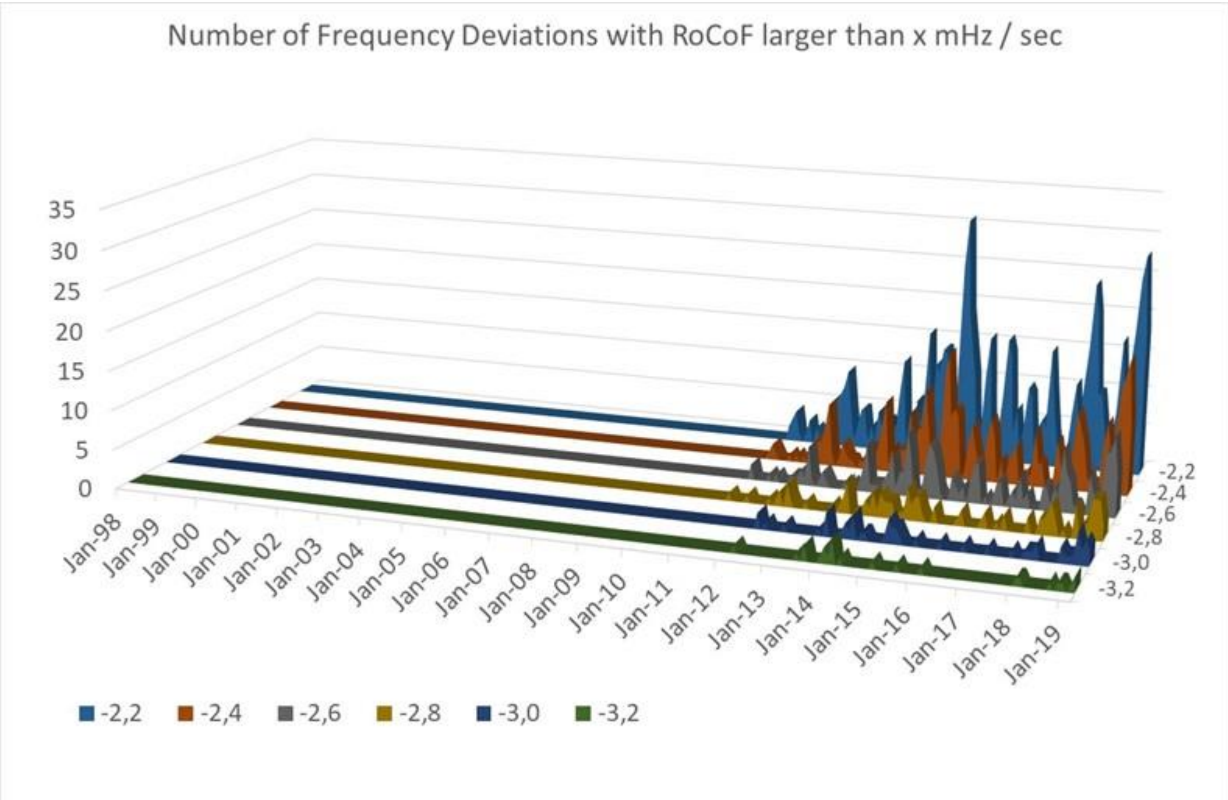


Fig. 6 a&b – Observed RoCoF of DFD in mHz / sec per month from 1998 until today

The table below shows the highest frequency variations observed in January 2019 over 30 seconds, which is the time of activation of FCR. The highest variations were almost 100 mHz, which is almost half of the speed at which FCR currently reacts. It is worth noting in the table below that most of the fastest variations on DFDs occur at 22:00 each day, so it is worth investigating the possible root causes for these fast variations of frequency at 22:00.

Date	Timestamp	mHz change over last 30 sec
07/01/2019	22:00:35	-98.30
13/01/2019	22:00:35	-92.32
26/01/2019	22:00:35	-91.28
16/01/2019	22:00:30	-89.33
14/01/2019	22:00:35	-83.38
12/01/2019	22:00:35	-79.53
22/01/2019	22:00:35	-79.05
28/01/2019	22:00:35	-76.47
02/01/2019	21:00:50	-75.38
27/01/2019	22:00:35	-74.98
30/01/2019	23:00:50	-73.42
08/01/2019	22:00:35	-71.80
01/01/2019	22:00:40	-71.73
31/01/2019	22:00:30	-71.12
29/01/2019	19:01:00	-69.82
04/01/2019	22:00:40	-69.18
15/01/2019	00:00:35	-68.60
22/01/2019	20:00:45	-67.17
11/01/2019	22:00:35	-66.33
29/01/2019	20:01:00	-66.07

Table 1 - 20 highest RoCoF in January 2019

The problem has worsened remarkably during the winter months of 2018 and 2019, with DFDs reaching values higher than 100 mHz daily, and even several times a day. Furthermore, extremely high values of DFD have been reached, e.g. -168 mHz on 6 February 2018 at 20h and -166 mHz on 14 February 2018 at 22.00. Prior to that, only two frequency deviations (stochastic, in 2010 and 2011 with values of around 160 mHz) have reached similar values since the incident in November 2006, which was caused by the split of the CE Synchronous system.

In the beginning of 2019, the DFD amplitudes continued to grow and the problem with DFDs reached a culmination on 10 January. Fig. 7 illustrates the average values of frequency during all days at the same time of day for January 2019. This figure shows the average value for the 31 days, where the frequency is taken each day at the same time.

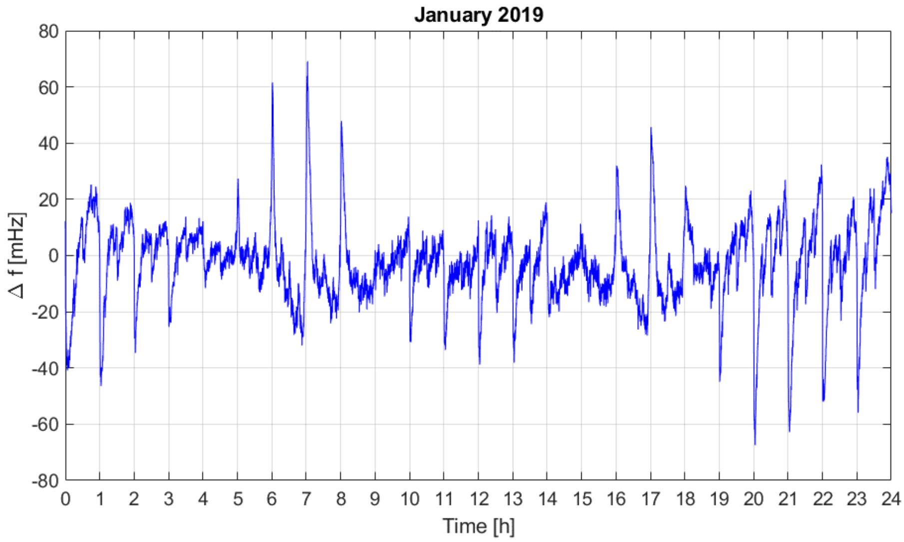


Fig. 7 – Average values of Frequency per time of day for January 2019

The worst (lowest) frequency deviation since November 2006 occurred on 10 January at 21:02. Frequency deviation reached -192 mHz and was the result of the superposition of a strong DFD and the long-term frequency deviation caused by the tie-line measurement error in the AGC controller of TenneT DE.

By comparing the schedule changes of 9, 10 and 11 January (three working days) at 21:00, we can detect that for a few CE TSOs, those changes were extremely high on 10 January 10. Five control blocks had changes above 2 GW at that time, which also overlapped with additional changes in load.

1.3 Impact of Deterministic Frequency Deviations

1.3.1 Impact on system operation

Flow changes: The frequency deviations cause additional unscheduled power flow due to activations of frequency containment reserves that were not foreseen in the reference flow. This results in regular higher loading of transport lines during the hour-changes where DFD occurs.

This means that the remaining capacity of the lines (as foreseen in the reliability margins Transmission Reliability Margin [TRM] or Flow Reliability Margin [FRM]) is used more frequently than only during system outages, for instance, every hour during the DFD, and must be guaranteed to be available at all times.

Misuse of Frequency containment reserves: The DFDs diminish the capability of TSOs to ensure the reliability of the system, as the operational reserve (FCR) is activated to maintain frequency stability.

To mitigate frequency deviations, independently of the structure of frequency control in different synchronous areas, FCR is delivered automatically and the synchronous system subsequently activates additional restoration reserves (FRR). In systems using automatic frequency restoration control, the activation of FRR is proportional to the deviation. The reserves are activated in both directions, dependent on the direction of the frequency deviation, with the highest contributions coming from the control blocks with the highest imbalances at that time.

DFDs have a major influence on reserves in systems which balance on FRCE, as described previously.

$$FRCE = \Delta P + Kri*\Delta f.$$

In CE, for control blocks with a power frequency characteristic constant (Kri) greater than 1000 MW/Hz, a frequency deviation of $\Delta f = \pm 0.075$ Hz implies a reserve activation of ± 75 MW.

For a medium sized TSO carrying 100 MW of FCR, a DFD of 0.075 Hz uses 37.5% of this reserve (0.075 Hz/0.2 Hz) or 37.5 MW for mitigation of inter-hour frequency deviations.

At the CE level, for a calculated power-frequency characteristic constant of 26700 MW/Hz, a frequency deviation of ±0.075 Hz leads to a total FRCE deviation of approx. 2000 MW and a total FCR activation of 1125 MW (37.5% of 3000 MW FCR).

Simply put, during the time that the DFD occurs, the CE system is weaker and could not have sufficient reserves to cover the loss of 3000 MW without dropping below the level of 49.8 Hz

System Damping issues: In situations of low availability of FCR, the damping of inter-area oscillations is also reduced. Figure 8 clearly shows an increase in the amplitude of the oscillation at a higher frequency deviation from the setpoint. This could require additional operational measures and, in some cases, could lead to challenging operational situations such as the loss of generating units and/or system separations. In other words, during the DFD, the electricity system of CE has a slower reaction in responding to oscillations, which may occur at any time, thereby increasing the risk that such oscillations cause additional issues (e.g. possible additional outages) in the system.

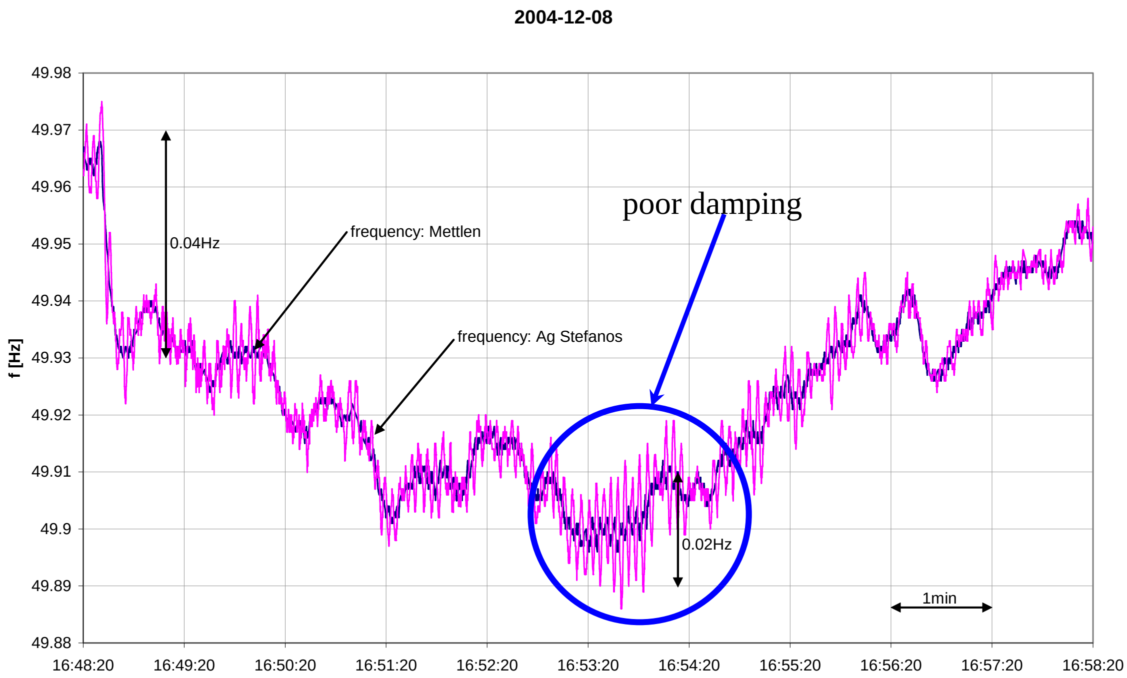


Fig. 8 – Recording of poor damping of inter-area oscillations during frequency excursion [1]

1.3.2 Impact on Market Parties

(a) **Synchronous generation**

Synchronous generation is designed and tuned to operate efficiently and safely within a limited operational domain defined mainly by frequency and voltage. Frequency limits are a concern for rotating machines, since deviation from the typical frequency ranges can affect generation lifecycle or cause damage.

Depending on the prime-mover and control strategy of such generation sources further constraints can be observed.

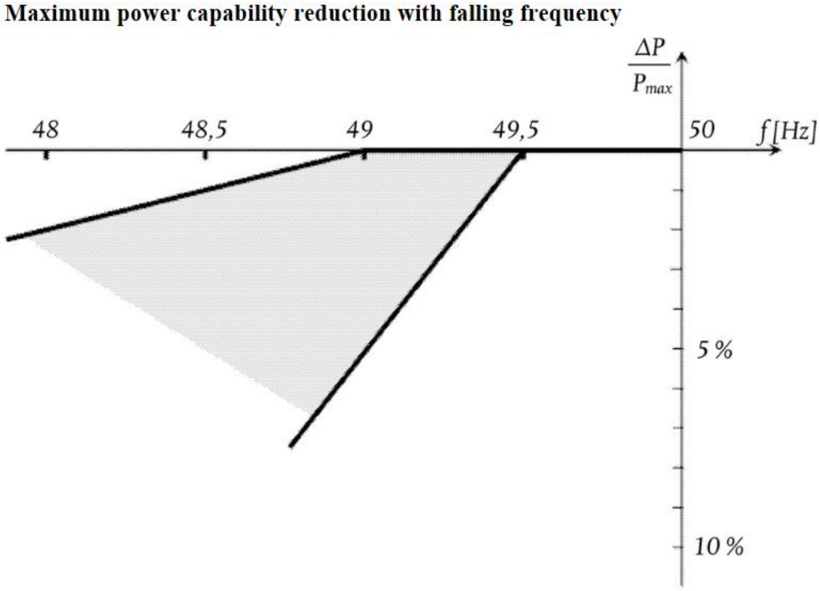


Fig. 9 – Admissible power reduction under falling frequency [2]

The Network Code on requirements for grid connection of generators [2] enables units to reduce their active power injection due to the technical limitations associated with under-frequency deviations, as illustrated in Fig. 9. However, even if the code requirements ask for a larger frequency band conformity, the impact described below shall not be underestimated. This is mainly due to the inherent characteristic of losing some output at a lower frequency (particularly Gas Turbines), i.e. at a lower rotational speed of the synchronous machine. This is not caused by a controller action but purely due to the physical fact that with a lower rotational speed comes a reduced mass flow, which immediately translates into a reduced power output. To maintain the same power output under the same rotational speed, a higher mass flow is required.

(b) **Non-synchronous generation**

Frequency quality usually does not have a substantial impact on non-synchronous generation (e.g. full-converter wind turbines, PV installations connected via converter or Storage facilities), as these generation types often cover a large band of frequency.

Activation of FCR in large quantities for more and longer periods leads to higher wear and tear of production units. Structural activation without the occurrence of outages is considered 'abuse' and can lead to installation problems for production companies. These effects are a disincentive from keeping the frequency controller in service and increases the (acquirement) cost of FCR.

2 Main causes of Deterministic Frequency Deviation

DFDs have been increasingly occurring in the CE Synchronous system over the last few years, like other Synchronous Areas which have introduced energy markets.

The causes of the DFDs were identified to be:

I. A weakening in the strong link between power consumption and power generation dynamics. With the liberalisation of the EU energy market, the market rules between generation and consumption are based on the exchange of energy blocks of fixed time periods.

II. The physical ramping which is applied on generation and load is not aligned between all market participants. The resulting imbalances are reflected in the frequency deviations.

III. There is also the rule for BRPs to be balanced over the whole MTU, which leads to effects whereby they will adjust their production at the latest point in time by the fastest gradient possible.

IV. Local legislation can cause rapid changes in generation or load at specific hours (noise emission constraints, night tariff changes, …)

2.1 Hourly schedule changes

There is a significant correlation between on the one hand the size of changes in schedules within control areas / market bidding zones and on the other hand the number of DFDs observed. Indeed, we have observed evidence of a significant increase of both market activity and frequency deviations from 2001 to 2018, Fig. ***10 –***0 illustrates the sum of the hourly schedule absolute changes within the UCTE North, East and West regions from 2008 until 2018, with a sustained increase in magnitude with a direct correlation to the DFD figures. In addition, we observe that frequency deviations occur more frequently in winter than in summer, which is again reflected in the changes in schedule which are higher in winter than in summer.

Figure 10 below gives a view of the amplitude of schedule changes. This graph is made by examining the change in net position of each control area hour per hour in absolute value and adding the numbers together. The changes in the net position of the synchronous area, which do not correspond directly to the slower evolving load, cause the DFDs. These changes in the net position of the synchronous area are reflected in changes in the net positions of the individual control areas. However, it must be noted that a change in the net position of one area could be compensated by an opposite change in the net position of another area, which should not lead to a DFD.

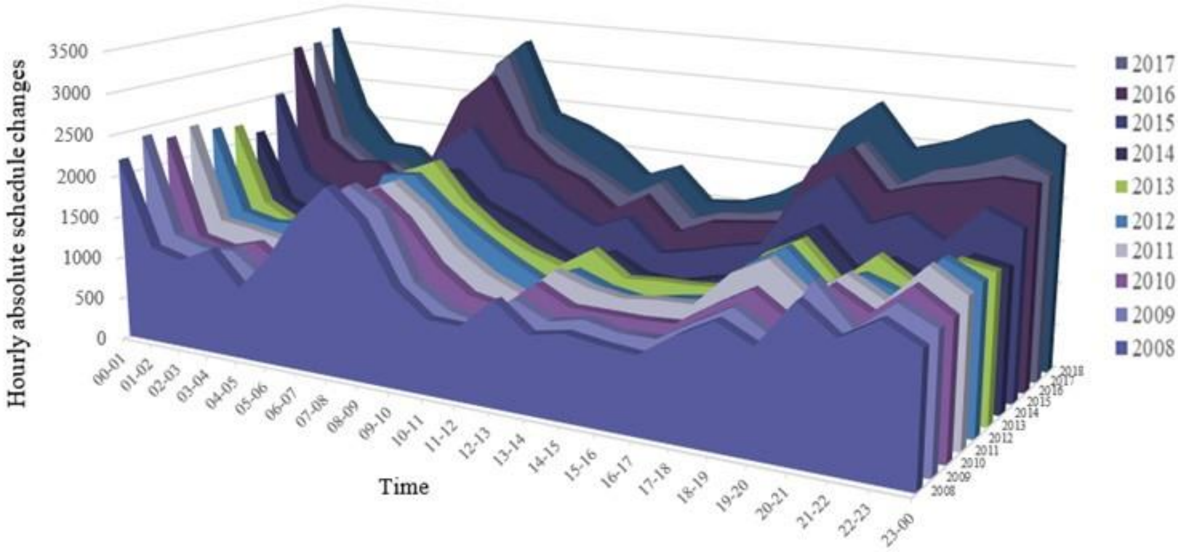


Fig. 10 – Total delta in hourly schedules for within CE (UCTE North, East and South)

2.2 Fast acting vs slow acting production units

As the number of changes in schedules increases, the number of changes in the generation mix increases too. If one unit reacts faster than another, this also implies imbalances and frequency deviations due to the mismatch of ramps.

- Fast unit's behaviour is near a power step without correspondence in real load. In this manner, the hourly behaviour of fast units is quite similar to an incident. The impact on system frequency is in relation to schedule steps, leading to frequency deviation in the whole system.

- Slow units are faced with opposite requirements: technical requirements which impose the natural ramp and commercial ones which impose the delivery of scheduled energy in the time frame.

  Both behaviours contribute to frequency deviations.

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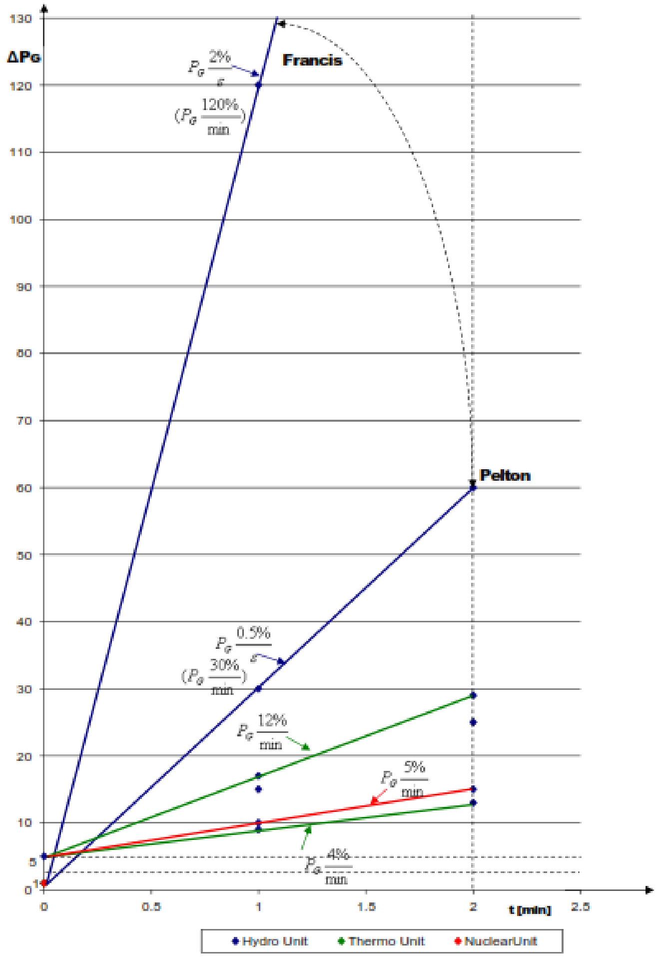

A programme change would be mainly impacted by generation response time, where we can distinguish:

(i) Fast scheduling:

HVDC 100 MW / min

Hydro 20..100 % / min

Gas 6..10 % / min

(ii) Slow scheduling:

Nuclear 2..4 % / min

Coal 1..2 % / min

Load 0.1… 0.5 % /min

Fig. 11 – Total delta in schedules for UCTE North and UCTE South [1]

2.3 Incompatibility between load ramping and block schedules

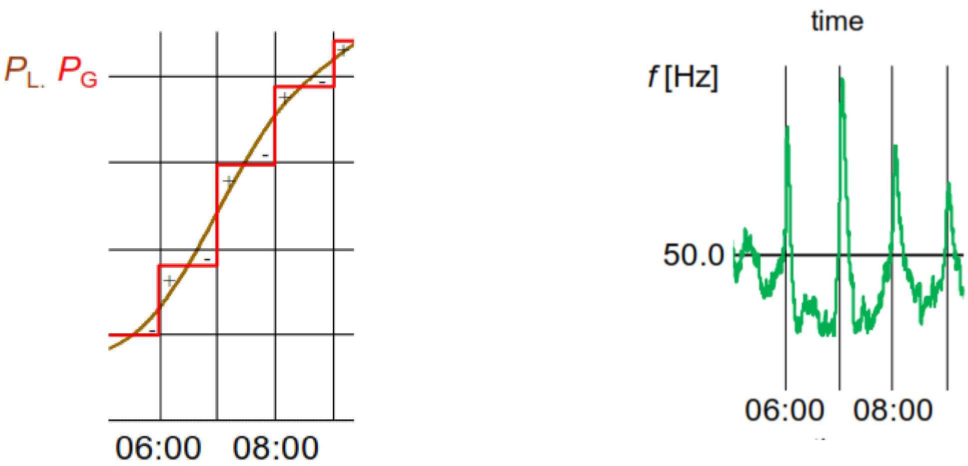

Fig. 12 – Effect of difference between load and schedules on frequency

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Such behaviour occurs on a large scale typically during large demand variation that occurs in the morning and evening. Whereas the demand varies in continuous fashion, the incentive for BRPs and generators is to follow as closely as possible the block shape. This results in an imbalance between the load and the generation. Such power deficit resulting in 'stepwise' imbalance cannot be balanced by control energy at any reasonable cost; as a consequence, the frequency can rise instantly and drop again within the hour. Such power excesses and deficits depend on the Market Time Unit (MTU) on the day-ahead and intraday markets (currently MTU = 1 hour; due to evolve towards 15 minutes) and depend on the ISP. (currently 1 hour, 30 minutes or 15 minutes; due to evolve towards 15 minutes).

Traditionally, in vertically integrated energy systems, system operators scheduled generation in ramps according to their best estimate of the demand. This represents the most efficient way to schedule generation as it reduces the regulating needs to a minimum. However, since the end of the mandatory pool e.g. in the UK, demand-side bidding has been the rule and generation is scheduled to fit the demand purchases. Imbalance settlement provides incentives to make the best forecast of the demand possible. However, these forecasts have a time resolution equal to the ISP (15 min, 30 min or 1 h) and are therefore designed to predict average load values. The averaging of the load over the ISP leads to the instantaneous imbalances which cause the DFDs.

2.4 Behavior of generation units following block-shaped incentives

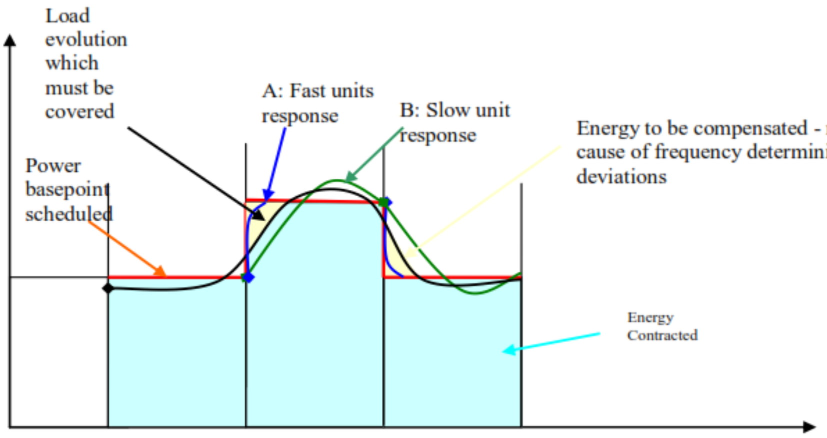

Fig. 13 – Unit behaviour in scheduled time frames [3]

During the morning ramp, the stepwise increase in generation followed by the slower continuous increase in load results in a power imbalance. This 'stepwise' imbalance cannot be possibly balanced by aFRR or mFRR due to the full activation time, which is slower than 5 minutes; in consequence the frequency rises instantly and drops again below 50 Hz over the hour. It must be noted that these root causes for the DFDs are expected to increase in the future with the higher penetration of fast units (e g batteries).

This behaviour can be linked to the fundamental difference in control target for BRPs and for TSOs: in most CE synchronous systems, market participants or BRPs deliver and buy energy (on an hourly or half-hourly, or quarter-hourly basis) whereas the TSOs control real-time power balance. Furthermore, BRPs are treated to be balanced over the whole ISP and therefore react at the latest point and as fast as they can to change their production.

2.5 Ramping on HVDC lines

Difference in ramping rates on HVDC cables, compared with each other and compared with the ramping rates put on the FRCE control inside CE (of +/- 5 minutes) can also contribute to the DFD.

Suppose a change in set-point on GB-BE cable from +1000 to -1000 MW and suppose the full programme change is going through Belgium to other bidding zones, such that it is reflected on the AC borders of Belgium as a 2000 MW programme change as well.

Given the ramp rate of +/- 5 minutes on the AC borders and 100 MW / min on the GB-BE cable, this leads to the following contribution to the FRCE-open loop in the Belgium control area that would need to be compensated by the activation of aFRR and mFRR, but this might be too slow to react to the ramping.

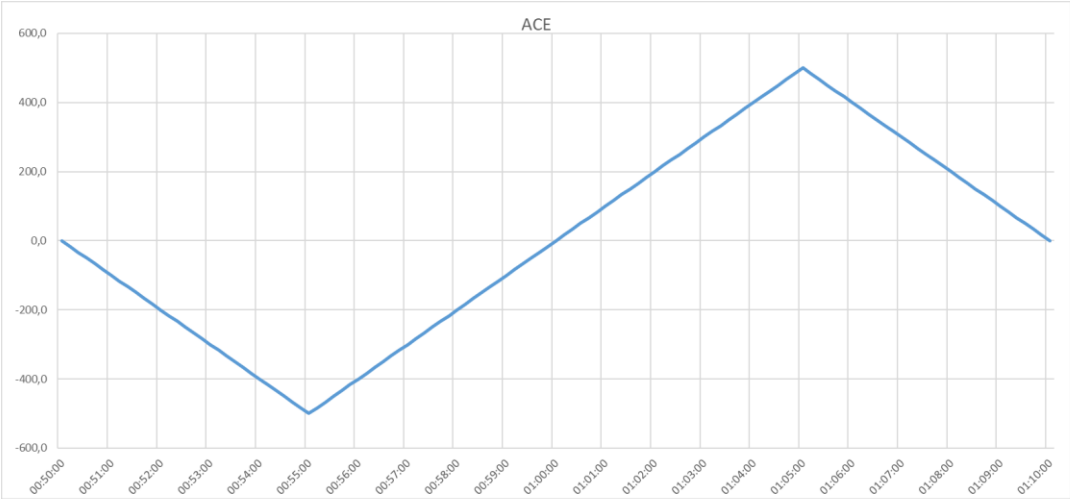

Fig. 14 – Effect of HVDC ramping on the FRCE of the Belgian Control area

The issue is currently under investigation.

3 Managing the problem

3.1 Expected frequency quality

3.1.1 Setting the target of maximum DFD

ENTSO-E proposes establishing which size of DFD is detrimental to the security of the power system, and which DFD size can be considered as acceptable. The target will be used to check if the proposed solutions are adequate to reduce the size of DFD to the acceptable level.

The proposal of an acceptable DFD size comes from the realisation that it will be virtually impossible to completely eliminate the DFD as there will always be a remaining mismatch between the accounting schemes of balancing and the load curve which changes constantly and smoothly.

First Target: Maximum Frequency Deviation

In a CE synchronous area, a DFD should allow the occurrence of the defining incident of FCR without going below 49.8 Hz, which means the frequency deviation should always be smaller than 200 mHz.

The dimensioning incident (double outage of power plants) of FCR is 3000 MW which causes a quasi-stationary frequency deviation of (3000 MW / 27000 MW/Hz) approx. 115 mHz for standard conditions. However, sometimes load/production is higher or lower and the regulating power of the system is also sometimes higher and lower.

Therefore, expected frequency deviation would be in an interval of 100 to 125 mHz.

The total margin should therefore be 125 mHz.

To maintain a margin of 125 mHz, the absolute frequency deviation caused by a DFD should never be larger than 75 mHz.

This leads to an acceptable DFD = 75 mHz

Second Target: Frequency Outside Interval range of SOGL

A second target could be related to the quality target which is given in SO GL:

Article 127 and Annex III of SO GL specify frequency quality defining parameters in CE, establishing +/- 50 mHz as the standard frequency range, which shall not be exceeded during more than 15,000 minutes per year.

This volume covers both the DFDs and the frequency deviations due to outages in the power system. Given that there are statistically less than 100 large outages per year and more than 2,500 DFDs per year, most of the 15,000 minutes will be used by DFDs.

Considering that there are daily about 7 large DFDs, the duration of the DFD above an absolute frequency deviation of 50 mHz should not be longer than 5 minutes per DFD in order to avoid violating this SOGL target.

Therefore, a second target could be:

A DFD should not leave the interval of +/- 50 mHz for more than 5 minutes

3.1.2 How to monitor the target

The synchronous area monitor can take the responsibility of monitoring the target per analogy to articles 128-132 of the SO GL.

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The System Frequency SG will set up the necessary reporting to follow the actual DFDs observed during the DFDs and to count the number of times the targets have been triggered.

In a first step, a simplified approach could be to follow the most critical time stamps (each day, the hours 00, 06, 07, 21, 22 and 23).

In addition, it is recommended, from now on, to follow the actual RoCoF observed during the DFDs and count the number of times that this RoCoF is above 2, 3, 4, 5 and 6 mHz / second.

As we know from the statistics that this RoCoF is steadily increasing, it is very important to keep track of this and to see at which rate we are reaching the average speed of activation of FCR, which is currently 200 mHz in 30 seconds.

3.2 Expected FRCE quality

The SO GL and SAFA Policy on Load-Frequency Control and Reserves define FRCE quality targets, to ensure frequency quality in the synchronous area CE. These FRCE quality targets, defined on a 15-min basis, are good at identifying the contributions of each TSO to frequency deviations, which last for a significant amount of time, in order to be reflected in the 15-min average values.

Since DFDs have a short duration in relation to this 15-min period, there is a loss of information through the averaging process. This has the following consequences:

- The 15-min FRCE quality targets do not reflect the individual contributions of each TSO to DFDs. This especially applies to systematic contributions, so that the TSOs are potentially unaware if and how much they contribute to DFDs on a regular basis.
- The analysis of individual DFDs is made on an ‘ad-hoc’ basis: only in cases where DFDs played a significant role, i.e. the 10th of January.

The best indicator for the operational contributions of TSOs to DFDs is the FRCE calculation on a maximum 10 second basis:

- It allows a systematic evaluation of TSO contributions to DFDs. Thus, systematic contributions from specific TSOs can be identified.
- TSOs can therefore perform a detailed analysis of their contributions to DFDs and define tailor-made solutions for any local issues, which have an added value to the already known causes and proposed solutions.
- Situations with high DFDs can be identified easily and analysed.

The definition of FRCE quality targets should be made on the basis of ‘instantaneous’ measurements (measurement interval maximum 10 sec), in line with the quality targets for the frequency, as given above.

- Such a target sets the basis for the reduction of DFDs, as it defines acceptable behaviour during DFDs and gives clear guidance for when mitigation and alleviation measures should be taken by the TSOs. The quality target should be tailor-made for certain DFD-prone times, i.e. hour changes (±5 minutes).

Based on these quality targets, the TSOs can choose the most effective and efficient measure to reduce its contribution to DFDs, considering the respective particularities of the LFC Block in terms of market design and technical capability.

4 Possible solutions

4.1 How are DFD already managed today

Between 2013 to 2016 measures (due to recommendations from the ENTSO-E Eurelectric Joint Investigation Team [1]) were implemented to improve the frequency quality. For instance, a market time unit of 15 minutes was introduced in 2012 in Germany and unit ramping was also introduced in the Italian market.

4.1.1 GB

In GB, spot power balancing is carried out. The demand is matched by active power, in theory, second by second through market mechanisms in the balancing mechanism. A 300 MW mismatch in power with demand can lead to the frequency breaching the operational limits of 0.2 Hz (i.e. outside the standard frequency range in SOGL). This method removes large mismatches causing large frequency deviations due to market mismatch. This is also known as Residual Central Dispatch and takes place after in day gate closure i.e. the market meets settlement period energy requirements and residual central dispatch is used to meet spot power requirements within the settlement period.

The market participants are obliged legally and contractually to provide certain automatic acting ancillary services to balance the frequency in real time.

Mandatory Frequency Response

The mandatory frequency response (MFR) is an automatic change in active power output in response to a frequency change by providing continuous dynamic modulation in power responses via synchronised generation through their automatic governing systems with a 3 to 5 percent governor droop characteristics. This is a mandatory service that must be provided as a part of the connection agreement with the TSO. Providers can offer one or a combination of the following response times:

* Primary Response (Available within 10 seconds & sustained for a further 20 seconds)

* Secondary Response (Available within 30 seconds & sustained for a further 30 minutes)

* High Response (Available within 10 seconds & sustained indefinitely)

This frequency response can be activated by sending an electronic instruction to any participating generator operating in Frequency Sensitive Mode unless they declare limitations (commissioning, maintenance) also called ‘Limited Frequency Sensitive Mode’ where after 50.4 Hz they drop 2% of their output for every 0.1% deviation in system frequency.

Firm Frequency Response

The firm frequency response (FFR) is a commercial service that can provide the GB TSO with both a dynamic and non-dynamic response to change in frequency during a particular window of time. The dynamic frequency service provides a continuous modulation to changes in system frequency, whereas the non-dynamic service is triggered by the operation of a Low Frequency Relay when the frequency deviation activates that relay. This service can include generators connected to the transmission and distribution systems, battery storage providers, HVDC interconnector support and aggregated demand side response that consists of interruptible load contracts which automatically reduce/disconnect load when triggered by a Low Frequency Relay.

Enhanced Frequency Response

The enhanced frequency response (EFR) is a dynamic service where the active power changes proportionally in response to changes in system frequency. The participants of this service must be capable of responding

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within one second to frequency deviations and operate in frequency sensitive mode within the operational envelope.

Reserve Services

Fast Reserve

Fast reserve provides the rapid and reliable delivery of active power through increasing output from generation or reducing consumption from demand sources via electronic instruction form the national balancing engineer during their contracted service windows, with a reserve rate in excess of 25 MW / min. This type of reserve has a droop characteristic of 1% to 4% based on their reserve contracts. Fast reserve utilisation can vary depending on system conditions, the demand profile and the generating plant on the system. However, on average, providers are utilised for approximately 5 minutes at a time, ten times a day. The providers are expected to have the capability to sustain reserve for at least 15 minutes.

Short Term Operating Reserve

The short term operating reserve (STOR) service is provided by units greater than 3 MW that are typically used to replace eroded frequency response following a frequency deviation, demand mismatch or generation uncertainty. These units are instructed using a single point dispatch tool used by the TSO typically available within 20 minutes and could be sustained for at-least two hours thereafter.

Additional Pumped Storage Services

In addition to pumped storage participating in the above services, they also provide certain services (at an initiating/holding cost to the TSO) to help mitigate frequency deviation by increasing their output at a near instantaneous run up rate to full output. These services play a pivotal role in arresting the deviation of system frequency and restoring it back to its operational limits.

Part Loaded Response (PLR)

This is a dynamic FFR service provided by certain hydro units that are contracted to be part loaded and generate up to their full output during a frequency deviation, providing a fast response at a default droop setting of 1%

SpinGen on LF

This is a static response service provided by pumped storage units that is triggered by a low frequency relay operation at 49.75 Hz, which allows the valves of the pumped storage unit to open and the unit to generate to its full output at a run up rate of 999 MW / min. For this service to operate, the turbines of the unit needs to be spinning in air in preparation for the valves to open to provide a faster response.

Pump on LF

Some hydro power plants can be used in load mode (using pump to store water). They are used in load mode when demand is low (to store water in anticipation to further needs). Hydro Pump Storage can also be used in cased of frequency deviation: stop pumping in case of under-frequency, and even start in generation mode if frequency continues to decrease, depending on their build. Like the SpinGen, these pumping loads can be disconnected by a low frequency trigger typically set at 49.75 Hz. The response rate is instantaneous and plays a pivotal role in arresting and restoring system frequency.

4.1.2 Nordic

Based on the planning information and real-time information, each TSO assesses the impact of ramping around hour shifts from a national perspective. In addition, Svenska Kraftnät and Statnett assess whether the changes in production plans in the Nordic area and the HVDC exchange around the hour shift will impact the system frequency in a way that cannot be entirely handled by control centres in the minutes before and after the operating hour. If so, there is a need to advance or delay parts of planned production steps at the hour

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shift. The power schedules may be changed from 30 minutes before hour shift till 30 minutes after the hour shift.

This coordination is mainly important during morning and evening hours and also around day shift. If the changes in the production plans are deemed to be too high, the TSOs make a coordinated plan on how to level out these changes by an agreement with BRPs that represent power generating modules to reschedule the production. In situations with congestions, there is also a need to decide in which order the rescheduling should take place. For example, in the event of close to congestion on Hasle from Norway to Sweden, it may be wise to start with increased production in Sweden/Finland 15 minutes before the hour shift and decreased production in Norway in the first 15 minutes after the hour shift. The volumes to be shifted after the hour might be reassessed closer to the hour shift if something unplanned occurs that would interfere with the initial plan.

The trading plans on the HVDC interconnectors between the Nordic LFC block and other LFC blocks can potentially change so much from one hour to the next that the changes in power flows at the change of hours must be restricted to manage balance regulation and to stay within system security limits. Restrictions are placed on the gradient for change in flow and on changes to the trading plans from one hour to the next in the energy market

The current capacity on HVDC-connections between the Nordic synchronous system and the CE synchronous system is 5340 MW. The Nordic system is about 1/5 as large as the Continental system. This – together with the fact that the flow pattern on the connections behaves like consumption seen from the Nordic system (more export in the morning and opposite in the evening) – leads to HVDC connections having a much larger impact on the Nordic system than the Continental system. The variation in exchange on those connections is more and more synchronised, resulting in price variations in the two systems in the day-ahead markets. Due to this, there are potential risks for up to 10,000 MW change in flow on those cables at the one hour shift. Such a change in schedule could lead to a huge, unmanageable RoCoF in the Nordic Area.

To avoid this threat to system security, the Nordic TSOs agreed to restrict possible changes in the exchange on each cable connection to a maximum 600 MW from one hour to the next in all time frames (including the day-ahead market). Currently, this allows for up to 5–6,000 MW changes in exchange at any one hour shift. The TSOs are monitoring the economic consequences of this restriction and comparing them with other alternative actions such as extra reserves, counter trade in the market, etc. The goal is to find the best socioeconomic solution. There is also a restriction on the gradient for changed flow on the individual connection (max 30 MW / min giving a total of about 200 MW / min for the synchronous system).

The restrictions in power change between hours is to control the frequency in the Nordic area, and the restrictions in ramp rates are to control the voltage in the local areas where the HVDC links are implemented.

4.1.3 Switzerland

Switzerland has a – requirement in national grid code (Transmission Code) & accounting of inadvertent exchanges based on the schedule change ramping (-/+ 5 min)

In fact, the schedules for the calculation of the inadvertent exchanges are ‘corrected’ in such a way that they already contain the -/+ five minutes ramp around the changing of the schedules. By doing so, an incentive was created in order to avoid penalising those market participants who follow the change of schedule ramping as required in the grid code. This is given in more detail in the solution, ramping on schedules.

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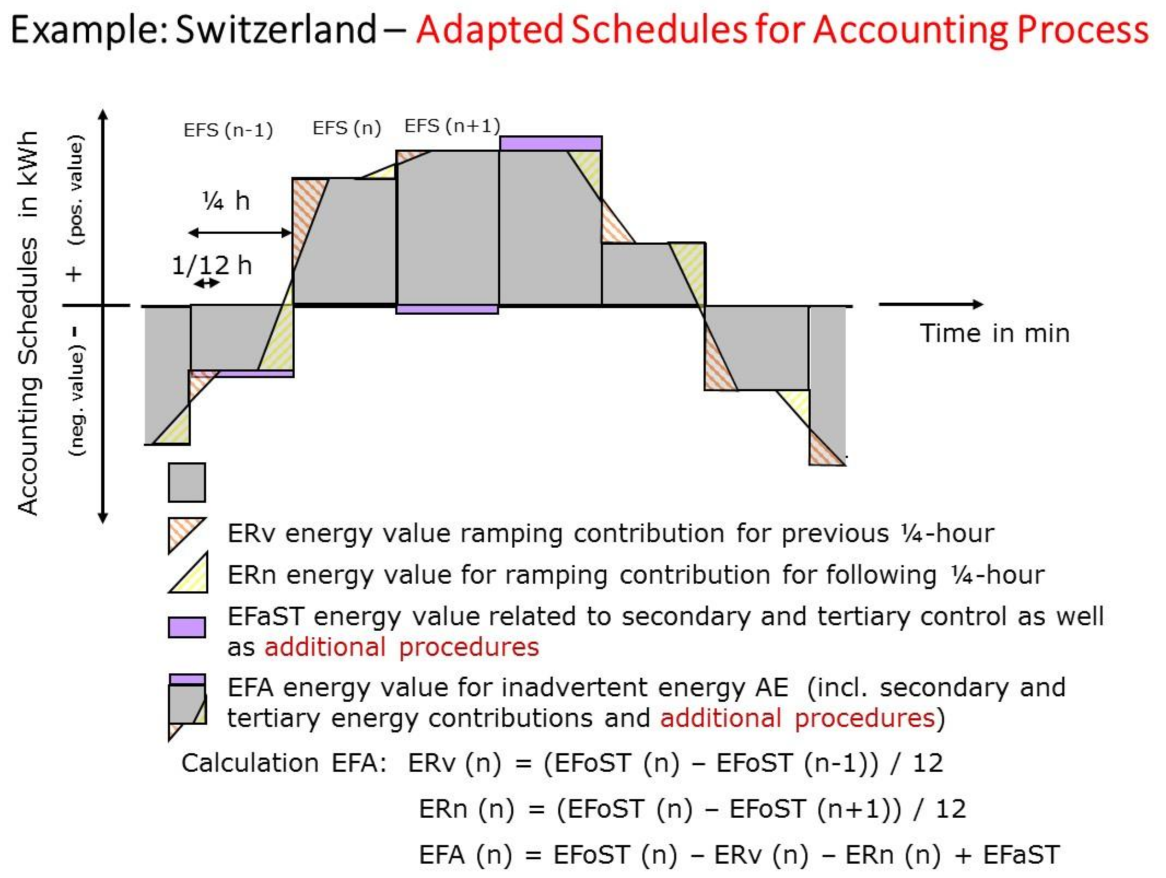

Fig. 15 – Ramping on schedules applied in Switzerland

4.1.4 Spain

In Spain, aFRR provision is made through large regulating areas (acting as BSPs), which can aggregate several generation units from different technologies (e.g. hydro + thermal + wind). The verification of the provision of the service at ‘regulating area’ level (portfolio) guarantees that, regardless of the possible technical restrictions of the units behind (i.e. thermal), the joint provision ensures the answer asked by the TSO (in terms of power). In addition, the commitment of each regulating area is continuously taking into account the action of the other regulating areas, so they have an economic incentive to give a faster response (i.e. for ‘extra’ provision there can be a bonus, whereas for slower provision a penalty is applied). This has resulted in a very good functioning of aFRR provision in the Spanish system and thus in small DFDs.

4.1.5 France

RTE monitors continuously the amount of reserved capacity available in the LFC Block (procured aFRR and mFRR, plus additional mFRR and RR free bids) and takes measures to replenish or release reserve capacities when necessary in order to always have at least the dimensioning volume.

Regarding the aFRR and FCR provided, RTE ensures in real time that providing units are correctly delivering FCR and aFRR and takes measures to replenish reserves in case the providing units (even if scheduled by BSP) are not correctly providing FCR or aFRR

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The k-factor is re-estimated every 30 minutes and (if larger than the default value, as established yearly by ENTSO-E) adapted in the secondary controller.

4.1.6 Germany:

The introduction of quarter-hourly resolution for MTU in the German Intraday-Market leads to a decrease of deterministic imbalances at the change of the hour, but to an increase at every change of quarter-hour.

The improvement of the imbalances contributing to DFDs in Germany after the introduction of a MTU of 15 minutes can be seen in figures 16 and 17. Figure 16 shows that the aFRR need in Germany before the introduction of a 15 minute MTU experienced high peaks during the change of the hour. In figure 17, the peaks have been significantly reduced. However, as mentioned before, some peaks can be experienced with the change of quarter hour (see 08:30 on 2nd January 2016).

That the introduction of a 15 minute MTU does not completely avoid the contribution to DFDs as can be clearly seen in figure 18, showing the behavior of the aFRR need in the German LFC block on the 30 April 2018. High peaks with the change of the hour or quarter hour are still occurring, especially in the morning and evening hours. Therefore, Germany is still contributing to DFDs, especially in the morning and evening hours. The contribution is based on several reasons:

- shut down and startup of wind due to environmental protection (bats, noise,…)
- contribution of large water pump storages, which change from pump to turbine and vice versa in ~1 minute
- high rate of change of load

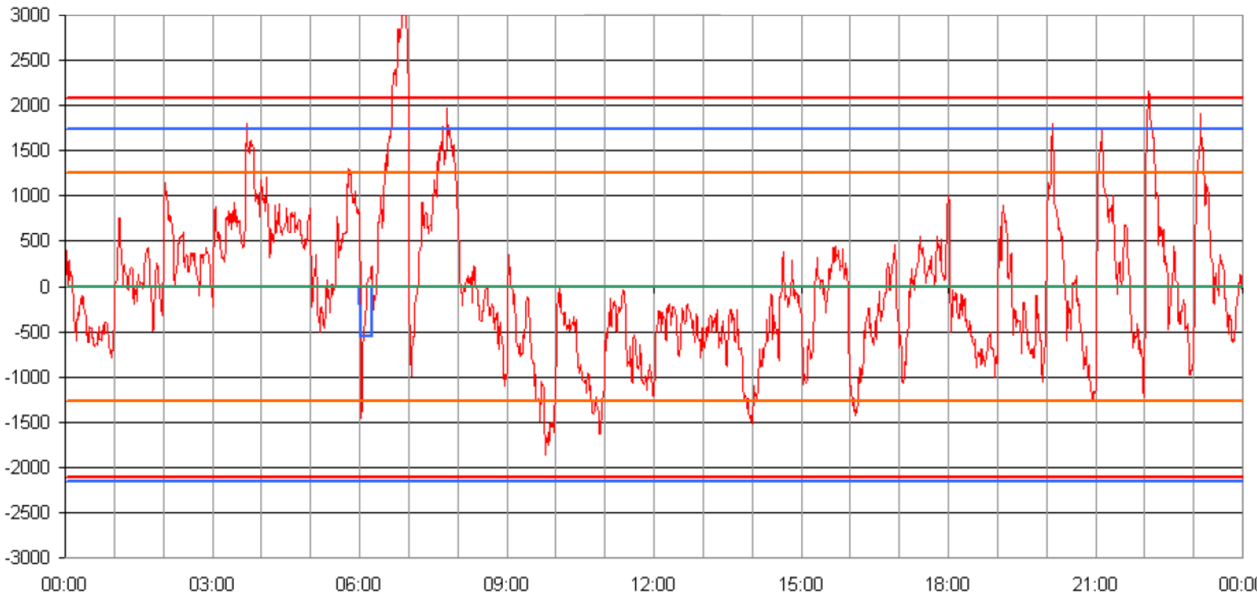

Fig. 16 – Behavior of aFRR need in German LFC block on 16th January 2012 (before introduction of 15 minute MTU)

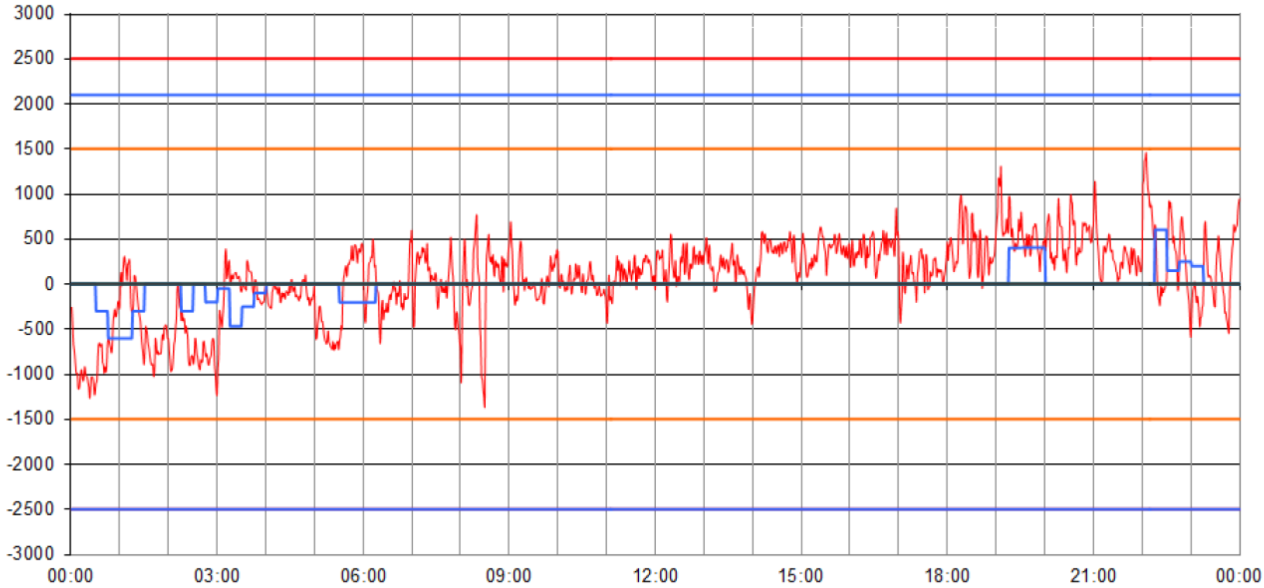

Fig 17 – Behavior of aFRR need in German LFC block on 02.01.2016 (after introduction of 15 minute MTU)

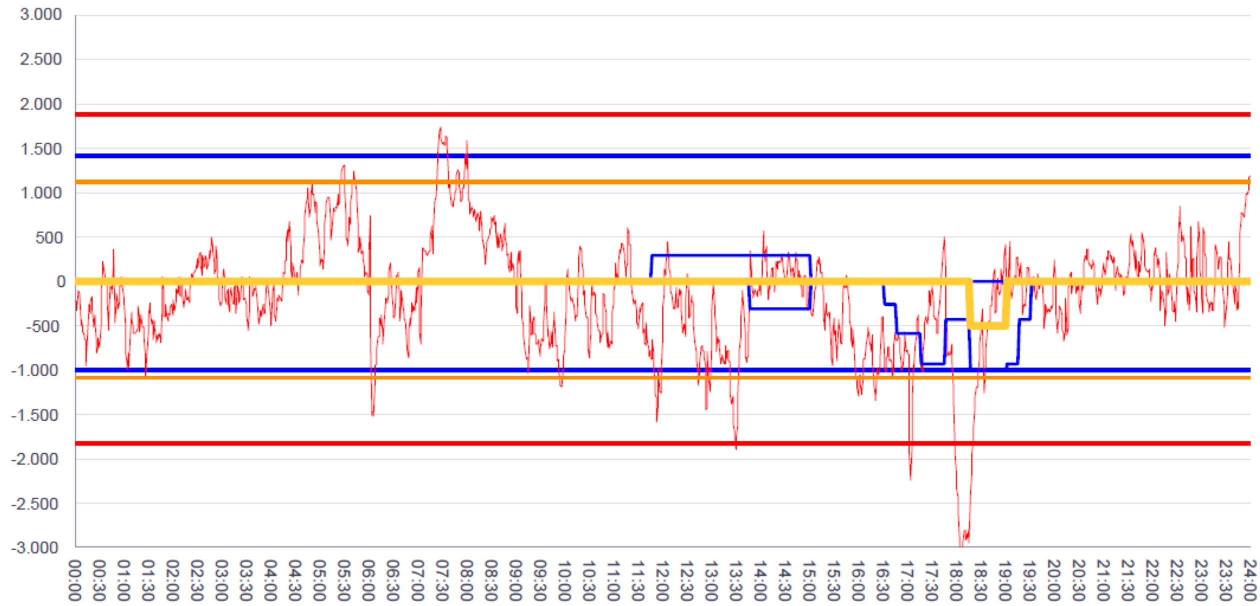

Fig. 18 – Behavior of aFRR need in German LFC block on 30th March 2018 (after introduction of 15 minute MTU)

4.1.7 Denmark:

Energinet has requirements for all new production units to have a ramp rate limiter. Only for batteries is there a limit of max 100 kW / s.

4.2 Regulatory Framework

Extract from RfG NC:

Article 15
General requirements for type C power-generating modules

6.(e) the relevant system operator shall specify, in coordination with the relevant TSO, minimum and maximum limits on rates of change of active power output (ramping limits) in both an up and down direction of change of active power output for a power-generating module, taking into consideration the specific characteristics of prime mover technology

Extract From SO GL:

Article 127
Frequency quality defining and target parameters

3. The default values of the frequency quality defining parameters listed in paragraph 1 are set out in Table 1 of Annex III.
4. The frequency quality target parameter shall be the maximum number of minutes outside the standard frequency range per year per synchronous area and its default value per synchronous area are set out in Table 2 of Annex III.
5. The values of the frequency quality defining parameters in Table 1 of Annex III and of the frequency quality target parameter in Table 2 of Annex III shall apply unless all TSOs of a synchronous area propose different values pursuant to paragraphs 6, 7 and 8.
6. All TSOs of CE and Nordic synchronous areas shall have the right to propose in the synchronous area operational agreement values different from those set out in Tables 1 and 2 of Annex III regarding:

(a) the alert state trigger time;
(b) the maximum number of minutes outside the standard frequency range.

7. All TSOs of the GB and IE/NI synchronous areas shall have the right to propose in the synchronous area operational agreement values different from those set out in Tables 1 and 2 of Annex III regarding:

(a) time to restore frequency;
(b) the alert state trigger time; and
(c) the maximum number of minutes outside the standard frequency range.

8. The proposal for modification of the values pursuant to paragraph 6 and 7 shall be based on an assessment of the recorded values of the system frequency for a period of at least 1 year and the synchronous area development and it shall meet the following conditions:

Annex III - *Table 1* **Frequency quality defining parameters of the synchronous areas**

Table 1

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 2

Frequency quality target parameters of the synchronous areas

	CE	GB	IE/NI	Nordic
maximum number of minutes outside the standard frequency range	15 000	15 000	15 000	15 000

Article 128

FRCE target parameters

1.All TSOs of the CE and Nordic synchronous areas shall specify in the synchronous area operational agreement the values of the level 1 FRCE range and the level 2 FRCE range for each LFC block of the CE and Nordic synchronous areas at least annually.

2.All TSOs of the CE and Nordic synchronous areas, if consisting of more than one LFC block, shall ensure that the Level 1 FRCE ranges and the Level 2 FRCE ranges of the LFC blocks of those synchronous areas are proportional to the square root of the sum of the initial FCR obligations of the TSOs constituting the LFC blocks in accordance with Article 153.

3.All TSOs of the CE and Nordic synchronous areas shall endeavour to comply with the following FRCE target parameters for each LFC block of the synchronous area:

(a) the number of time intervals per year outside the Level 1 FRCE range within a time interval equal to the time to restore frequency shall be less than 30 % of the time intervals of the year; and

(b) the number of time intervals per year outside the Level 2 FRCE range within a time interval equal to the time to restore frequency shall be less than 5 % of the time intervals of the year (…)

Article 131

Frequency quality evaluation criteria

1.The frequency quality evaluation criteria shall comprise:

(a) for the synchronous area during operation in normal state or alert state as determined by Article 18(1) and (2), on a monthly basis, for the instantaneous frequency data:

(i) the mean value;

(ii) the standard deviation;

(iii) the 1-,5-,10-, 90-,95- and 99-percentile;

(iv) **the total time in which the absolute value of the instantaneous frequency deviation was larger than the standard frequency deviation**, distinguishing between negative and positive instantaneous frequency deviations;

(v) **the total time in which the absolute value of the instantaneous frequency deviation was larger than the maximum instantaneous frequency deviation**, distinguishing between negative and positive instantaneous frequency deviations;
(vi) **the number of events in which the absolute value of the instantaneous frequency deviation of the synchronous area exceeded 200 % of the standard frequency deviation** and the instantaneous frequency deviation was not returned to 50 % of the standard frequency deviation for the CE synchronous area and to the frequency restoration range for the GB, IE/NI and Nordic synchronous areas, within the time to restore frequency. The data shall distinguish between negative and positive frequency deviations;

(b) for each LFC block of the CE or Nordic synchronous areas during operation in normal state or alert state in accordance with Article 18(1) and (2), on a monthly basis:

(i) for a data-set containing the average values of the FRCE of the LFC block over time intervals equal to the time to restore frequency:

— the mean value,
— the standard deviation,
— the 1-,5-,10-, 90-,95- and 99-percentile,
— the number of time intervals in which the average value of the FRCE was outside the Level 1 FRCE range, distinguishing between negative and positive FRCE, and
— the number of time intervals in which the average value of the FRCE was outside the Level 2 FRCE range, distinguishing between negative and positive FRCE

(ii) for a data-set containing the average values of the FRCE of the LFC block over time intervals with a length of one minute: the number of events on a monthly basis for which the FRCE exceeded 60 % of the reserve capacity on FRR and was not returned to 15 % of the reserve capacity on FRR within the time to restore frequency, distinguishing between negative and positive FRCE;

Article 137

Ramping restrictions for active power output

1. All TSOs of two synchronous areas shall have the right to specify in the synchronous area operational agreement restrictions for the active power output of HVDC interconnectors between synchronous areas to limit their influence on the fulfilment of the frequency quality target parameters of the synchronous area by determining a combined maximum ramping rate for all HVDC interconnectors connecting one synchronous area to another synchronous area.

3. All connecting TSOs of an HVDC interconnector shall have the right to determine in the LFC block operational agreement common restrictions for the active power output of that HVDC interconnector to limit its influence on the fulfilment of the FRCE target parameter of the connected LFC blocks by agreeing on ramping periods and/or maximum ramping rates for this HVDC interconnector. Those common restrictions shall not apply for imbalance netting, frequency coupling as well as cross-border activation of FRR and RR over HVDC interconnectors. All TSOs of a synchronous area shall coordinate these measures within the synchronous area.

4. All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE target parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:

(a) obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units;

(b) obligations on individual ramping starting times for power generating modules and/or demand units within the LFC block; and

(c) coordination of the ramping between power generating modules, demand units and active power consumption within the LFC block.

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(a) obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units;
(b) obligations on individual ramping starting times for power generating modules and/or demand units within the LFC block; and
(c) coordination of the ramping between power generating modules, demand units and active power consumption within the LFC block.

Article 138
Mitigation

Where the values calculated for the period of one calendar year concerning the frequency quality target parameters or the FRCE target parameters are outside the targets set for the synchronous area or for the LFC block, all TSOs of the relevant synchronous area or of the relevant LFC block shall:

(a) analyse whether the frequency quality target parameters or the FRCE target parameters will remain outside the targets set for the synchronous area or for the LFC block and in case of a justified risk that this may happen, analyse the causes and develop recommendations; and

(b) develop mitigation measures to ensure that the targets for the synchronous area or for the LFC block can be met in the future.

Article 16
Annual report on load-frequency control

1. By 30 September, ENTSO for Electricity shall publish an annual report on load-frequency control based on the information provided by the TSOs in accordance with paragraph 2. The annual report on load-frequency control shall include the information listed in paragraph 2 for each Member State.
2. Starting from 14 September 2018, the TSOs of each Member State shall notify to ENTSO for Electricity, by 1 March every year, the following information for the previous year:

a) the identification of the LFC blocks, LFC areas and monitoring areas in the Member State;
b) the identification of LFC blocks that are not in the Member State and that contain LFC areas and monitoring areas that are in the Member State;
c) the identification of the synchronous areas each Member State belongs to;
d) the data related to the frequency quality evaluation criteria for each synchronous area and each LFC block in subparagraphs (a), (b) and (c) covering each month of at least 2 previous calendar years;
e) the FCR obligation and the initial FCR obligation of each TSO operating within the Member State covering each month of at least 2 previous calendar years; and
f) a description and date of implementation of any mitigation measures and ramping requirements to alleviate deterministic frequency deviations taken in the previous calendar year in accordance with Articles 137 and 138, in which TSOs of the Member State were involved.

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Extract from EBGL:

Article 18
Terms and conditions related to balancing

6. The terms and conditions for balance responsible parties shall contain:

(l) where existing, the provisions for the exclusion of imbalances from the imbalance settlement when they are associated with the introduction of ramping restrictions for the alleviation of deterministic frequency deviations pursuant to Article 137(4) of Regulation (EU) 2017/1485.

Extract from Swiss Grid Code:

2.6. Operational implementation of schedule changes and load controls

(1) The Operation Handbook of the UCTE / ENTSO-E (Policy 1) stipulates that schedule changes must take place in a linear fashion between control areas over a period of 10 minutes, beginning 5 minutes before the schedule change.

(2) To avoid unnecessary use of control power, the PPOs must adhere to the regulations described in point (1) when implementing their production schedules.

(3) To prevent excessive load variations, the DSOs must stagger the conscious connection and disconnection of loads (e.g. ripple control systems) in such a way as to produce an on balance roughly linear load change over a period of approximately 10 minutes, beginning 5 minutes before the schedule change.

(4) The requirements described in points (2) and (3) should be implemented on a user-pays basis according to a non-discriminatory and transparent procedure.

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4.3 Solutions addressing the root cause of DFD

Several possible solutions can be implemented to mitigate the DFD issues on both a short or long term timescale. It is, however, important to distinguish solutions that address the root cause of DFD from a more general solution that aims to continuously enhance the frequency quality.

4.3.1 15 minute trading and 15 minutes ISP

Balance responsible parties have the obligation to balance themselves over the ISP. In principle, the shorter the ISP, the more closely the production will follow the load and the smaller the variation in term of power shift during schedule changes. The joint study of ENTSO-E and Eurelectric showed in 2011 that moving to a 15' ISP would significantly reduce DFDs compared to the current situation.

Today, ISPs are not harmonised in CE, where 15', 30' and 60' ISPs coexist. The Electricity Balancing Guideline imposes on TSOs, however, the requirement to adopt a 15' ISP by end 2020, with possible derogations until 1st January 2025.[1] Many TSOs in the CE synchronous system already apply the 15' ISP.

It is important to note that imposing a 15' ISP puts an obligation on the BRP to balance their portfolio over this (short) period but will result in an efficient balancing <u>only</u> if:

(i) **BRPs have the possibility to trade on the wholesale market products with the same granularity**. This is possible today on the OTC market, but only a few countries (Germany, Austria, Switzerland) have power exchanges offering 15' (or even 30') energy products. This situation will change in the near future (see below);

(ii) **BRPs adapt their behaviour in the desired way, according to the incentive signals they receive.** TSOs should monitor this and adequately incentivise BRPs to balance their portfolio through their local terms and conditions related to balancing.

Intraday market

ACER has recently taken a formal position interpreting the legal framework and urging TSOs to align on each border the MTU of the cross-border intraday market (XBID) with the longest of the ISPs of the TSOs of that border (e.g. between Belgium [ISP 15'] and France [ISP 30'], the intraday MTU should be 30').

TSOs participating in XBID are currently calculating by when they can apply this change, but about 20 TSOs (most of them in CE) have already implemented this rule or intend to do so by end 2020 at the latest. TSOs having a 30' ISP may be moving already from 1h cross-border trading to 30' cross-border trading, which will be an intermediate step towards the target market design.

This evolution should have a significant impact on the possibility for market parties to better balance themselves on a shorter ISP, which will also help reduce DFDs.

Day-ahead market

The Article 8.2 of the clean energy package regulation on the internal market for electricity requires from nominated electricity market operators (NEMOs) that they facilitate the trading in time intervals at least as short as the imbalance settlement period both in day-ahead and intraday markets by 2021. Although given the flexibility provided by EB GL for derogating the implementation of ISP 15' until 1st January 2025, it is

[1] Such derogation has been granted e.g. to France, which applies a 30' ISP.

clear that at some point Single Day Ahead Coupling (SDAC) will also evolve towards a 15' resolution across CE.

This evolution of the day-ahead market may lead to a further reduction of DFDs. However, the additional benefits compared to the adoption of 15' products on the intraday market are not straightforward and the 2021 deadline seems very challenging for various reasons (performance of the single day-ahead coupling algorithm, appetite of market parties to trade 15' products in day-ahead, feasibility for TSOs to generate D2CF and DACF files with a 15' granularity, etc.). This evolution towards 15' trading in day-ahead seems therefore less of a priority than the adoption of a 15' ISP and a 15' energy product in the intraday timeframe.

Conclusion

The legal and regulatory framework will clearly require BRPs in CE to balance their portfolio over shorter periods in the coming few years and to introduce 15' cross-border trading products on the intraday market as of 2020 and at the latest by 2025 for countries having obtained a derogation. These combined measures should be considered the harmonised target solution to reduce DFDs.

If necessary, additional measures could be taken on an ad hoc basis, for example as an intermediary step in countries with a derogation from 15' ISP, or in countries with a production mix largely contributing to DFDs.

Merits:

(a) This solution must be implemented anyway, as it will be imposed by the CEP. A proposal could be to increase the priority of this and implement it earlier if possible.

(b) A higher granularity of the discrete schedule step will always reduce the deviation between the power ramping and the actual evolution of the load, if it is accompanied by a correct control of the frequency target parameters.

(c) Quarter-hourly products can partly solve the DFDs at its source, as it will split the hourly DFDs into quarter-hourly DFDs and with that the physical effect will be reduced. Thus, the DFD itself will be lower but will not be eliminated.

Impact on the Congestion Forecast Processes (IDCF, DACF):

It makes sense to firstly implement quarterly hour products for the ID trading in XBID. A next step could be to implement quarterly hour products in DA and D-2 processes, as this is likely to be more challenging. When the Cross Border Intra Day trading is available in 15 min products then it would also be possible to see the large differences between the individual quarterly hours in flows between the bidding zones. The flows can be significantly different from quarter to quarter hour during high ramp rates of load and/or RES production. In this situation, an Intraday Congestion Forecast (IDCF) process using quarterly hour resolution would need to be implemented. In the second phase, when the quarterly hour products are also implemented in DA and D-2 market coupling processes, a Day-ahead Congestion Forecast (DACF) process in quarterly hour resolution would be required.

4.3.2 Ramping on load and generation schedules

The idea of this solution is to incentivise the BRP to apply slower ramps on the physical output in a control area (generation and/or load schedules) which will reduce the size of DFD.

Ramping could be applied on generation schedules only or on both generation and load schedules.

According to article 137(4) of SOGL, a ramping restriction can be applied to generating modules and/or demand units. Article 18(6)(l) of EBGL then requires imbalances to be excluded due to these ramping restrictions from the imbalance settlement.

The following text gives an explanation of the solutions with a simplified example.

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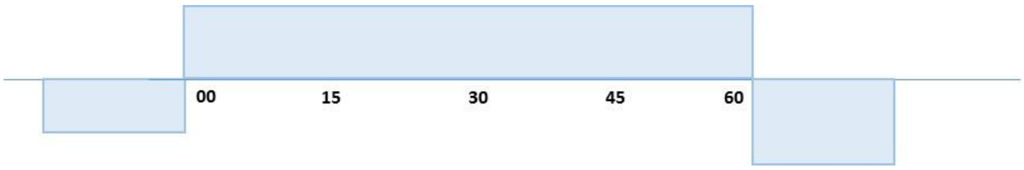
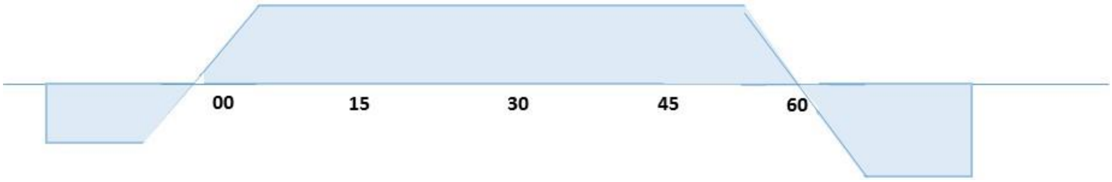
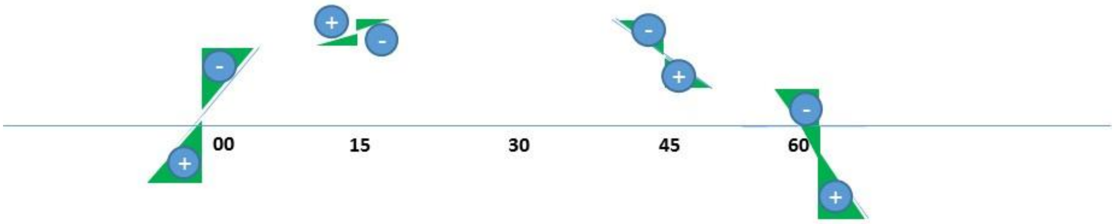
As explained previously, the BRPs are incentivised to avoid an imbalance through the ISP. In an hourly schedule market, for example, the incentive of the BRP in a system selling all its production on the wholesale market would be to follow this shape:



However, the change of the demand is naturally different from the shape of production of this BRP. For example, let us assume a load which has a ramp starting 5 minutes before the hour change, and finishing 5 minutes after (i.e. symmetrical ramping period of 10 minutes):



The difference between the schedules is the following:



The difference between the generation schedule and the demand schedule which occurs especially at the hour change is one of the main reasons for DFDs.

The proposal is to apply ramping periods to the BRP's production schedules and/or load schedules. One possibility would be to apply the ramping periods currently applied in inter-TSO XB schedules within CE (starting 5 min before and finishing 5 min after the start of each MTU)[2].

In accordance with article 18(6)(l) of EBGL, this implies redistributing the energy of generation and possibly load schedules in the previous/following period as follows:

[2] The closer the ramping of generation and the ramping of the load, the smaller the DFDs. The closer the ramping of generation/load and the ramping applied on inter-TSO cross-border schedules, the smaller the FRCE of the TSO when energy is exported/imported.

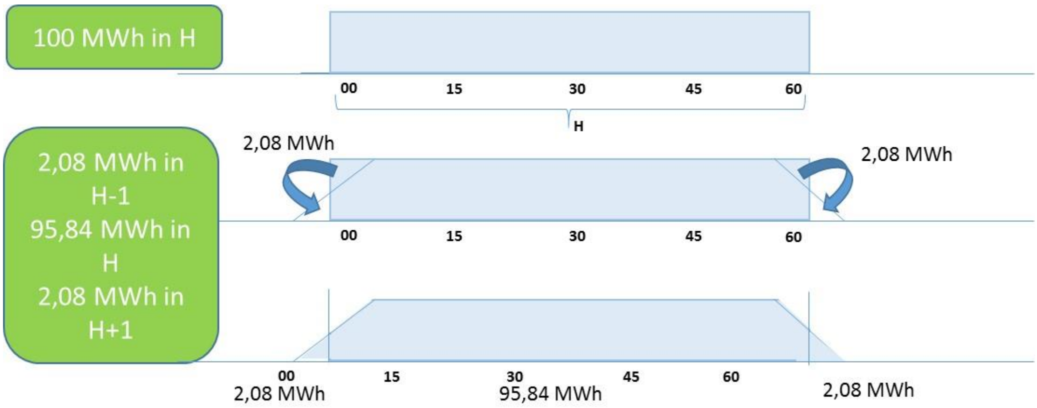


Fig. 16 – Impact of Ramping on schedules

This correction in the energy for the imbalance settlement (it could be implemented only in the imbalance settlement procedure or through an additional scheduling process to the BRP[3]) will allow BRPs to ramp their generation schedules closer to the variation of the load without being penalised. If the incentive to avoid step changes in production is sufficient (ideally production is actually ramped as required), this will help address the root cause of DFDs, as the instantaneous difference between the generation and the demand will be reduced.

This solution is currently applied in Switzerland (cf. section 4.1.3).

Merits:

- This solution reduces/minimises the instantaneous difference between generation and demand, thus attacking directly the source/root of DFD
- The solution is already foreseen as a possibility by SOGL and EBGL, but it is not simple, as is shown below.
- This solution affects the national schedules only (XB trades are not affected; current ramping constraints do not apply to XB trades), but the positive impact on DFDs will also be extended across borders.
- Even if the BRP does not apply exactly the shape in power, the gap between the schedules is expected to be smaller in any case than without applying ramps → the situation of DFDs will be improved. The effectiveness of this solution will, however, depend on the technical incentives for BRPs to follow the ramping constraints (e.g. to preserve the asset by applying slower ramps) and/or the penalties (if any) foreseen for not respecting the required ramping constraints.
- Experience exists nowadays in some systems (e.g. Switzerland) with positive results.

Issues:

- Relevant impact on market models, in the definition of the internal schedules of the BRPs.
- Metering and monitoring of the power delivery to enforce penalties on deviations from required ramping, if applicable.
- In those systems which currently do not apply this, amendment of Terms & Conditions for BRPs and of LFC Block operational agreements, and regulatory approval.
- Requiring technical adaptation for both TSOs and BRPs (operations, IT).

[3] It would be at the discretion of each TSO how to implement the solution.

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4.3.3 Ramp restrictions on specific power plants and/or demand units

The mitigation measure is implemented on specific power plants and/or demand units, by enforcing maximum ramping limitations according to SOGL Article 137(4). These ramping limitations can be enforced without limiting the general ability of plants to offer their flexibilities to the market. This could be specifically relevant for Large Hydro power stations; in such cases limitation can be implemented by spreading the starting time (time delay). All individual measures are embedded in a coordinated approach also containing the behaviour of other very fast generation units, in order to achieve a steady generation change within the market area and with the intent to reduce the DFD. Any financial disadvantage for the individual market participant will be compensated according to the rules of EBGL Article 18(6)(l), hence this solution should not influence market behaviour but only the physical activation.

Ramping restriction can also be implemented as a rule under which the start or stop of a set of small production units can be spread over a time period which would allow a large instantaneous change in power to be avoided, causing a DFD.

The spreading of the start or stop of a set of small production units over a time period, which would allow a large instantaneous change in power to be avoided, is covered by art 137 of SOGL.

> *All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE target parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:*
> *(b) obligations on individual ramping starting times for power generating modules and/or demand units within the LFC block;*

In some countries, local legislation exists which gives an incentive to certain types of power plants to start or shut down at a specific moment in time. Such legislation could be a source of DFD and it would be good to consider whether legislation can be adapted to create a spread of the start and stop of units over a period of time of at least 10 minutes (+/- 5 minutes before and after the change of an hour, for instance).

Merits:

- Technically very efficient, as it tackles the main source of the frequency variations
- This solution would be very efficient against the very fast changes in hydro or wind output which currently exist in several countries. One example is the shutdown of wind at exactly 22:00 due to noise emission rules, which is one source for the large frequency deviations over 30 seconds observed at that time (see chapter 1.2)
- Due to the mechanism foreseen in Art. 18(6)(l), whereby the imbalances due to ramping restrictions shall not be considered in the imbalance settlement, the BRPs shall be compensated for the ramping. This means that there is no limitation to the offers on the market, but rather an adjustment of the physical injection in order to support system security.

Issues:

- It would leave less flexibility for the market participants as 4.4.2
- Needs to be compensated in the balancing mechanism as foreseen in art 18.6(l) of EBGL
- Requires technical adaptation including the enforcement monitoring of restrictions.
- Metering and monitoring of the power delivery to enforce penalties on deviations from required ramping, if applicable.
- In those systems which currently do not apply this, amendment of Terms & Conditions for BRPs and of LFC Block operational agreements, and regulatory approval.
- Requires technical adaptation for both TSOs and BRPs (operations, IT).

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4.3.4 Limit net position changes between MTU

This solution consists of putting a limit on the change in net position allowed for a certain market area or market areas inside an LFC block.

As it has been established that changes in international schedules are partly causing the DFDs, limiting these changes could reduce the DFD.

This feature is included in most market algorithms, but rarely used inside CE.

The euphemia algorithm description for the SDAC states the following:

> *4.1.1. Net position ramping (hourly and daily)*
>
> *The algorithm supports the limitation on the variations of the net position from one hour to the next. There are two ramping requirements on the net position.*
>
> *- Hourly net position ramping: this is a limit on the variation of the net position of a bidding area from each hour to the next.*
>
> *- Daily (or cumulative) net position ramping: this is a limit on the amount of reserve capacity used during the day.*

It is, however, common practice on the interconnections between CE and Scandinavia, where each HVDC line has such a limitation applied.

The following borders already have those constraints active:

bidding zone FROM	bidding zone TO
Estonia	Finland
Netherlands	Norway 2
Denmark 1 internal	Norway 2
Denmark 1	Denmark 2
Poland Internal	Sweden 4
Lithuania	Sweden 4
Denmark 1 internal	Sweden 3
Lithuania	Poland Internal
Sweden 4	Germany
Denmark 2	Germany
Great Britain (EPEX)	Republic Of Ireland
Great Britain (EPEX)	Northern Ireland.

<u>Issues:</u>

- This is a highly market-impacting measure which should not be taken lightly and will require extensive justification to market parties and regulators.
- The task force recommends that this measure should only be taken by an LFC block if no other measures are reasonably available or are sufficient to control its contribution to the DFDs
- Be aware that sometimes large changes in solar or wind output might justify or even require large changes in the international schedule, and this measure might prohibit this and thus create a new problem for the LFC block.

4.3.5 Balancing products on a 15 minute basis.

The introduction of 15 minutes products in balancing, for example through the implementation of the mFRR platform (MARI project), could also be a measure for some LFC blocks to help reduce DFDs (allowing the demand to be approached with generation schedules coming from the activation of balancing energy of BSPs with a 15 minute resolution).
The applicability and usefulness of this measure depends on the way each LFC block performs balancing.

4.4 General solutions to improve the frequency quality

This section covers possible solutions that aim to improve frequency quality in general, this therefore does not target specifically the DFD that occurs during schedule changes. Such solutions can be technically very effective as they aim to contain any frequency deviations and therefore limit DFD occurrence and impact. Nonetheless, relying exclusively on such mitigation could result in further deterioration, as the root cause of the problem is not properly addressed.

4.4.1 Additional FCR

Additional FCR reserves can be utilised to contain frequency deviations and mitigate risks of excursions, the reserves to be procured would be higher than the dimensioning incident (3000 MW) using a probabilistic approach. Determination of the Ci factor contribution can be done using the existing methodology.

Based on rough estimations and considering a network power/frequency characteristic of around 27000 MW/Hz, the FCR increase is expected to be around 5400 MW.

This FCR requirement increase would lead to an increase of the network power/frequency characteristic but not in a proportional way, because procured FCR contribution is only a part of the overall power/frequency response. Therefore, the target for DFD reduction might not be reached. Furthermore, it is not certain that the system has this additional margin available and that there is enough liquidity on the market for this FCR.

An alternative solution resulting in a lower required FCR increase (around 2000 MW) could consist of a specific new product with a full activation at 75 mHz but this would most likely require even more complex implementation and would need more time and effort to put it in place.

The additional volume which would reduce DFD to the set targets would be around 2000 MW on top of the existing 3000 MW for the whole CE synchronous area.

Any LFC Block which chooses this as a solution will need to increase its FCR obligation (prescriptions and procurement) by 66% at least during the time period when DFDs occur, and will in such a way assist in reducing the DFD with the additional FCR provided.

The additional FCR would only be needed during the usual time periods when DFD occur, making the additional FCR a specific product which could be cheaper.

Merits:

- Technically efficient, does not require the definition of a new product or specific operational implementation.

Issues:

- Will not solve the root issue of DFDs; will only reduce the physical effect.
- The solution is considered expensive and difficult to justify economically.
- The introduction of new suppliers of FCR (e.g. battery providers, electric vehicles, aggregators…)

could in the future make this a more economical way forward.

- It could be that not enough FCR offers are available in some countries
- Having two different FCR services (0-75 mHz and 0-200 mHz) is not considered a quick-win solution
- Increasing FCR should reduce DFD but the actual impact is not known and not easily foreseen
- Increasing the FCR requirement for CE will not lead to a proportional increase of K
- Properly sharing FCR within TSOs to maximise the K increase
- TSOs expect Regulatory changes/NRAs approvals to increase FCR
- TSOs expect Regulatory changes/NRAs approvals to introduce 'new' FCR (0-75 mHz)
- Market Frameworks and IT developments may be necessary to implement the proposed solutions (e.g. market design, new products, new bidding processes)
- SAFA need to be amended and approved by all NRAs
- TSOs expect changes to their IT infrastructures
- Technical changes to generating units controllers are expected (e.g. droop changes, two different FCRs)
- Regulatory/Market changes may require mid/long-term timings
- IT developments may require mid-term timings
- 'Asynchronous' implementations by TSOs → Cost compensations

Timeline:
Relatively short compared to the creation of a new product.

4.4.2 Faster acting Reserves

Provide a new product which reacts immediately on fast frequency changes at the change of the MTU.

For instance batteries would be able to provide very quickly reserves which would stop the frequency going down.

In addition, the product is only needed for a short period before and after the change of the MTU (currently mostly at the change of the hour), meaning it does not require a huge energy storage (a storage of 5 minutes would probably be sufficient)

Merits:

- The fast reaction of batteries would allow less use of the (slower) FCR and a faster way to stop the frequency from deviating too far from 50 hertz.

Issues:

- New products will need to be developed, but there is a willingness (in MC) to consider this development, which would need to be followed by WG Ancillary Services
- The solution is expensive, although probably less expensive than additional FCR.

Timeline:

- Relatively long as it requires the creation of a new product.

4.4.3 Additional aFRR

Increasing aFRRs to act on the imbalance volume deviation during schedule changes.

Merits:

- Already analysed in previous investigations on DFD mitigation measures [1] [3], the effect is minimal, even for large volume.
- aFRR is able to manage DFD with relatively slow variation.

Issues:

- Expensive and economically difficult to justify.
- The increase in term of reserves among control blocks can be difficult to define (not as transparent as FCR); this would require NRA validation.
- Simulations show that aFRR is too slow to solve the DFDs with high RoCoF.

Timeline:

- Relatively short compared to the creation of a new product.

4.4.4 Use of higher K factor in AGC

Increasing the K factor in the automatic FRCE controllers of the control areas will incite the aFRR to activate in the same direction as the FCR (so increasing the volume of FCR) during frequency deviations.

However, doing so will create only an additional source of 'false' control, as the FCR contribution of the LFC block will not change. The K factor and FCR should correlate for one control block as close as possible.

Given the speed of aFRR, for DFD with a RoCoF above 1 mH / sec, the aFRR is too slow to react and cannot limit the change in frequency. It will, however, reduce the frequency change before the DFD and thus could even lead to increasing the maximal frequency deviation.

Sufficient simulations need to be performed to check if increasing the K-factor reduces the DFD also for the highest RoCoF values (up to 5 mHz / sec) before such a change can be accepted.

Nevertheless, the K factor used in AGC should be as close as possible to the 'real K factor' of the control block. Therefore, it is better to use an estimation of the real time K factor instead of the theoretical K factor which is calculated only once a year by SG SF. The value of SG SF should be understood as the minimum value to use in AGC (to be corrected by the results of FCR cooperation).

4.4.5 Mutual frequency assistance between synchronous areas

Frequency Coupling between synchronous areas as mutual exchange will increase FCR response in all synchronous areas (SAs) without lowering the procured FCR capacity.

The paper [12] presents more details on frequency coupling and its limits.

The frequency coupling process is one agreed between all TSOs of two or more synchronous areas involved and allows linking the activation of FCR by an adaptation of HVDC flows between the synchronous areas.

Currently, there are several HVDC interconnectors providing frequency coupling services. The characteristics of these services are quite varied and do need to comply with SOGL.

Three technical classes of frequency coupling have been defined, namely FCR exchange, frequency netting and frequency optimisation. These are different services, and specific limits for the implementation and clarification of the existing definitions (FCR versus frequency coupling) from SOGL are proposed in the framework [12].

FCR exchange should not affect the dimensioning needs of FCR for the providing SA, as defined in SOGL article 173(3). Hence, to facilitate FCR capacity exchange, additional physical FCR provision in the providing SA is necessary.

It is concluded that frequency netting and frequency optimisation are mutual SA-SA support services that could affect the FCR dimensioning needs in the receiving and/or delivering SAs by improving the frequency quality by design. The gains in frequency quality can result in benefits associated with FCR volume reduction via the concept of sharing, as defined in SOGL. Indeed, whereas FCR sharing within a SA is not allowed, it is allowed between SAs. However, for this to be possible, preconditions must be satisfied: an all TSO-agreement within a SA would be required as would transparency regarding the amount of the remaining final FCR available after sharing.

Merits:

- No consumer will feel any changes
- Increased K-value, lower frequency deviations

Issues:

- Operational Limits on ENTSO-e Frequency Coupling have been identified in 2017 [12].
- SAFA has limited the use of this function, which could need to be re-evaluated.
- NRA validation will be needed

Timeline:

- Several months would also depend on the concerned TSOs

4.5 Solutions which are under investigation

The following possible solutions require further investigation to analyse the feasibility and efficiency but are already given for completeness, as they have been proposed by one or more LFC blocks.

4.5.1 Introduction of Spot Power Balancing

The introduction of Spot Power Balancing (also known as residual central dispatch) could also be a way to reduce large DFDs. Spot Power Balancing takes place after in day gate closure i.e. the market meets the settlement period energy requirements and residual central dispatch is used to meet spot power requirements within the settlement period.

Normally active power and demand will be balanced so there will be no large mismatches. There may be some, as it is impossible to estimate the demand correctly all the time but this method will remove large mismatches. There may also be active power failure which may also lead to smaller frequency deviations for a short time.

Market mechanisms may be used to alter the active power so it matches the demand second by second.

Issues:

- this will be a major change politically in many control blocks in CE.

4.5.2 Use changes between ISP for BRPs as market based aFRR.

DA-result (Bilateral and stock-market) gives a change in MWh/h from one ISP to the next for each LFC-area. DA stock market gives a price difference between these two ISP in each price area.

The idea is to avoid a sudden change in production at the ISP shift time, which is caused by the ramping of (most) consumption, with the purpose of promoting load to be followed.

By converting the change in MWh/h position and the change in DA price between the two ISP to additional aFRR-bids with the bids covering the last half of the first ISP and the first half of the last ISP this will lead to

- No sudden change at ISP change time (DFD eliminated) – voluntary participation will not be enough to get a level playing field for all types of production.
- The LFCs will activate the necessary capacity to follow the change in consumption (will cause a small frequency deviation due to the delay between LFC-input and aFRR response)
- If consumption rises faster than a straight ramp, the additional aFRR capacity can be activated as needed.
- Only in the event the ISP in its totality (over all BRPs) is short or long will the traditional aFRR be activated.

4.5.3 Dynamic Frequency Setpoint

As the DFD is very consistent, it is possible to mitigate very high frequency deviations and peaks by giving all LFCs a frequency set point that goes in the opposite direction as the expected frequency deviation.

This solution has another benefit, as it can also reduce the effect of long lasting imbalances.

SG SF has had this on their agenda for years, and asked Erlangen University to perform a study on it, with the following conclusion:

From the simulation results it can be concluded that the model proves a significant frequency quality improvement to deal with the deterministic frequency deviation by the use of a DFSP in the secondary controllers.

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4.6 Impact study of the proposed solutions – full model

Several models were tested to analyse the impact of the different proposed solutions on the DFD. This chapter gives the results of these solutions, which provide an indication of the impact to be expected from each solution.

4.6.1 Simulation model used

The model, which was used to simulate several solutions, is based on MatLab SimuLink and was built by TenneT Germany on behalf of the ENTSO-E SG SF. The idea was to have one model covering all Load-Frequency-Controller of the CE Synchronous Area to simulate different cases, which were or will be discussed in ENTSO-E. This model can also be used to simulate the effect of future developments such as MARI, PICASSO or TERRE.

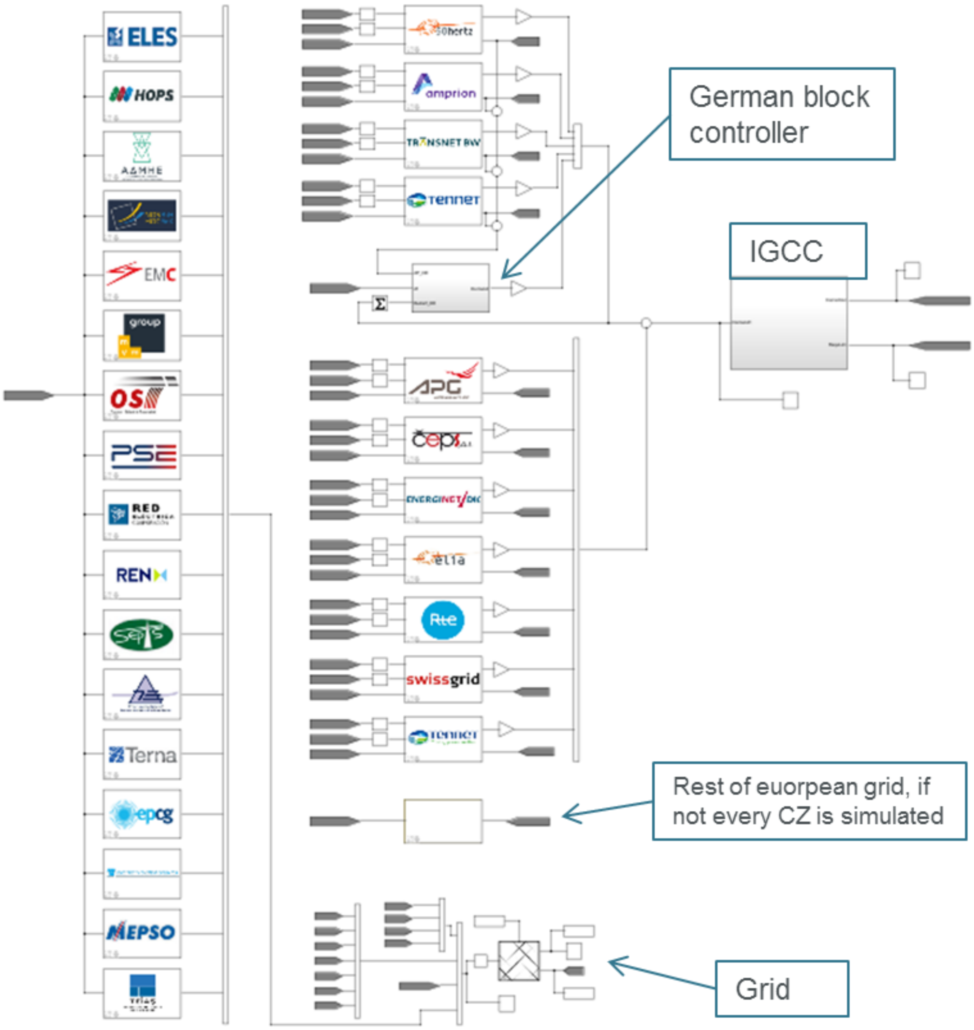

Fig. 17 – LFC-Model CE

The model is based on a development in Germany and consists of several blocks. One block covers the German LFC-Block and connected to that is the block on IGCC, which consists of all IGCC-Partners. Another block covers all currently non-IGCC-TSOs. The last block describes the 'grid'. This block depends on the consideration of LFC-Blocks in the simulations. Simulations can be done for single LFC-Areas up to the whole synchronous area. Depending on the simulation, the 'grid' consists of all those LFC-Areas not considered.

The model consists of individual blocks per TSO, whereby each TSO has its own Load-Frequency controller. As not all information and every LFC-setting is public, a standard PI-controller with Anti-Windup was used and adjusted by individual LFC-parameters, as:

- proportional factor,
- time constant,
- type of aFRR activation (MOL-based or pro-rata) and
- full activation time of aFRR.

The LFC-Parameters are based on a Survey by SG SF from 2018. For data that have not been delivered within the survey, the parameters from an ENTSO-E Study 'Impact of Merit Order activation of automatic Frequency Restoration Reserves and harmonised Full Activation Times' were used.

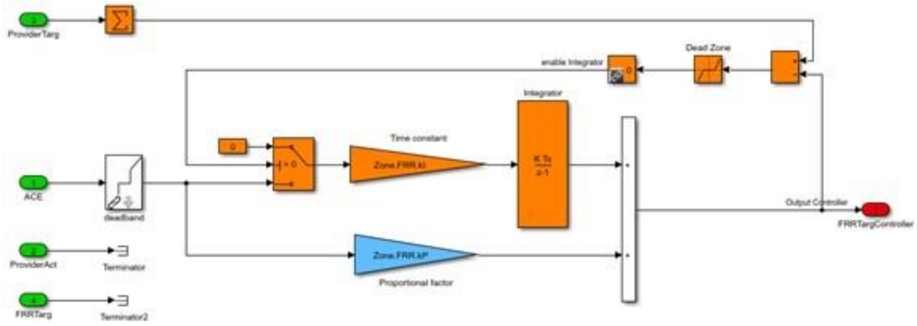

Fig. 18 - Standard PI-controller with Anti-Windup

To be realistic in the results of the model, it also considers the type of aFRR activation as well as some assumptions regarding the behaviour of aFRR activation. Within the model, it is possible to choose between the following settings for aFRR behaviour:

- slow PT 1,
- fast PT 1 or
- ramp.

Ramp means a static ramp over the full activation time, whereby the gradient is calculated based on the requested volume divided by the full activation time.

In addition to the individual LFCs, the current set-up of the IGCC is also considered. That means that the simulation model also simulates the netting of imbalances between all current IGCC partners. If one TSO has a negative imbalance and another a positive imbalance, the model also takes netted imbalance into account in the further calculations. As only frequency is simulated in that study and we assume that all have a deviation in the same direction, netting will not have any impact on the results.

The following figure shows how load interacts with the frequency. The frequency within the model is described by an integrator. The inequality of power is divided by a constant load of 422,728 MW and a time constant of 12 s. For the simulations in that study, dP is calculated as the deviation between load and generation.

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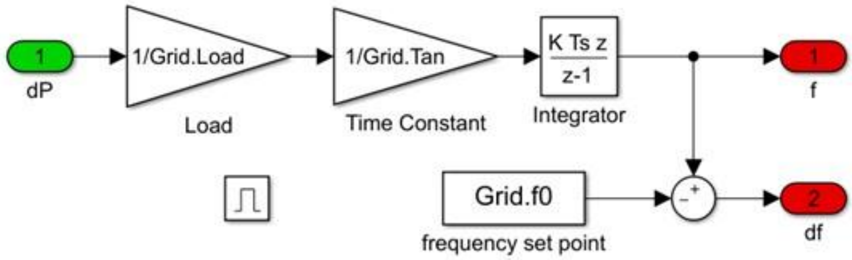

Fig. 19 – Frequency

Due to the assumptions made, the model is limited in its results compared to the reality. The following assumptions will have an impact on the results:

- self-regulation effect of load: is assumed as a constant value based on the formula from SG SF:

$$\lambda_{Self\ Regulation} = \frac{1\%}{Hz} \times 439.127GW = 4391{,}27\ MW/Hz$$

- FCR delivery: The FCR delivery is calculated based on the k-value only. As we know that, for example, France usually provides more FCR than their initial obligation, this additional FCR is not considered in the model.
- constant k: As we know, the k-value varies in some LFC-blocks over the day. The model assumes a constant k-value for the whole day.
- aFRR: The total amount of aFRR per LFC-block is currently not known, therefore each LFC-Block is simulated with only 200 MW of aFRR. An inclusion of the total amount aFRR per LFC-Block would increase the quality of the results.
- aFRR activation behaviour: Some assumptions have been made to simulate the effect of aFRR activation. As these assumptions do not perfectly fit the reality, the assumed aFRR behaviour will have an impact on the simulation results. The results can be increased when a normalised aFRR behaviour is included in the model.
- timely resolution of input data: the quality of the results are depending on the data used for simulation. As data of generation and load for whole CE is only available in 15 min resolution A continuous course of load can only be calculated by interpolation between every 15 min value. The same counts for feed-in of renewables.
- ramping of generation and load: Some assumptions have been made for the ramping behaviour of different generation types. An overview can be found in the following table:

Name	Generation types	Ramping time before and after (quarter-)hourly change
Very fast	HydroPumpedStorage, HydroWaterReservoir	30 sec before, 30 sec after
fast	Biomass, FossilGas, FossilOil, HydroRun	2 min before, 3 min after
slow	FossilBrownCoal, FossilCoal, FossilHardCoal, FossilOilShale, FossilPeat, Geothermal, Nuclear, Other, OtherRenewable, Waste	5 min before, 5 min after

continous	Marine, Solar, WindOffshore, WindOnshore	7.5 min before, 7.5 min after or 30 min before, 30min after

The ENTSO-E Transparency platform was the source of the data for generation and load, which were used for the simulations for this report. These schedules were the main input for the model to simulate the effects of proposed solutions.

To compare the results with the reality, we have chosen 4 April 2019 as a day which was special in terms of height of frequency deviation, but without any further special situation, such as on 10 January. The 4 April was characterised by several DFDs over the day. At 21:00, the minimum frequency of the day reached 49.89 Hz. The maximum frequency that day was 07:00, with a value of 50.08 Hz.

The following figure shows the day as a result of the simulation model. This figure was the base case for all other simulations. The effects of the individual simulations were always compared to that base case. For that comparison, the following statistical parameters have been used:

- mean value,
- standard deviation,
- minimum,
- maximum and
- Variation.

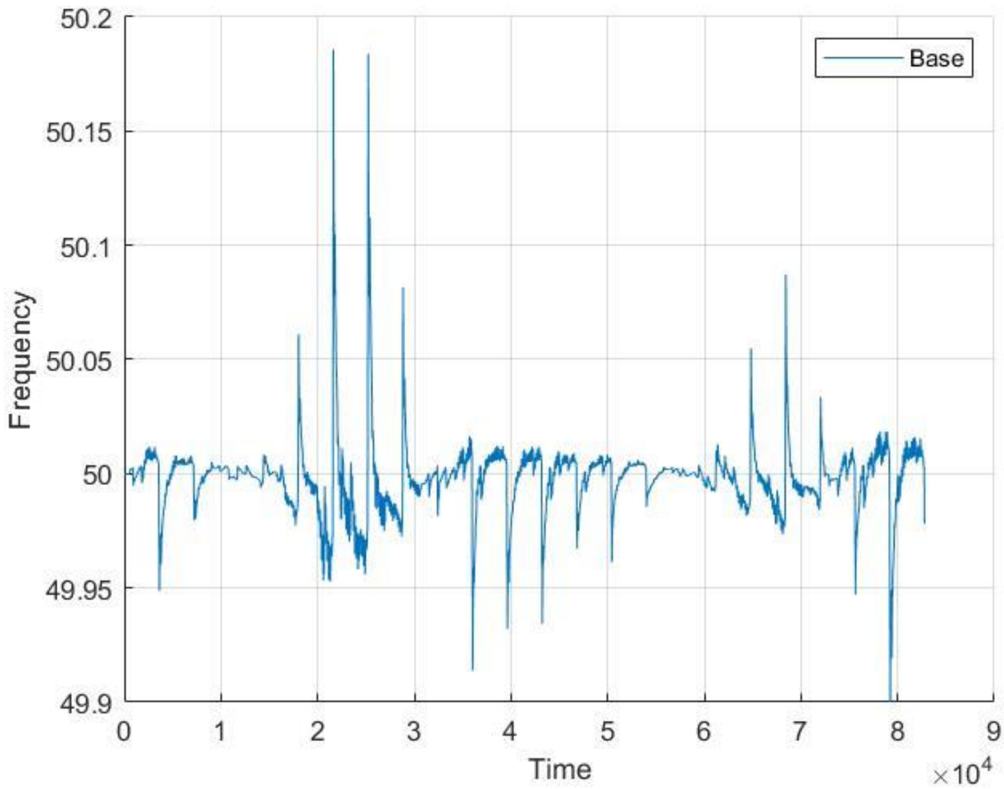

Fig. 20 – 4 April – simulated by the model

The following figure shows 4 April with real data. We can see the difference between reality and simulation by comparing figures 20 and 21. An explanation of why the model is more sensitive, especially in the frequency peaks, was given above. However, the mean frequency peaks can be seen in the real data as well as in the simulation, even though the height of deviation deviates.

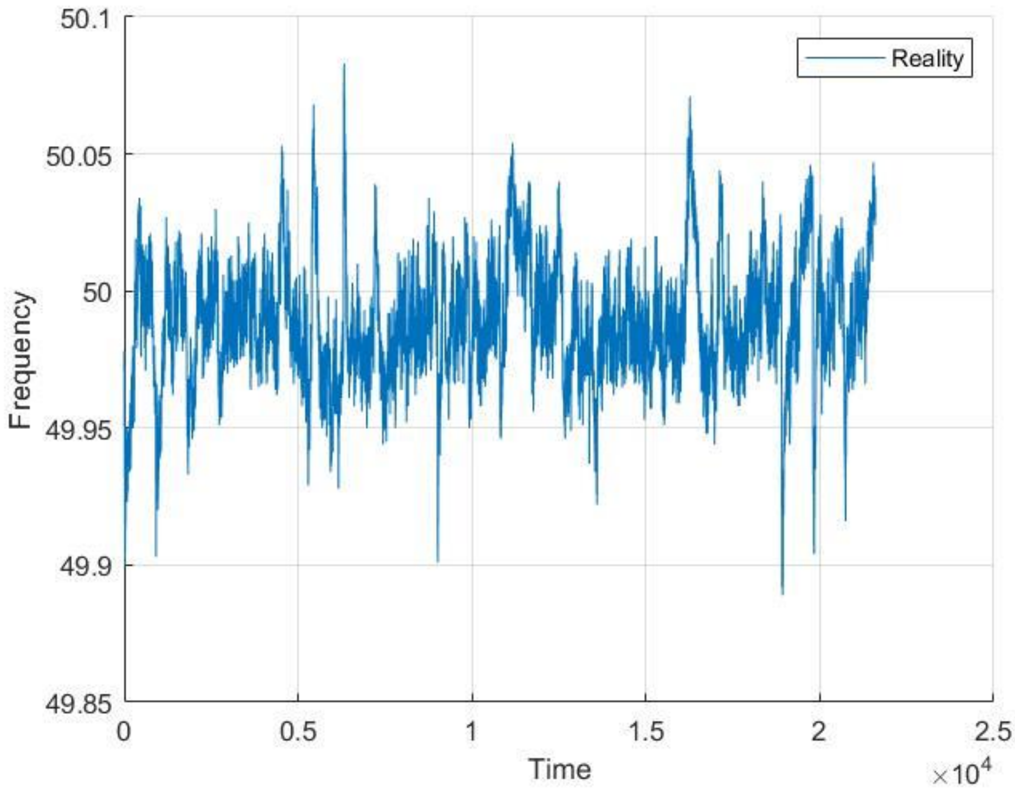

Fig. 21 – 4 April – real data

4.6.2 Ramping on load and/or generation schedules

As described above, the model considers different ramping rates per generation type. To simulate the effect of ramping on generation schedules, each generation type received the same ramping rate as all the others. For example: Wind was assumed with a continuous ramp to simulate the base case. For the simulation case 'all generation jumps[4]' it was assumed that wind generation ramps between 30 sec before until 30 sec after the shift of MTU.

Based on that principal, the following cases were analysed:

- All jumps: mean that all generation type ramps 30 sec before till 30 sec after the MTU.
- All fast: mean that all generation types ramp between 2 min before till 3 min after MTU.
- All slow: mean that all generation types ramp between 5 min before till 5 min after MTU.
- All continuous: mean that all generation types ramp between 7.5 min before till 7.5 min after MTU.

In the following are figures for each of the cases in comparison to the base case.

[4] The term "jump" is used here to represent very fast, almost instantaneous, variation of power output

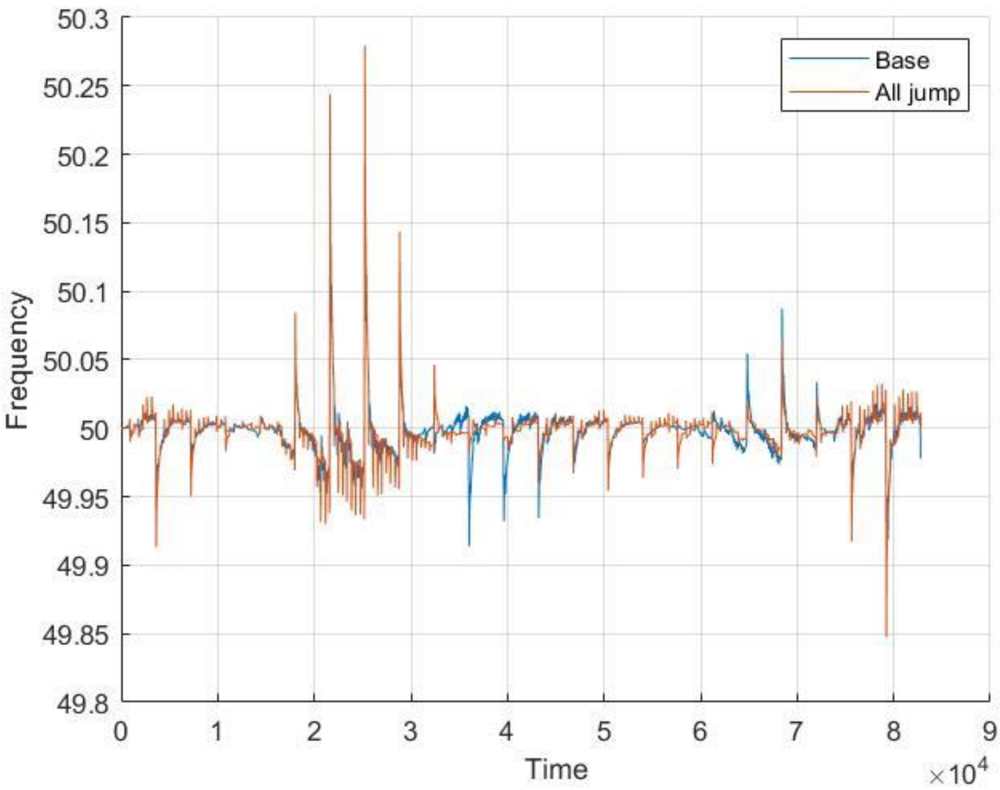

Fig. 22 – All generation ramps between 30 sec before till 30 sec after MTU

Based on the figure, it is clear that the frequency will be worse than in the base case. In particular, the peaks in the morning and evening hours are much higher. The following table gives an overview of the statistical comparison.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All jump	49.9982	0.0168	49.8475	50.2794	2.8108E-04

The following figure is a zoom into the highest frequency peak in the morning hours to give an impression of the ramping rate and also to observe the difference between the base case and simulated case in more detail.

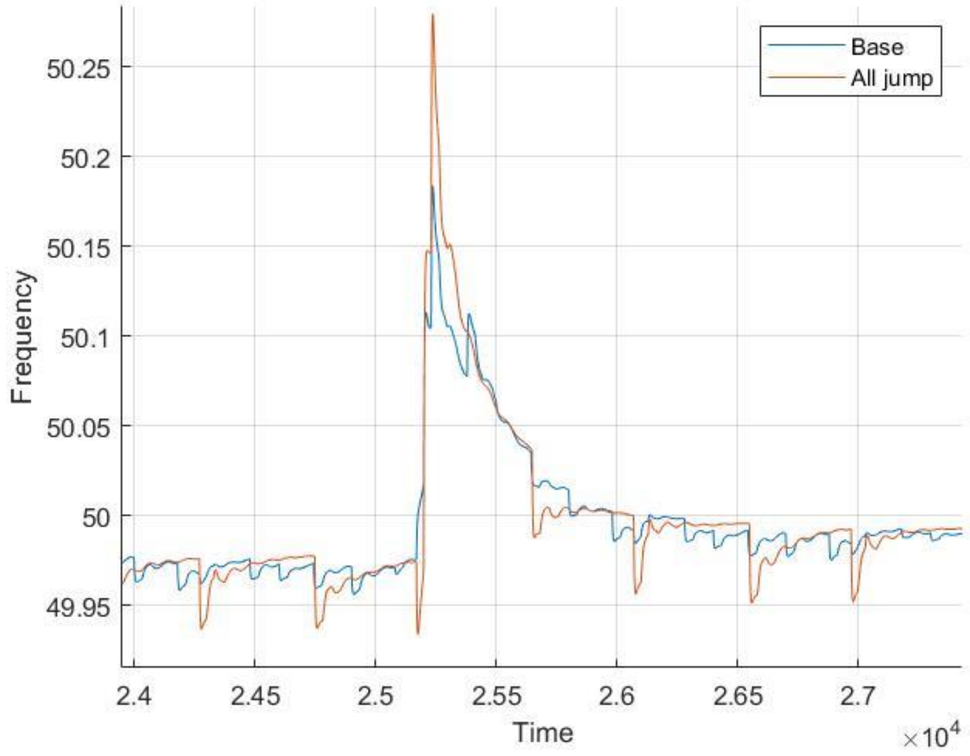

Fig. 23 – All jump - zoom in

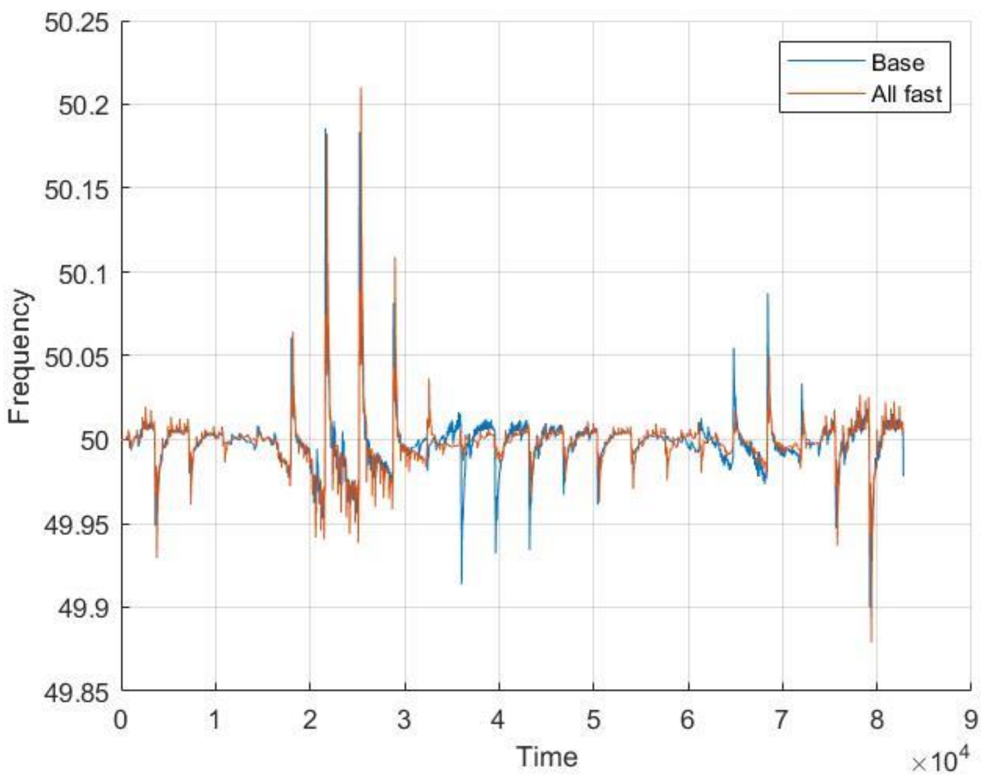

Fig. 24 – All generation ramps between 2 min before until 3 min after MTU

Based on the figure, you can also see that a fast ramping of all generation will make the frequency worse. The frequency quality is slightly better than in the case of 'All jump', but it is still out of operational range.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All fast	49.9983	0.0145	49.8791	50.2101	2.1003E-04

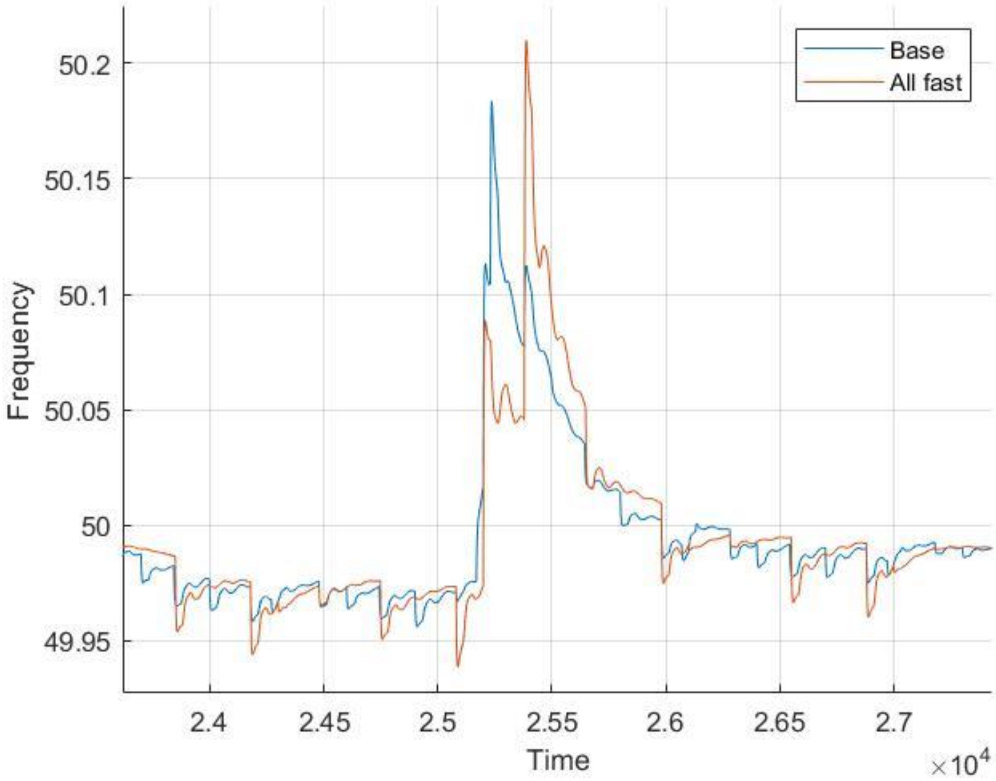

Fig. 25 – All fast – zoom in

As we can see in the figure above, due to the change in ramping, it comes also to a shift in the time of the frequency peak. Whereas in the case of 'all jump' the frequency peak is at the same time as in the base case, we can now observe that it is later than in the base case. This leads to the conclusion that a huge part of the overall generation, especially in the base case, comes from very fast reacting units.

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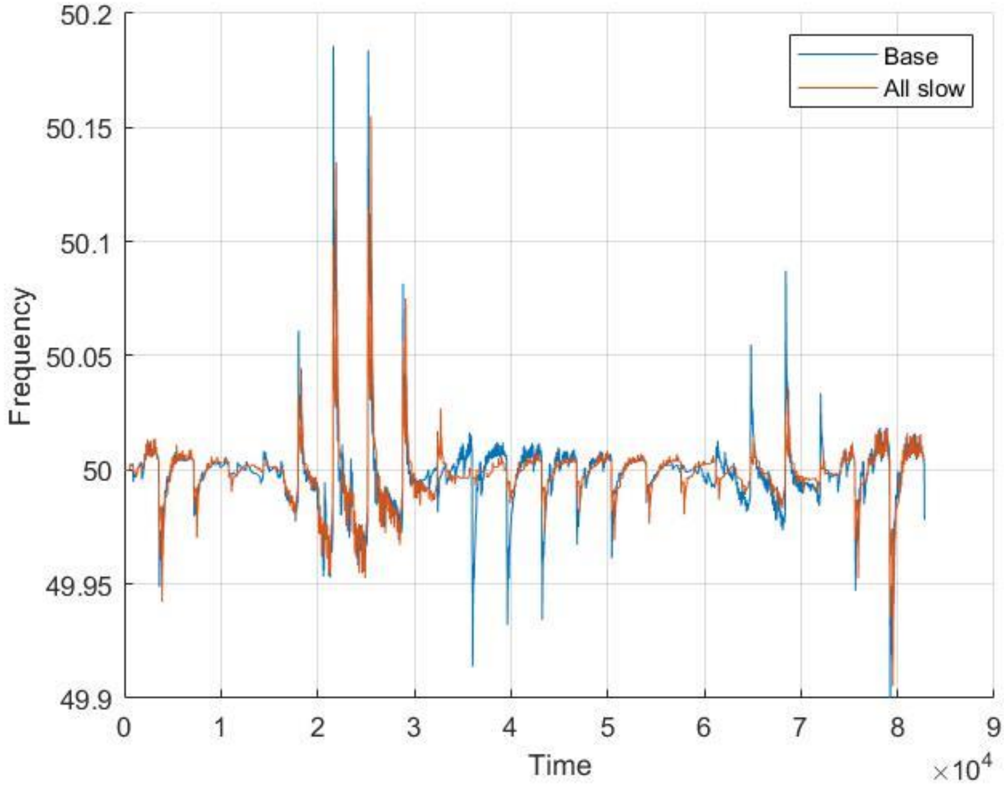

Fig. 26 – All generation ramps between 5 min before until 5 min after

Based on figure 26, we can see that the slower ramp rate for all generation units increases the frequency quality. The frequency becomes smaller than in the base case. However, the frequency deviation is higher than 100 mHz in overfrequency and slightly lower than 100 mHz in underfrequency. This can also be seen in the following table and in the following figure.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All slow	49.9985	0.0127	49.9053	50.1550	1.6129E-04

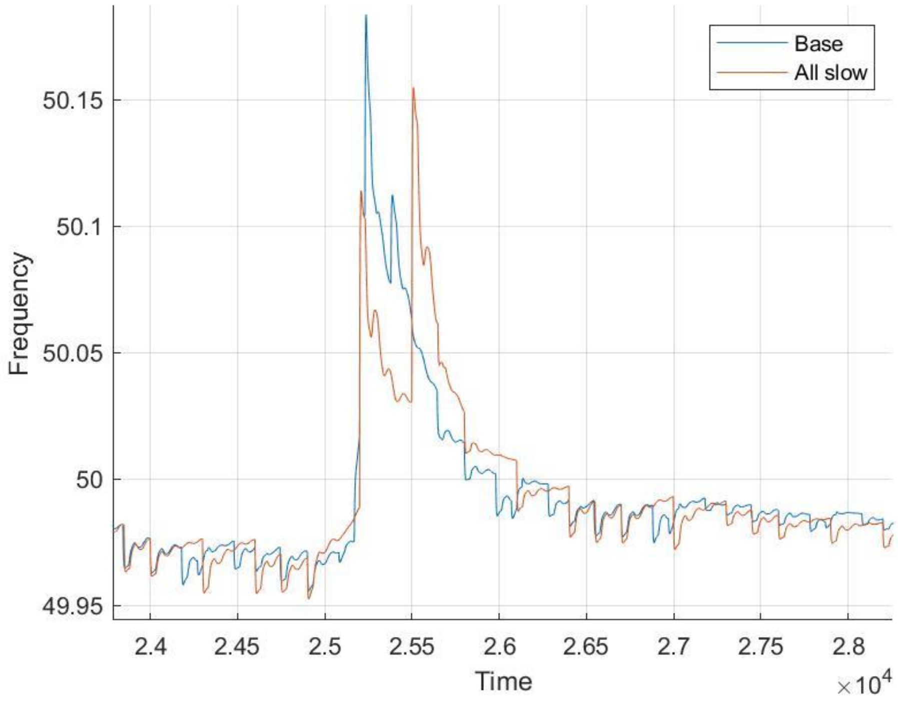

Fig. 27 – All slow – zoom in

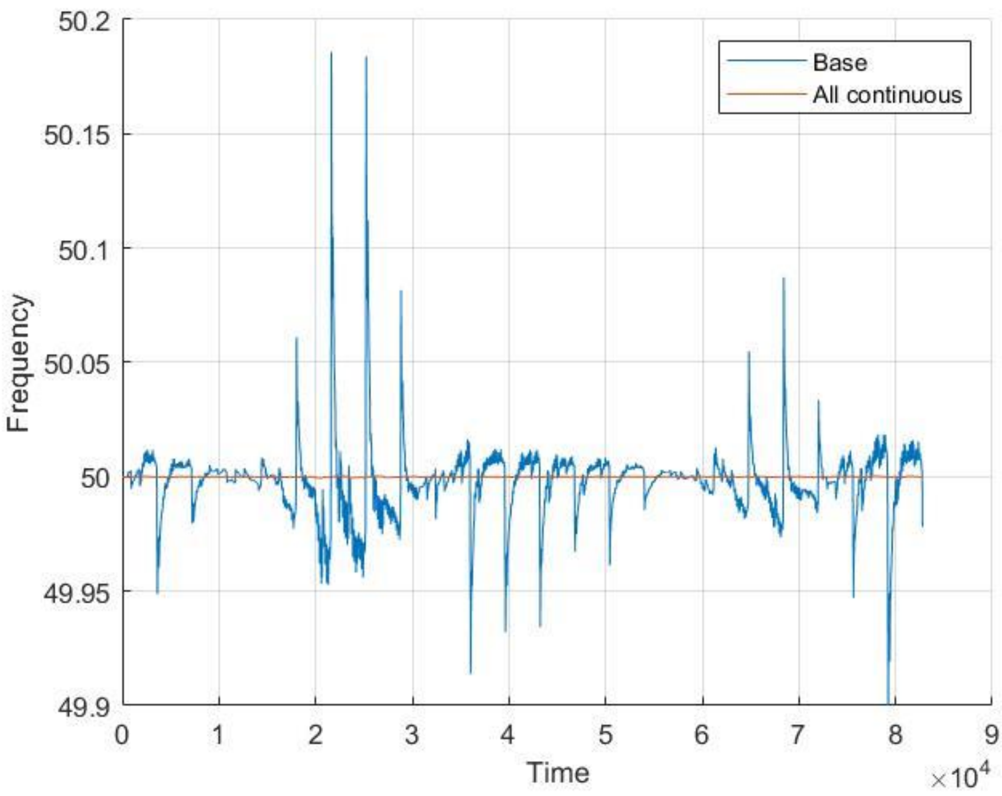

Fig. 28 – All generation ramps continuously between 7.5 min before till 7.5 min after MTU

Based on figure 28, we can see the effect of an extreme scenario whereby every generation is load following. In this case, there would not be any huge frequency deviation. There are only slight deviations from 50 Hz, as we can also observe in the following figure and table.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All slow	49.9985	0.0127	49.9053	50.1550	1.6129E-04

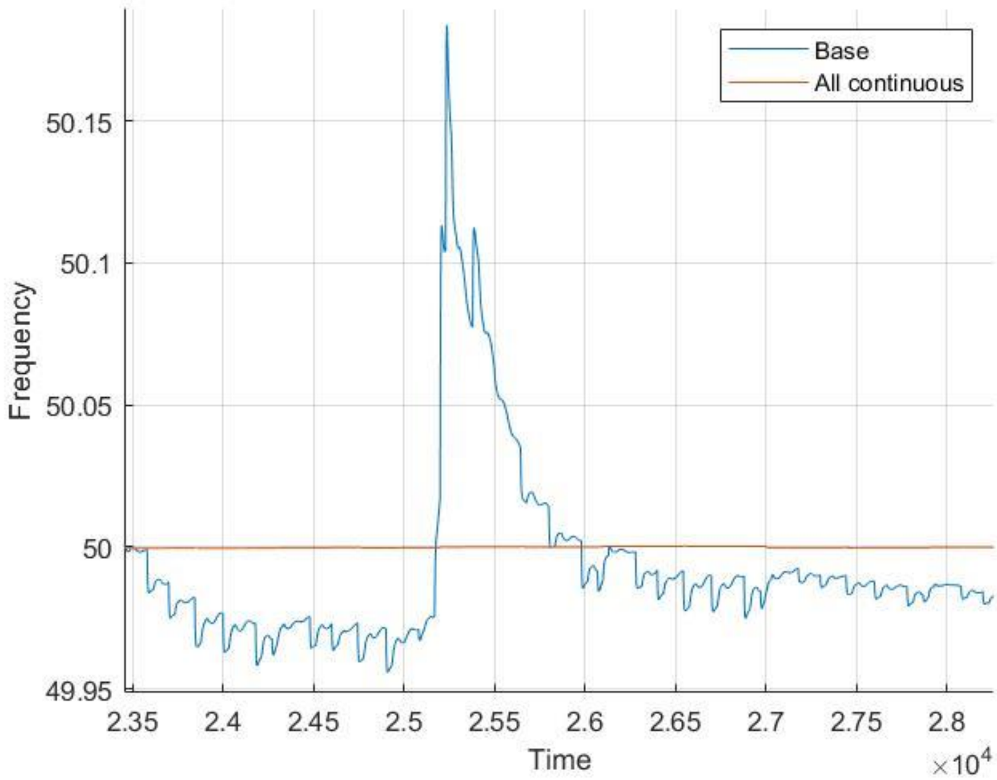

Fig. 29 – All continuous – zoom in

4.6.3 Ramp restrictions on specific units

In opposition to the simulations for ramping on generation schedules where ramping of all generation types were changed, in these simulation cases, only specific generation types have been changed in their ramping behaviour. The ramping behaviour of wind generation and water power plants have been changed, as they are usually under suspicion when discussing DFDs. All other generation types have the same ramping behaviour as they have in the base case.

Wind was assumed with a continuous ramp to simulate the base case. For the simulation case ‘wind jumps’, wind generation ramps were assumed between 30 sec before until 30 sec after the shift of MTU. The following figure provides an overview of the result.

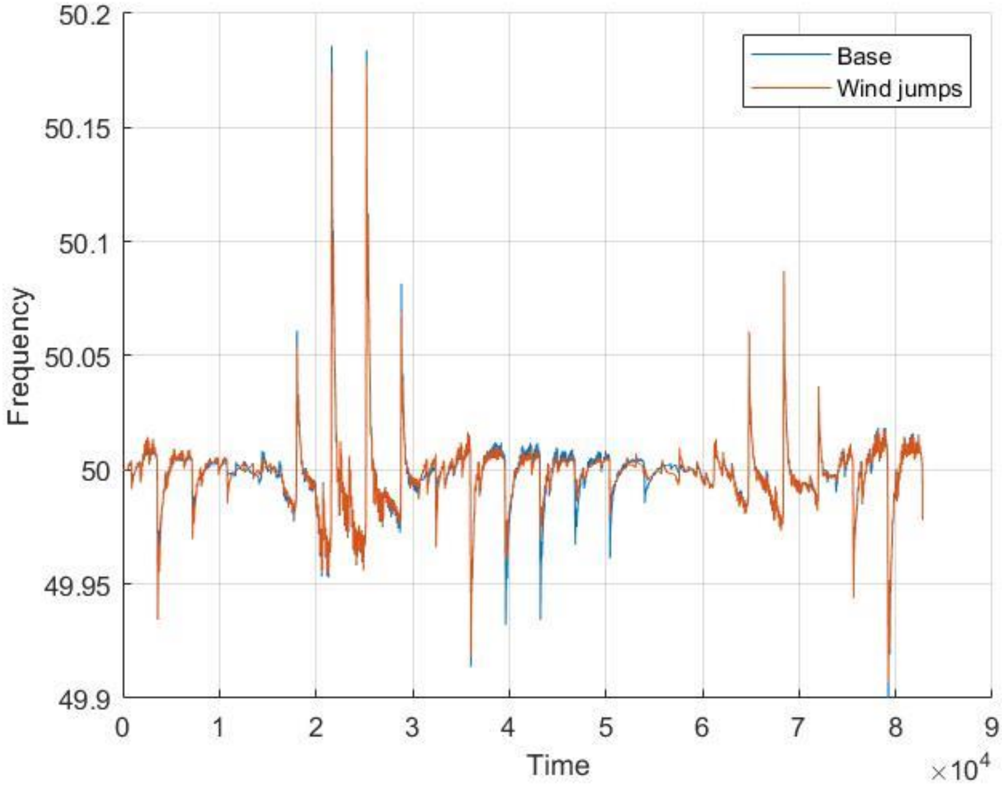

Fig. 30 – Wind jumps – ramping 30 sec before until 30 sec after the MTU

Based on the figure, we can observe an increase in frequency quality, but it is still in the range of the base case. This leads to the conclusion that wind generation compared to the total sum of generation has a small impact on frequency behaviour. This can also be seen in the following figure, where we can observe almost no difference between the base case and the simulation.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Wind jumps	49.9983	0.0146	49.9068	50.1783	2.1250E-04

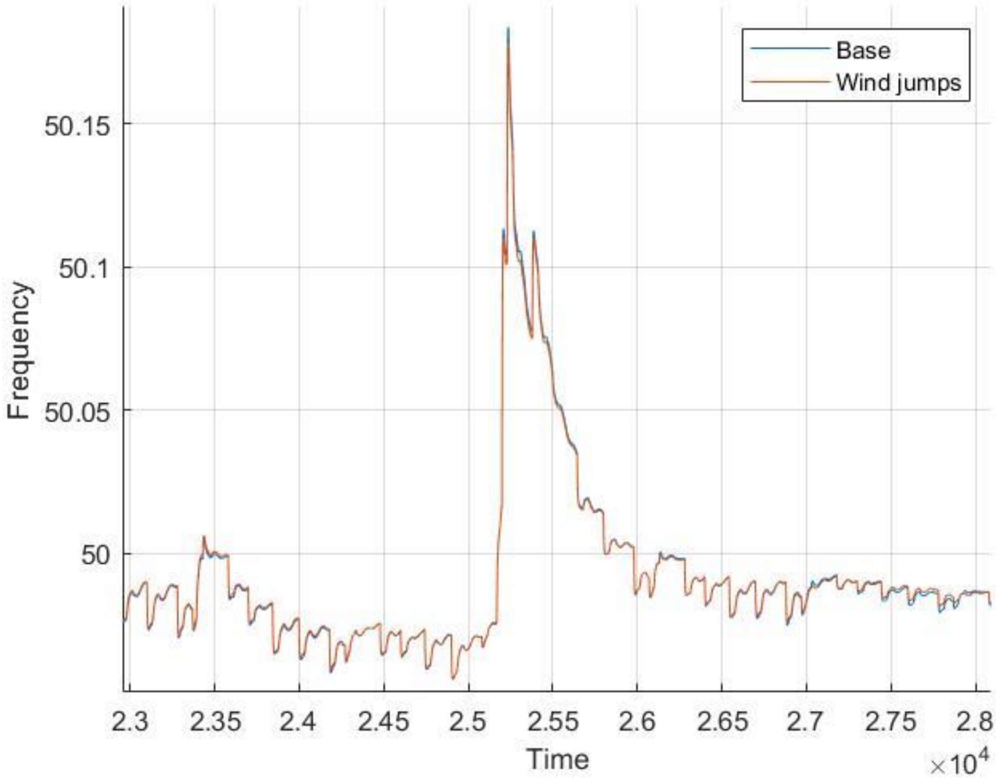

Fig. 31 – Wind jumps – zoom in

Water was assumed with a very fast ramp between 30 sec before until 30 sec after the shift of MTU for the simulation of the base case. This ramping behaviour was changed to slow, 5 min before until 5 min after MTU. The following figure gives an impression of the effect.

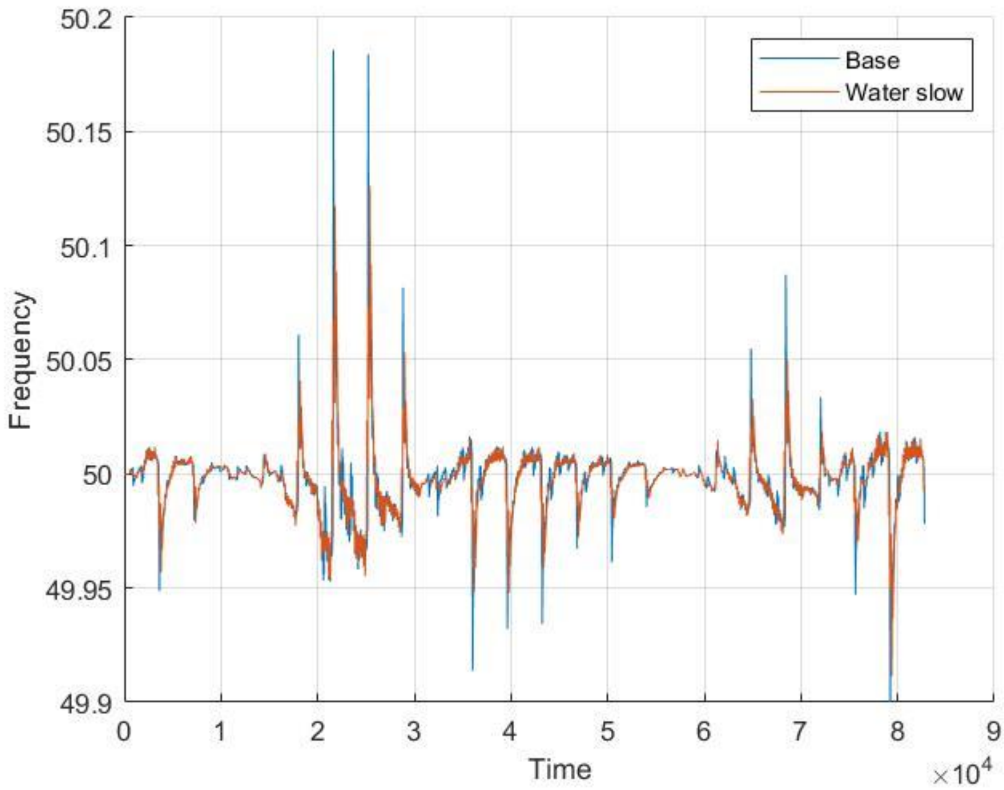

Fig. 32 – Water slow – ramping from 5 min before until 5 min after MTU

In figure 32, we can see a significant reduction in the height of frequency peaks. The maximum frequency is 50.1216 Hz and the minimum frequency 49.9114 Hz. Based on the following table and figure, we can observe the increase in quality.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Water slow	49.9983	0.0128	49.9114	50.1216	1.6423E-04

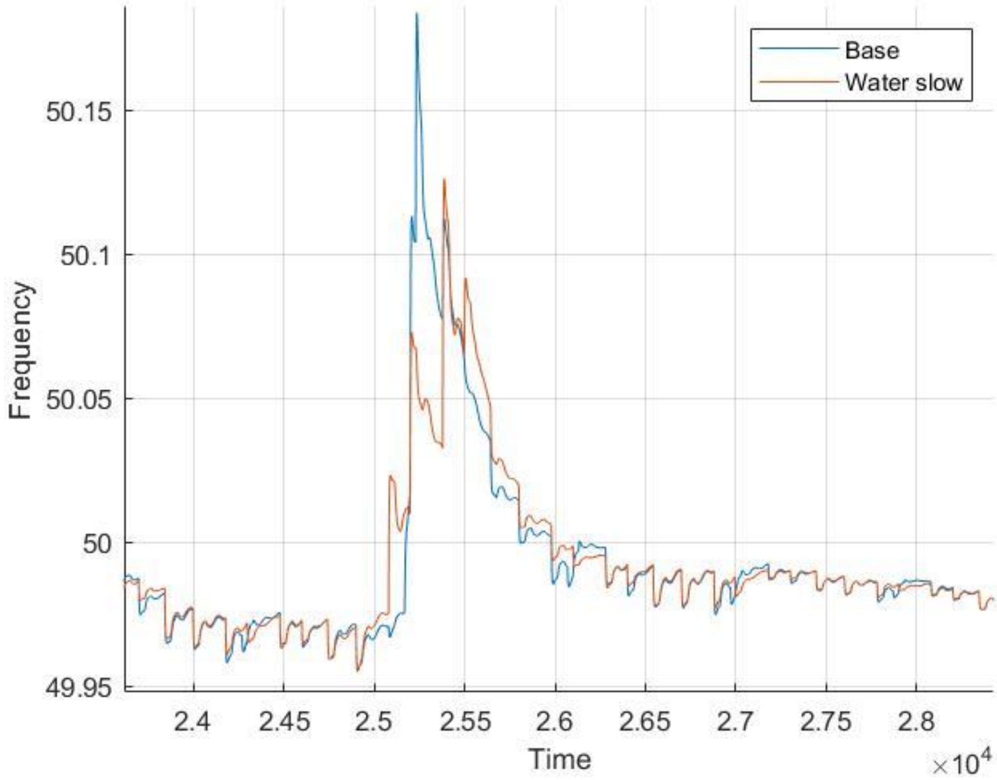

Fig. 33 – Water slow – zoom in

4.6.4 Additional FCR

For simulating the effect of additional FCR, the ramping behaviour of the base case has been used. Only the amount of FCR and the corresponding k-value was increased. While the FCR in the base case is 3000 MW and the k-value 27.000 MW/Hz, the simulation has been performed with 6000 MW FCR and a k-value of 42.000 MW/Hz. The new k-value of 42.000 MW/Hz corresponds to the original 27,000 MW/Hz + 15,000 MW/Hz from the additional 3000 MW FCR (3000/0.2Hz = 15,000 MW/Hz).

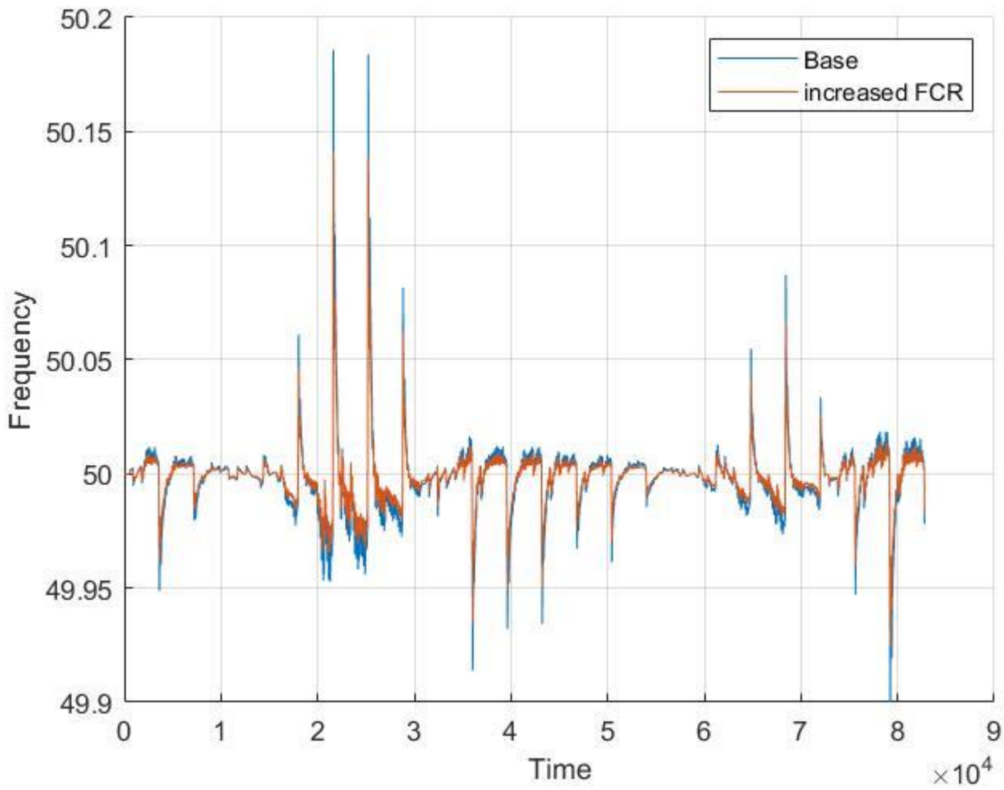

Fig. 34 – increased FCR – FCR: 6000 MW and k-value: 42,000 MW/Hz

Based on the figure above, we can see that frequency quality will increase. The frequency peaks are still there, but the size is reduced. Based on the simulation model, an increase of FCR will only reduce the height of the peaks, but not the dynamics of frequency. This we can see in the next figure. The following table show the statistics compared to the base case.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Increased FCR	49.9987	0.0109	49.9247	50.1411	1.19E-04

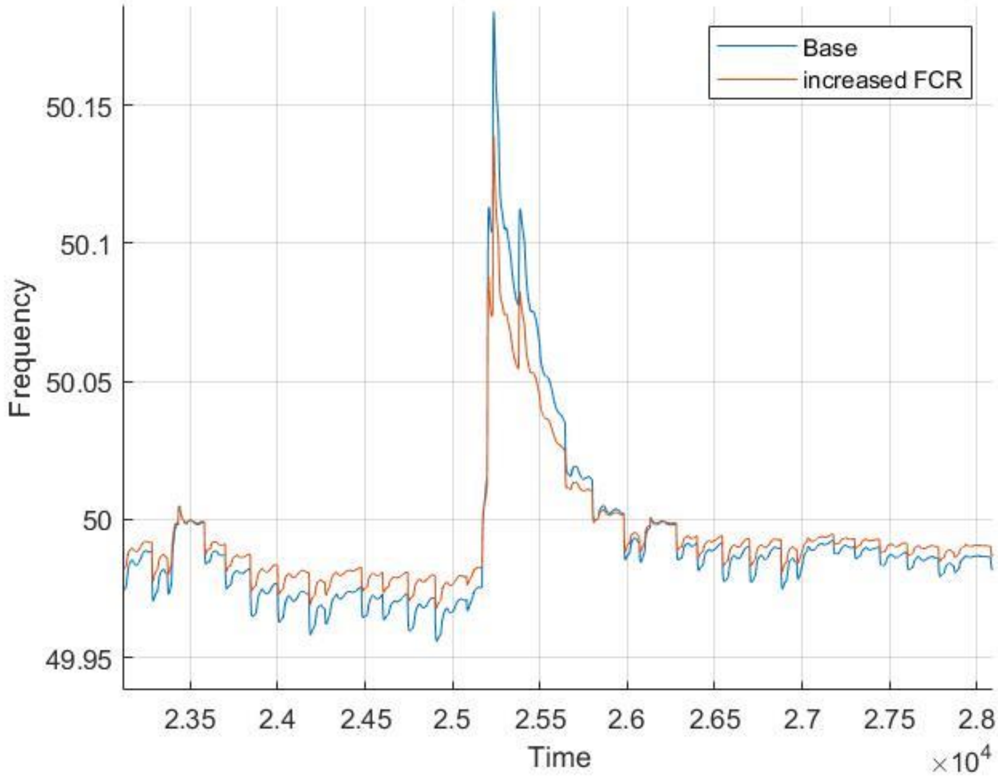

Fig. 35 – increased FCR – zoom in

4.6.5 Additional aFRR

To simulate the effect of additional aFRR, the ramping behaviour of individual generation types from the base case have been used and only the aFRR amount per LFC block has been increased. The MOL per LFC-Block has been increased from 200 to 2000 MW. The results of this simulation can be seen in the following figure, compared to the base case.

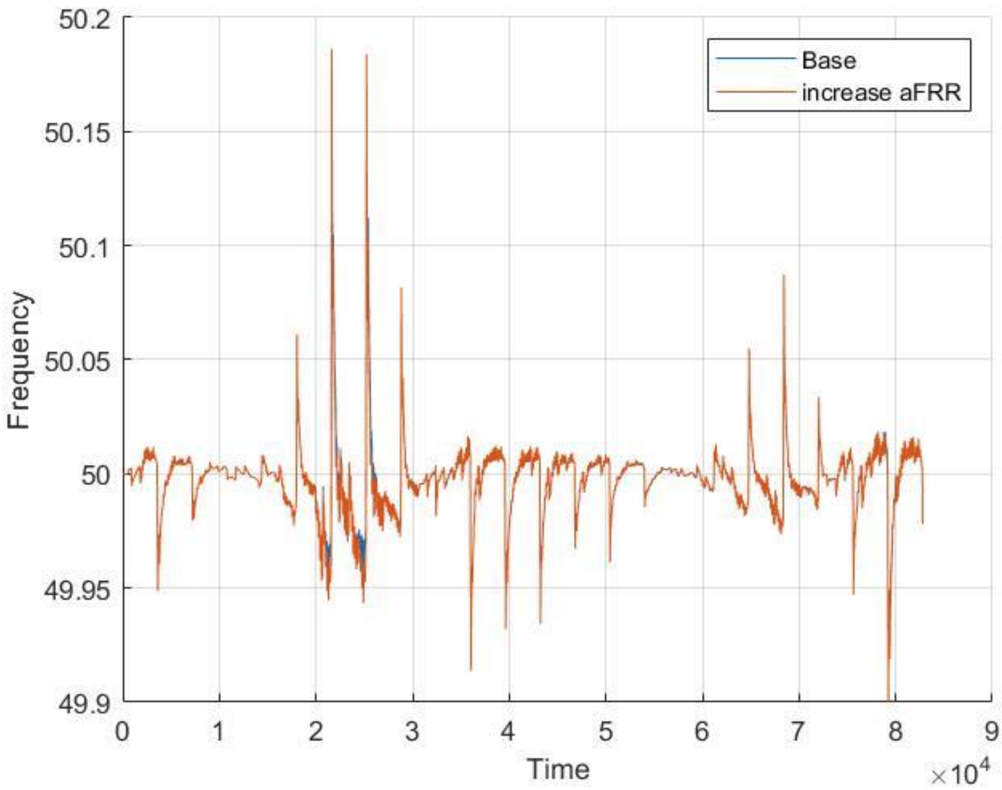

Fig 36 – increased aFRR

Based on the figure above, we can see that an increase of aFRR will not increase the frequency quality. The behaviour is similar to the base case. Only slight changes can be figured out, by comparing statistical factors. In addition, in the zoom in on the big DFD, we can see that there is no real change compared to the base case. We can observe some kind of an offset, but the dynamic behaviour of frequency will not be changed.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Increased aFRR	49.9979	0.0153	49.9001	50.1860	2.3340E-04

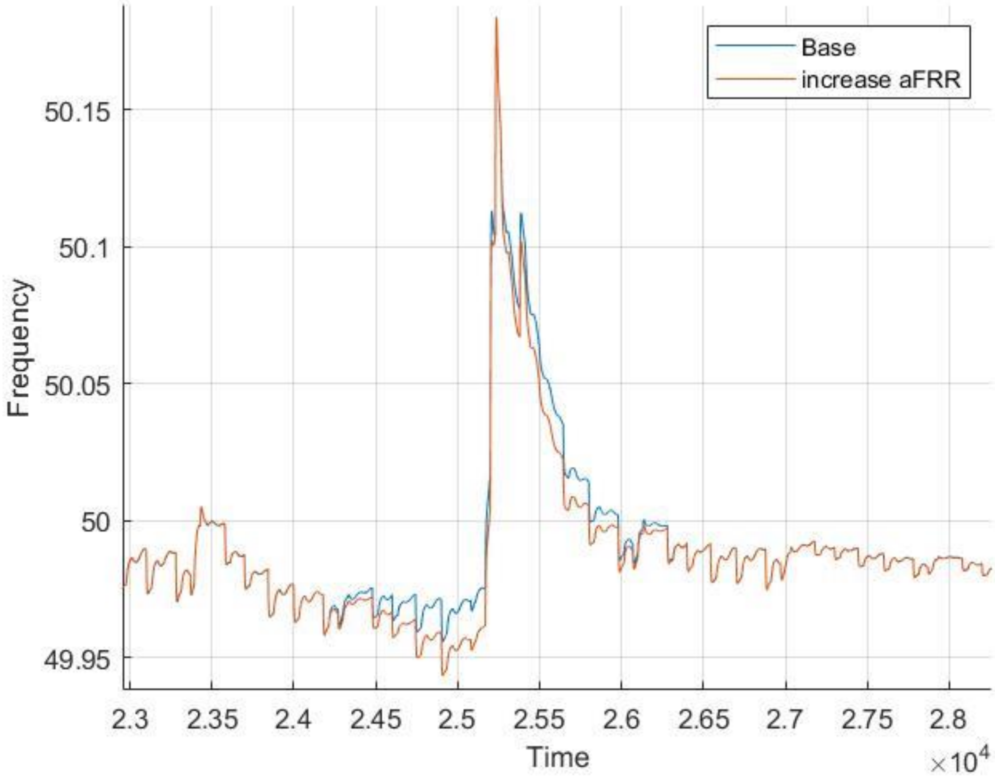

Fig. 37 – increased aFRR – zoom in

4.6.6 Higher K factor

As opposed to the increase of FCR, where FCR value as well as K-value has been increased, in this case only the K-value will be increased, while FCR will be constant with 3000 MW. The K-value for that simulation was assumed as 42,000 MW/Hz. The result can be found in the following figure.

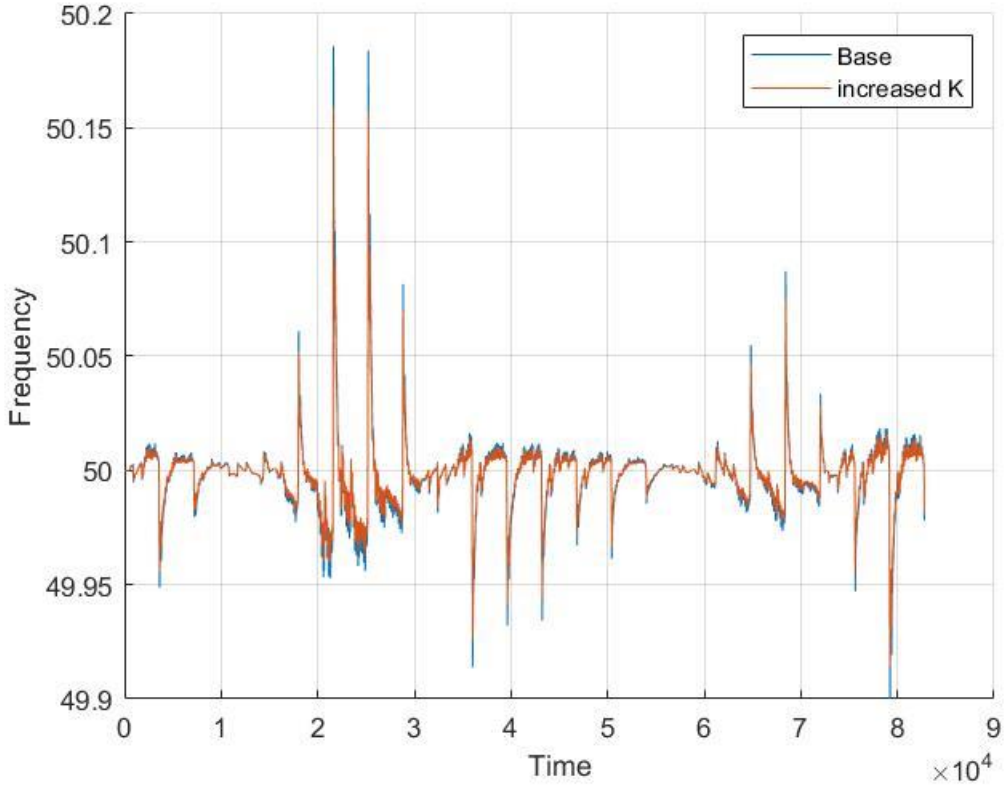

Fig. 38 – increased K-value – 42.000 MW/Hz by 3000 MW FCR

Based on the simulation, we can see that, at least for the DFD with small RoCoF up to 1 mHz / sec, an increase of K-value will also increase frequency quality. However, the observed gain in quality is quite small. Similar to the increase of FCR, an increase of K-value will reduce the frequency peaks, without any influence on the dynamic. The following figure shows this, while the following table shows the statistics compared to the base case.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Increased K-value	49.9979	0.0153	49.9001	50.1860	2.3340E-04

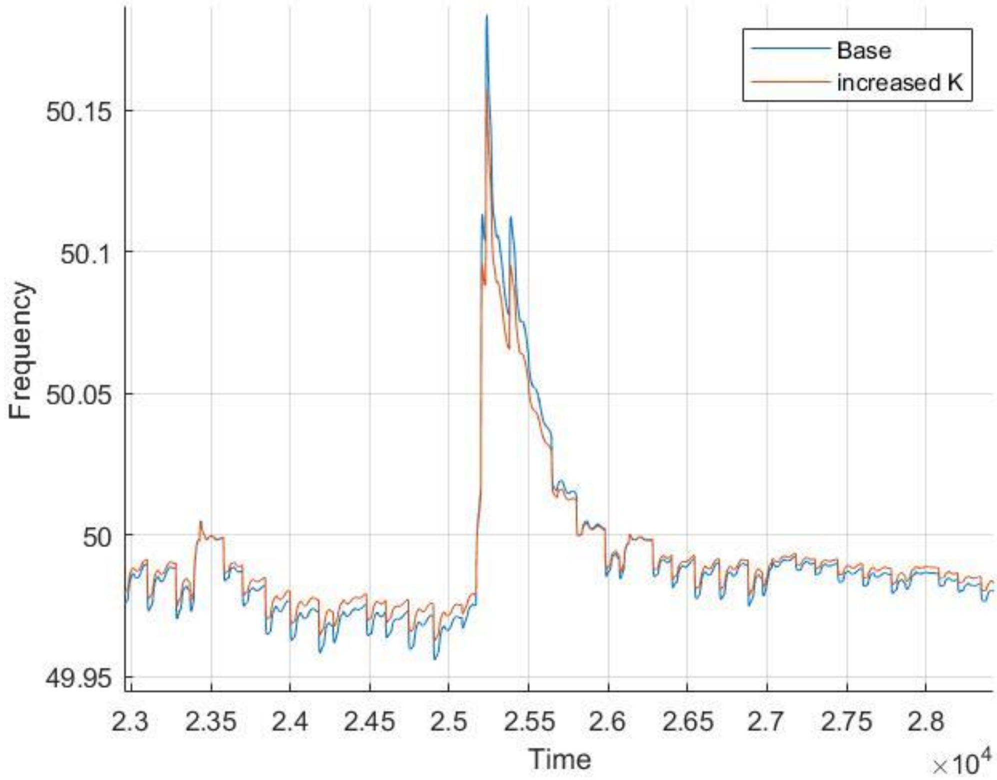

Fig. 39 – increased K-value – zoom-in

4.7 Impact study of the proposed solutions: Model B

It is important to be certain about the possible solutions for dealing with DFD and, in order to check the results from the simulations with the full model described before, a second set of simulations was executed by the task force.

4.7.1 Simulation model used

These simulations use a simplified model and check three typical hours of the evening, one with a mild DFD (hour 21 in the simulation), one with a very strong DFD with a RoCoF of 3 mHz / sec (hour 22 in the simulation) and one with a fast shutdown of a significant set of generation units at the change of the hour (hour 23 in the simulation).

The model uses the same inertia as the grid of CE but the grid is split up in four representative control blocks which distribute the active reserves (FCR, aFRR and mFRR) between them. Each control block contains 4 BRPs. Each BRP has an international programme with hourly changes, an internal programme with quarter-hourly changes, a load with a varying in a smooth way, and a set of generating units which are controlled to keep the imbalance of the BRP on a quarter-hourly basis as small as possible. The model emulates the reaction of the market parties (BRPs) as a reaction towards large imbalances; although such behaviour is very difficult to model accurately it is important to consider such a possible impact.

In each control block, one BRP has hydro units (very fast), one has coal units (very slow), one has gas units (intermediate speed) and one has no production. On top of the control mechanism to keep the quarter-hourly imbalance low, the coal BRP also has an anticipation built in to already move its unit to the programme of the next quarter-hour in the last five minutes, in order not to lag too much towards the next quarter-hour.

The base case simulation gives the result as shown in the graph below where the frequency at its lowest point is 49.84 Hz and the fast variation is just above 3 mHz / sec.

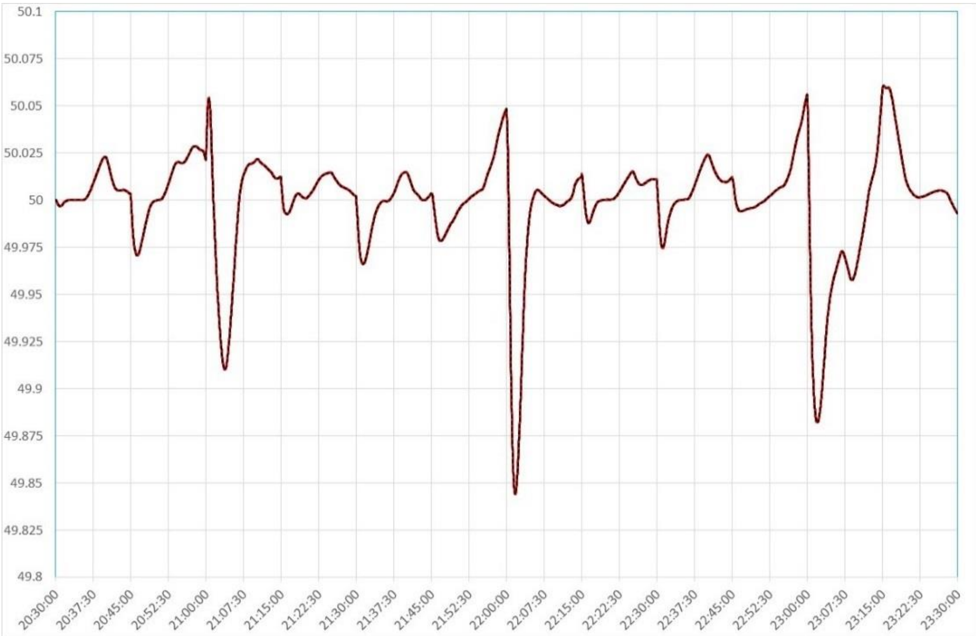

Fig. 40 – frequency simulated during the base scenario

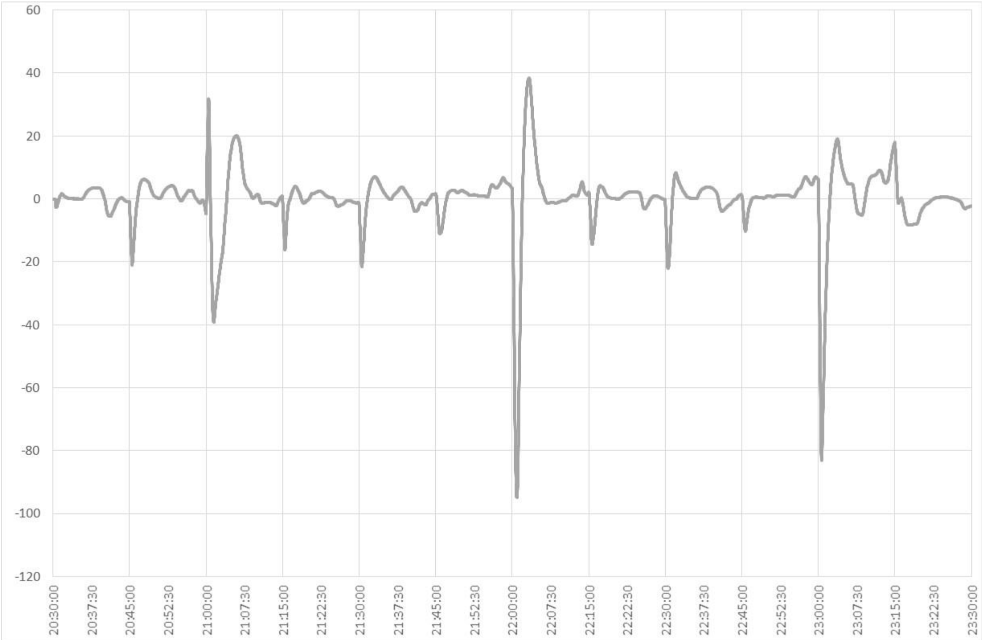

Fig. 41 – Rate of change of frequency, value on axis is measured in mHz over 30 seconds

4.7.2 15 minute trading

This solution was simulated by spreading the schedule change at the change of the hour over two successive MTUs, giving half the change at hour-15min and the other half at the hour. Statistically, it is defensible to say that if we move from hourly schedules to quarter-hourly schedules, the observed changes in schedule will be on average half as big from each MTU to the next, representing concretely an interpolation of the overall hourly based schedule.

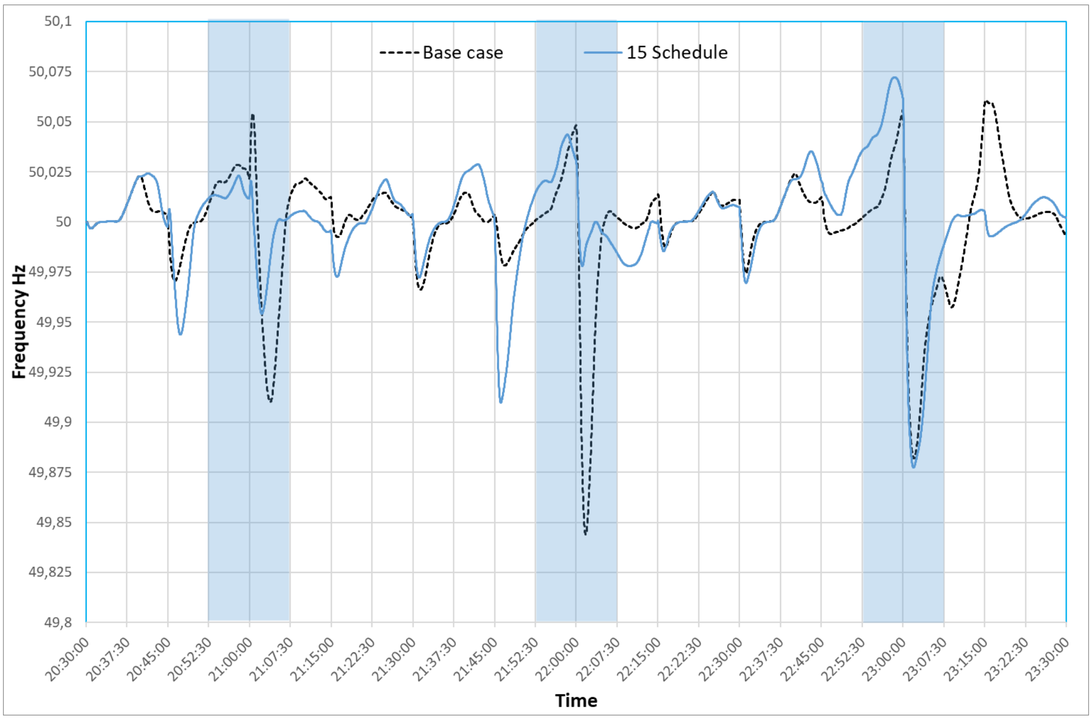

Fig. 42 – Simulated frequency profile of the 15 min MTU compared to the reference base case scenario profile

The simulated scenario based on 15 minutes MTU shows a smaller frequency deviation specifically during the hour changes where the DFDs occur (area shaded with blue in the above curve). This is in line with the expected behaviour, as smaller MTU duration will limit the gradient during schedule changes, while this creates new deviations compared to the base case (new schedule changes) the overall impact of DFDs is limited compared to the base case.

The simulations show that this solution allows most DFD to be reduced to acceptable levels, as the large DFD at 22:00 has even completely disappeared. However, it cannot solve the fast shutdown of a set of generation units programmed at a specific time, such as one simulated at 23:00. Here, the DFD will still subsist, as generation will still shutdown as in the base case.

Changing the MTU to 15 minutes will therefore solve most but not all DFD and can be seen as a major step forward, which might need to be complemented in some cases with a spreading of start-up or shutdown of specific generating units.

The box plot below covers only the frequency measurement during programme change, therefore illustrating specifically the impact of the simulated solution with respect to DFD time scale. We can observe that the Inter-quartile Range (IQR) is much narrower when 15 min MTU is considered and therefore there is an improved behaviour during DFD events.

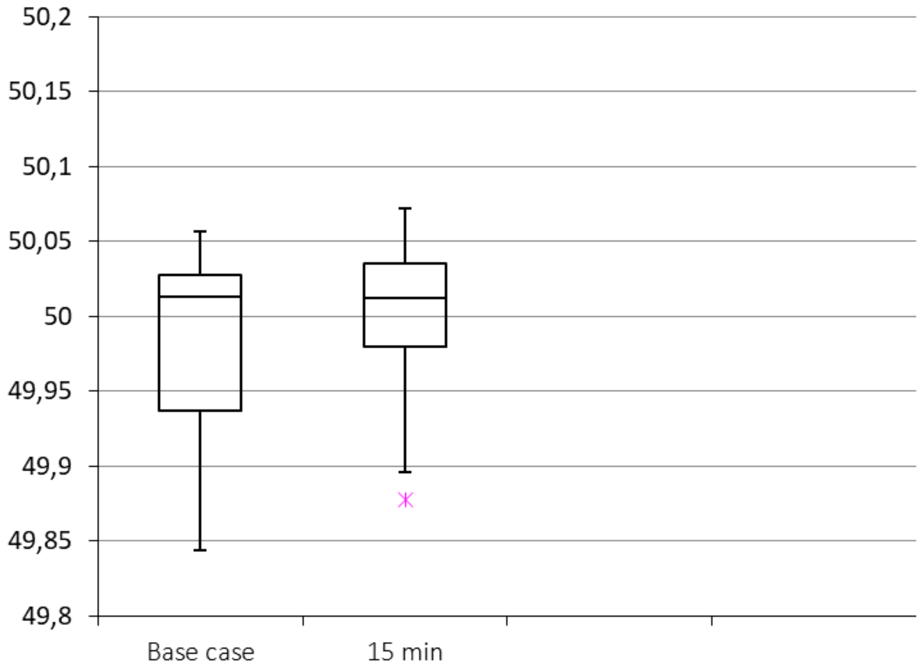

Fig. 43 – Box-whisker plot 15 min MTU comparing to the reference base case scenario profile

4.7.3 Ramping on load and/or generation schedules

The solution introducing the impact of ramping into the imbalance settlement during the change in schedules is simulated by inserting the ramping, which is already used today in the schedules between TSOs, into the schedules used by the BRP as well.

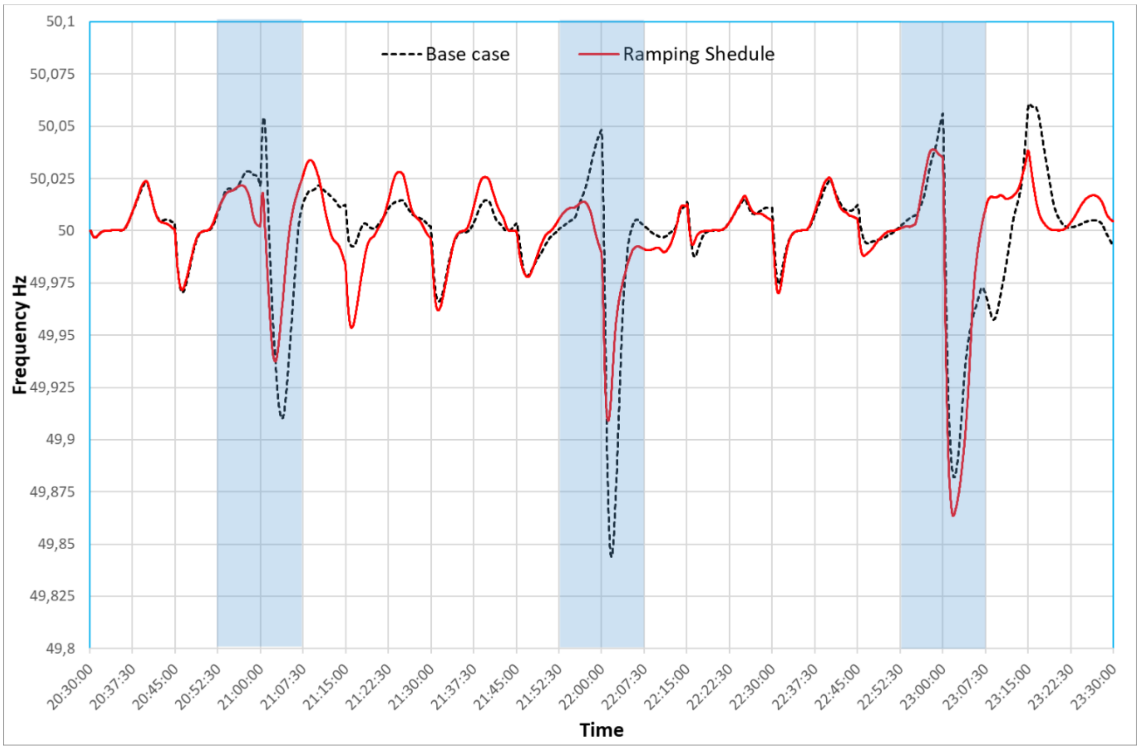

Fig. 44 – Simulated frequency profile of the ramping schedule compared to the reference base case scenario profile

The simulated base case scenario considering ramping on load and generation during programme change shows some improvements in term of frequency deviation specifically during the hour changes where the DFDs occur (area shaded with blue in the above curve).

The simulations show that this solution also allows most DFD to be reduced to acceptable levels. The large DFD at 22:00 has been reduced to 90 mHz. However, again, it does not solve the fast shutdown of a set of generation units programmed at a specific time, such as that simulated at 23:00. Here the DFD will still subsist as generation will still shutdown as in the base case.
The box plot below illustrates specifically the impact of the simulated solution with respect to DFD time scale. We can observe that the Inter-quartile Range (IQR) range is much narrower, as are the quartiles, presenting considerable improvement compared to the initial base case.

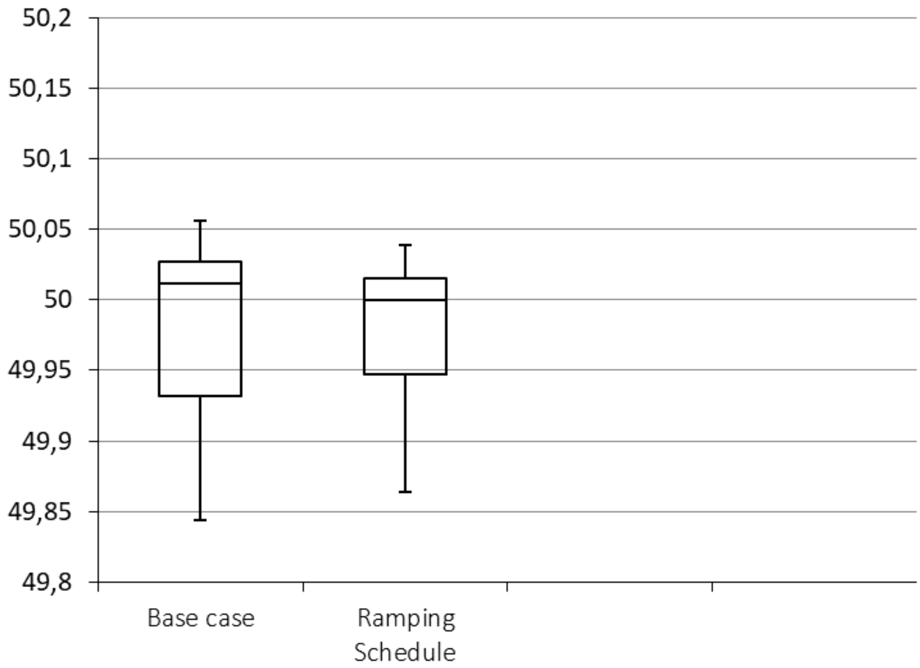

Fig. 45 – Box-whisker plot 15 min MTU and the reference base case scenario profile

4.7.4 Additional FCR

This simulation scenario investigates three possible sensitivities for increasing FCR volumes consisting of 1 GW, 2 GW increments covering the whole contractible frequency span (i.e. +-200 mHz); the suggestion within the report to contract a specific reserve of 2400 MW that covers only the range of the allowable DFD is included and referred to as the 75 mHz (i.e. +- 75 mHz) case in the following figure.

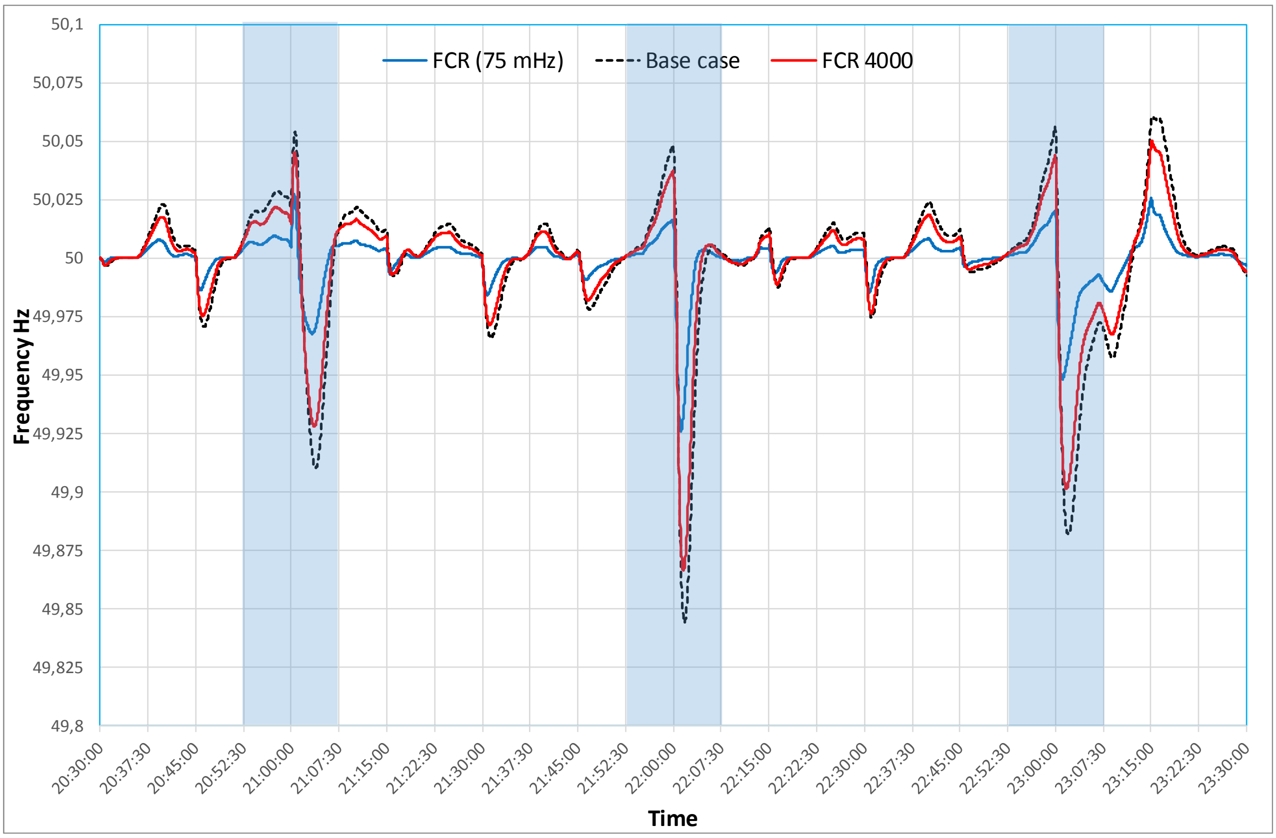

Fig. 46 – Simulated frequency profile of the FCR increase cases compared to the reference base case scenario profile

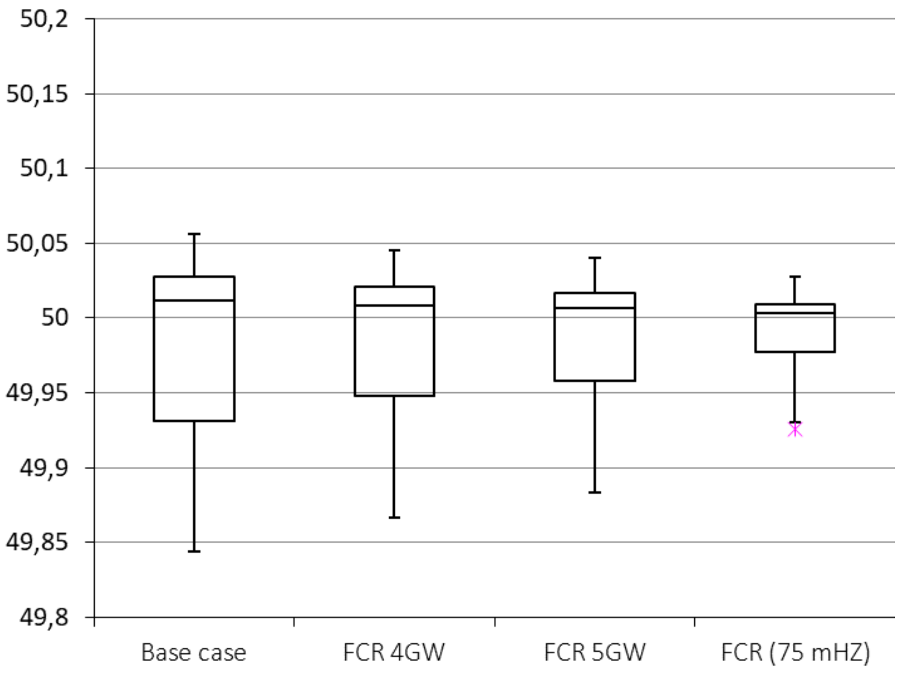

Fig. 47 – Box-whisker plot of the FCR increase and the reference base case scenario profile

Similarly, the box plot shows that higher FCR reserves always results in further improvement in terms of statistical spread during the DFD occurrence, which also remains valid for the overall operation as the additional reserves would generally improve the frequency quality of the system.

4.7.5 Additional aFRR

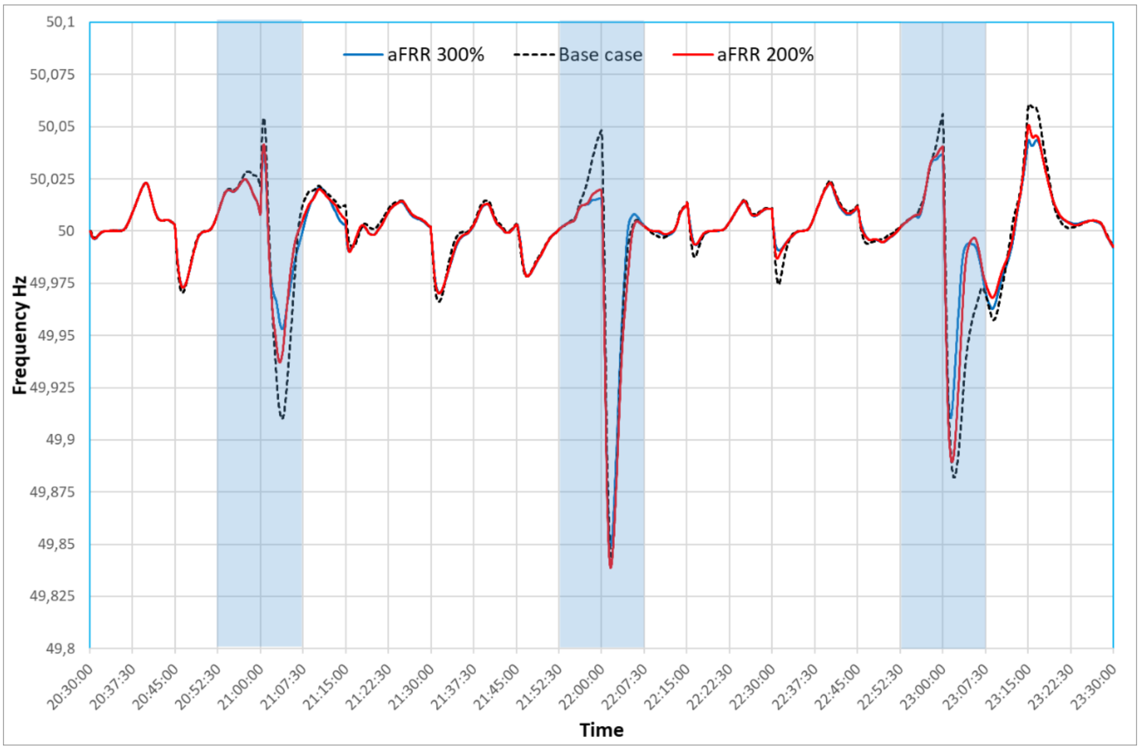

Fig. 48 – Simulated frequency profile of the aFRR increase cases compared to the reference base case scenario profile

The above figure illustrating the frequency profile shows that additional aFRR reserves have relatively limited impact on the frequency profile during DFDs even when the aFRR reserves are doubled or tripled. Limited improvement can be observed with respect to slow dynamic imbalances characterised by those which occur outside the DFD range.

The box plot figure below shows that additional aFRR volumes provide limited improvement on the frequency spread (smaller IQR), which is expected as the initiation and the terminal phase of the DFD are characterised by smaller frequency deviation; nevertheless, we still can observe outlier values, especially as we considerably increase aFRR volumes of more than double (outliers values are 1.5 IQR below the first quartile).

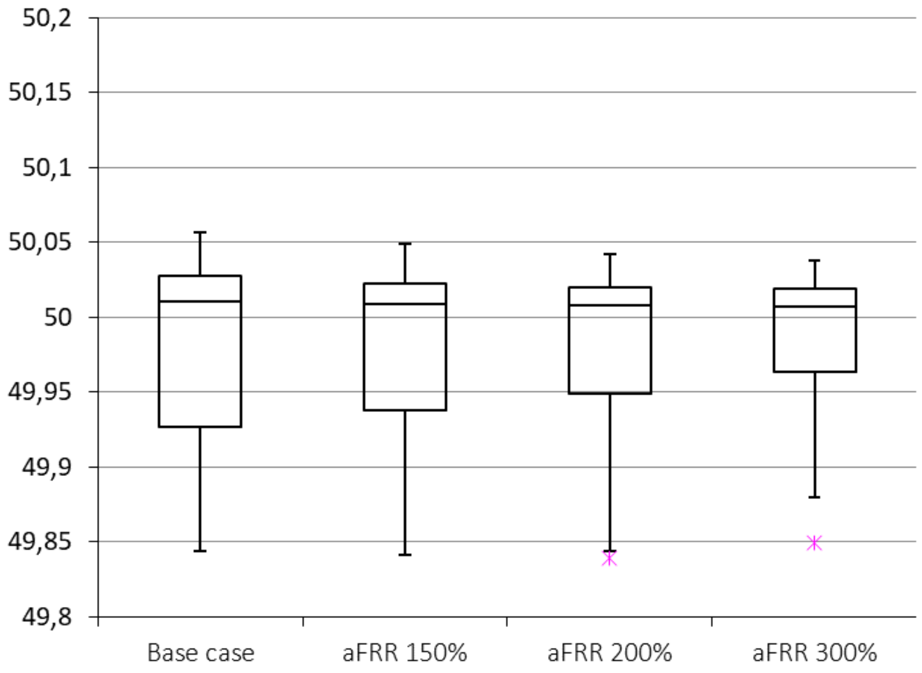

Fig. 49 – Box-whisker plot of the aFRR increase and the reference base case scenario profile

As expected, the frequency quality is better for the smaller DFD which can indeed be reduced with aFRR; however, for the large DFD the aFRR is not helping, and even making the situation a little bit worse, by cancelling the anticipatory behaviour of some market parties who already move their generation towards the programme of the next quarter-hour; therefore it is not recommended to increase aFRR with the purpose of reducing DFD.

4.7.6 Higher K factor

For this simulation, we tested the effect of doubling the K-factor in the controller of each control block. The idea is to test whether increasing a frequency behaviour of the centralised controllers helps in the reduction of DFD.

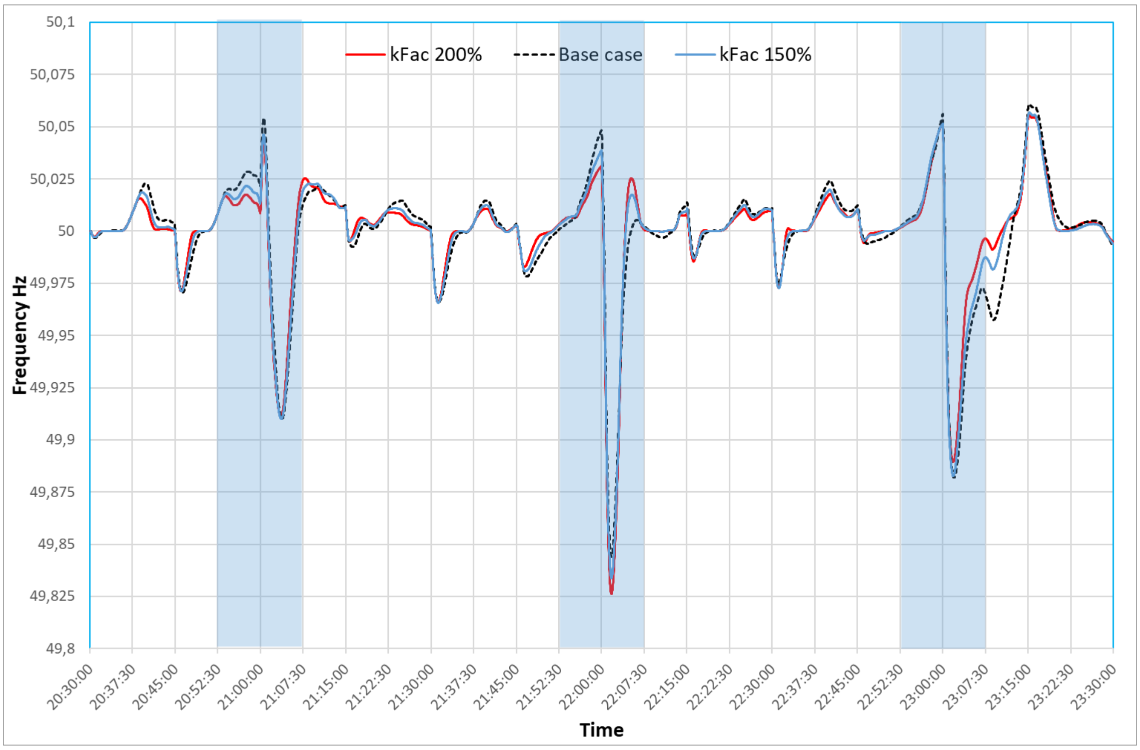

Fig. 50 – Simulated frequency profile of the k-factor increase cases compared to the reference base case scenario profile

The simulation case related to the increase of k factor provided similar results as the case of increasing aFRR capacity; in fact the k factor results in the higher activation of aFRR volumes until the full reserves are activated. The above figure shows a limited improvement in term of frequency profile specifically during the DfD occurrence; as expected and highlighted in section 4.4.4, the additional activation request of aFRR has limitations both in term of activation time and volume of reserves. In fact, we can see in the below box whisker plot that for all the tested k factor adaptation, an improvement is observed in the overall statistical spread but considerable presence of outliers remain. The impact in general remains limited as we increase the k-factor adaptation.

As we can see, the result was not improved specifically for the large DFD at 22:00. The frequency drops relatively deeper as in the base case, as it starts from a lower value just before the change of the hour.

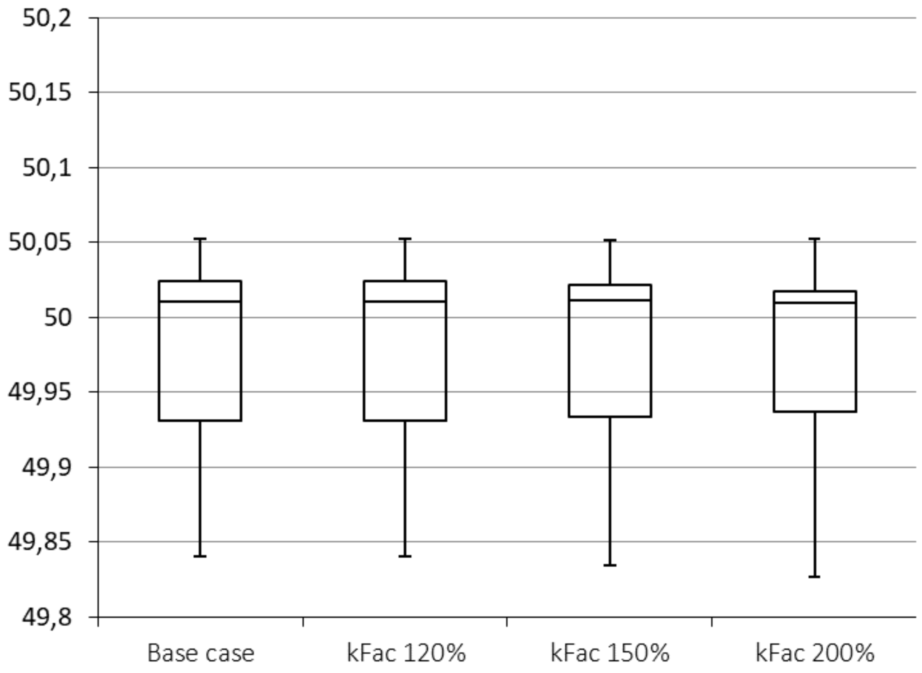

Fig. 51 – Box-whisker plot of the k-factor increase and the reference base case scenario profile

4.7.7 Ramping on Generation

In order to simulate ramping, we have put a maximum ramping of 5 MW / sec on all BRP in all control blocks. The slower ramping effect (which was not simulated in the base case) is applied to the generation shutdown at 23:00 and now spreads the shutting down of the generation over time, with a maximum change rate of 5 MW/sec. The result is given below and compared to the base case.

The result of this simulation shows that ramping does indeed work. Spreading the start and stop of units over time will greatly reduce the DFD. The effect is at least as good, if not better, than the simulation result on additional FCR.

In particular, the DFD at 23:00 which was due to the simultaneous shutdown of a large set of generating units has disappeared, as the unit's shutdown are now spread over time given the ramping requirement. There is a frequency overshoot just after 22:00 which is due to an exaggerated anticipation of a BRP, which was not needed given the slow ramping used by all parties. This also means that less anticipation will be required from BRP when the slower ramping of generation is used.

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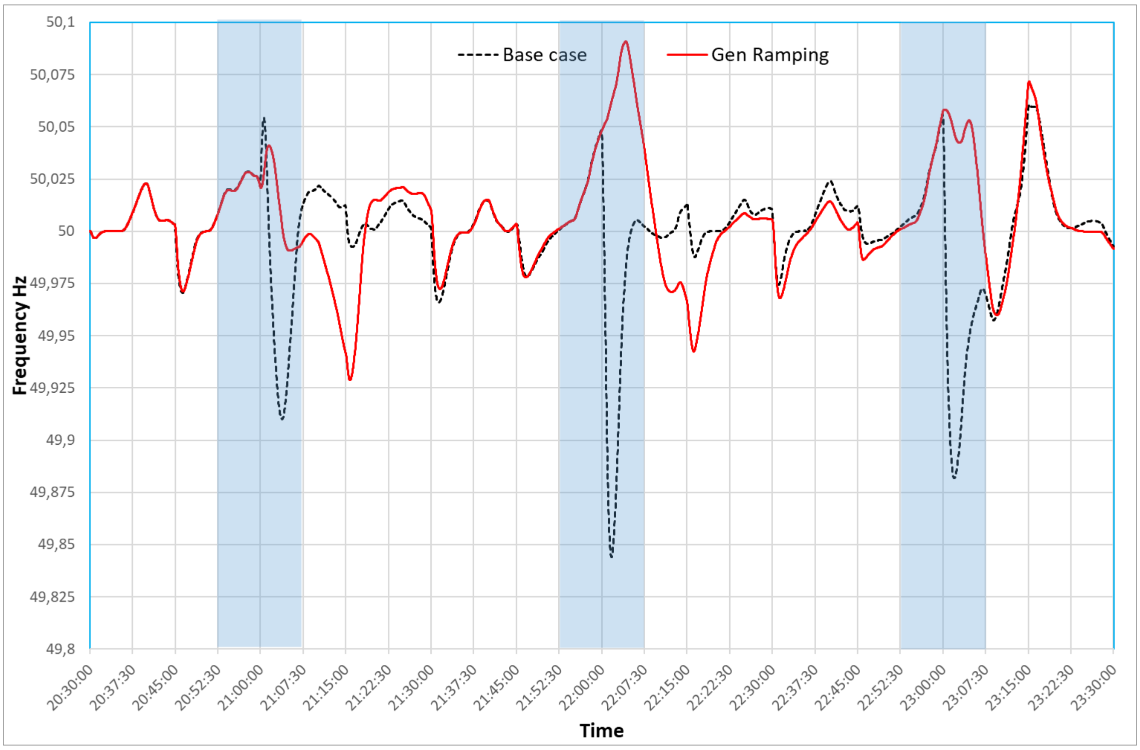

Fig. 52 – Simulated frequency profile of the ramping on generation case compared to the reference base case scenario profile

The figures above and below shows clearly for the investigated scenario that the limitation on the generation ramping did limit the amplitude of the frequency (21:00 and 23:00), yet the maximum observed frequencies in the time series is after 22:00 due to the anticipated effects of BRPs balancing their position.

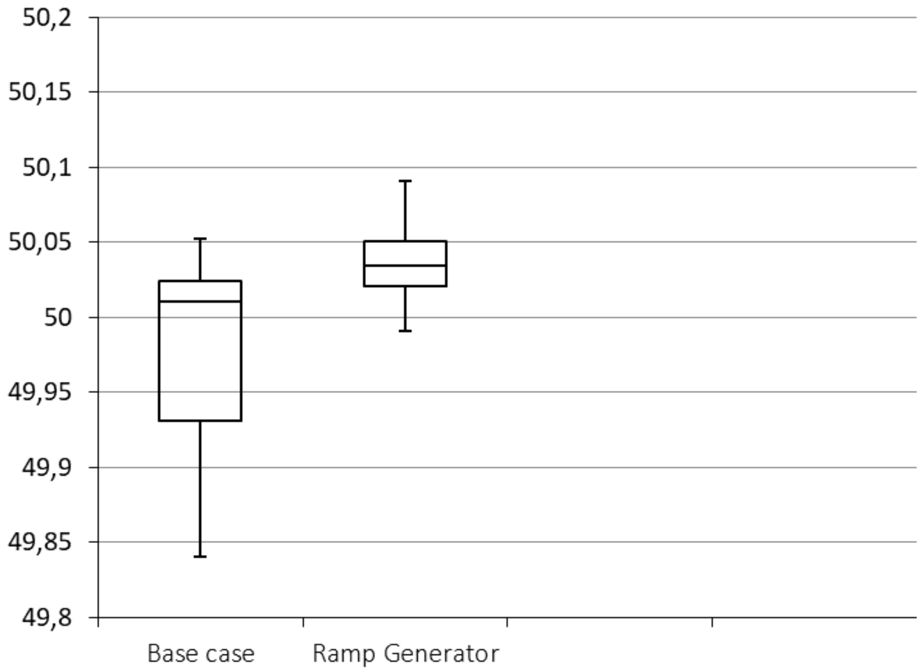

Fig. 53 – Box-whisker plot of the ramping on generation case and the reference base case scenario profile

4.7.8 Conclusion of the second set of simulations

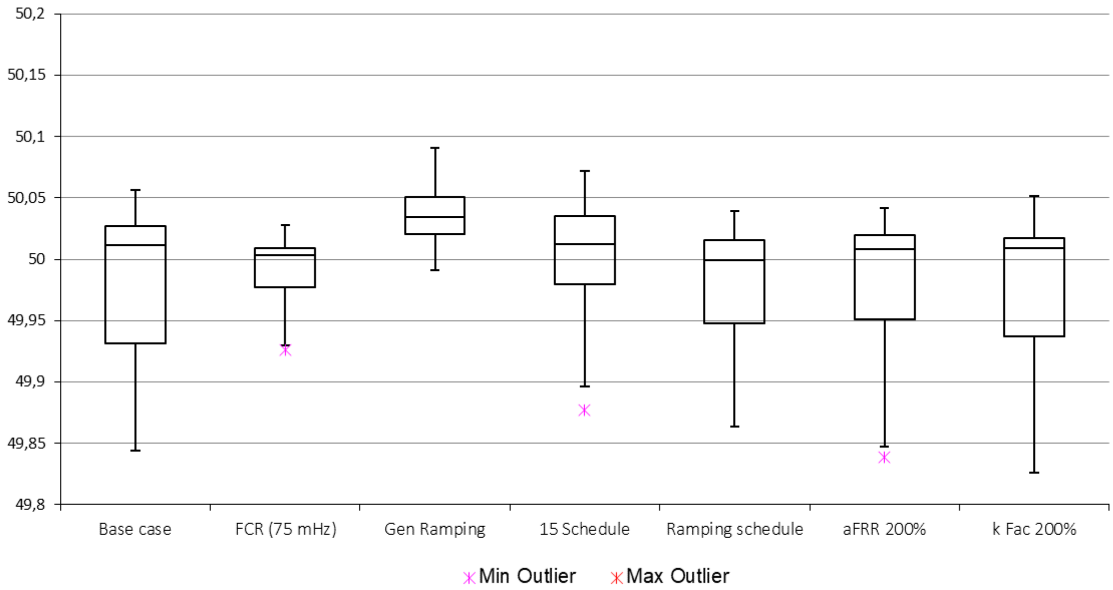

Fig. 54 – Box-whisker plot of the simulation solution and the reference base case scenario profile

The above figure provides a good statistical overview of the effectiveness of each of the investigated solutions. Certain solutions, such as the increase of FCR contracted volumes or ramping on generation, show effectiveness in mitigating the DfD issues. Other investigated solutions have, on the other hand, quite a limited impact for the assessed scenarios. Each control block, depending on their actual performance, can opt for the most cost-effective solution to achieve their compliance target.

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5 Way Forward

5.1 Solutions which come out as preferred from analysis

Working Package 3 of the Task Force Significant Frequency Deviations' preferred solution is moving towards a 15-minute ISP and MTU, in a stepwise manner, at the national and international level and for any or all relevant timeframes. This proposal is in line with existing or upcoming legislation (Network Codes, Guidelines and Clean Energy Package) and is described in more detail in section 4.3.1 of this report.

In addition, as permanent or intermediate measures, the following solutions can reduce the impact of the DFD:

1. ramping imposed on generation units on a national level (section 4.3.3);
2. include a provision for ramping on load and generation schedules at the national level (section 4.3.2);
3. increase the volume of FCR available to control the DFD (section 4.4.1) as a temporary measure, awaiting the implementation of other solutions.

Other possible solutions which have been discussed and which could be investigated for particular control blocks could include:

(a) Introduction of a limit of change in net position of a market area / bidding zone between two successive market periods;
(b) Introduce Spot Power Balancing;
(c) Use changes between ISP for BRPs as marked based aFRR bids;
(d) Additional Very Fast Reserves from Battery Storage;
(e) Additional aFRRs;
(f) K-factor adaptation;
(g) Introduction of a Dynamic Frequency Setpoint in Control Areas / Blocks.

5.2 National implementation

Given the Market situation and that the production mix (shares of units with considerable ramping capabilities) may differ in different market areas of Member States within CE Synchronous Area, the Task Force also recommends a possible hybrid solution where different mitigation measures are implemented at the national level, depending on the specifics of each country. The goal of the hybrid solution is to reduce the level of DFDs to an acceptable level while supporting flexibility in terms of the selection of cost-effective measures within the local context.

ENTSO-E proposes to leave the decision on which solutions to mitigate the DFDs to be implemented in each LFC block, and at national level to the national TSOs and regulators. The proposed solutions in this report are not exhaustive, and any other local solutions can be proposed.

Each LFC Block must set up and follow an action plan to implement the chosen solution(s). Each LFC Block will report to ENTSO-E periodically regarding the implementation of the measures.

5.3 Setting the target

Each LFC block needs to respect the quality target as proposed in this report, Chapter 3 – acceptable DFD level of 75 mHz. Once the targets are accepted, they will be integrated into the SAFA to cover:

- The establishment of the quality targets values per LFC block;

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- The measurement of the targets compliance by following instantaneous or average FRCE values;
- The mechanism by which the targets' compliance is monitored;
- The TSOs consequences for non-compliance.

5.4 Monitoring and Enforcement

ENTSO-E Regional Group Continental Europe will set up a process for monitoring the DFDs and report on a quarterly basis on all LFC Blocks' compliance level. The observed DFDs during the monitoring process are those which violate the frequency quality target as defined in Chapter 3 of this report.

The DFD monitoring process will formally start in 2021, allowing time for all LFC Blocks to implement the selected mitigation measures. A status report should be available during 2020, to follow the evolution of DFDs and FRCE quality targets before the actual start of the monitoring process.

If an LFC block is not complying with its quality target, as observed during monitoring in a specific quarterly report, it will be required to decide on an additional solution to be implemented.

5.5 Concrete action plan to tackle the DFD

The recommendations of the final report will require the implementation of at least one of the suggested solutions by 2021, with the aim to meet the quality targets set for each LFC block of CE.

Recognising the ongoing challenges in managing the system frequency, both across the hourly schedule change & during steady state operation, it is prudent to implement a comprehensive action plan to address these challenges. The proposed solutions are to be implemented progressively with all actions completed by 2021.

Each LFC Block not yet complying to the FRCE target will be required to deliver its implementation plan to the ENTSO-E's relevant body.

In case no solutions are implemented by some LFC Blocks and the DFDs are still too high according to the targets established by the Task Force, the ENTSO-E's relevant body could decide that these Control Blocks acquire additional FCR to assist in the reduction of DFDs until the necessary solutions are in place.

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