Report on Deterministic Frequency Deviations: Lowering the contribution of the Belgian Control Block

DRAFT for CONSULTATION

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Contents

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
FCR	Frequency Containment Reserve
IDCF	Intraday Congestion Forecast
LFC	Load Frequency Controller
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
SA	Synchronous Area
TSOs	Transmission System Operators
SIDC	Cross Border Intraday Market

Executive Summary

Elia is conducting a study regarding the impact of the Belgian Control Block on the deterministic frequency deviations ("DFD") that are observed within the Continental Europe synchronous area and of which the frequency and magnitude are increasing. The study contains an analysis of the main current and possible future causes as well as of the possible options to limit Belgium's contribution to the European deterministic frequency deviations.

If no action is taken in continental Europe to stop the worsening of the DFD problems, this leads to the following risks

(i) overloading of high voltage lines at hourly changes

(ii) using the FCR reserves for another purpose (namely for the DFD) than those for which they are normally intended (frequency stabilization following an incident), resulting in the inability to stabilize the frequency when both events occur simultaneously

(iii) a slower response of the system to frequency fluctuations during DFD resulting in an increased risk of decoupling production units.

In order to guarantee an adequate frequency (control) at all times, new, stricter quality criteria have to be agreed upon by every network operator within the framework of the operational cooperation between TSOs in continental Europe, which take better into account the DFD problems.

If these criteria are not met, a network operator will have to propose measures to be able to meet the criteria in the future. In the absence of convincing and effective measures, a network operator will have to contract more FCR to cover the quality shortage (which entails a social cost).

Proposed Solutions

The preferred solution is moving towards a 15-minute Market Time Unit (MTU) in a stepwise manner, at the international level and for 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 4.2.1 of this report.

Following solutions are worthy to be investigated and could complement the main proposed solution in order to reduce the participation of Belgium control area to the DFDs even further

- Activation of mFRR and/or tuning of LFC output on the basis of system imbalance prediction algorithms at the change of the MTU when there is an expectation (prediction) that the imbalance of the Belgian control area could be large during the following MTU. (section 5.3.2). Elia intends to thoroughly investigate the predictive algorithms in the coming year.
- Discussion with owner of fast acting production units to try to spread the starting and stopping of such units over a longer period of time and to avoid stopping or starting a set of fast acting units at the same time. (section 5.2.2)

The mutual support from other synchronous areas (section 5.3.6) will actually be implemented by entso-e and will be as such one additional measure to reduce DFD in Continental Europe. This will however not have an effect on the Belgian control area contribution.

The alignment of the ramping speed on HVDC with the ramping of cross-border inter-TSO schedules inside continental Europe will be further investigated by a inter-synchronous area task force under entso-e, which can be expected to deliver proposals during the next year.

1 Definition of the Problem

1.1 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).

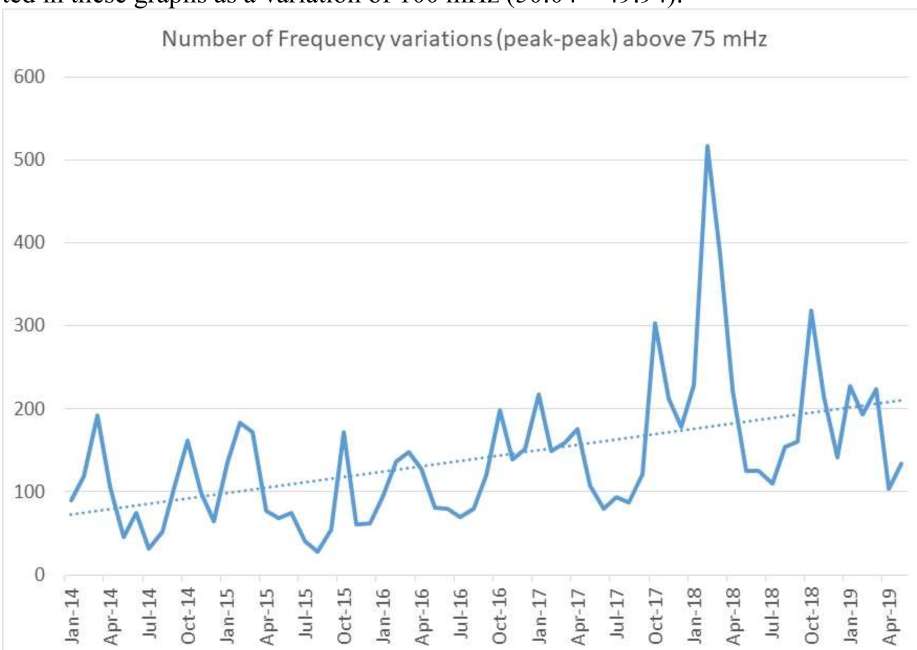


***Figure 1** – Number of +/- 75 mHz criteria violations*

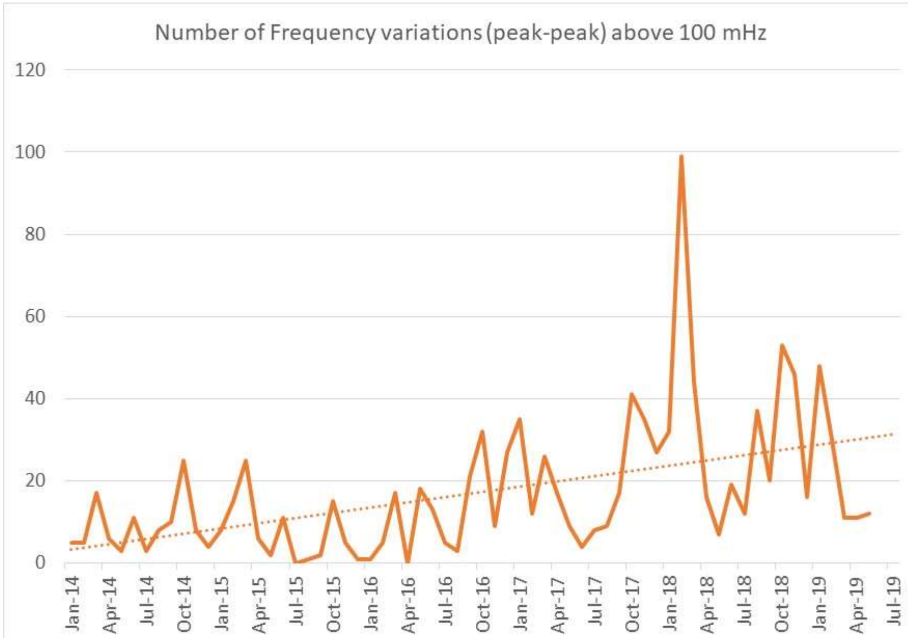


***Figure 2** – Number of +/- 100 mHz criteria violations*

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.

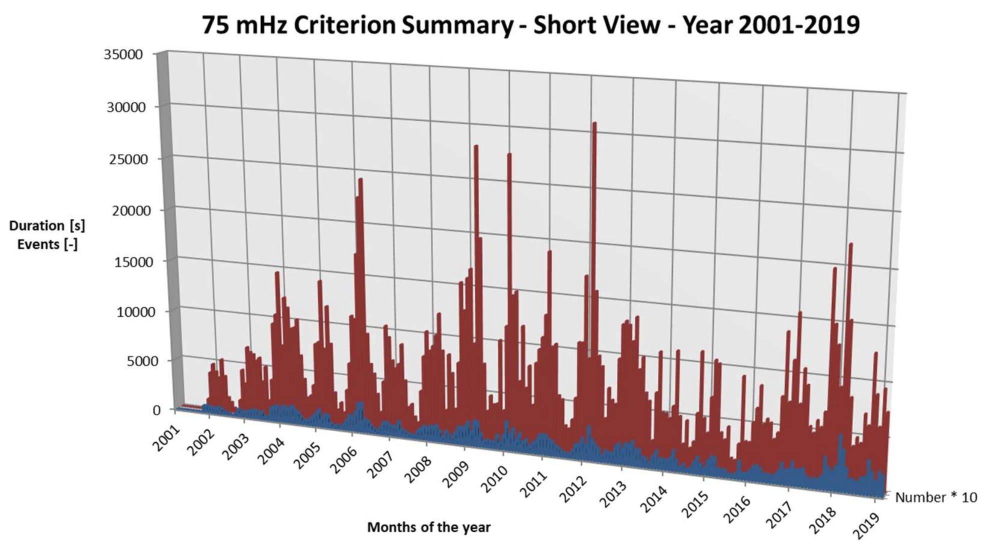


***Figure 3** – Number and duration of +/- 75 mHz criteria violation*

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.

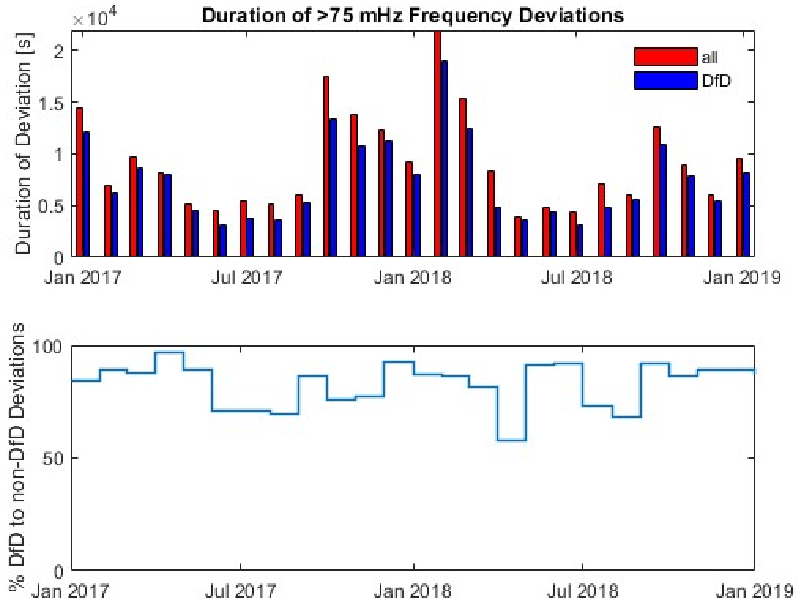


***Figure 4** – Duration of DFDs and % of DFD compared to all deviations in the last 2 years (>75 mHz)*

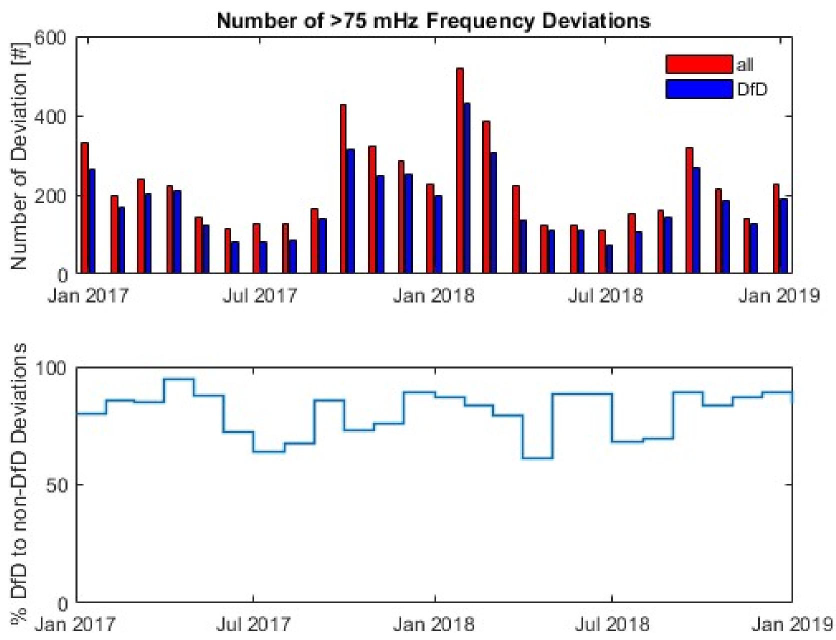
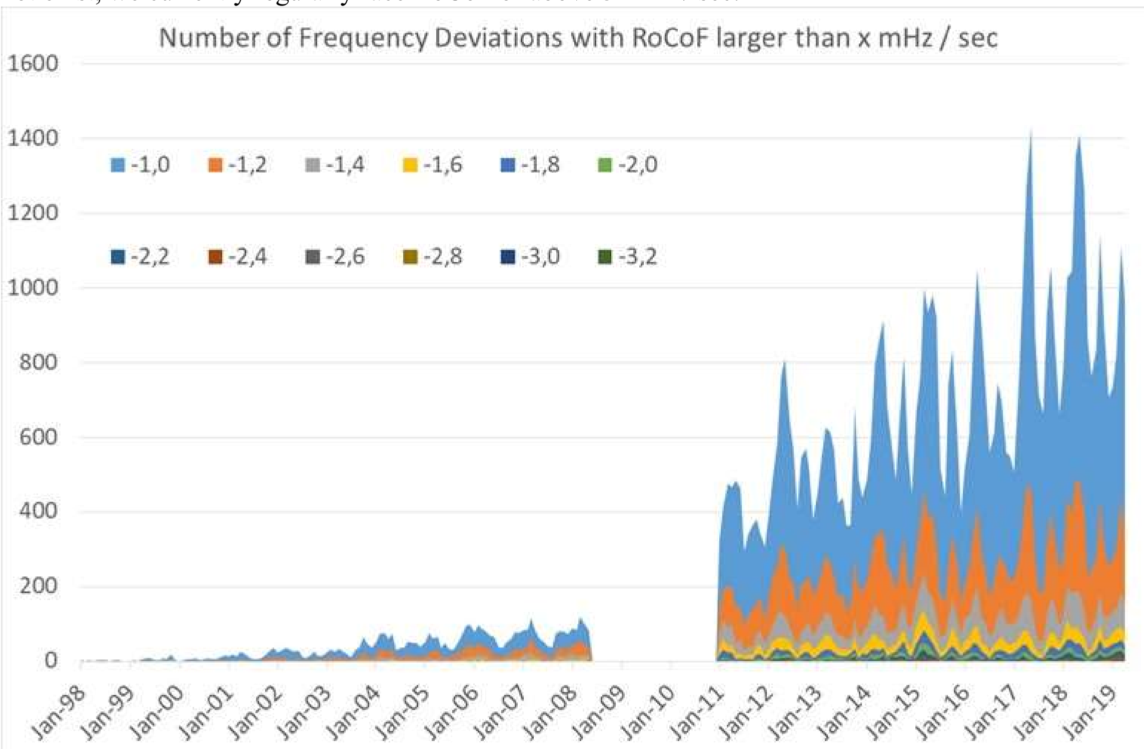


***Figure 5** – Number of DFDs and % of DFD compared to all deviations in the last 2 years (>75 mHz)*

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.

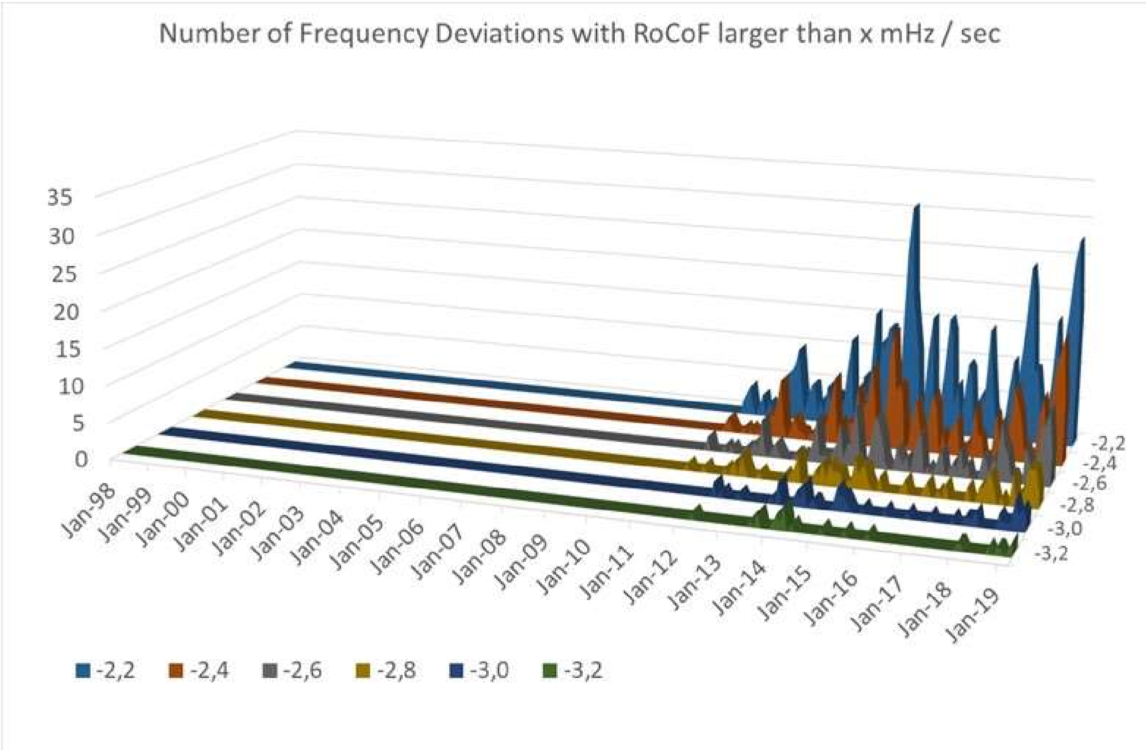


***Figure 6** – Observed RoCoF of DFD in mHz / sec per month from 1998 until today*

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.

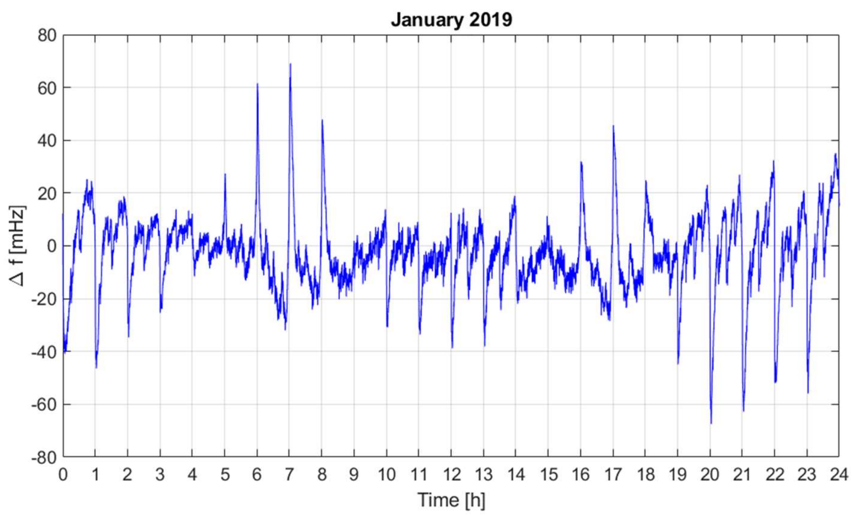


***Figure** 7 – Average values of Frequency per time of day for January 2019*

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.

1.2 Impact of Deterministic Frequency Deviations

1.2.1 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.

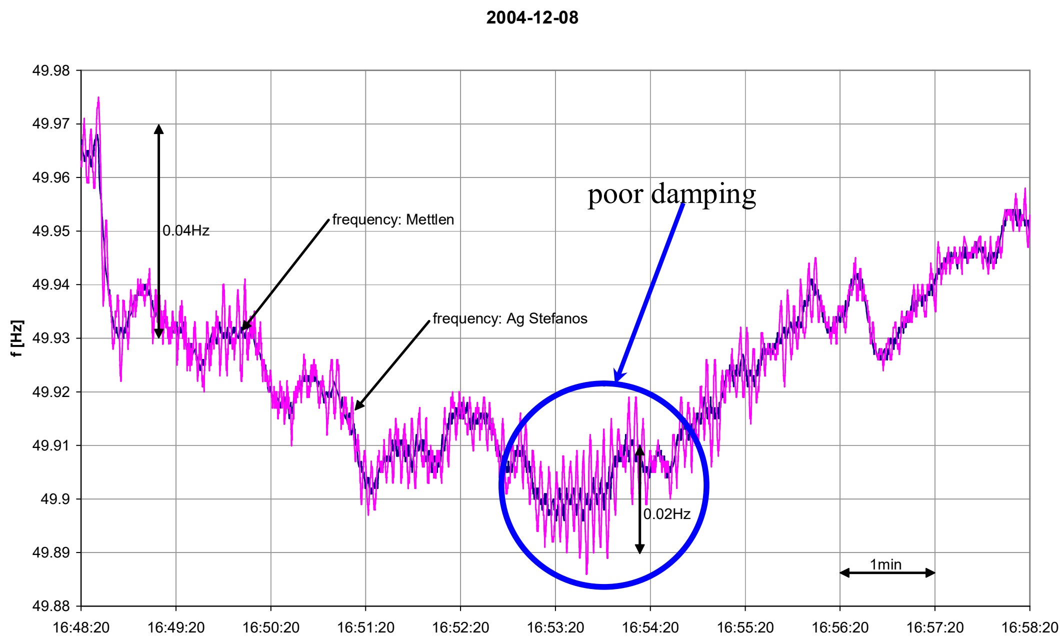


Figure 8 – Recording of poor damping of inter-area oscillations during frequency excursion [1]

1.2.2 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.

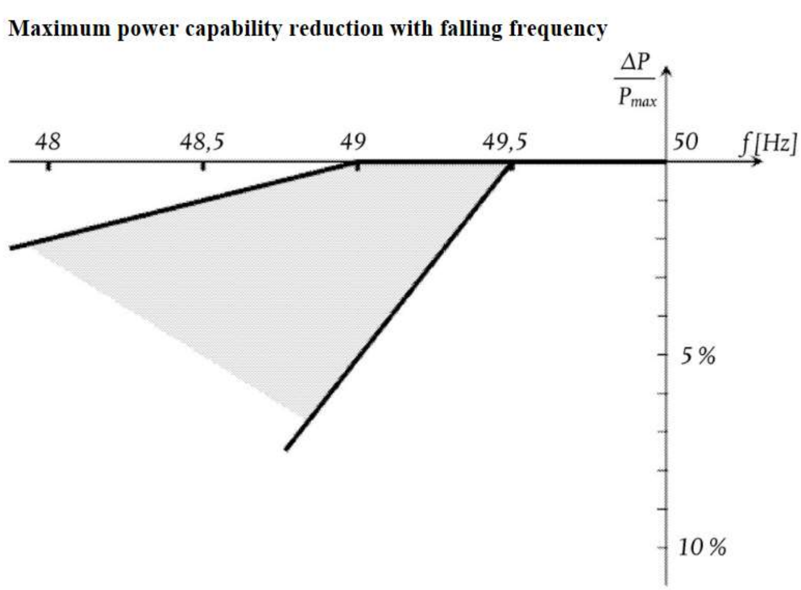


Figure 9 – Admissible power reduction under falling frequency [2]

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.

1.2.3 Impact on all Stakeholders in the Belgian control area

The main impact is that if we do not solve DFD on a European level, that this could lead to a more regular occurrence of load shedding. It is difficult to predict when this would happen, but it is reasonable to expect that it will happen, and over time will start to occur more and more often.

This loss of 5 % of load which would occur automatically after a frequency drop, has a huge economic impact on the consumer.

Estimated at the balancing maximum value of 14500 € / MWh, and given that 5% of load corresponds to about 500 MW and supposing an impact of two hours to reconnect and restart, the total economic impact can be estimated at 14.5 M€.

The worst case scenario is that a DFD would ultimately cause a blackout of the system which would cause Belgium to be without power supply for probably about one day (on average over the territory). This economic loss would be far greater than any measure to contain DFD.

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, Figure 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.

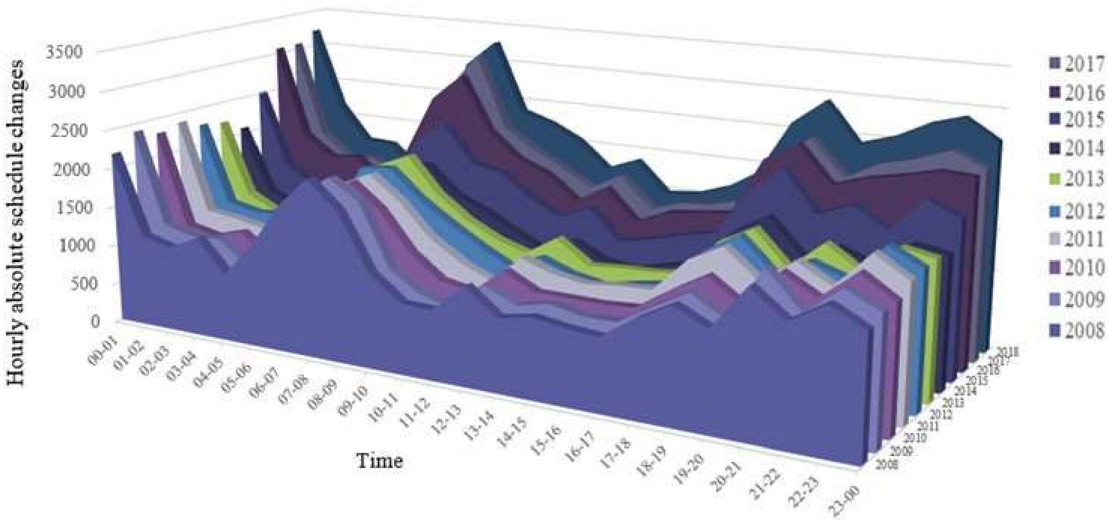


Figure 10 – Total delta in hourly schedules for within CE (UCTE North, East and South)

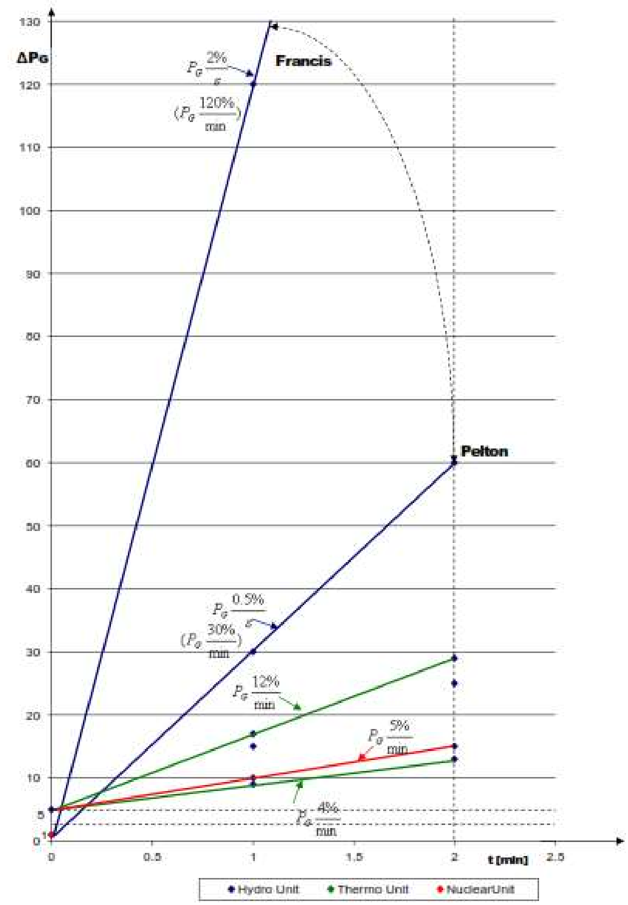
2.2 Fast acting vs slow acting production units

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.



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

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

2.3 Incompatibility between load ramping and block schedules

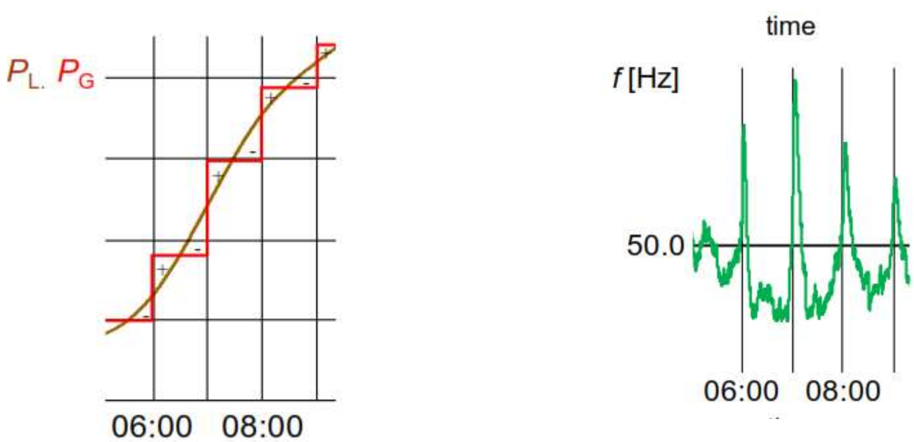


Figure 12– Effect of difference between load and schedules on frequency

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

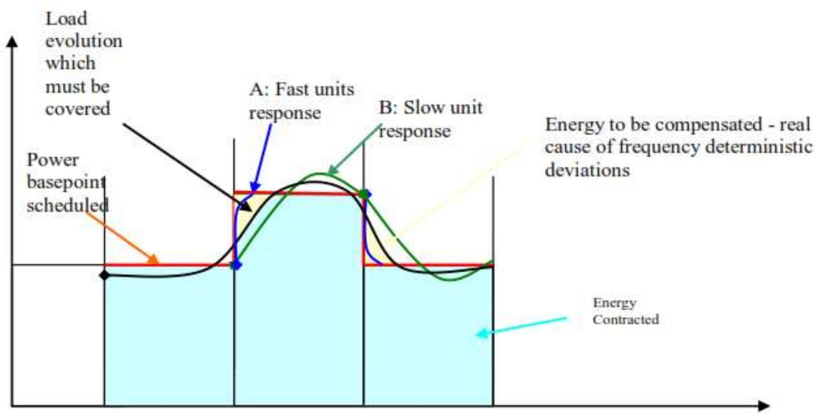


Figure 13 – Unit behaviour in scheduled time frames [3]

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.

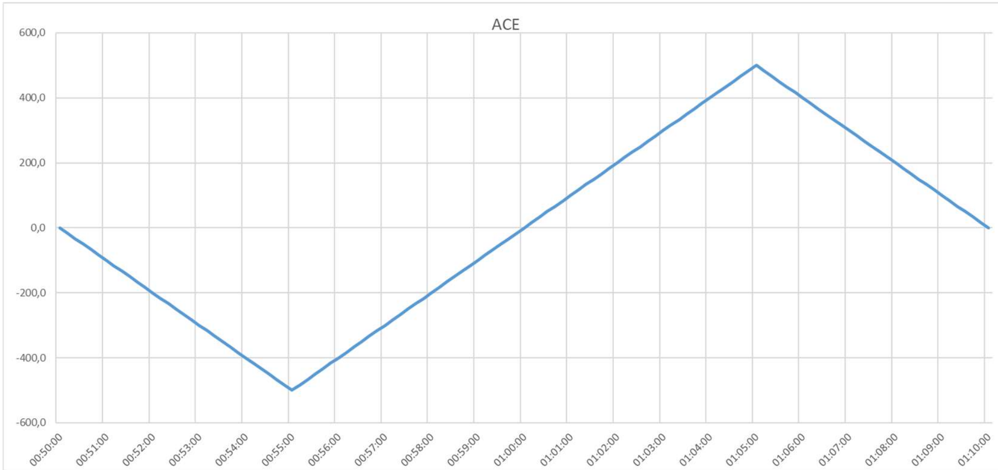


Figure 14 – Effect of HVDC ramping on the FRCE of the Belgian Control area

The issue is currently under investigation on entso-e level in a dedicated task force which deals with inter-synchronous area matters.

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.

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.

For the Elia Control Block the FRCE target has been tentatively calculated to be **214 MW**. So the instantaneous deviation during DFD should be smaller than this value, most of the time.

4 Contribution of the Belgian control block to DFD

4.1.1 Analysis of Belgian contribution to key DfDs in 2019

	Q1	Q1	Q1	Q2	Q4
	10-Jan	24-Jan	12-Mar	3-Apr	7-Oct
	20:55	05:55	09:55	20:55	20:50
	21:10	06:15	10:10	21:10	21:10
Frequency deviation	**DFD**	**DFD**	**DFD**	**DFD**	**DfD**
BE major Contribution	YES	NO	NO	YES	YES

The above table reports the most extreme deterministic frequency deviation observed in 2019 which triggered ENTSO-e reporting for TSOs that have large contribution. The criteria of large deviation in this case is more strict than the one to be used for new monitoring (100 mHz deviation contribution is considered), however this already shows that certain countries have limited contribution due to the control block size and limited schedule changes. In this section the analysis focus only on these most extreme DfD events whenever the Belgian LFC block has been identified as a significant contributor which occurred 3 times out of the 5 major observed events.

4.1.1.1 DfD event of the 7th of October 2019

The DfD event observed on the 7th of October 2019, resulted in industrial load service activation in France. The nadir of the frequency value was very close to the emergency trigger threshold (49.8 Hz). The DfD impact was very important as the DfD event was preceded by a loss of 934 MW generation of a nuclear power plant in France. This case shows specifically the risks of any DfD that can occur subsequently to large system imbalance or contingencies[1]. The Figure 15 shows the evolution of the frequency excursion during the event and the proportional frequency contribution of different control blocks (taking into consideration the actual imbalance and an assumed power/frequency factor). Belgium in this case is identified as a main contributor (11% of the overall ACE deficit). The curve illustrates as well the deterministic behavior of all LFC blocks which results in general in limitation of possible iGCC netting opportunities (most of the control block tend to follow the same the deterministic direction of imbalance).

[1] In normal condition (not within hour change) this should be covered without issue respectively by FCR and aFRR reserves to reestablish the frequency to 50 Hz

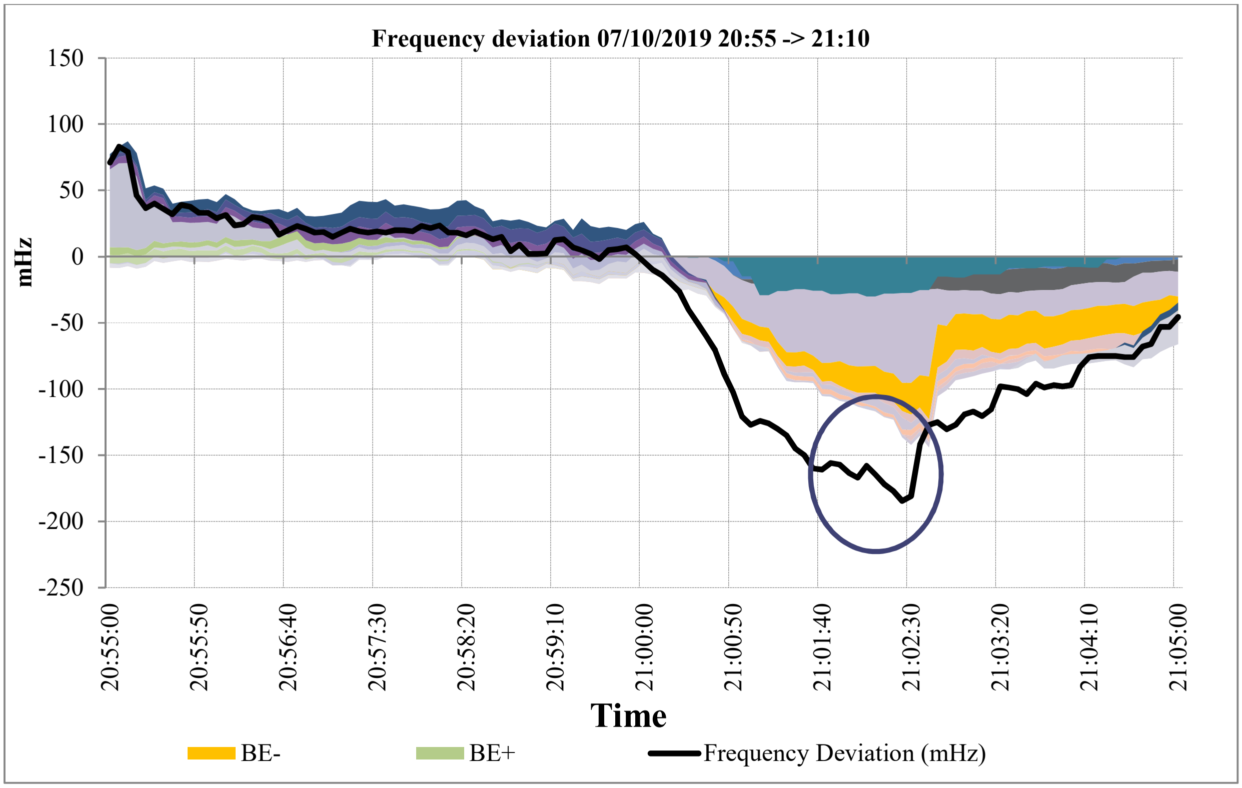


Figure 15 Frequency excursion during the DfD and ACE contribution

During the DfD event the ACE in Belgium reached an extreme instantaneous value of 850 MW[2], however the ACE corresponding to the nadir of the frequency corresponds rather to 583 MW, which is still considered as very high contribution (272 % the maximum fixed target of 214 MW).

Figure 16 shows that the aFRR reserves activation is lagging to correct the ACE which is due to the typical dynamic of a DfD where in the initial phase the ACE is long and reserves are fully activated in the "opposite" direction. Specifically, the Integral component and the Raw ACE filter function result in a lag on the reverse of the requested secondary output. This effect is mitigated since beginning of 2020 by adapting the anti-windup function to force the LFC controller to cancel the integral term whenever the RAW ACE value change of sign (zero crossing). This would shorten the lag[3] and initiate the activation of reserves in the same direction of the imbalance as soon as possible.

[2] A discontinuity in the ACE measurement has been observed, this corresponds to a measurement shift between cross-border lines at the time of the activation industrial reserves in France. This issue has been investigated and is already addressed by the new EMS system in place.
[3] Considering the actual case, the aFRR lag corresponded to 18 MW, in general the exact volume would depend on level of the activation at the time of the change of sign and the maximum contracted volume.

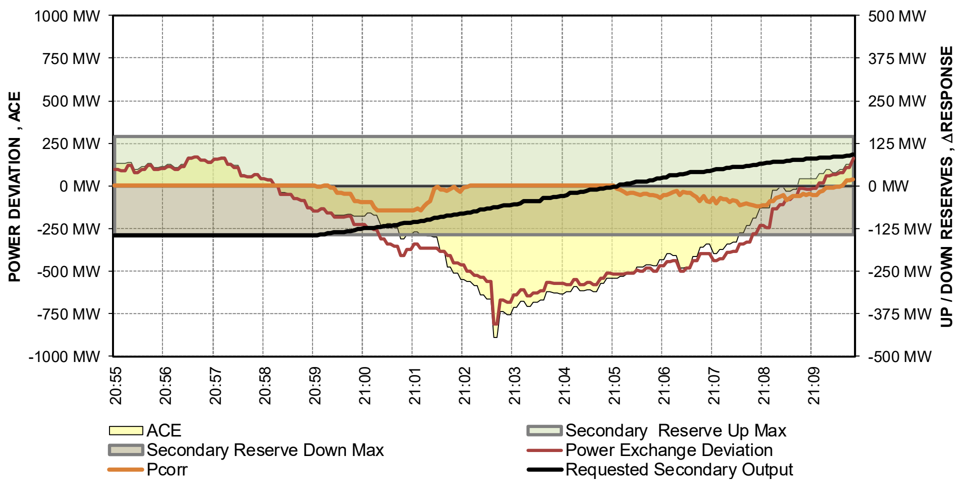


Figure 16 ACE evolution and reserves activation throughout the DfD

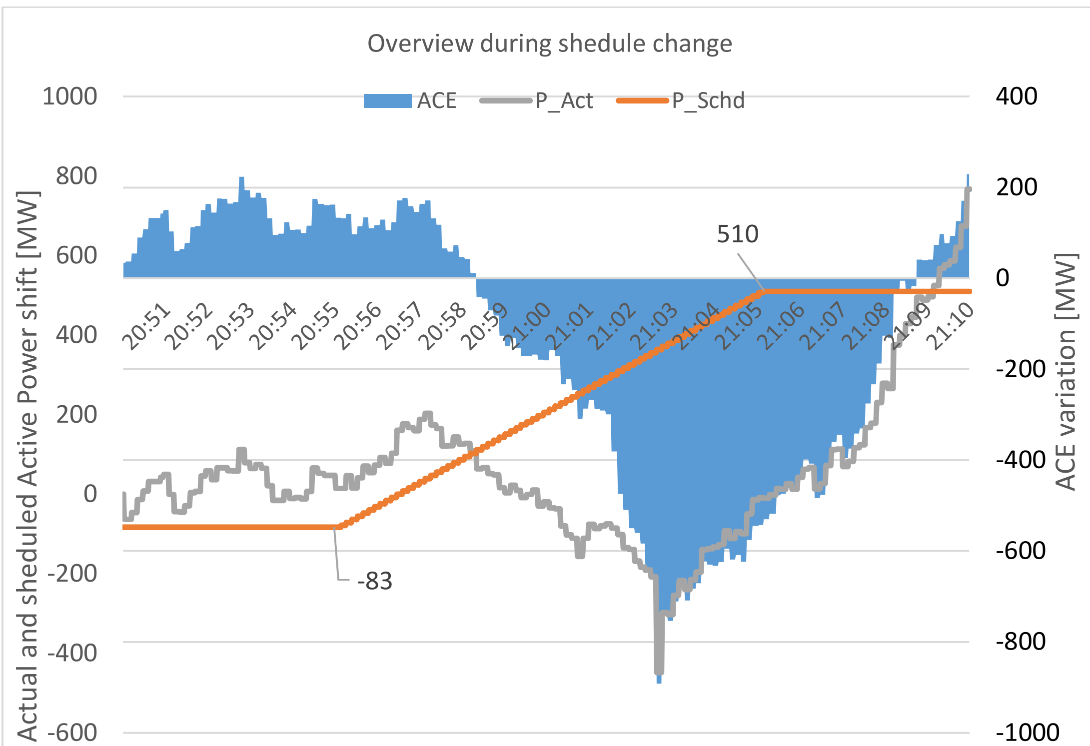


Figure 17 illustrates more in detail the deviation observed between the actual and scheduled cross-border exchange in Belgium which constitute the major component of the ACE term. It is clear that while the schedule change remains relatively not very large (-83 MW -> 510 MW) corresponding to 593 MW already resulted in considerable mismatch. Furthermore, it is interesting to observe that around 21:00 the actual schedule (P_act curve in grey) diverged even in the opposite direction of planned change until correction by market and reserves activation by Elia.

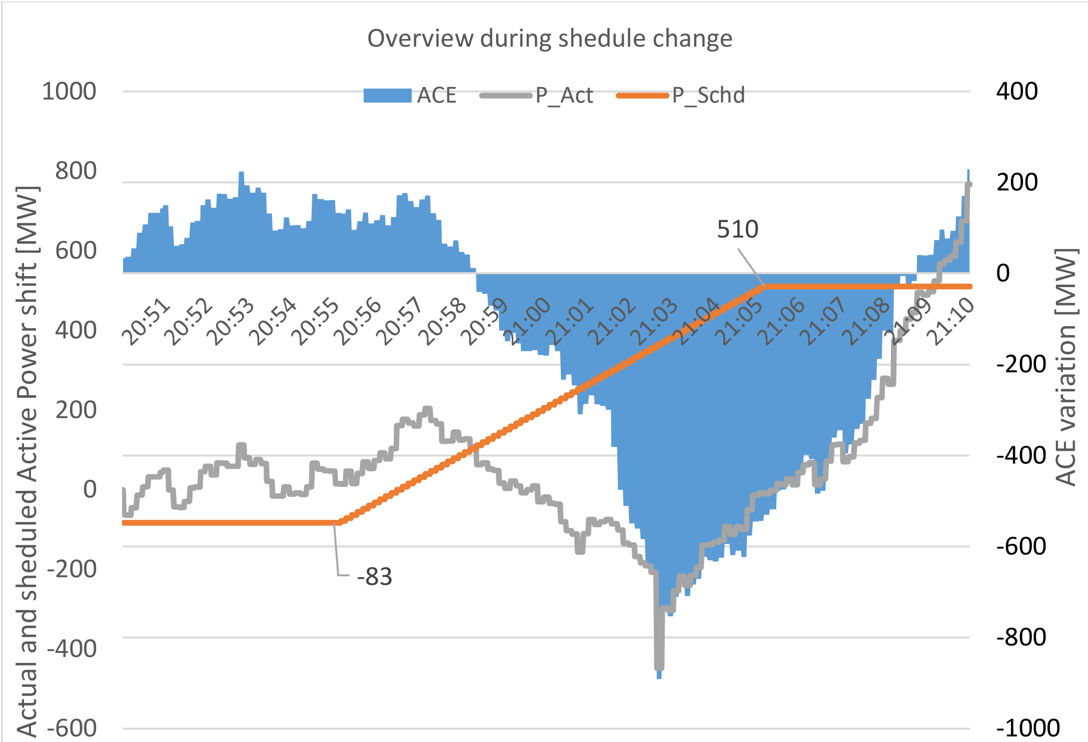


Figure 17 Cross-border flow comparison between schedules and actual power exchange

In order to understand the evolution of the ACE, in the following section we take a look individually at the behaviour of production throughout the duration of the observed DfD. Figure 18 illustrates the Gas production units, were a mismatch equivalent to 500 MW is observed between the nomination and the production during the nadir of the frequency deviation (effective BE ACE 583 MW). The mismatch provides already a possible explanation to ACE in Belgium. Nonetheless, it is worth mentioning that the deviation could be partly intended to compensate the higher infeed of Offshore wind comparing to the nominations as it can be seen in Figure 19 (approximately 200 MW).

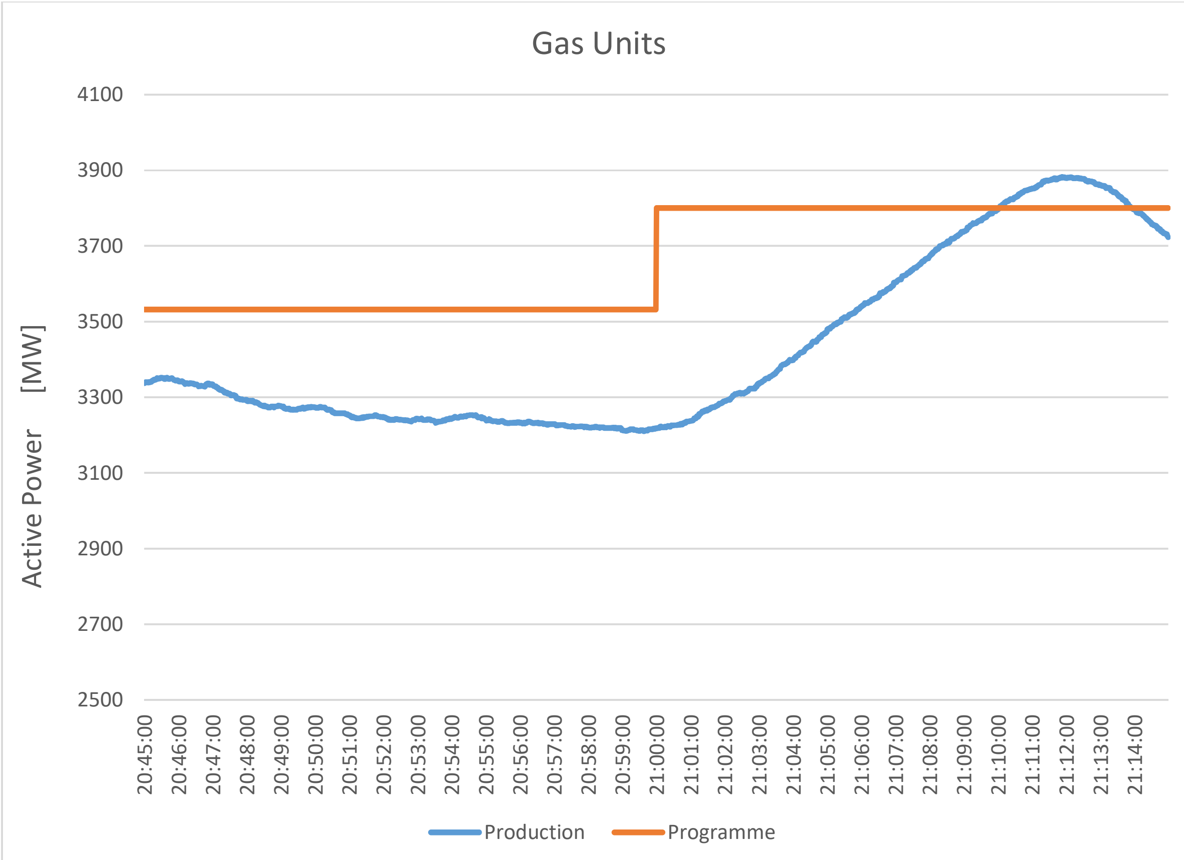


Figure 18 Gas Units nomination and production during the DfD

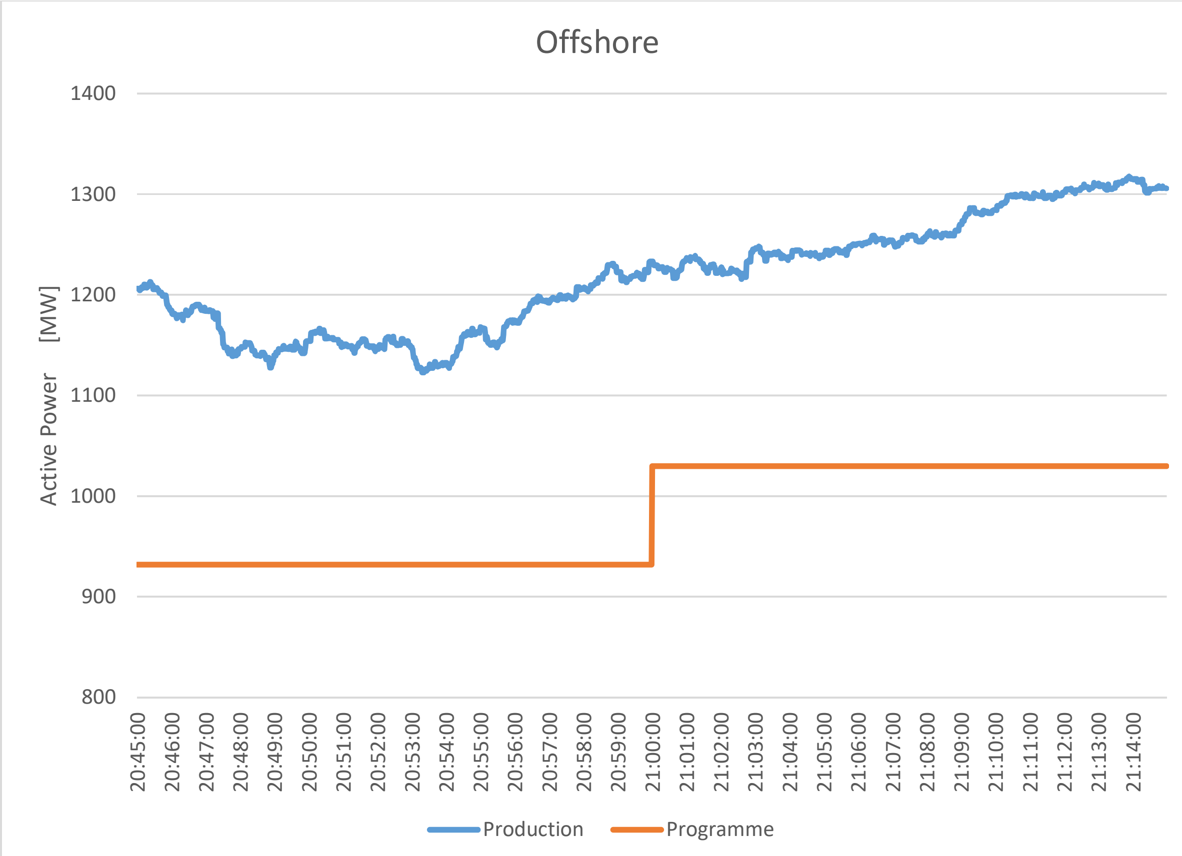


Figure 19 Offshore wind nomination and production during the DfD

The above analysis shows the lag of Gas production to follow the schedule change which is partly related to the shift between the ISP blocks and the TSO ramping (+-5 min around hour). On the other hand, the trend showing further deterioration of the ACE, where the schedule gradient evolves into the opposite direction of the shift can be traced taking into consideration the schedule change as observed on Nemo link as illustrated in the Figure 20.

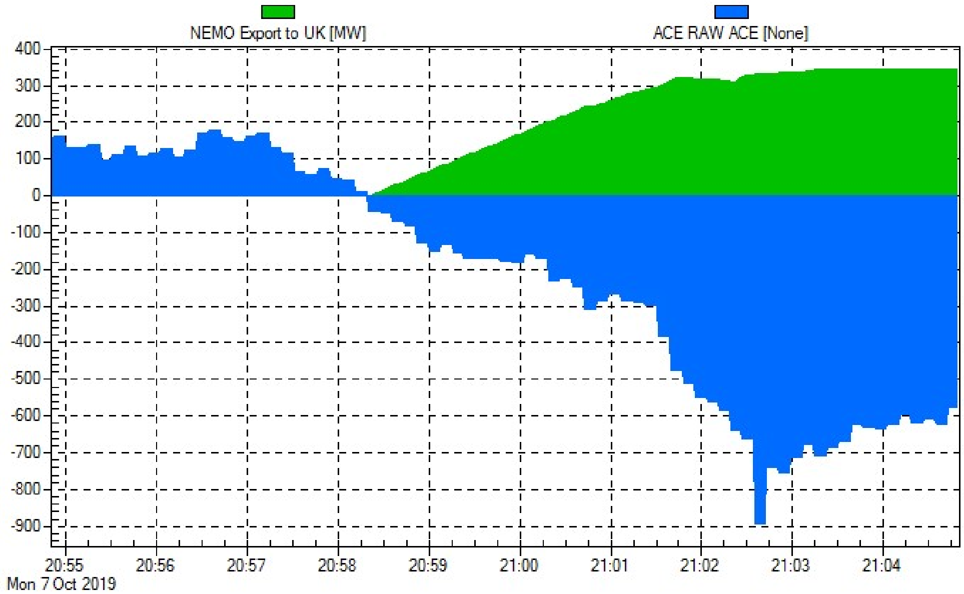


Figure 20 Nemo measured active power ramping during the DfD

In fact the change of direction of the actual schedule change as observed in the Figure 17, could be associated to the initiation of the schedule shift in Nemo. The shift started 2 minutes prior to the hour change which is explained by the effective schedule change of 345 MW and the applicable fixed ramping of 100 MW/min. Such change comes on top of the mismatch already observed in Gas production, which should have been normally anticipated by market parties. The Figure 20 shows also that the linear ramping on the link has been partly impacted due to the activation of the Limited Frequency Sensitive Mode – Under (LFSM-U) function. The activation resulted in a reduction of the exports volume as the frequency reached the threshold of 49.90 Hz. Such activation have positive impact on the frequency and the violation of the Belgian LFC block.
The activation of the LFSM-U support the overall frequency behaviour but remains quite limited as the maximum activated volume was equal to 35 MW (reduction occurring at 21:02 as a result of Δf 86 mHz deviation with respect to the activation threshold).

Conclusion:

The below Table summarises the contribution of several factor to the Belgian LFC Block large impact to the DfD within the +-5 minutes change. The reported contribution per category is calculated based on the difference between the nominated value (changing at the hour shift) and the minute based average measured value[4].

The Table shows that the mismatch with the offshore expected infeed resulted in positive imbalance, on the other hand it can be seen that the Gas production and Nemo mismatch both contributed to the observed imbalance. In general, large Gas production schedule changes are very well correlated to the violation, while it is difficult to statistically draw conclusions on all observed violations in the year 2019. The section 4.1.2 and specifically the Figure 39, provide already a very good qualitative view on how such mismatch are correlated to violation occurrences and allow us to conclude that limiting such mismatch would considerably address the observed violations in the Belgian LFC block.

It is also fair to assume that certain deviation can be partially intended to compensate the excess of offshore production.

[4] Technically the ACE calculation takes into consideration the TSO schedule shift ramping, for the simplicity of interpretation the contribution per each category takes into consideration direct shift at the change of the hour as per the nomination of the BRP.

For the current DfD events mainly Gas and Nemo are impacting while the rest is aggregated under the category ''*other*'' which reflect in general the capability of BRPs to properly forecast the impact on their respective portfolio and act timely within the ISP to cover their imbalance. These aspects possibly includes possible reasons as a forecasting mismatch, load variation and other infeed of non-CIPU units and cannot be directly quantified in this analysis.

Time	Gas	Offshore	Nemo	Other	ACE
20:55	-297	229	0	190	123
20:56	-300	256	0	188	144
20:57	-308	267	0	146	106
20:58	-312	286	0	-12	-39
20:59	-318	288	23	-155	-162
21:00	-574	196	-227	375	-230
21:01	-535	200	-128	90	-374
21:02	-489	196	-48	-342	-683
21:03	-432	210	-19	-427	-668
21:04	-363	211	0	-446	-599
21:05	-292	215	0	-414	-491

4.1.1.2 Event of the 3rd of April 2019

During this specific DfD event the ACE in Belgium reached an extreme instantaneous value above -400 MW, however the ACE corresponding to the nadir of the frequency of 156 mHz as observed in the below figure corresponds rather to -233 MW, which is considered as relatively limited contribution just above the fixed target (8 % the maximum fixed target of 214 MW).

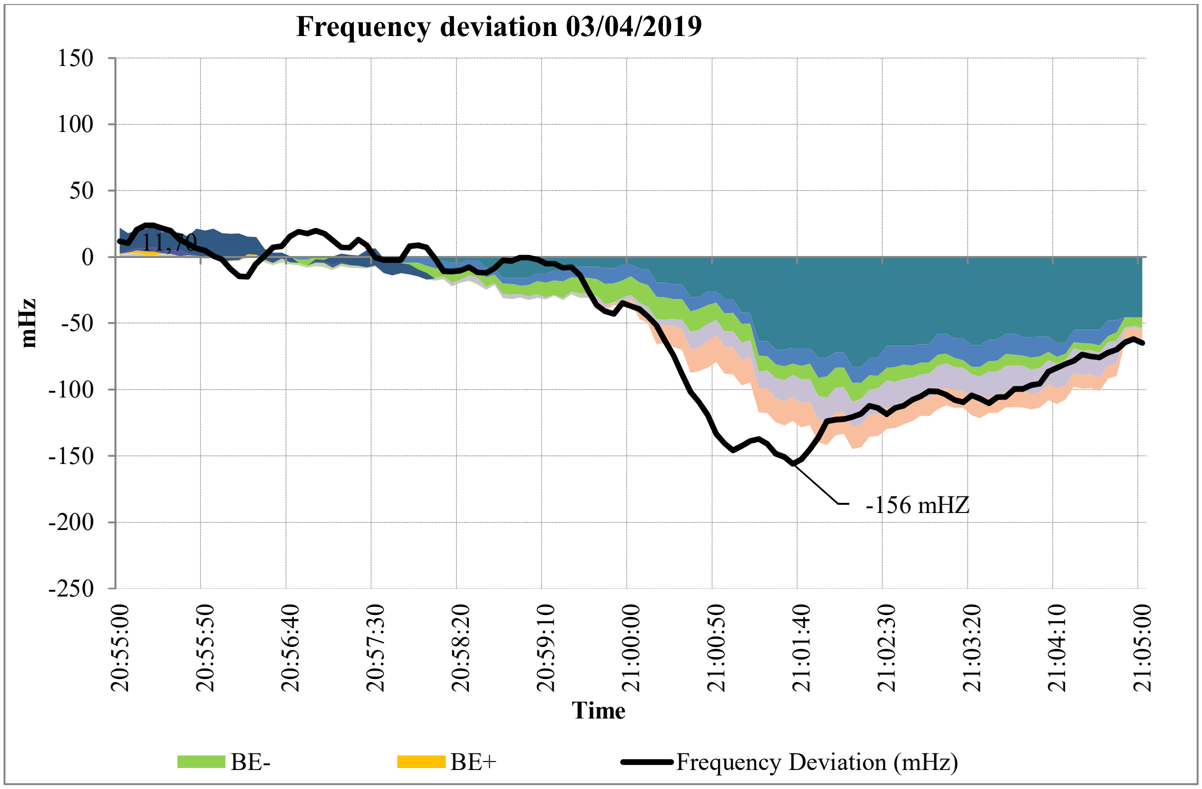


Figure 21 Frequency excursion during the DfD and ACE contribution

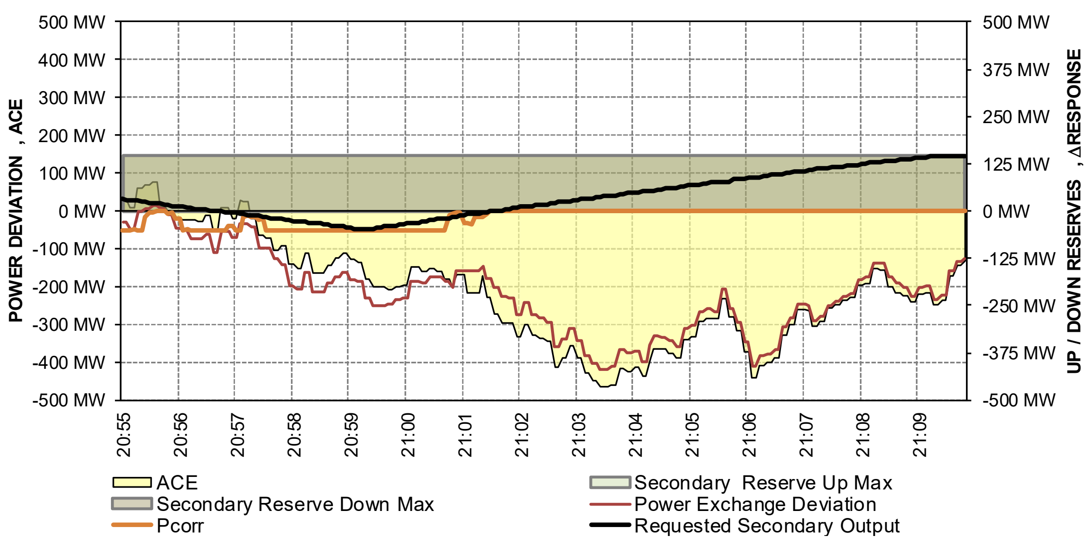


Figure 22 ACE evolution and reserves activation throughout the DfD

Similarly to the previously reported DfD, the above figure show that the aFRR reserves activation is lagging to correct the ACE which is due to the typical dynamic of a DfD where in the initial phase the system is long and reserves are fully activated in the long direction. While this measure would indeed effectively decrease the contribution of Elia it would not solve the issue in the root as aFRR volumes and their activation time remain limited comparing to the rate of change of the imbalance and its order of magnitude. The Figure 22 show as well that iGCC imbalance netting which was not available right after the change of the hour which resulted in restitution of the netted volumes and further rapid deterioration of the FRCE.

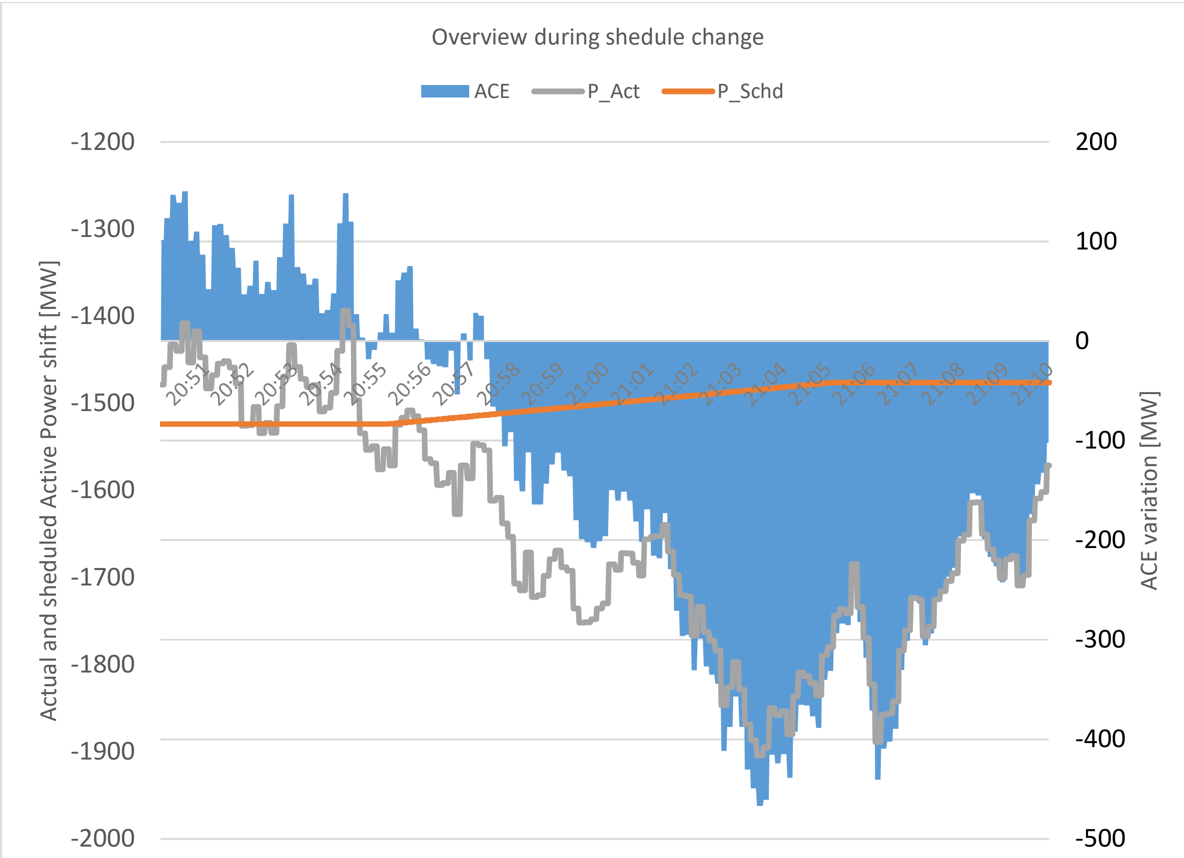


Figure 23 Cross-border flow comparison between schedules and actual power exchange

It is interesting to notice that in the actual DfD event, the cross-border schedule Change was less than 50 MW (from 15024 MW to 1476 MW) as depicted in the above figure. Furthermore, no change in Nemo schedule occurred as the link maintained full export toward the UK. This already provides a first hint that the observed imbalance is strictly related to internal BRPs position shifts where, it can be seen clearly that the actual power flow tends to go toward the opposite direction of the expected scheduled active power flow.

In the below figure it is observed that overall gas production is lower than expected nomination well before the schedule change with around 100 MW which can be explained by market parties correction of their own portfolio and activation of secondary reserves. The initial mismatch at the beginning of the schedule change of 100 MW has been corrected gradually to retrieve the nominated values.

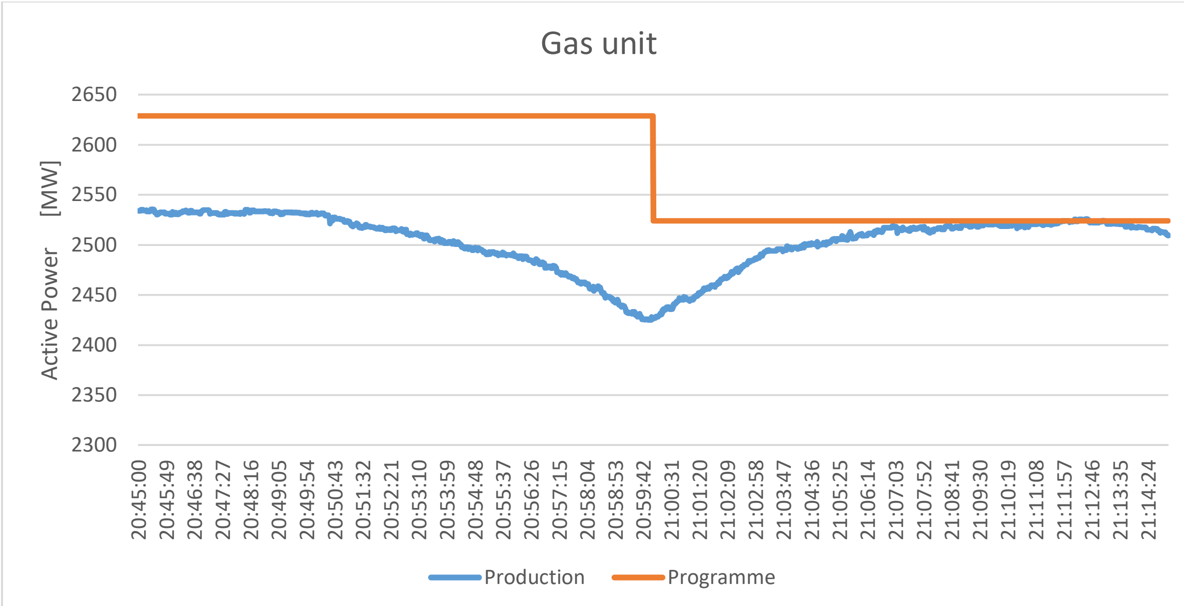


Figure 24 Gas Units nomination and production during the DfD

On the other hand it can be seen on the below figure that during the DfD event the offshore wind nomination were substantially low without considerable deviation in term of forecasting error. The deviation in this case was in the opposite direction of the imbalance during the DfD (less than 20 MW long).

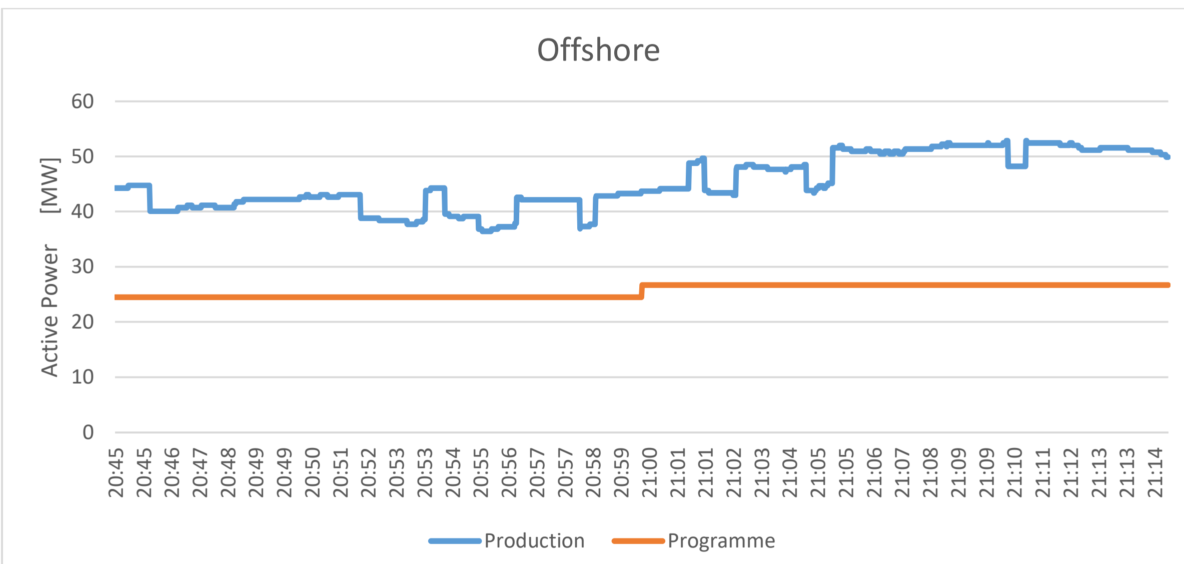


Figure 25 Offshore wind nomination and production during the DfD

The Figure 26 shows the schedule and actual power observed for Nemo link (export to the UK), as it can be seen there was no schedule change thus no contribution to the ACE imbalance is expected. The active power reduction observed during the frequency deviation (decrease of export) is due to the activation of the LFSM-U function with an equivalent reaction to a Δf of 50 mHz, the decrease in export in general helps to correct the short position of the Belgian LFC Block but remain very marginal comparing to the toala observed imbalance.

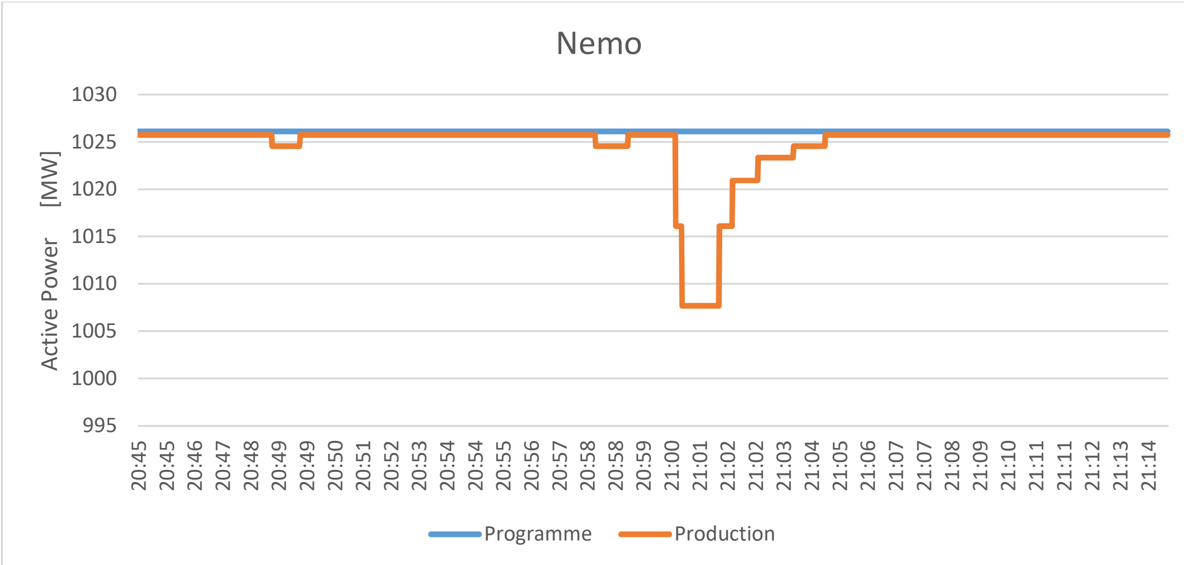


Figure 26 Nemo Link nomination and export during the DfD

Figure 27 illustrate the interesting trend of the imbalance observed where its evolution can be directly linked to Hydro-pumped storage power modulation. The initial reduction prior to the change of the hour (in the same direction of the imbalance) did result in further deterioration of the ACE up to 21:04 where the highest ACE value is observed. The subsequent increase of active power of Hydro-pumped storage jointly with the activation of aFRR reserves resulted in restauration of the ACE. The respective nomination during the hour change 20:00 to 21:00 is respectively from 160 MW to 35 MW, the hydro-pumped was in any case higher than the nomination, this is explained by the fact that the generation is mainly used to correct the market parties internal portfolios.

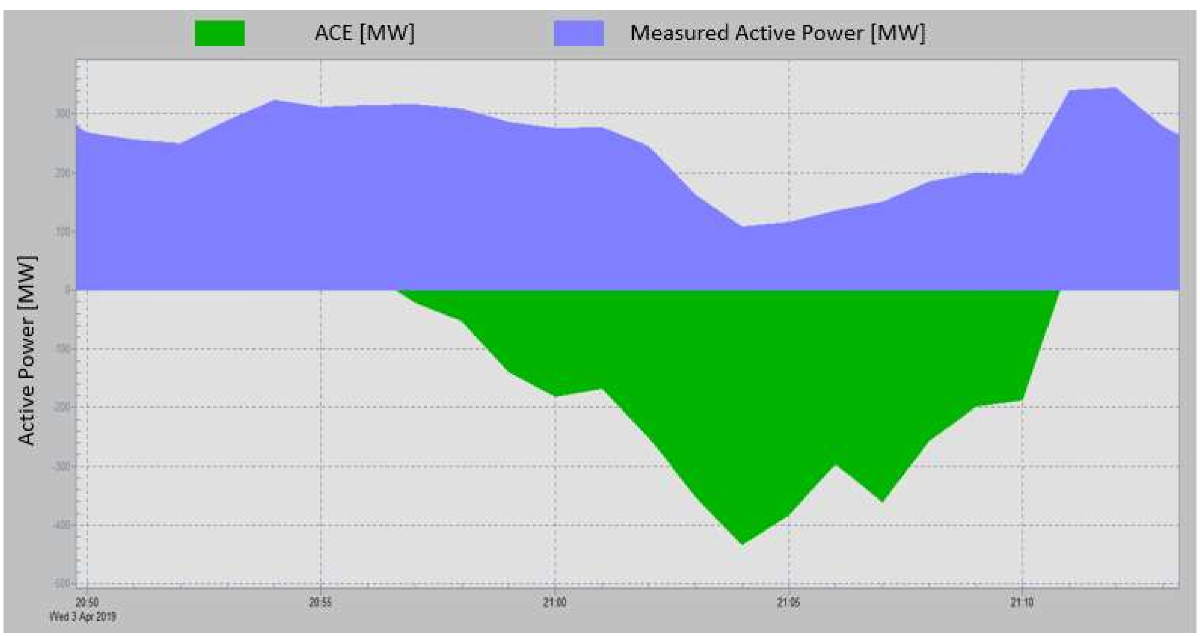


Figure 27 Hydro-pumped storage behaviour throughout the DfD

Conclusion:

Time	Gas	Offshore	Nemo	Other	ACE
20:55	-138	13	0	157	33
20:56	-145	16	0	108	-21
20:57	-159	18	0	93	-48
20:58	-176	16	1	20	-139
20:59	-198	19	1	0	-178
21:00	-88	17	5	-104	-170
21:01	-70	20	18	-212	-244
21:02	-48	18	7	-326	-349
21:03	-31	21	3	-425	-431
21:04	-25	20	2	-382	-386
21:05	-18	22	0	-299	-295

For the current DfD event, the main contribution of the ACE imbalance during the first 5 minutes of the hour change is mainly related to the mismatch of the Gas related production. The offshore Nemo link did not have considerable contribution throughout the event. On the second part of the defend (after the hour change) as it can be seen in the Table, the highest ACE deviation were rather related associated to various impact factors listed as ‘’other’’, such elements include possible mismatch due to expected load forecasting and the ability of certain market to follow their respective schedules as observed in the trend depicted in the Figure 27.

4.1.1.3 Event of the 10th of January 2019

During the DfD event the ACE in Belgium reached an extreme instantaneous value above 416 MW, however the ACE corresponding to the nadir of the frequency of 198 mHz corresponds rather to -340 MW, which is also well beyond the maximum allowed contribution. Throughout the DfD the Belgian control block have an overall contribution of 8% within all the synchronous area which is considered to be high taking into account the relatively limited size of the block. Figure 28, illustrates the evolution of the DfD and the respective imbalances within the continental synchronous area, reaching 49.81 Hz resulted in activation of interruptible industrial demand which had immediate effect on the frequency.

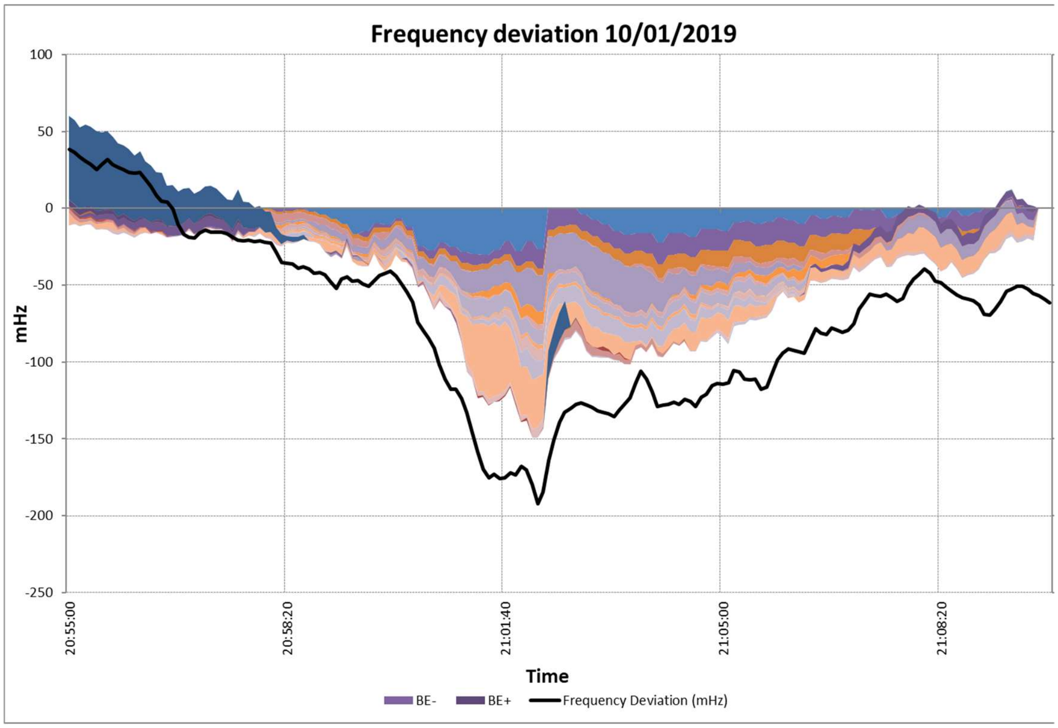


Figure 28 Frequency excursion during the DfD and ACE contribution

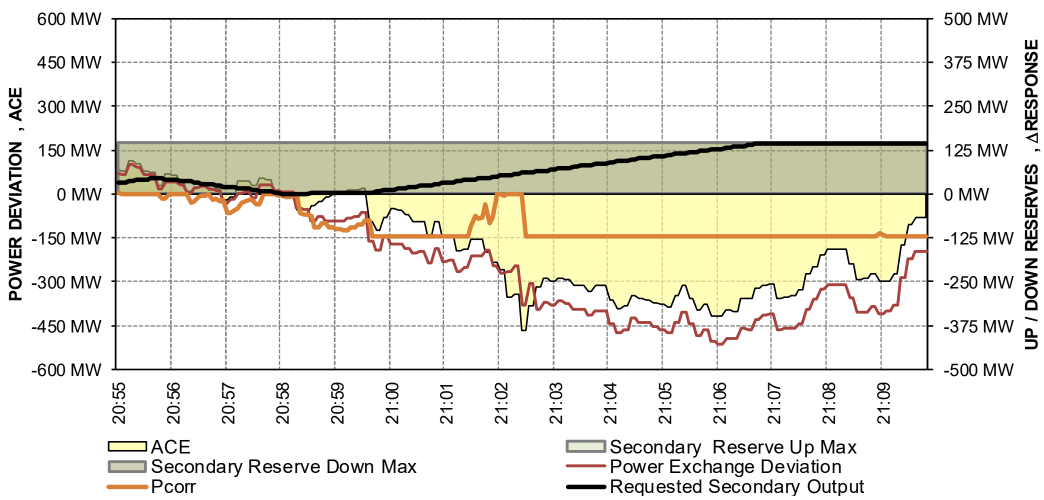


Figure 29 ACE evolution and reserves activation throughout the DfD

Figure 29 illustrates the detailed behavior of the Belgian LFC block, in the actual case the integral component of the PI controller was very limited which allowed prompt positive reserve activation to counter-act the DfD imbalance. Throughout the event iGCC correction was available mostly but capped to the existing profile limits, such limits has been largely extended in 2020 which would allow to limit the Belgian contribution during such events.

It is interesting however that the netting potential have been available to the maximum (following 21:02), which normally not to be expected due the deterministic nature of the event (ie most of the block tend to be short) this could be ultimately explained by the activation of the industrial reserves in France which created a netting opportunity and thus potentially limiting the impact of their activated means.

It is however clear that the iGCC netting opportunity should not be considered as a guaranteed resource but rather as good efficiency mechanism aiming to optimize reserves activation. Typical adverse effect can be observed in the Figure 29, where loss of netting opportunity have important and immediate impact on the FRCE (observed between 21:02 and 21:03) which could be further impacting for higher profile limits.

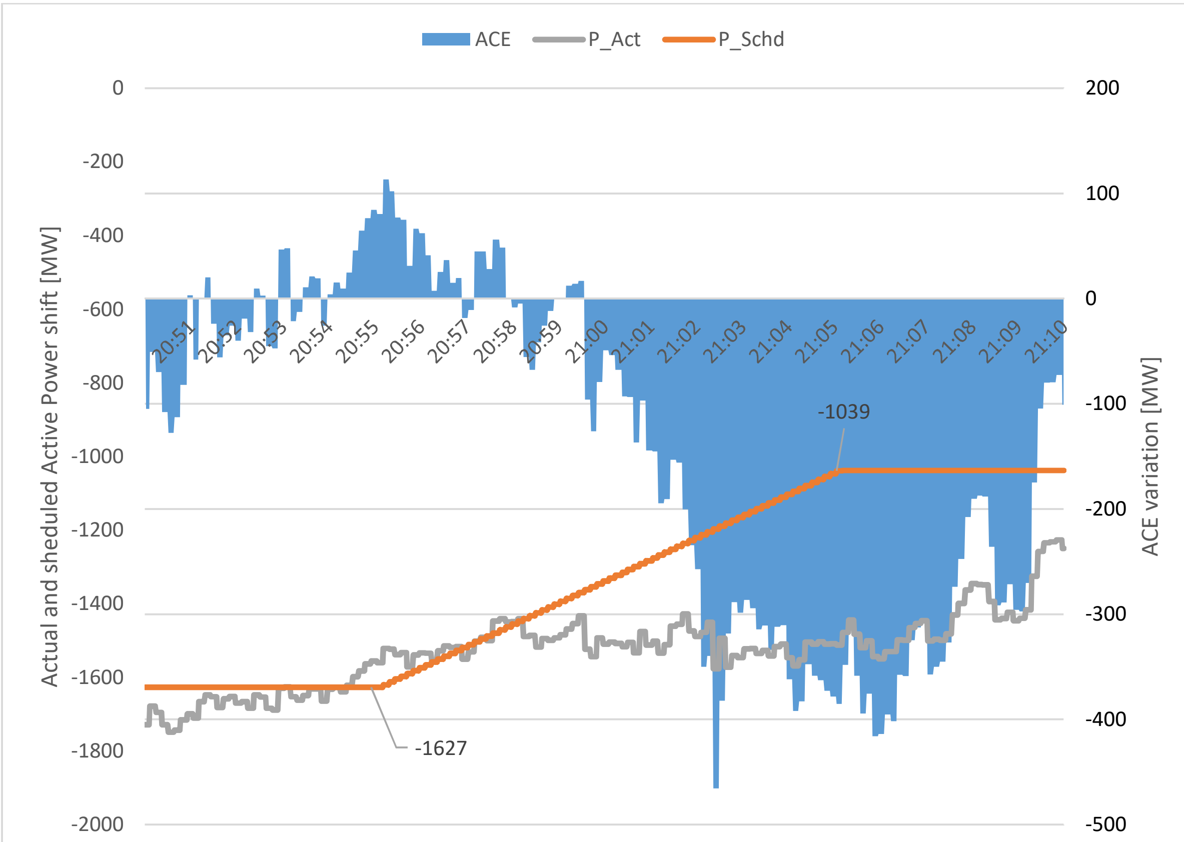


Figure 30 Cross-border flow comparison between schedules and actual power exchange

Figure 30 illustrates the root cause of the DfD event as the internal schedule fails to follow the cross-border schedules observed in most of control blocks and thus resulting in a concurrent large imbalance in the same synchronous area which leads ultimately into a large frequency deviation. Large short imbalances in the Belgian control block occur during important schedule changes as per the case of the 10th of January 209 this is specific when import are reduced (or vice versa). For the actual case the scheduled shift corresponds to 421 MW (-1627 MW -> -1201 MW), the delay of market parties correction resulted in maximum FRCE imbalance of 465 MW (560 MW imbalance without netting).

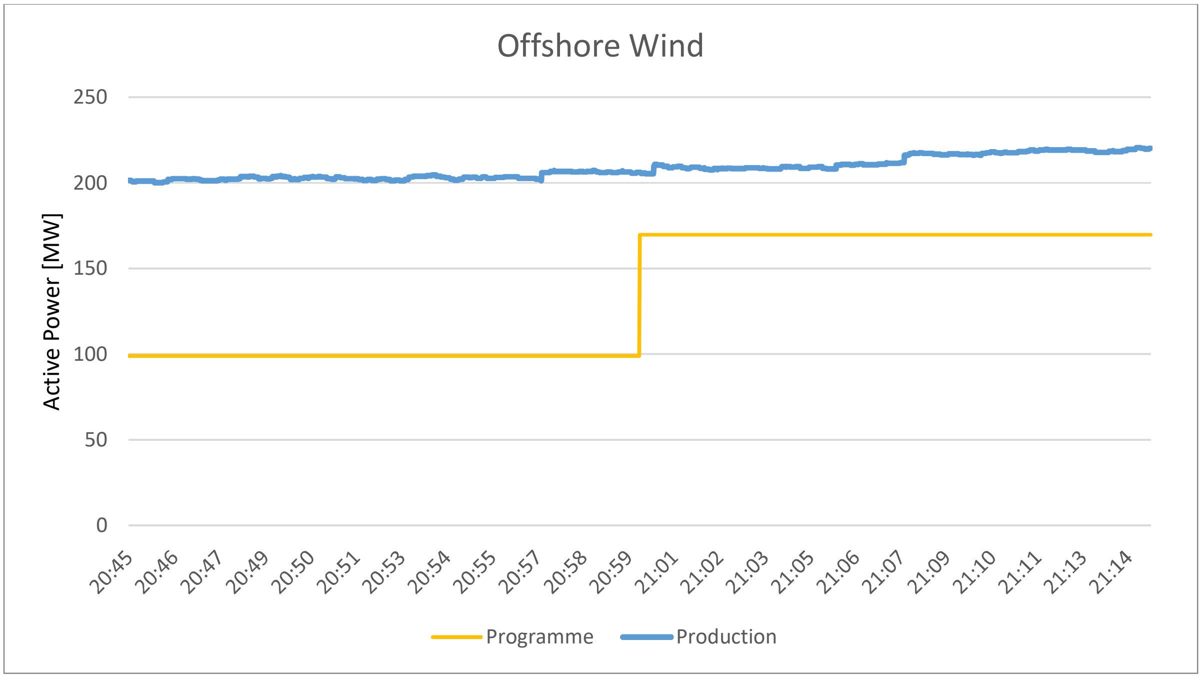


Figure 31 Offshore wind nomination and production during the DfD

On the other hand it can be seen on

Figure 31 that during the DfD event the offshore wind nomination were substantially low without considerable deviation in term of forecasting error. The deviation in this case was in the opposite direction of the imbalance during the DfD (less than 20 MW long).

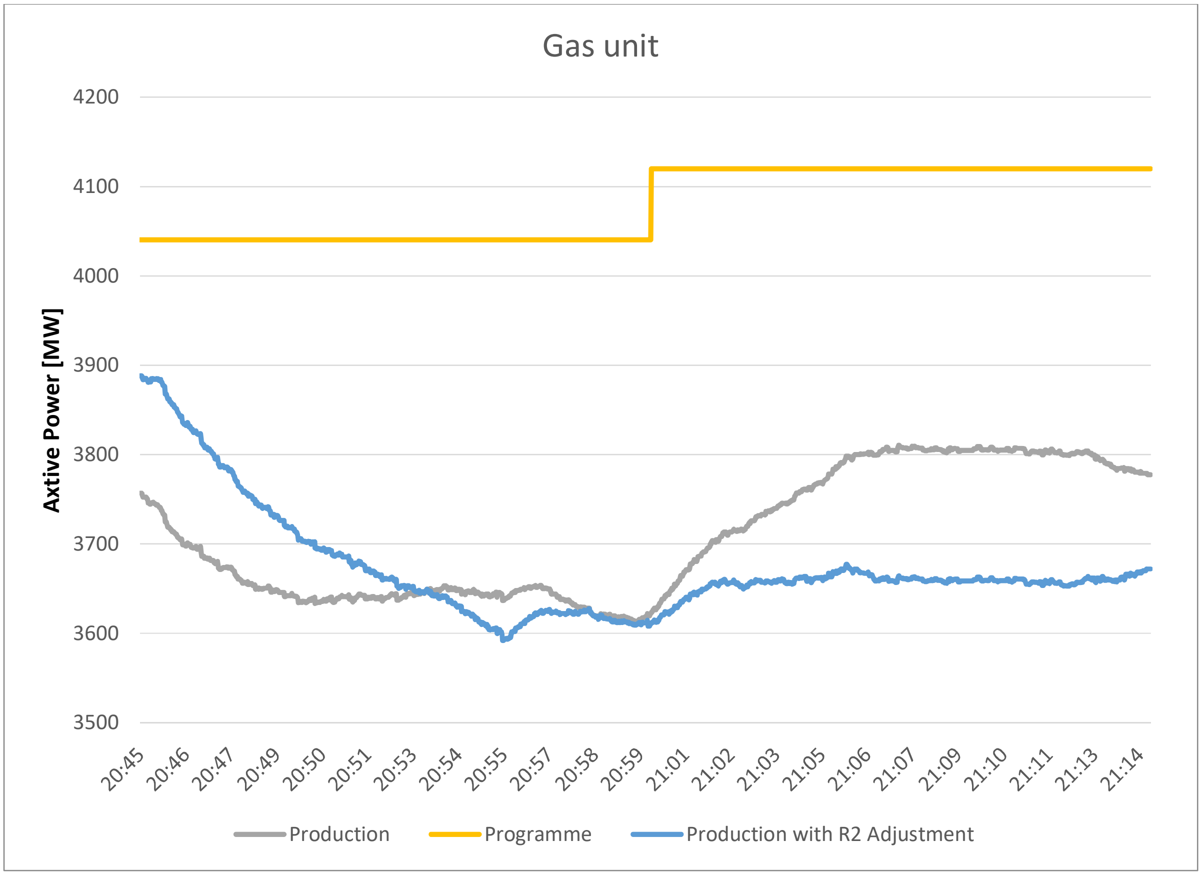


Figure 32 Gas Units nomination and production during the DfD

Figure 32 shows that overall gas production is lower than expected nomination well before the schedule change with around 400 MW which could be partially explained by market parties correction of their own portfolio. Considering that aFRR reserves are delivered by Gas Units, if we subtract the extra activation that has been requested by Elia we could see that the difference between the initial nomination and the respective infeed can reach 560 MW.

While a large mismatch is indeed observed there is no direct link to the DfD in term of schedule execution lag as the shift during the hour change is very limited and have been partly executed within 2 minutes. This ultimately means that for this DfD the large imbalance is most likely related to inaccurate forecasting of certain market parties portfolios as the imbalance have been sustained more than 10 minutes after the hour change. This in turn resulted in an important imbalance price reaching 181 €/MWh in the Qh of the schedule change as depicted more in detail in the below figure.

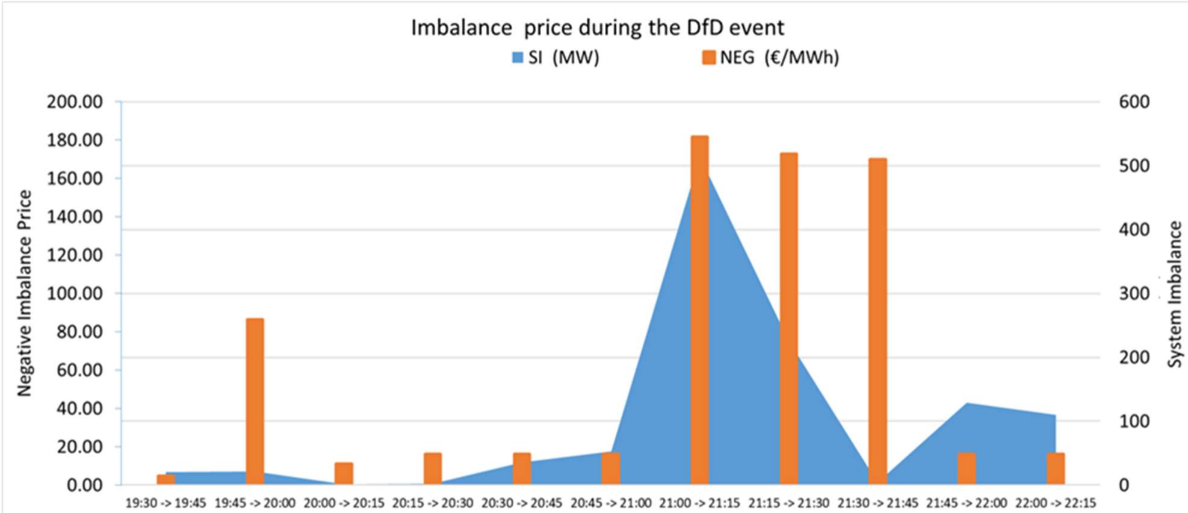


Figure 33 System imbalance and imbalance price during the DfD event

As per the DfD observed on 3rd of April; Figure 33 illustrate as well a direct link between the imbalance correction and the Hydro-pumped storage power modulation where the restauration of the imbalance have been mainly corrected by a joint action of the aFRR reserves activation (Figure 29) and the Hydro-pump correction (initial nomination is 29.7 MW for 20:45 and 21:15), the imbalance has been fully restored after an increase up to 400 MW of active power which corresponds to more than half of the observed most extreme imbalance.

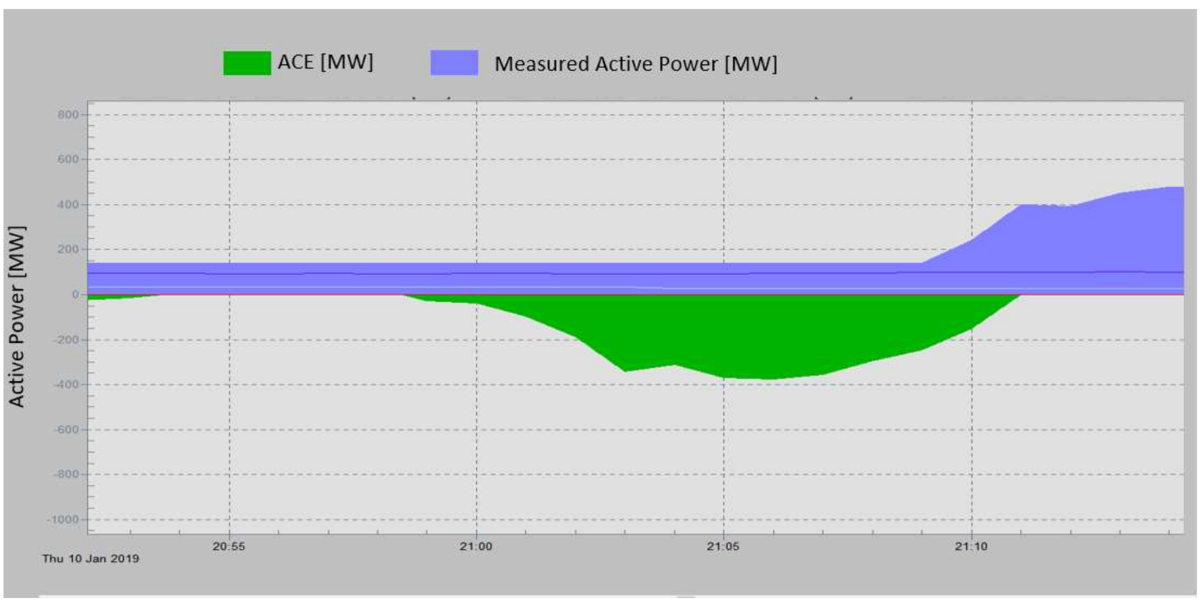


Figure 34 Hydro-pumped storage behaviour throughout the DfD

Conclusion:

For the current event, Nemo is not taken into consideration as no commercial flows were executed on the date of the DfD. Similarly to the event of the 3rd of April, a large contribution in term of imbalance can be identified for the Gas power mismatch between the reference schedule and the measured production especially if the reserves activated by Elia are subtracted (Figure 32). While the miss-match can be observed well before the hour change, the expected increase in term of schedule (while being relatively small) has not been achieved. Thus it can be concluded that the actual large imbalance can be justified by the combined effect of the Gas generation miss-match and possible issue to forecast properly the shift of schedule and the resulting impact for market parties to balance their own portfolio.

Time	Gas	Offshore	Nemo	Other	ACE
20:55	-398	104	0	371	77
20:56	-390	104	0	308	22
20:57	-403	107	0	325	29
20:58	-419	107	0	283	-28
20:59	-423	107	0	279	-37
21:00	-475	38	0	344	-93
21:01	-431	39	0	207	-185
21:02	-404	38	0	24	-342
21:03	-383	39	0	32	-311
21:04	-361	39	0	-48	-369
21:05	-334	39	0	-79	-374

4.1.2 Statistics of all DfDs and Belgian contribution in 2019

In this section we present an overview of all the recorded DfD events as per the criteria defined in the section 3.1.1. The monitoring would be based on 5s based resolution of EAS frequency and ACE measurements. For practical reason, a DfD would be considered valid if the limit is violated in three successive time stamps (eg frequency below 49.925 Hz for three time stamps).

In order to calculate the respective contribution of each control block, the maximum frequency deviation observed during a DfD event is used as a reference to identify the corresponding ACE which would be in turn compared to the targets to be defined per each LFC block.

In the actual evaluation, the contribution threshold considered for Belgium as per 2019 preliminary estimation is 214 MW, the maximum limit of violation is fixed to 30 % per quarter, it is however expected that the acceptable percentage will evolve into more stringent conditions if the DfD issue is not solved in the coming winter.

Considering the previous year, already Belgium had only one violation in the Q1 (slightly above of the limit of 30 % ratio), other violations were under the ratio of 20 % throughout the rest of the year.

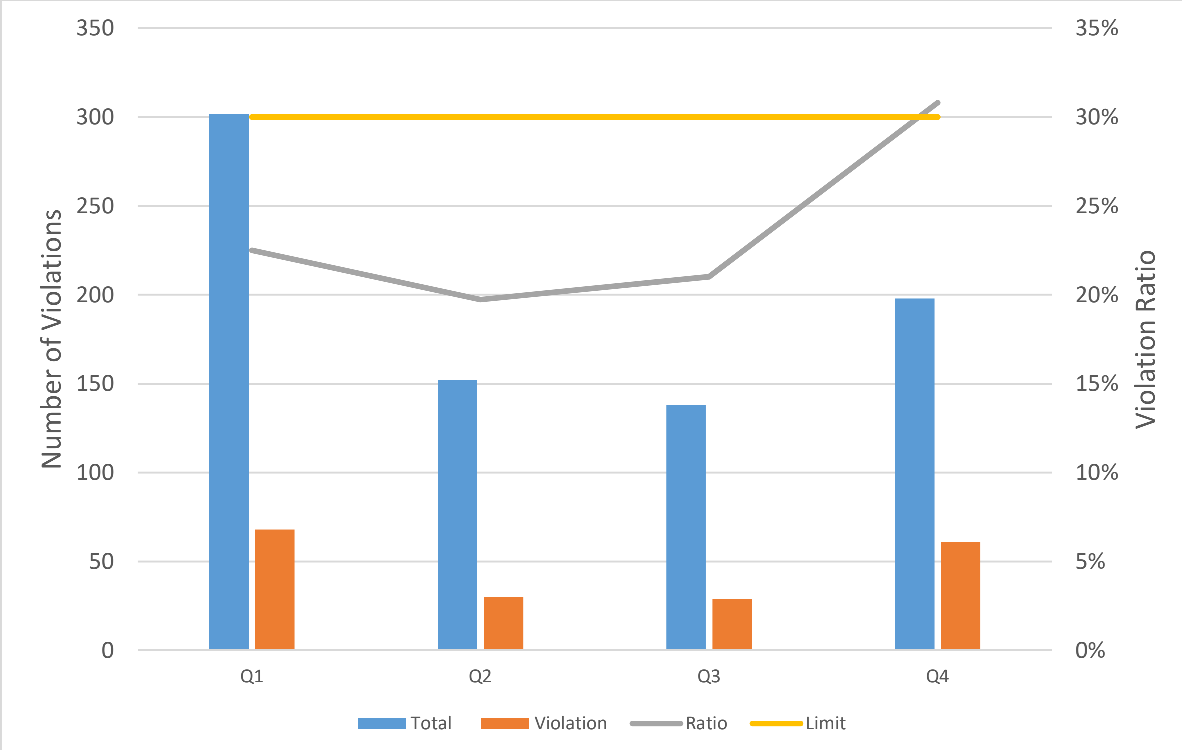


Figure 35 Monitoring of violations and Belgian contribution per quarter in 2019

Figure 35 illustrates the total violations per quarter in 2019 (the monitoring is done on quarterly basis), it is visible that the highest number of DfD are reported in the winter period in Q1 and Q4. Similarly the contribution of the Belgian control block (violation of the maximum ACE limit during the DfD) is also higher during winter period. This could be seen more in details in the below figure as the highest reported DfDs and Belgian violation are well correlated to the cold period characterised by higher cross-border exchanges.

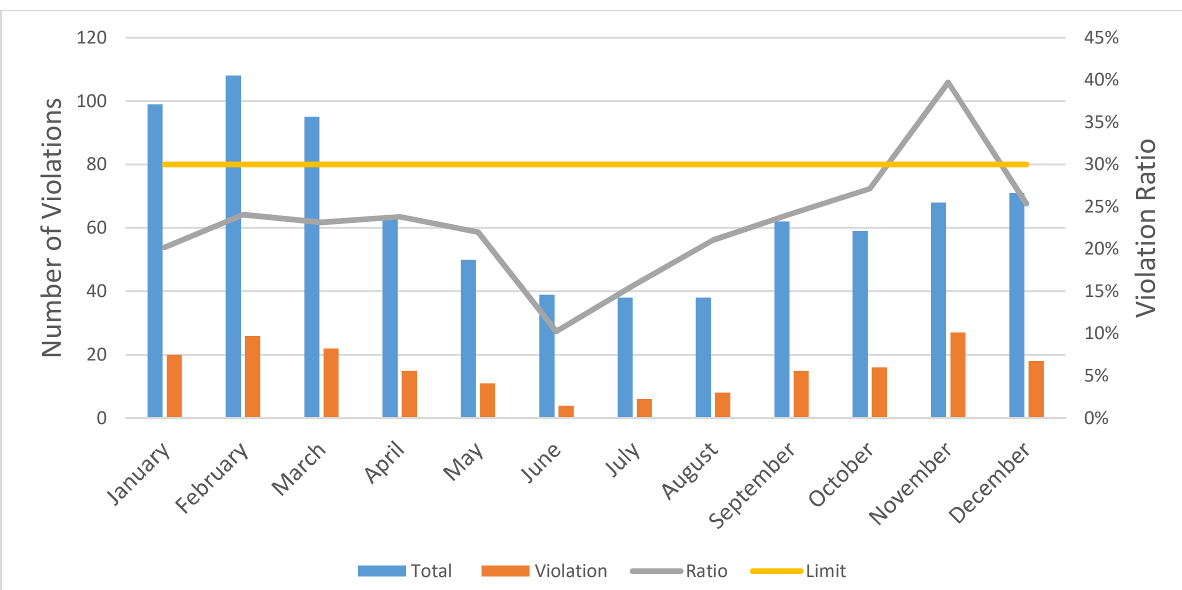


Figure 36 Monitoring of violations and Belgian contribution per month in 2019

Figure 36 illustrates the evolution of DfD occurrence and respective violations, where the ratio (curve in grey) is used as compliance threshold. It can be observed as per the trends in the quarterly data that cold period which is correlated to higher energy exchanges. The average of violation ratio for 2019 is around 23 %, while such value is lower than the preliminary target of 30 %. It is nevertheless important to precise that the target is assessed on quarterly basis which would imply observation of violation in the Q4 as the ratio was above 30 %. Within the cold period the ratio of violation remains relatively stable (from September to April) except for November where a higher ratio is observed and could be explained by the relatively higher shifts in schedule changes during the observed DfD violations. Furthermore, comparing the statistics of November to a similar month of December higher ratio of Belgian violation is observed, such increase would provide a hint on the contributing elements. In fact the Figure 37 shows clearly that higher shifts in term of Gas production has been observed in the month of November comparing to December. The shift illustrated in the Figure 37 are calculated as the cumulative sum of the absolute value of the observed hour shifts of Gas production. Such observation means that the higher we observe shift in Gas hourly schedule the higher is the probability to have a violation in term of imbalance in the Belgian control block.

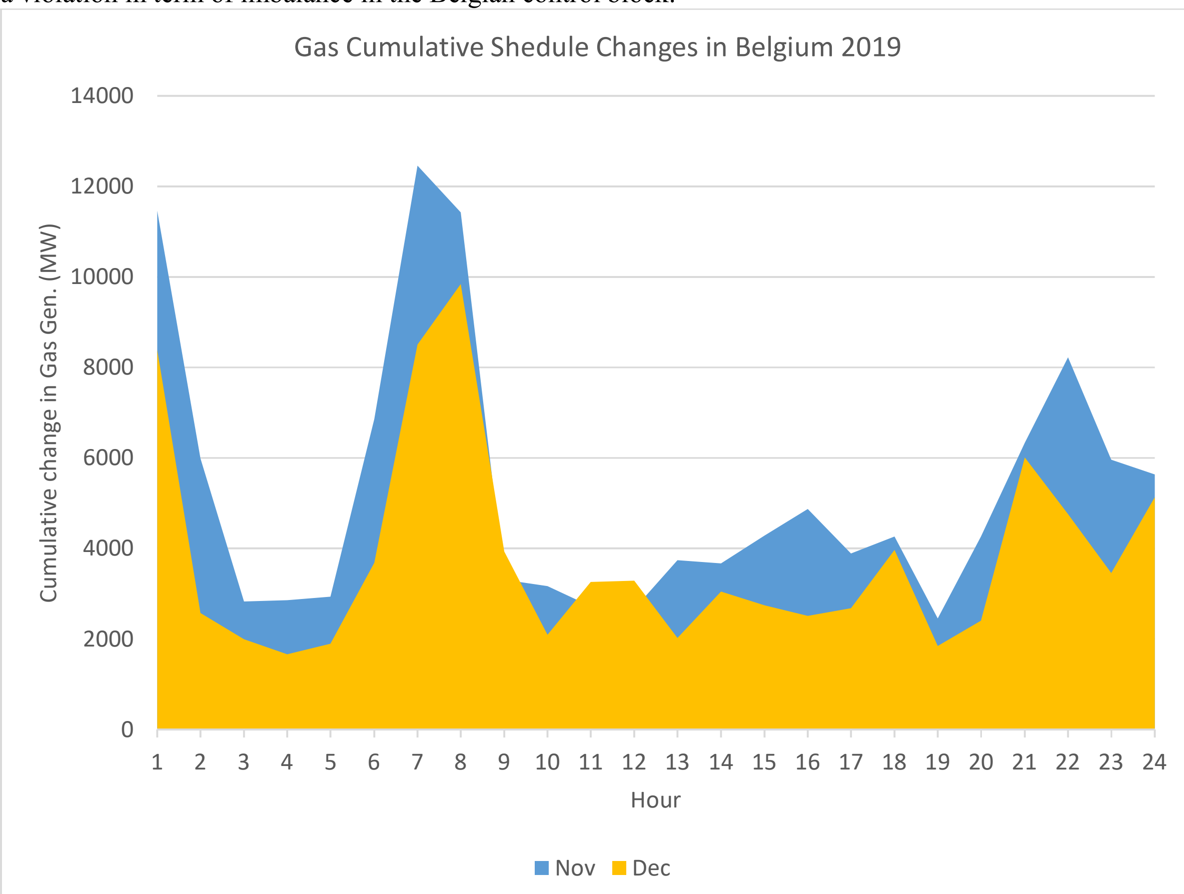


Figure 37 Cumulative absolute hour shifts of Gas production in the Belgian control block in November and December

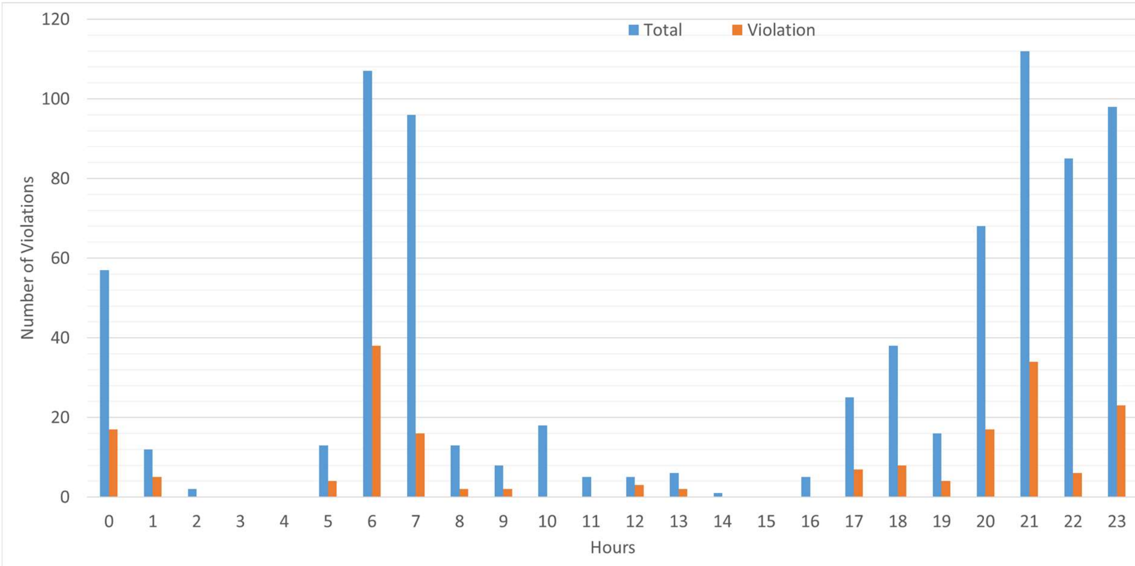


Figure 38 Monitoring of violations and Belgian contribution per month in 2019

Figure 38 illustrates the reported DfDs and the respective Belgian contribution per hourly distribution, which are in line with the typical DfDs timing as they occur either early in the morning or in the evening following the important demand hour shifts. Violations are both observed in over frequency events as well as under-frequency events.

The hourly statistics depicted in the Figure 38, shows as well a higher violation rate typically observed in the morning hour shift at 6 am as well as the evening hour shift of 21:00. This is quite in line with the expected general behaviour of DfDs as it can be observed in the Figure 10 CE level throughout the past years. The tendency is also confirmed in the Belgian LFC where the likelihood of a violation is higher during such DfDs. The occurrence can be explained by looking at the correlation between these specific hours and their respective schedule shifts for Gas and Hydro pumped generation and storage throughout the year in general and more distinctively during the winter period as illustrated below.

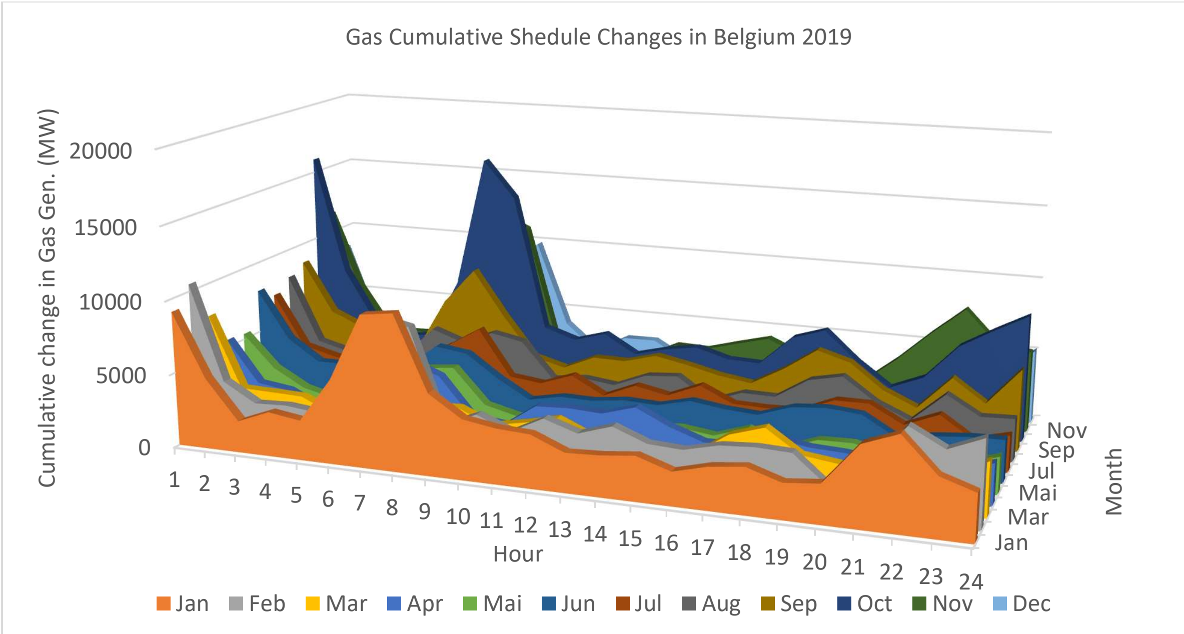
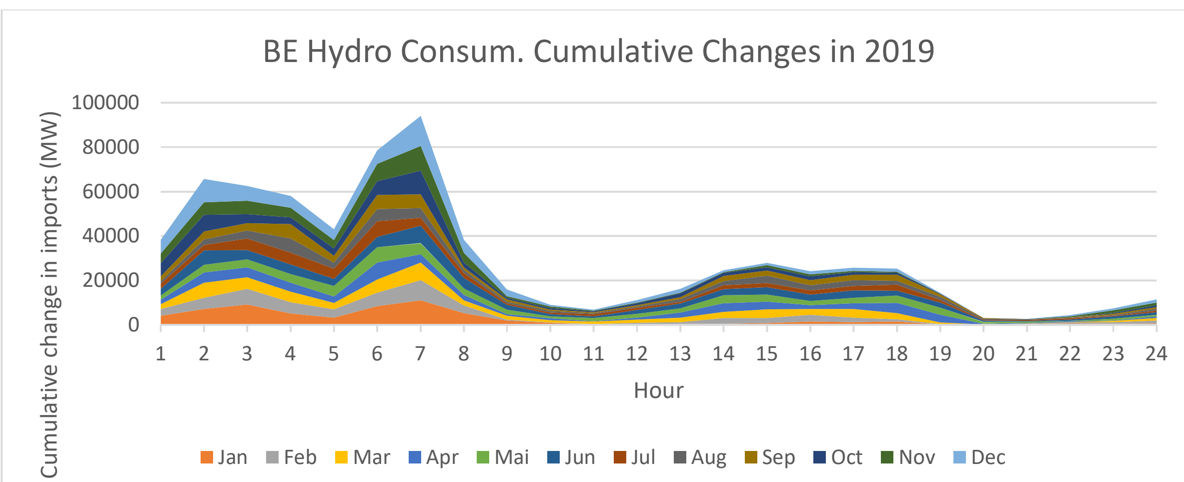


Figure 39 Cumulative absolute hour shifts of Gas production in the Belgian control block in 2019

Figure 39 illustrates throughout the year 2019 the cumulative absolute value of power generation shifts for gas production, we can observe higher shifts at hour 6 am and 9 pm specifically during the winter period. The same observation remains valid as well if we consider the shifts that are observed for the Hydro-pump schedule changes, where early morning and evening violations are respectively linked to shifts in generation and consumption as depicted in the below Figure 40.



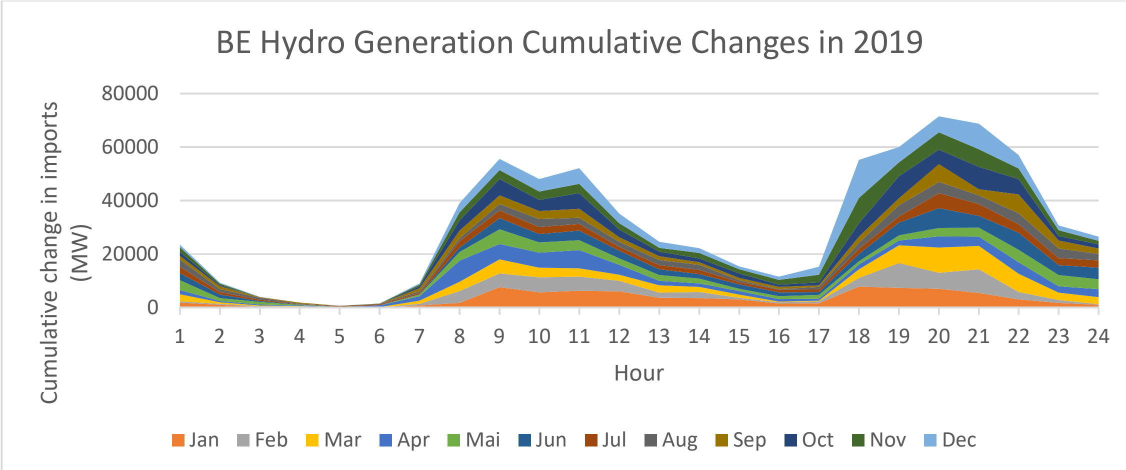
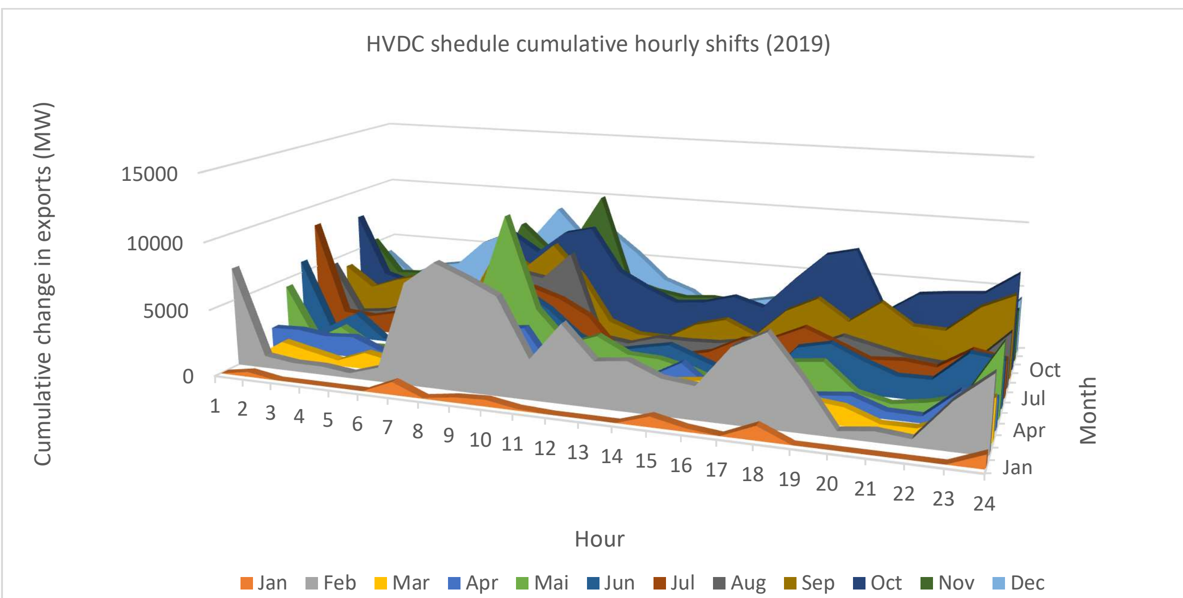


Figure 40 Cumulative absolute hour shifts of Hydro consumption and generation in the Belgian control block in 2019

It is clear from the above overview that for the Gas production and Hydro schedule change a clear correlation between possible violations in the Belgian LFC block and the cumulative schedule changes both in term of time occurrence (hours) and period (month and season) is identified. On the other hand, limited correlation can be also observed considering shifts for Nemo schedule, this could be explained by the relation between the schedule initiation and the planned shift volume and relevance of the direction of the shift. In fact, a large shift requires an earlier initiation (comparing to smaller shift) of the schedule. This large shift would not necessarily be more challenging than compensating a smaller shift as in such case this would allow more time to initiate the follow-up ramping rate for the respective BRP.



5 Possible solutions

5.1 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.

(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.

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.

5.2 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.

5.2.1 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.[5] 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 only 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 (SIDC) 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 SIDC 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 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.

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

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 SIDC. 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.

Efficiency of the measure to reduce DFD

This solution was simulated in the entso-e report on DFD 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.

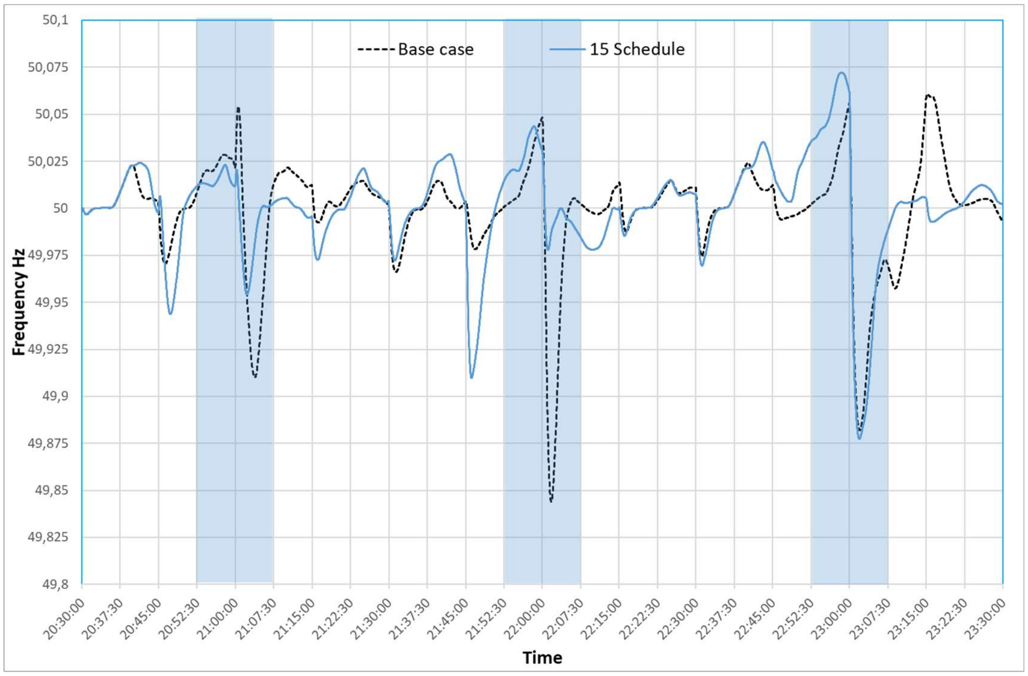


Fig. 42 – Simulated frequency profile of the 15 min MTU compared to the reference base case scenario profile

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.

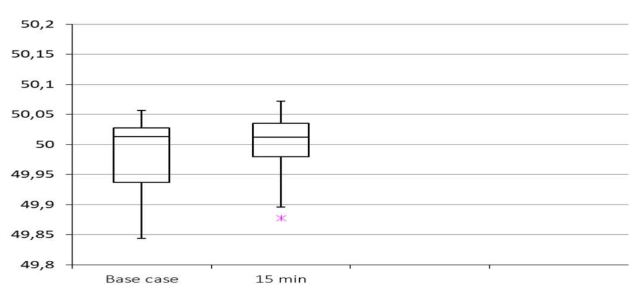


Fig. 43 – Box-whisker plot 15 min MTU comparing to the reference base case scenario profile

<u>Implementation planning</u>

The MTU of the ID cross-border markets is currently 1 hour for the Belgian borders. The objective is to implement:

- A 15' MTU for continuous trading for the BE-NL border
- A 15' MTU for continuous trading for the BE-DE border (new connection going live Q4 2020)
- A 30' MTU for continuous trading for the BE-FR border

A 2 steps approach will be followed

- Implementation of MTU 15' (30' for BE-FR) with 24 gates in Q4 2020
- Implementation of MTU 15' (30' for BE-FR) with 96 gates in 2021

It's to be noted that there are some uncertainties remaining on the border BE-GB.

<u>Cost of the measure for Belgian control block</u>

Considering that:

- The ISP is already 15 minutes in Belgium ;
- The already planned evolution to a 15' MTU for the Intraday cross-border market is a legal obligation,

the costs of this measure are not developed here.

5.2.2 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).

<u>Merits:</u>

- 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
- Needs to be compensated in the balancing mechanism as foreseen in art 18.6(l) of EBGL
- Requires technical adaptation for both TSOs and BRPs (operations, IT)
- 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 are needed, as well as regulatory approval.

Efficiency of the measure to reduce DFD

In order to simulate ramping, we have put a maximum ramping of 5 MW / sec on all BRPs 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.

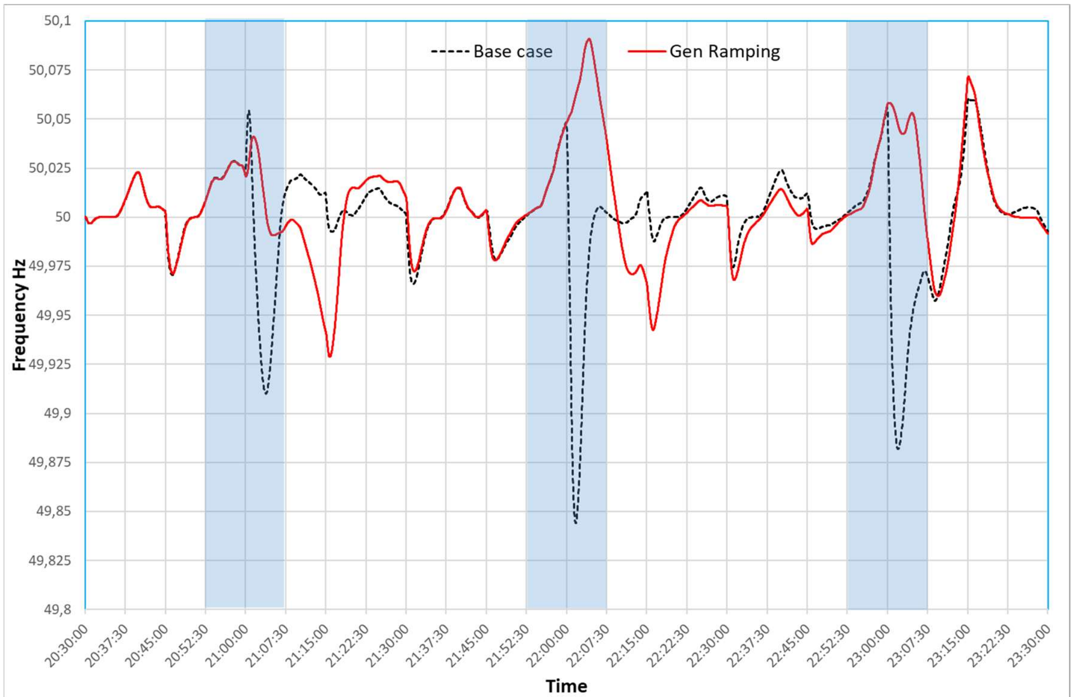


Fig. 52 – Simulated frequency profile of the ramping on generation case compared to the reference base case scenario profile

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.

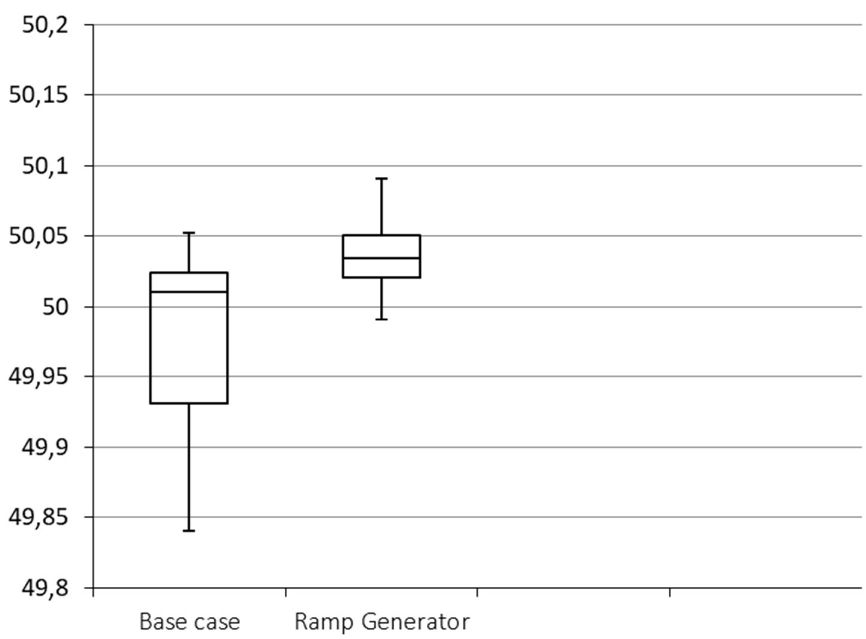


Fig. 53 – Box-whisker plot of the ramping on generation case and the reference base case scenario profile

<u>Impact of the measure for Belgian control block</u>

- As allowed by the BRP contract, market parties may deviate from their balance to “help” the system balance. Imposing a ramping restriction would not be aligned with Elia's efforts to incentivize BRPs to react to (close to) real-time prices

- The need to compensate the BRPs introduces an additional complexity, especially in a portfolio bidding scheme.
- It's unclear for Elia whether the process & tools and /or the bidding strategies of the BRPs would be impacted. Elia welcomes market parties to provide input on this question.

As a conclusion, it is proposed not to use this mitigation measure.

5.3 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.

5.3.1 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.

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 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)
- 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.

Efficiency of the measure to reduce DFD

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.

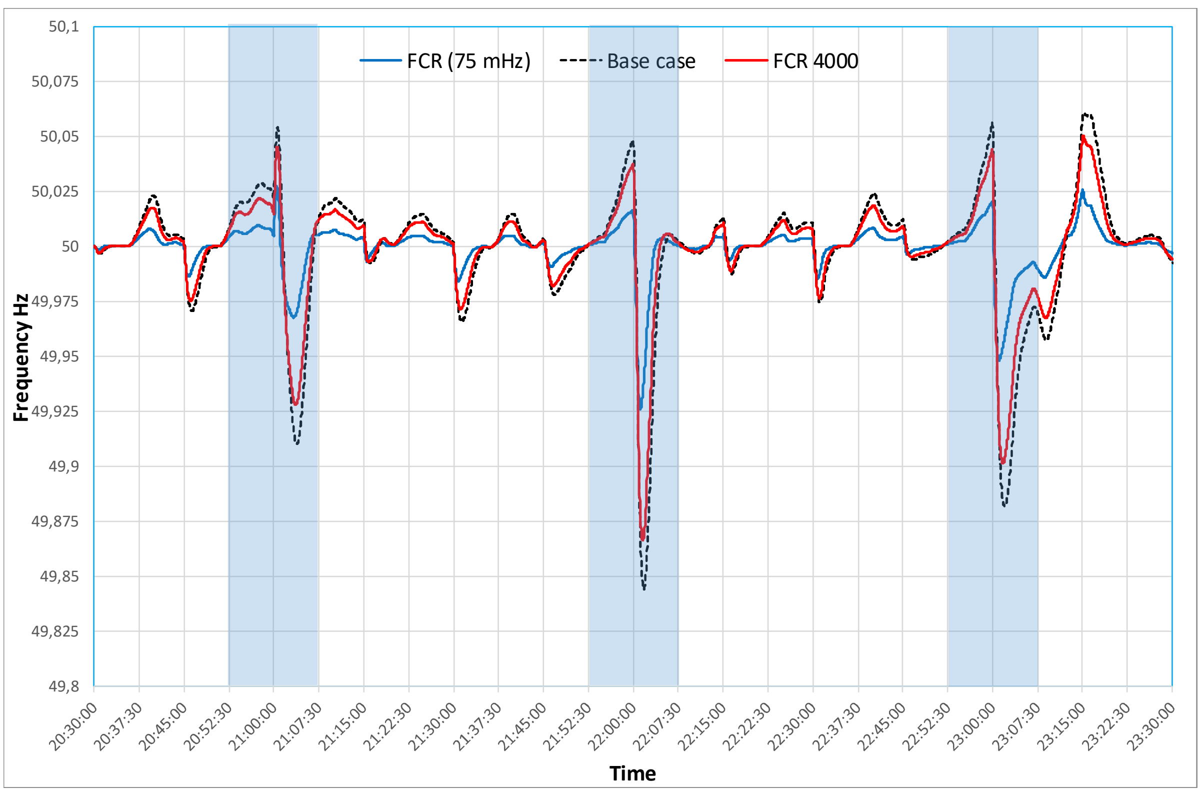


Fig. 46 – Simulated frequency profile of the FCR increase cases compared to the reference base case scenario profile

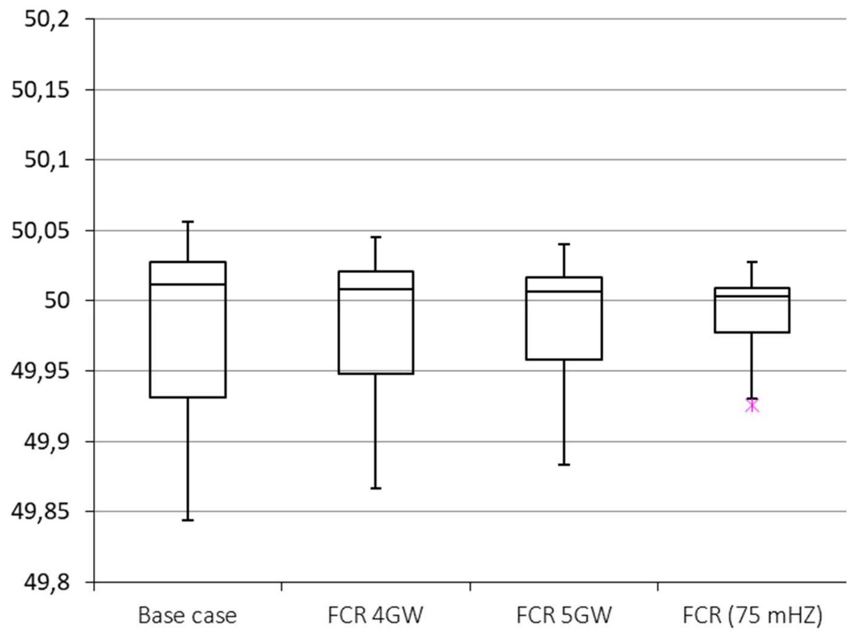


Fig. 47 – Box-whisker plot of the FCR increase and the reference base case scenario profile

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.

Impact of the measure for Belgian control block

Depending on the years, Elia provides about 3% of the total FCR volume of the CE SA.

Focusing on the alternative which shows the biggest improvement of DFDs (the new product operating between +/- 75mHz), the expected impact for the Belgian control block would be the following

- An increase of FCR volume to be procured from about 80MW to 145MW. As the additional bids selected would be at the end of the merit order, this could result in more than a doubling of the procurement costs. This could however be mitigated if the capacity is only contracted for some specific moments during the day.
- A new product would need to be developed, preferably at the Synchronous Area level if several TSOs intend to use this mitigation measures. This would lead to high implementation costs for Elia and for the BSPs and to a long implementation time

As a conclusion, it is proposed not to use this mitigation measure. Such measure, by nature would help the the containment of the frequency but would not mitigate potential ACE violation in the Belgian LFC block as it would be neutralised by the k-factor. Nevertheless, it is important also to mention that such measure could be requested from non-compliant LFC blocks with respect to the fixed maximum violation ratio.

5.3.2 FRR activations based on system imbalance prediction algorithms

Given the analysis performed on the contribution of Belgian control area to the DFD, we see some patterns appearing which are worth to be developed.

For instance the change of set-point on the NEMO cable is currently not performed on a 10 minute interval like the schedule changes on the other borders (ramping for 5 minutes before the change of MTU until 5 minutes after change of MTU), but rather at a constant rate of 100 MW per minute. This causes predictable deviations on the Belgian FRCE.

Also we see, especially during the hour changes with large DFD that there is a delay in reaction of market parties in general. There is a tendency to stick to the schedule of the previous hour until the end of the hour and then only to start adapting programs to adapt to the new schedules sometimes with 5 to 10 minutes delay. This also causes a large deviation on the FRCE of the Belgian control area.

Finally, experience have shown that aFRR is sometimes activated in the opposite direction of the DFD at the beginning of the quarter-hour. This is illustrated in Figure 16 and is explained by the typical behavior of the DFDs. The adaptation of the anti-windup function will shorten the lag, but the deactivation time of the units still need to be taken into account.

The proposal here could be to use a prediction algorithm to estimate the system imbalance that can be expected in the minutes following the change of MTU, for those hours where large DFD are expected. On this basis, in order to reduce the FRCE deviation, ELIA could

- Preventively activate a corresponding amount of mFRR and/or
- Use the Frozen Mode or the Manual Control Mode of the LFC[6].

It's to be noted that a study on system imbalance prediction algorithm is proposed in the framework of the incentives 2021.

Merits:

- The measure will reduce the FRCE deviation and thus the contribution of the Belgian control area to the DFD
- The activation of mFRR and the activation of additional aFRR will increase the imbalance price for the first quarter after the change of the hour, and thus provide an additional incentive to all market parties to reduce their imbalances at that time, which is at the time of DFD occurrence. This should also reduce the contribution of the Belgian control area to DFD.
- Using the manual control mode of the LFC output (or at least a frozen control mode) would allow to optimise the use of aFRR reserves during DFDs. Combined with preventive mFRR activations, it would prevent costly and counterproductive neutralization of the mFRR activation by aFRR before the change of hour.

Issues:

- The feasibility of the development of a rigorous and transparent prediction algorithm still needs to be confirmed.
- The activation of mFRR would start before the change of hour to have a significant volume activated at the peak of the DFD. These activations could give incorrect signals to the market before the change of hour. This would need to be further investigated if it appears that a prediction algorithm can be used.

Timeline:

- Can be implemented relatively quickly. Current balancing mechanisms can be used for this mitigation measure. There is just the time needed to develop the prediction algorithm which will be used as an aid to the system operator at Elia to decide on the amount of mFRR to activate to reduce DFD.

Efficiency of the measure to reduce DFD

It is very difficult to simulate the effect of this mitigation measure.

One can assume that this measure will indeed assist to reduce the FRCE of the Belgian Control Area during a DFD. The possible effect or reduction could be anywhere between 10 to 50 % of the FRCE depending on the amount of reserves activated at the moment that the DFD reaches its deepest point, which is usually around 2 minutes after the change of the hour.

[6] These modes are described in the Synchronous Area Framework Agreement (SAFA), Article B-6.

Cost of the measure for Belgian control block

There are no significant implementation costs associated to this measure, as the prediction algorithms would not be used only for DFDs and would be developed outside of the scope of this project.

The cost for the system will depend on the implementation choices. In general, a better usage of reserves is expected to have a positive impact on costs.

5.3.3 Faster acting Reserves to increase the inertia

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)

This option is indeed on the table but has to be aligned with the current FCR design. Batteries can indeed be used for fast(er) frequency response in order to further reduce the fastest DFD and this option is under investigation on entso-e level.

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.

Efficiency of the measure to reduce DFD

At this time it is too early to estimate the efficiency of this option as DFDs have not yet reached the limit of FCR activation time.

Once DFDs start changing faster than the FCR is able to reply, the effect of this mitigation measure will be huge.

Cost of the measure for Belgian control block

A new product needs to be developed, preferably at the Synchronous Area level if several TSOs intend to use this mitigation measures. Next to the discussions between TSOs and the approval of NRAs that it would require, the development of a fully new product requires extensive process and IT developments for the TSOs and for the BSPs.

5.3.4 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.

Efficiency of the measure to reduce DFD

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).

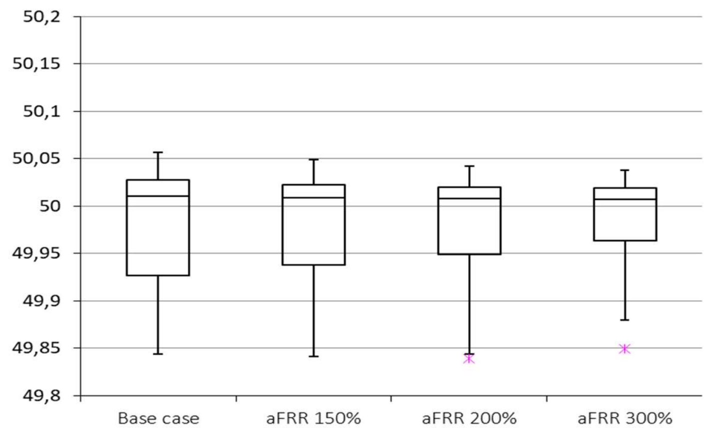


Fig. 49 – Box-whisker plot of the aFRR increase and the reference base case scenario profile

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.

<u>**Impact of the measure for Belgian control block**</u>

Increasing aFRR volumes would not require a modification of the tools for Elia, nor for the BSPs. It would however require to determine how the volume increase is quantified in the aFRR dimensioning methodology. It is to be noted that aFRR volumes will be fixed for blocks of 4 hours.

If we assume that the additional reserved aFRR will be compensated by a decrease by the same volume of reserved mFRR, the additional procurement costs will be the difference between the aFRR and mFRR capacity prices (at the end of the merit orders).

5.3.5 "FAT approach" for aFRR activation

The activation method for aFRR currently used within Elia is the ramping approach. This means that Elia sends a ramped signal to the BSP for the accepted bids and that the BSP is requested to closely follow this signal within a limited band. This is illustrated in Fig. 50.

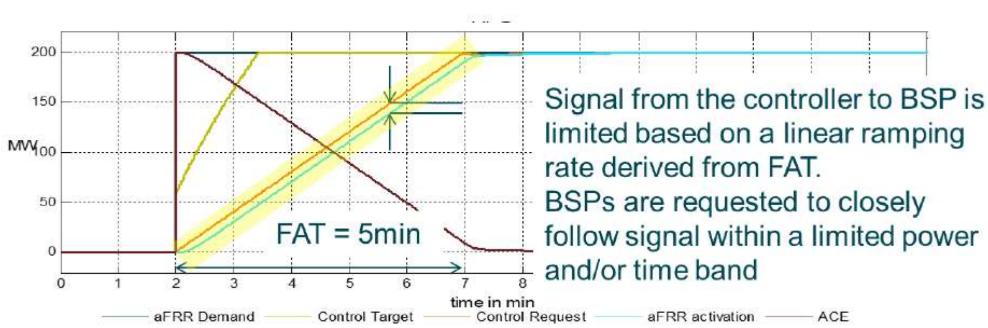


Fig. 50 – aFRR activation method: ramping approach

An alternative to this activation method is the "FAT approach", in which volume requested by LFC controller is directly sent to BSP, without taking into account BSP capabilities. This is illustrated in Fig. 51.

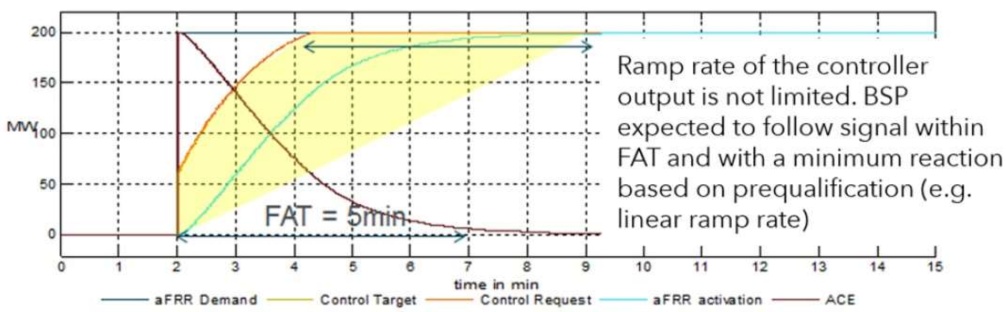


Fig. 51 – aFRR activation method: FAT approach

The ramping approach is well fitted when the aFRR delivering units have limited ramping capabilities. The BSP response is predictable and the settlement is easier to implement. When more reactive units are participating to the aFRR product, the FAT approach can improve the balancing quality, especially in case of fast evolving demand.

Merits:

- Allows potentially a better balancing quality without significant cost increase

Issues:

- Need for Elia to adapt the BSP activation method, as well as the settlement and penalties
- Need for BSPs to adapt their processes and tools
- Only relevant if a significant amount of fast reacting units deliver aFRR

5.3.6 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 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.

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.
- NRA validation will be needed
- Only relevant if other SAs don't have DFDs at the same moments

Timeline:

- Several months, would also depend on the concerned TSOs and the approval process

5.4 Other possible mitigation measures which have been discarded for the Belgian control area

Ramping on load and generation schedules

This mitigation measure is very invasive in the market design as it changes completely the way that power is scheduled in the market. Given that simulations show that there is only a limited improvement from this option, we propose not to analyze it further in the Belgian context, as there are several other mitigation measures which are much more promising. Such measures, would require discussion at synchronous area level due to the possible impact on other LFC block.

Limit net position changes between MTU

We believe that it is not a good idea to limit schedule changes between different MTU. Several elements of the BRP portfolio can change significantly (for instance and especially a change in wind infeed) between one MTU and the next, that it would be wrong to forbid a BRP to follow the changes in its portfolio in its scheduling. A limit on changes in schedules could lead to a BRP being forced to be imbalanced as it cannot close its portfolio on the market.

Balancing products on a 15 minute basis

This is already implemented in Belgium

Use of higher K factor in AGC

It has been shown in the simulations performed by entso-e that this mitigation does not help to reduce DFD so we have discarded it

Introduction of Spot Power Balancing

This is contrary to current market design and has been discarded

Use changes between ISP for BRPs as market based aFRR

This mitigation is currently still a purely theoretical proposal which according to our analysis cannot be implemented in Belgium and furthermore we do not see how it would assist in reducing the DFD. So we discarded this option

Dynamic Frequency Setpoint

This option is currently under investigation in an entso-e task force, but for now this can not yet be proposed as a possible improvement until entso-e finalizes its investigation.

Anyway this is a European wide mitigation measure which we cannot propose solely for the Belgian control area

The size of the large LFC Blocks could be questioned.

This option is according to us out of scope of the current investigation. We can transmit this mitigation option to entso-e for SF sg to investigate it, but we propose to leave it out of the current study.

6 Preliminary conclusions for Belgian control area

The preferred solution is moving towards a 15-minute Market Time Unit (MTU) in a stepwise manner, at the international level and for 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 4.2.1 of this report.

Following solutions are worthy to be investigated and could complement the main proposed solution in order to reduce the participation of Belgium control area to the DFDs even further

- Activation of mFRR and/or tuning of LFC output on the basis of system imbalance prediction algorithms at the change of the MTU when there is an expectation (prediction) that the imbalance of the Belgian control area could be large during the following MTU. (section 5.3.2). Elia intends to thoroughly investigate the predictive algorithms in the coming year.
- Discussion with owner of fast acting production units to try to spread the starting and stopping of such units over a longer period of time and to avoid stopping or starting a set of fast acting units at the same time. (section 5.2.2)

The mutual support from other synchronous areas (section 5.3.6) will actually be implemented by entso-e and will be as such one additional measure to reduce DFD in Continental Europe. This will however not have an effect on the Belgian control area contribution.

The alignment of the ramping speed on HVDC with the ramping of cross-border inter-TSO schedules inside continental Europe will be further investigated by a inter-synchronous area task force under entso-e, which can be expected to deliver proposals during the next year.

References

[1] "UCTE Ad Hoc Group Frequency Quality Investigation Final report – September 2008".

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[3] "Deterministic frequency deviations – root causes and proposals for potential solutions – Joint Eurelectric – entso-e response paper -," December 2011.

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[9] "ENTSO-E AdHoc Team Quarter hour products as long term solution for Deterministic Frequency deviations," 2014.

[10] "Note on Dynamic Frequency Setpoint," Erik Orum, Lasse Borup, energinet, February 2014 .

[11] "Deterministic Frequency Deviations - Facts and Graphs -," June 2017.