» Continental Europe Synchronous Area Separation on 08 January 2021

ICS Investigation Expert Panel » Final Report » 15 July 2021

Main Report

Disclaimer

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This Final Report presents facts and analyses of the sequence of the events and where necessary consequent recommendations. It is not the intention of the Expert Panel to express judgements which may prejudice the assessment of liability of any TSO, third party or person. Even if not explicitly stated, the analyses and the simulations presented in this report are based on information provided by the TSOs. No audit was done. Everything expressed in this report refers to the specific events and its findings will not constitute any binding general reference to the involved TSOs or other parties mentioned in the report.

Expert Panel Members

Frank Reyer	Amprion, Expert Panel Chair
Tahir Kapetanovic	APG & Chair of the ENTSO-E System Operations Committee
Brendan Lyons	NGESO & ENTSO-E Steering Group Operations Convenor and ICS representative
Laurent Rosseel	RTE & ENTSO-E Regional Group CE Convener and representative of the affected TSOs
Jens Møller Birkebæk	Nordic RSC & Representative of the six RSCs
Mihai Cremenescu	Transelectrica & representative of TSO at system separation line
Danko Blazevic	HOPS & representative of TSO at system separation line
Dusko Anicic	EMS & representative of TSO at system separation line
Gjorgji Shemov	ENTSO-E Secretariat
Ioannis Theologitis	ENTSO-E Secretariat
Uros Gabrijel	ACER
Maria Barroso Gomes	ACER
Francois Beaude	ACER
Stefano Bracco	ACER
Vincenzo Trovato	ACER
Jochen Gerlach	BNetzA, German NRA
Nicolas Krieger	BNetzA, German NRA
Pierrick Muller	CRE, French NRA
Julio Quintela Casal	CRE, French NRA
Jacques De Saint Pierre	CRE, French NRA
Francesco Cariello	Arera, Italian NRA
Marco Pasquadibisceglie	Arera, Italian NRA
Rodrigo Mangas Calvo	CNMC, Spanish NRA
Zsolt Topa	MEKH, Hungarian NRA
Dániel Szendy	MEKH, Hungarian NRA
Marko Poljak	HERA, Croatian NRA
Katharina Bauer	E-control, Austrian NRA
Alina Poanta	ANRE, Romanian NRA

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Introduction

Background

On 08 January 2021 at 14:05 Central European Time (CET), the Continental Synchronous Area in Europe was separated into two areas (the north-west area and the south-east area) due to the tripping of several transmission network elements. The system separation resulted in a deficit of power in the north-west area and a surplus of power in the south-east area, leading in turn to a frequency decrease in the north-west area and a frequency increase in the south-east area.

The automatic response and the coordinated actions taken by the Transmission System Operators (TSOs) in Continental Europe ensured that the situation was quickly restored close to normal operation. Resynchronisation of the north-west and south-east areas was achieved at 15:08 CET.

Based on the legal obligations in the System Operation Guideline (SO GL), a mandatory classification of the incident according to the Incident Classification Scale (ICS) methodology has been performed. Following the classification of the incident, an expert investigation panel with TSOs, National Regulatory Authorities (NRAs) and Agency for the Cooperation of Energy Regulators (ACER) was established on 04 March 2021.

Classification of the incident according to ICS Methodology

The following analysis was performed based on the analysis of the incident, which will later be described in greater detail.

The event started with flows that were higher than had been foreseen in the grid models. This higher flow resulted in an N-state overload on the busbar coupler of Ernestinovo (classification ON2). The reason for this classification is that there was at least one wide area deviation from operational security limits after the activation of curative remedial action(s) in N situation. The overloaded busbar tripped, and thereafter several other network elements also tripped (classification T2). This criterion was met because there was at least one wide area deviation from operational security limits after the activation of curative remedial action(s) in N situation. There were also wide area consequences on the regional or synchronous area level, resulting in the need to activate at least one measure of the system defence plan. The cascading of several line trips led to the system split (classification RS2). This criterion was met because the separation from the grid involved more than one TSO and because at least one of the split synchronised regions had a load larger than 5 % of the total load before the incident. The splitting of the grid led to a region with over frequency and a region with under frequency. In the region with under frequency, the deviation of more than 200 mHz lasted less than 30 seconds. In the over frequency region, the deviation of more than 200 mHz lasted more than 30 seconds (classification F2). The criterion for an F2 was met because there was an incident leading to frequency degradation (200 mHz for more than 30 seconds).

All aforementioned classifications are scale 2 incidents (extensive incidents) according to the ICS methodology. Furthermore, there were some scale 1 incidents (significant incidents). This covers minor voltage deviations (classification OV1). In addition, only minor losses of load were reported. The largest loss of load was in the Transelectrica grid where approx. 191 MW of load was reported to have been disconnected. This was more than 1 % and less than 10 % of the load in the TSO's control area (classification L1).

The priority of each criterion is shown in Table 1 below, denoted by a number from 1 to 27, where 1 marks the criterion with highest priority and 27 marks the criterion with lowest priority. When an incident meets several criteria, the incident is classified according to the criterion that has the highest priority; however, information regarding all sub-criteria are also collected. The highest criterion from ICS methodology for this incident is thus F2: 'Incidents leading to frequency degradation'.

For incidents of scale 2 and 3, a detailed report must be prepared by an expert panel composed of representatives from TSOs affected by the incident, a leader of the expert panel from a TSO not affected by the incident, relevant RSC(s), a representative of SG ICS, the regulatory authorities and ACER upon request. The ICS annual report must contain the explanations of the reasons for incidents of scale 2 and scale 3 based on the investigation of the incidents according to article 15(5) of SO GL. TSOs affected by the scale 2 and scale 3 incidents must inform their national regulatory authorities before the investigation is launched according to article 15(5) of SO GL. European Network of Transmission System Operators for Electricity (ENTSO-E) must also inform ACER about the upcoming investigation in due time, before it is launched and no later than one week in advance of the first meeting of the expert panel.

Each TSO must report incidents of scale 2 and 3 classified in accordance with the criteria of ICS in the reporting tool by the end of the month following the month in which the incident began, at the latest. As the incident occurred on 08 January 2021, the affected TSOs had to classify the events during this incident according to the ICS methodology before 28 February 2021. An expert investigation panel with TSOs, NRAs and ACER was established on 04 March 2021 and thus now publishes its mandatory final report in adherence to its mandate.

Scale 0 **Noteworthy incident**		**Scale 1** **Significant incident**		**Scale 2** **Extensive incident**		**Scale 3** **Major incident / 1TSO**	
Priority / Short definition (Criterion short code)		**Priority / Short definition (Criterion short code)**		**Priority / Short definition (Criterion short code)**		**Priority / Short definition (Criterion short code)**	
#20	Incidents on load (L0)	#11	Incidents on load (L1)	#2	Incidents on load (L2)	#1	Blackout (OB3)
#21	Incidents leading to frequency degradation (F0)	#12	Incidents leading to frequency degradation (F1)	#3	Incidents leading to frequency degradation (F2)		
#22	Incidents on transmission network elements (T0)	#13	Incidents on transmission network elements (T1)	#4	Incidents on transmission network elements (T2)		
#23	Incidents on power generating facilities (G0)	#14	Incidents on power generating facilities (G1)	#5	Incidents on power generating facilities (G2)		
		#15	N-1 violation (ON1)	#6	N violation (ON2)		
#24	Separation from the grid (RS0)	#16	Separation from the grid (RS1)	#7	Separation from the grid (RS2)		
#25	Violation of standards on voltage (OV0)	#17	Violation of standards on voltage (OV1)	#8	Violation of standards on voltage (OV2)		
#26	Reduction of reserve capacity (RRC0)	#18	Reduction of reserve capacity (RRC1)	#9	Reduction of reserve capacity (RRC2)		
#27	Loss of tools and facilities (LT0)	#19	Loss of tools and facilities (LT1)	#10	Loss of tools and facilities (LT2)		

Table 1: Classification of incidents according to ICS methodology

Structure of the final report

The final report of the ICS expert panel presents an in-depth analysis of the incident on 08 January 2021. On the basis of this in-depth analysis, detailed recommendations are developed where necessary to prevent similar incidents in the future. On this basis, the final report is structured as follows.

Chapter 1 focuses on the system conditions before the incident. In that regard, the present conditions in the transmission system of the affected region, i.e. Balkan Peninsula, at the time of the incident are of special interest in Chapter 1.1. This covers the grid topology and further outages of grid elements in general but also the concrete topology of the substation Ernestinovo as well as the use of overcurrent protection in the substation, which were both crucial for the incident. Chapter 1.2 then outlines the real-time situation prior to the incident, i.e. the load flow situation before 14:00, the alarm handling in the HOPS control room in that time span as well as the load flow situation after 14:00 and directly until the incident after 14:04. As it was deemed of special importance for the incident, the system security calculation provides the focus of Chapter 1.3. This covers general aspects regarding the security calculation, both at TSOs and at regional level. Afterwards there is a dedicated focus on HOPS security calculation on 08 January, whereby results are also further compared in the different time stamps. Chapter 1.4 then summarises certain legal aspects of the incident, which must be further assessed after the publication of the final report. Based on this structure, numerous recommendations have been made, which are presented in detail in the according subchapters.

Chapter 2 outlines the dynamic behaviour of the system during the incident. Thus, the sequence of events that led to the system separation is described in detail in Chapter 2.1. This sequence of events is complemented in Chapter 2.2 by an in-depth analysis of the dynamic stability margin, while Chapter 2.3 summarises the recommendations in relation to dynamic stability and reduction of system inertia.

Chapter 3 considers the frequency support offered directly after the separation. Chapter 3.1 primarily focuses on the activation of frequency containment reserve as an automatic defence measure, but also examines the activated system protection schemes and the frequency support from other synchronous areas. In the course of the event, several generation units and loads were disconnected, which is outlined in Chapter 3.2. This covers both disconnections due to high transients as well as disconnections that occurred a great distance away from the separation line. Finally, Chapter 3.3 offers an in-depth analysis of frequency containment during the system separation. Following the same model as previous chapters, derived recommendations are presented in the respective subchapters.

Chapter 4 describes in detail the TSO coordination during the system separation. To this end, Chapter 4.1 looks at the individual manual countermeasures and the further system stabilisation. Both asynchronous areas are broadly analysed before the focus switches to the activation of automatic frequency restoration reserves. Additionally, the overall operation of load frequency control as well as the impact and the operation of the International Grid Control Cooperation (IGCC) are analysed. Chapter 4.1 further contains a general analysis of the coordinated execution of measures in case of extraordinary disturbances as well as further assessment of the application of relevant articles of the Electricity Emergency and Restoration Network Code. After the stabilisation of the system, the resynchronisation process took place, which is outlined in Chapter 4.2. This covers the preconditions for system resynchronisation as well as the preparatory actions and the resynchronisation sequence. Chapter 4.2 concludes with an analysis of the procedure in case of system separation and resynchronisation of separated grid areas. The communication between the coordination centres and Synchronous Area Monitors as well as the TSOs is of the utmost importance and is outlined in detail in Chapter 4.3. This covers the communication between north and south coordination centres and the affected TSOs, between the affected TSOs in the south-east area and the border region, and between TSOs during a system separation in general. There is then a further focus on the data representation in the ENTSO-E Awareness System, before Chapter 4.3 concludes with an analysis of the application of the relevant articles of the Electricity Emergency and Restoration Network Code.

Chapter 5 outlines the analysed market aspects before and after the incident. This covers both market aspects of system conditions in Continental Europe in Chapter 5.1 as well as in the Balkan Peninsula in Chapter 5.2. Since the capacity calculation is a basis for cross-border trades, its influence is analysed in Chapter 5.3 both on a regional and national level. Chapter 5.4 then focuses on the day-ahead and intraday market schedules, including a comparison with the bilaterally agreed net transfer capacities. Chapter 5 concludes with an analysis of the day-ahead and intraday prices in Chapter 5.5 and the evaluation of market impacts of the incident in selected areas in Chapter 5.6.

The final report concludes with a brief summary of the main findings. This is accompanied by a summary of the derived recommendations. Finally, an overall assessment is presented.

1 System conditions before the incident

This chapter elaborates on the system conditions before the incident. This includes some general considerations of the transmission system of Balkan Peninsula, an in-depth evaluation of the real-time situation on 08 January and also an analysis of the coordinated security analysis at different levels.

1.1 Conditions in the transmission system of Balkan Peninsula

1.1.1 Grid topology of Balkan Peninsula

HOPS operates the 400 kV, 220 kV and 110 kV transmission network in Croatia. This transmission network as well as the interconnection to neighbouring countries is depicted in Figure 1.1.

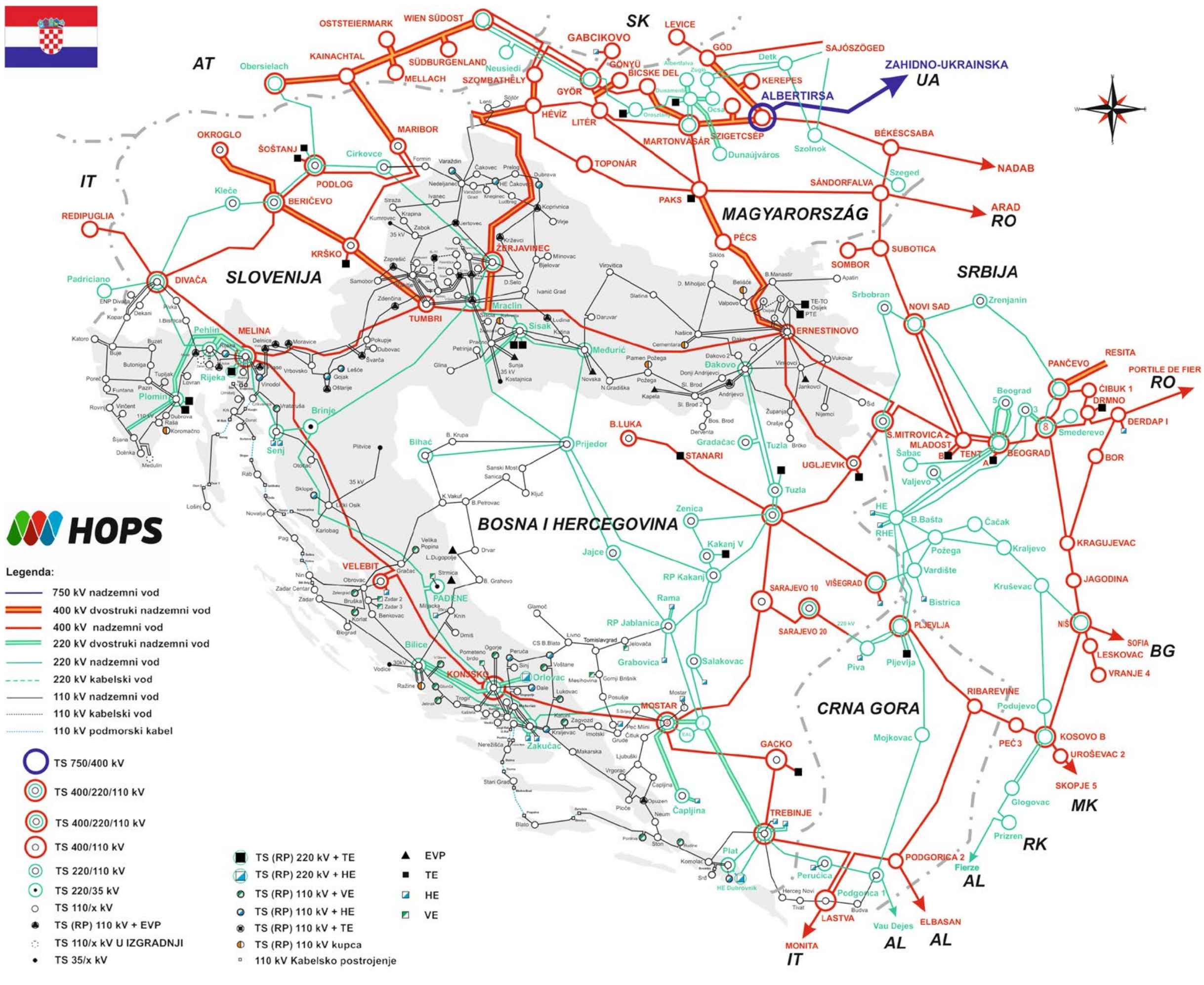


Figure 1.1: 400 kV, 220 kV and 110 kV Transmission Network of HOPS

1.1.2 Scheduled / planned outages of grid elements

HOPS

All outages of transmission lines were considered during the planning phase the day before. The following transmission lines were out of service:

» 400 kV Ernestinovo (HR) – Pecs (HU) 2: line was out of service as of 05 January 2021 due a technical circuit breaker failure in Substation (SS) Ernestinovo,

» 400 kV Žerjavinec (HR)–Heviz (HU) 1: line was switched-off as a corrective measure for voltage reduction as the flow on this line was below the natural load of the line, so it was producing reactive power.

Due to the collective annual leave during the Christmas and New Year holidays, no maintenance work on transmission assets was foreseen in the work plan, and therefore no other lines were out of service.

EMS

Due to the Christmas and New Year holidays, the scope of planned works in the grid was small. No maintenance work was foreseen in the weekly work plan; only 110 kV from SS Majdanpek 1 – SS Majdanpek 2 was switched off due to a circuit breaker failure in SS Majdanpek 1.

Transelectrica

One outage was considered during the planning phase the day before: 400 MVA, 400/220 kV autotransformer in Porțile de Fier substation, due to the refurbishment works (replacement of 400 MVA unit with another one of 500 MVA). On 08 January 2021, there was no further relevant change in Transelectrica grid topology before the occurrence of the incident at 14:05 CET.

1.1.3 Substation topology Ernestinovo

The topology in SS Ernestinovo immediately before the system separation can be seen Figure 1.2.

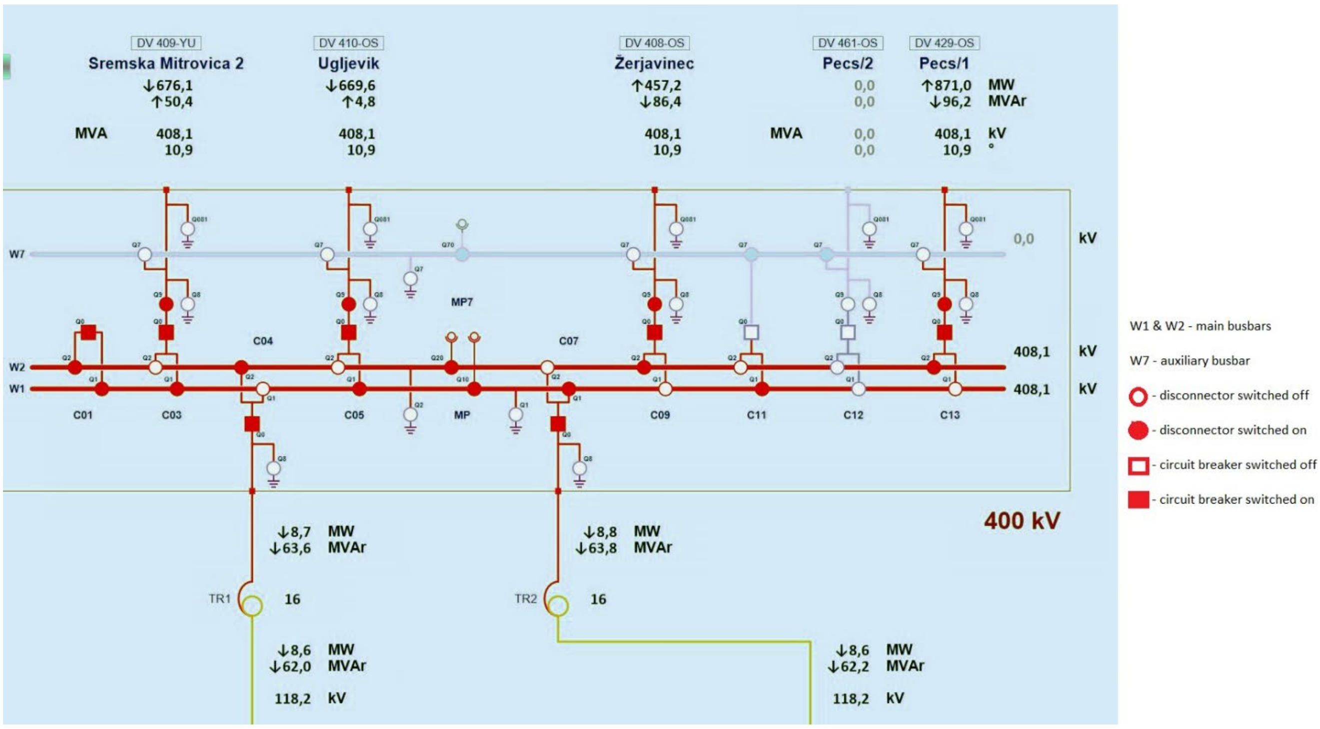


Figure 1.2: Topology in SS Ernestinovo immediately prior to the system separation

HOPS's general rules regarding topology in substations are:

- » All busbars in substations 400/220 kV, 400/110 kV and 220/110 kV are usually permanently connected via busbar couplers
- » In the event there are several transformers 400/220 kV, 400/110 kV and 220/110 kV, they are connected to different busbars at both voltage levels
- » In the event of double circuit lines, one circuit is connected to one busbar and the other circuit is connected to other busbar, e.g. Tumbri – Krško 1 & 2, Žerjavinec – Heviz 1 & 2, Ernestinovo – Pecs 1 & 2
- » Other transmission lines are connected without any special rules.

The general rules are not applied in the event that grid sectioning is frequently performed in a substation; in this case, topology is applied such that for the purpose of sectioning, it is not necessary to perform manipulations other than switching off the busbar coupler.

The topology in SS Ernestinovo always follows the rule that both 400/110 kV transformers (TR1 and TR2) are not connected to the same busbar. The choice of a configuration such as this is usual as the determination of the standard topology of a substation aims at a preferably even distribution of the load considering different aspects such as expected load flows, short circuit stability etc. Furthermore, both 400 kV tie-lines between Ernestinovo and Pecs (no. 1 and no. 2) are not connected to the same busbar. This rule is followed to avoid changing the topology in SS Ernestinovo too frequently and to avoid an additional reduction of the lifetime of transmission assets. Unless any (n-1) violations are detected, the usual topology is thus retained. As no (n-1) violations have been detected before the incident as well as the relatively low flows, the topology was not changed when the line Ernestinovo (HR) – Pecs (HU) 2 was taken out of service on 05 January 2021. If the line Ernestinovo (HR) – Pecs (HU) 2 had been in operation, it would have been coupled to the other busbar in Ernestinovo. The power flow over the busbar coupler would thus have been reduced by 50 % of the power flow on the line Ernestinovo (HR) – Pecs (HU) 1, yielding a hypothetical reduction of 400 MW or 600 A of power flow over the busbar coupler. The other three 400 kV-lines (Ernestinovo – Mitrovica 2, Ernestinovo – Ugljevik and Ernestinovo – Žerjavinec) are connected in different combinations during time. They are, however, never connected to the same busbar. In addition, most of the time, power flows are so low that one circuit of the Ernestinovo – Pecs (1 or 2) is switched off as a measure to prevent overvoltages. In that regard, the general topology, with only one circuit between Ernestinovo and Pecs in operation, is the usual topology.

Recommendation concerning the substation topology

ID	Recommendation	Justification	Responsible
Substation Topology			
R-1	The **substation topology** should be chosen in such a way that the **flow through the busbar coupler is as low as possible**. This should also be reflected in any TSO guidelines within the company where rules for the substation's topology are described.	On the day of the incident the topology led to the flow through the busbar coupler being relatively high and covering the flow of two subsequent transmission lines. A change of the topology of the substation can optimise the flow on the busbar coupler and thus lead to a reduction of the flow. Consequently, a possible outage of the busbar coupler will have a limited impact.	TSOs

1.1.4 Use of overcurrent protection

All 400 kV and 220 kV substations from HOPS that contain more than one main busbar are currently equipped with a busbar coupler, which is protected by an overcurrent protection function. The main purpose of the overcurrent protection function is to protect the high voltage equipment (measuring transformers, circuit breaker and disconnectors) regarding overloads. The measurement of the current through the busbar coupler is also necessary for the protection of the busbars itself, where differential protection is used. This requires measurements at all outgoing lines, couplers or transformers. Considering the nominal data of current measurement transformers, circuit breakers and disconnectors, the nominal current of the current measurement transformer is determined as a relevant (i.e. the most limiting) unit for selecting the overcurrent protection setting. The rated current of the current measurement transformer at the busbar coupler in Ernestinovo is 1,600 A. However, because of the current transformer's thermal rating factor of 1.2, a current transformer permanent loading of 120 %, i.e. 1,920 A, is admitted. However, as is usual for measurement transformers, the defined rated current can be even further exceeded for a certain time period if the transformer has to cope with higher loads. For that purpose, the maximum current was allowed to temporarily reach 130 % of rated current, i.e. yielding a current of 2,080 A, which respectively defined the protection setting at that point. If the current value of the protection device, i.e. 2,080 A, is exceeded for 5 seconds, the circuit breaker of the busbar coupler is opened to protect the current transformer. The timer is reset once the value again falls below the reset value 1,976 A, which was chosen as 5 % lower than the maximum current.

The Supervisory Control And Data Acquisition (SCADA) system of HOPS has alarm settings that warn the operators in case a trip of a transmission network element occurs or the power flow on a transmission network element is beyond a certain threshold. This threshold can be reached either by an overcurrent (overload) in the n-state or a predicted n-1 violation. However, busbar couplers are not monitored in n-1 calculation, as it is explained below in Chapter 1.3.3. Alarms related to overloads on busbar couplers are thus only triggered automatically on the basis of measurements. The values for the busbar couplers in n-1 state have to be calculated manually. The alarm setting and handling is further discussed in Chapter 1.2.2.

Recommendation concerning the setting and exchange of the protection parameters

ID	Recommendation	Justification	Responsible
Setting and exchange of the protection parameters			
R-2	Each TSO must transpose the set points of the protection equipment to **operational security limits**. To coordinate the protection of their transmission systems, neighbouring TSOs **shall exchange the protection set points** of the lines for which the contingencies are included as external contingencies in their contingency lists.	The sharing of the protection set points/operational security limits with regards to the observability area enables all impacted TSOs to realistically assess the system.	TSOs

1.2 Real time situation

1.2.1 Load flow situation before 14:00

The overall load flow situation before 14:00 is further separated into two parts, one covering the Pan-European cross-border load flows and one covering the local load flows, occurring in the affected countries. Both are described below.

1.2.1.1 Pan-European load flow situation

The difference between the actual market schedules and the measured power flows for the timestamp 13:45–14:00 (Source: Vulcanus/Verification Platform) is shown in Figure 1.3. The power flows in a meshed AC-grid are the result of actual state of generation (output and localisation), consumption (profiles and localisation), and transmission network (topology and technical parameters). In a highly meshed AC-grid, it is usual for physical flows to significantly differ from the scheduled exchange programmes. Flows in Direct Current (DC) connections can be fully controlled and changes from scheduled to actual flows can be activated for operational optimisation, as depicted in Figure 1.4 in greater detail for the affected countries.

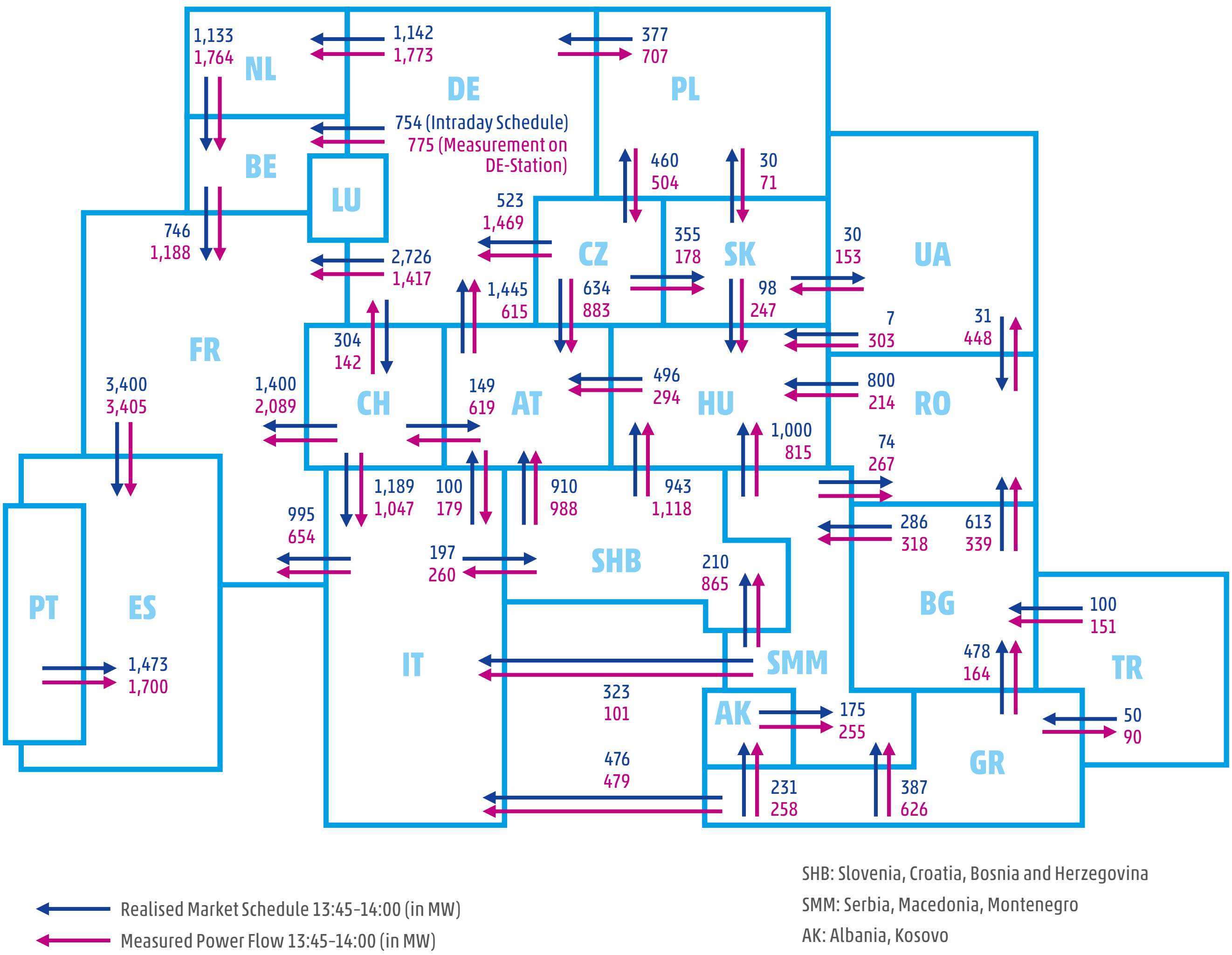


Figure 1.3: Comparison of actual schedules and measured power flows

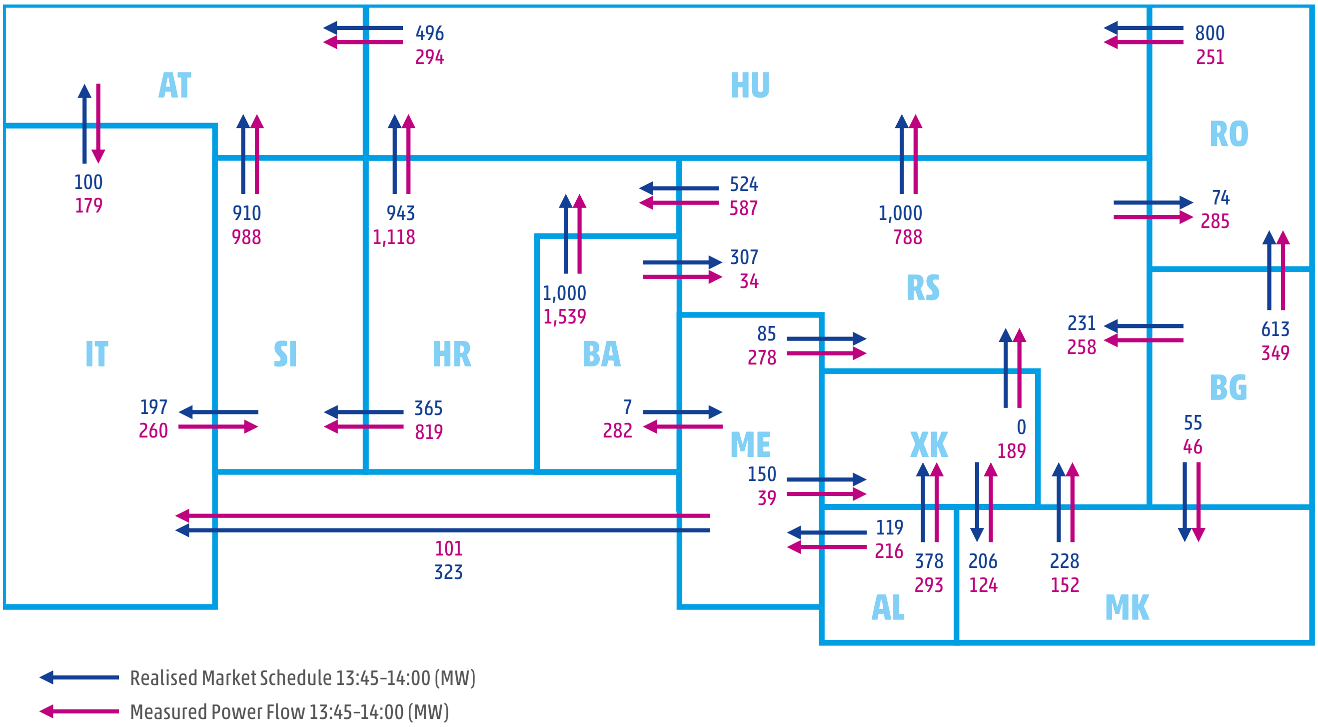


Figure 1.4: Comparison of actual schedules and measured power flows in the affected region for last market unit before the system separation

The resulting net positions as a difference of realised schedule and measures power flow are shown in Table 1.1. It should be noted, however that, first, the schedules and load flows as well as the resulting net position changed after the change of the hour at 14:00 and are thus not directly correlated to the incident. Second, volatile changes in the net positions are usual in today's power system, which is sometimes influenced by IGCC netting. Its direct influence on the incident is further evaluated in chapter 4.1.5. In the context of the net positions in Table 1.1 below (Source: Vulcanus/Verification Platform), Italy, for instance, was mainly netting against France in that time span, so the high net position of Italy was somehow caused by this. However, the netting changed significantly around 14:00 so that no major influence could be established based on this evaluation.

Country	Net Position	Country	Net Position	Country	Net Position	Country	Net Position
Italy (IT)	-716 MW	Slovenia (SI)	81 MW	Serbia (RS)	2 MW	Albania (AL)	-15 MW
Austria (AT)	92 MW	Croatia (HR)	27 MW	Montenegro (ME)	-68 MW	Kosovo (XK)	1 MW
Hungary (HU)	-51 MW	Bosnia-Herzegovina (BA)	-23 MW	Macedonia (MK)	24 MW	Romania (RO)	-26 MW
						Bulgaria (BG)	21 MW

Table 1.1: Net positions of countries from 13:45 to 14:00

To understand the system conditions before the system split, a more detailed analysis is performed at the interconnectors between the affected countries in South East Europe (Serbia, Croatia, Romania) and Central West Europe (Slovenia, Hungary). The analysis of the flow towards Central West Europe is performed by examining the physical flows in the hours 13:00–14:00, both on 07 and 08 January. The day before, the system separation is considered in order to give a comparison. In a final step, the total market flows are compared with the cross-border physical flows. For this purpose, Table 1.2 shows a comparison for the timestamp 13:00–14:00 for both 07 and 08 January (Source: ENTSO-E Transparency Platform). Similar correlations can be seen for the two days under consideration. The physical flows are slightly lower than the total market flows. At the same time, a shift of part of the market flows from RS » HU and RO » HU to physical flows of HR » SI and HR » HU can be observed.

Flows (MW)							
Date	**Type**	**HR » SI**	**HR » HU**	**RS » HU**	**RO » HU**	**RO » WPS**	**Sum**
7 January 13:00 – 14:00	Total Market Flow	676	581	1,000	799	–4	3,052
	CB Physical Flow	869	814	757	223	452	3,105
	Delta	**193**	**233**	**–243**	**–576**	**456**	**63**
8 January 13:00 – 14:00	Total Market Flow	365	943	1,000	800	–31	3,077
	CB Physical Flow	819	1,095	788	251	458	3,400
	Delta	**454**	**152**	**–212**	**–549**	**489**	**334**

Table 1.2: Total Market Flows and Circuit Breakers (CB) Physical Flows from South East Europe to Central West Europe (net values)

1.2.1.2 Regional load flow situation

The regional load flow situation before the incident is evaluated using an analysis of the local load flow situation, caused by generation and load surplus or deficit in the south-east (includes Bosnia and Herzegovina and the south-eastern parts of Croatia, Serbia and Romania) and north-west (includes Hungary and the north-western parts of Croatia, Serbia and Romania) areas of the affected countries, as depicted in Figure 1.5. Consequently, it was established that the south-eastern parts of the affected countries had a generation surplus of approx. 3.25 Gigawatt (GW), whereas the north-western parts of the affected countries had a generation deficit of approx. 2.58 GW.

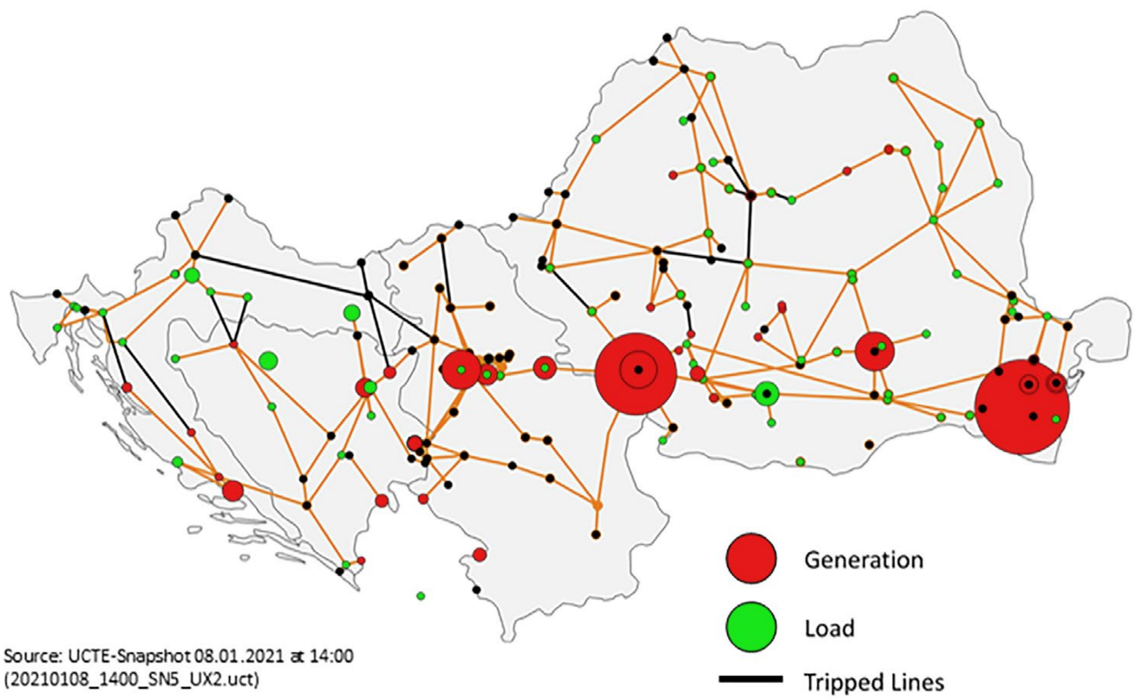


Figure 1.5: Generation and load surplus or deficit in the south-east and north-west areas of the affected countries

1.2.1.3 Overall load flow situation

The overall load flow situation resulted both from the Pan-European load flow and the local load flow. Whereas the first one accounted for 3,400 MW, the latter totalled 2,000 – 2,500 MW, yielding a total load flow of approx. 5,800 MW before the incident. The high load flow and therefore also highly stressed power system constituted itself in high voltage phase angle differences, as illustrated in Figure 1.6, with a corresponding heatmap representation as a result of the collected and merged Continental Europe (CE)-wide area measurements.

Figure 1.6 clearly indicates that the highest voltage phase angle difference is very close to the region where the system separation has occurred. The voltage phase angle heat map is mainly reflecting the quite significant change of the voltage phase angle along a short geographical distance exactly in the region where the system separation has taken place. However, the information shown in Figure 1.6 is a result of post-disturbance analysis based on a limited amount of nodes and its concrete local interpretation might be misleading.

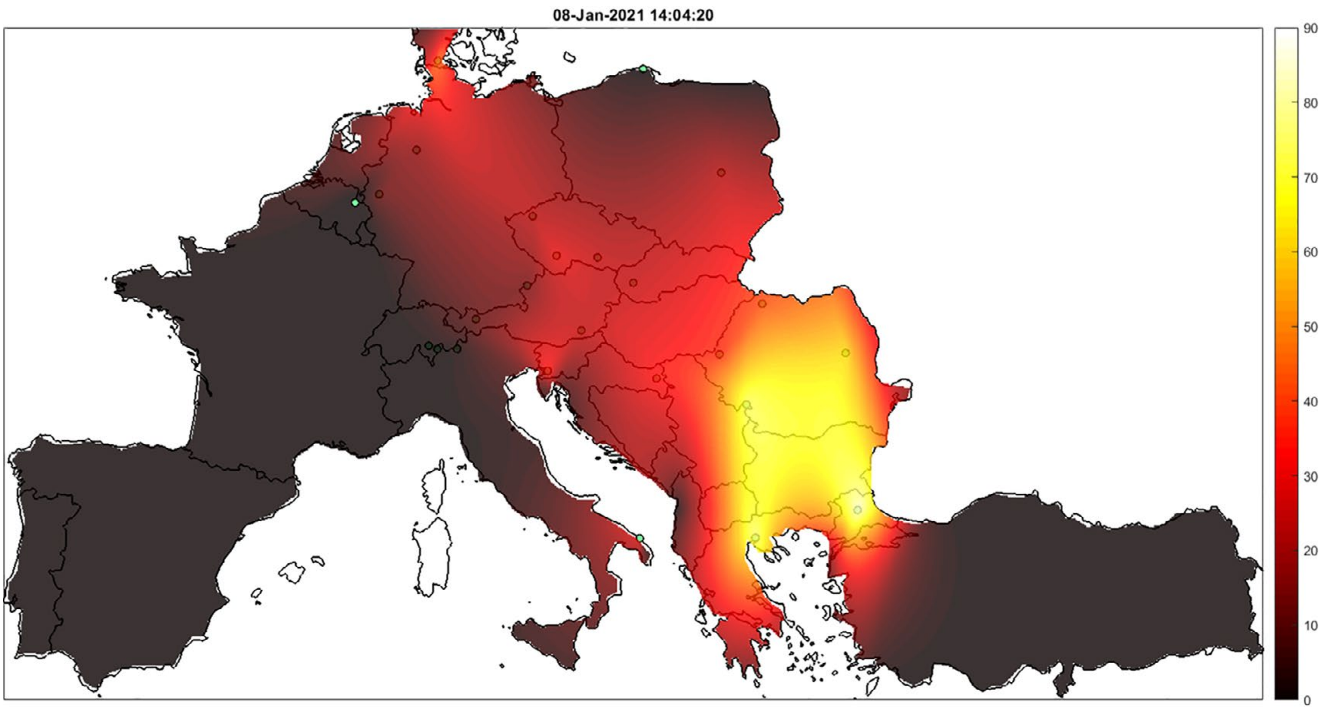


Figure 1.6: Voltage phase angle heat map representation

1.2.2 Alarm handling in HOPS control room before 14:00

1.2.2.1 General alarm handling procedures

According to the requirements of Article 25 of the SO GL, each TSO shall specify the operational security limits for each element of its transmission system, considering short-circuit current limits and current limits in terms of thermal rating, including the transitory admissible overloads. In RG CE Operation Handbook – Policy 3 "Operational Security", TSOs agreed on how to handle alarms in N and N-1 situations. Alarms are generated for different operational thresholds to draw the attention of the dispatcher when the loading or the voltage has reached a certain value ruled by an operational procedure. The corresponding alarm is displayed on the screen of the dispatcher and can activate a bell in the control room. Alarms are generated at least for each tie-line and each 380/400 kV line. For example, some TSOs use the value 90 % of current limit as the threshold for an alarm, as depicted in Figure 1.7.

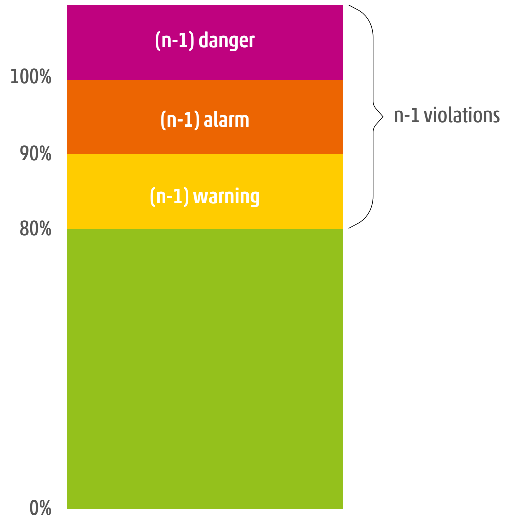


Figure 1.7: Example for alarm thresholds in n-1 calculation

1.2.2.2 Alarm handling procedures at HOPS

The alarm handling in HOPS is related to the hierarchical organisation for power system control, i.e. the National control centre, followed by the regional control centre and then the remote control centres.

Measurements which have a defined processing are audibly alarmed only in the remote control centres (operators confirm transient/ permanent alarms, which, depending on the processing, can generate an audible alarm). The processing definition for electrical measurements is described below.

The dispatchers in the national control centre as well as the regional control centres monitor thresholds, which are signalled in lists and on screen displays, but are not audibly alarmed. After acknowledging the transient alarms, they disappear from the alarm list but remain in the event list. After acknowledging the permanent alarm, they remain in the alarm list until the measurement value falls under the upper limit. The electrical values with defined processing are measurements of voltage, current, apparent power, frequency and measurements of operating and reactive power in the transformer field in WPPs.

The definition of alarms is shown in Figure 1.8 below.

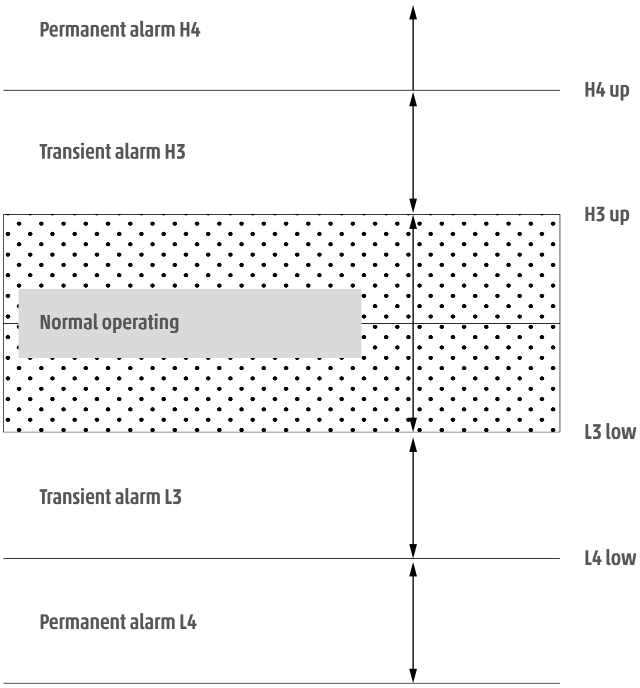


Figure 1.8: Definition of alarms

The rules for current-related alarms are given below; these limits relate to the permanent admissible (rated) current for that bay:

» Limit H3 is defined as a transient alarm (after confirmation it disappears from the alarm list) and, in the lists and diagrams, the measurement value that has exceeded this limit is visualised in yellow. The limit is defined as 80 % of the permanent admissible current for that bay.

» Limit H4 is defined as a permanent alarm (after confirmation it remains in the alarm list until the measurement value exits from the upper limit) and, in the lists and diagrams, the measurement value that has exceeded this limit is visualised in red. Furthermore, limit H4 generates an audible alarm. Limit H4 is set at 100 % permanent admissible current for that bay.

As explained above in Chapter 1.1.4, the 400 kV busbar coupler in SS Ernestinovo is limited by a protection device setting of 2,080 A. The protection device is triggered by a current measurement transformer. This measurement transformer has a rated current of 1,600 A, although, according to the manufacturer's recommendations, it can be operated at 120 % of this value for an unlimited timeframe. Therefore, the value for the permanent alarm is defined as 1,920 A (limit H4). The transient alarm is then defined as 80 % of the permanent alarm and thus yields a value of 1,536 A (limit H3). To prevent damage to the current transformer, the busbar coupler is disconnected by a protection device at 130 % of rated current 1,600 A, i.e. at 2,080 A.

The operational staff procedure during transient and permanent alarms related to the 400 kV and 220 kV network is defined as follows:

» A transient alarm is signalled to national control centre and regional control centre dispatchers and the operator in the remote control centre in lists and on screen displays. The operator acknowledges the alarm as seen and reports it to the regional control centre dispatcher. Next, the regional control centre dispatcher reports the alarm occurrence to the national control centre dispatcher. Both dispatchers can only monitor but not acknowledge the alarm.

» A permanent alarm is also signalled to both dispatchers and the operator visually and, in addition, the operator is alerted by an acoustic alarm. The operator reports the permanent alarm to the regional control centre dispatcher, who then reports it to the national control centre dispatcher. Both dispatchers can only monitor but not acknowledge the visual alarm in the alarm list.

Remedial actions (RAs) are not strictly related to alarms but can be taken when triggered by an alarm as well as independently of it. Currently, HOPS is implementing a project to unify alarms in the SCADA system, which includes the required response of staff to each alarm that may occur.

1.2.2.3 Alarm handling before 14:00 at 08 January

The course of the current over the busbar coupler is shown in Figure 1.9 for reference. Between 12:00 h and 13:00 h on 08.01.2021, the current values on the 400 kV busbar coupler in SS Ernestinovo varied around 1,536 A which caused more than 50 transient alarms. Both national and regional control centre dispatchers assessed the situation as follows:

» Based on the Intra-day Congestion Forecast (IDCF) results for the next few hours, it was concluded that no further significant change in power flow was expected. Further checks regarding changes in market schedules after IDCF have not been assessed, but regardless these changes were not a problem on 08 January according to Chapter 5.

» Based on the assessment of the flow through the busbar coupler through the past period, it was concluded that the flow was similar to the flow of the previous day and that the increase in flow was therefore probably only a transient issue.

The dispatchers in the national control centre therefore decided to take no further action but to keep on monitoring the situation. The last alarm in that regard occurred at 12:56:57, because after this the current did not fall below the value of 1,536 A.

After 13:00, the load flow on the 400 kV busbar coupler in SS Ernestinovo continued to grow slightly and was mostly stable at a value around 1,700 A. The actual real-time measurements at 13:30 were, furthermore, very close to the results in the IDCF results. The dispatchers in national control centre therefore assessed the IDCF as reliable and expected no tripping of the busbar coupler. For their assessment, they also considered several factors such as long-term fault statistics and calm weather conditions.

For the (n-1)-calculation, the tripping of 400 kV line Novi Sad – Subotica was chosen as the worst case scenario and no N-1 violation was detected. The choice of this line was based on the assessment that an outage of this line would stress the current of the busbar coupler most, whereas, for instance, an outage of the 400 kV line Ernestinovo (HR) – Pecs (HU) 1 would increase the resistance and thus relieve the busbar coupler. The decision was then taken again to continue to only monitor the situation.

Recommendation concerning Alarm levels

ID	Recommendation	Justification	Responsible
Alarm handling in control centre			
R-3	The **alarm levels** must be **clearly defined** and shall be consistent for all network elements. This also requires a harmonised protection device setting. It is recommended to define operators' actions at different alarm levels and appropriate remedial actions in order to resolve the problem.	The alarm levels must allow enough time for the operator to decide on and activate remedial actions. For each alarm level, clear predefined remedial actions tell the operator how to resolve the problem.	TSOs to implement, ENTSO-E to monitor

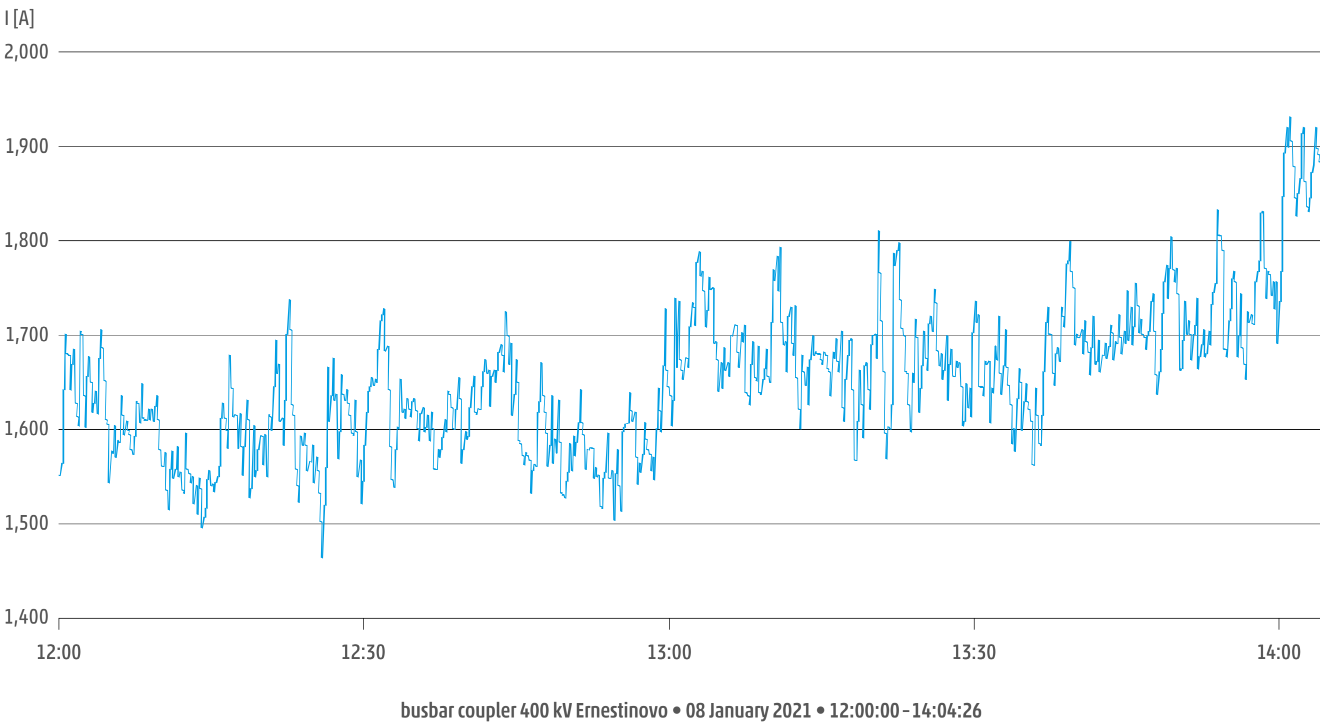


Figure 1.9: Definition of alarms

1.2.3 Situation after 14:00

1.2.3.1 Load flow situation after 14:00

Between 14:00 and 14:01, a sudden increase in the load flow over the busbar coupler occurred. While the current was 1,736 A at 14:00:00, at 14:00:59 the value of 1,931 A was reached and thus the alarm limit H4 of 1,920 A was exceeded. This caused the above mentioned permanent alarm. At 14:01:06 the power flow value fell again under 1,920 A and then fluctuated between 1,830 A and 1,920 A. At 14:04:16, the current again exceeded the alarm limit of 1,920 A. At 14:04:21, the current through the busbar coupler reached a value of 1,989 A. That course of the current is also shown in Figure 1.10.

During 14:01 and 14:04:26, time was spent on communication between the regional control centre and the subordinated operator in the remote control centre related to the alarm that occurred. The regional control centre contacted the national control centre to discuss possible RAs. No additional (n-1)-calculation explicitly considering the outage of the busbar coupler was then performed due to the unavailability of the automatic (n-1)-calculation of busbar coupler outages, whereas the manual adaption of the IDCF model or SCADA study mode would have required too much time. This aspect is also further covered in Chapter 1.3 regarding the coordinated security analysis.

The solution chosen in the short time available was to take a corrective measure to keep the busbar coupler in operation. At that time, it was still considered that the situation was far enough from a possible busbar coupler outage due to the tripping value of 2,080 A. During the communication, the current over the busbar coupler was below 1,920 A. The best measure to cope with the situation seemed to be the switching of the 400 kV line Ernestinovo – Pecs 2 via the auxiliary busbar to the busbar 1, which would have relieved the busbar coupler. However, as too much time was spent on the assessment, the corrective measure was not implemented on time.

The trip of the busbar coupler led to a shift of the flows, i.e. the current through the busbar coupler was now flowing through the 400 – 110 kV-transformers TR1 and TR2 in Ernestinovo. Those two transformers were interconnected via the underlying 110 kV busbars and were therefore still connected to the two 400 kV busbars in SS Ernestinovo (compare with Figure 1.2). Due to the resulting overcurrent, both transformers TR1 and TR2 tripped at 14:04:28 and led to a complete separation of the two busbars in SS Ernestinovo.

Further data regarding EMS and Transelectrica are provided in the Annexes.

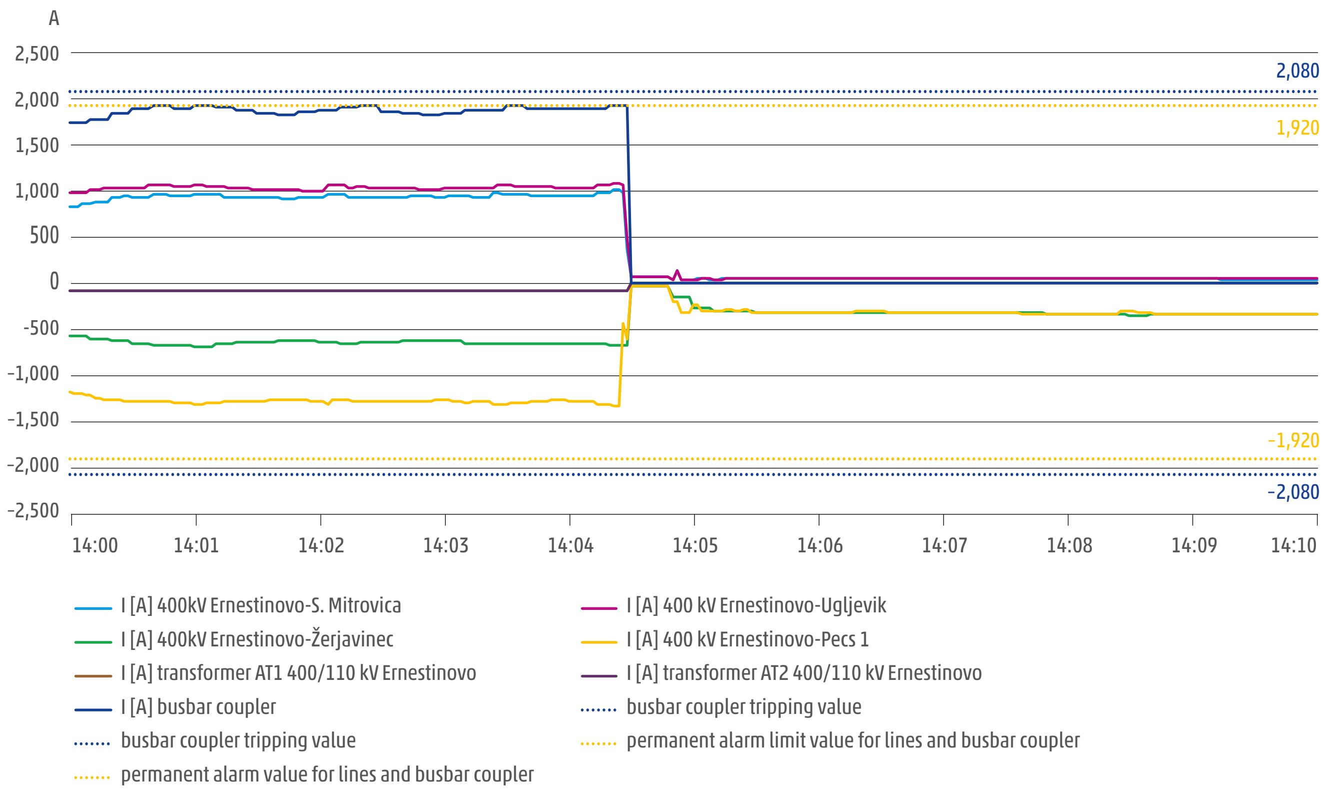


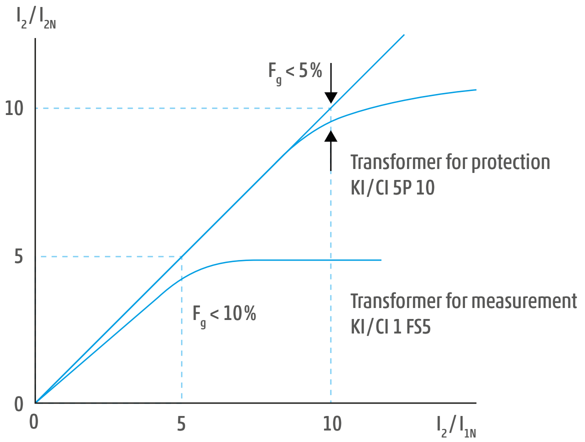
Figure 1.10: Currents of transmission network elements in SS Ernestinovo between 14:00 and 14:10 (SP W12 corresponds to the busbar coupler)

1.2.3.2 Further evaluation of behaviour of current measurement transformer

The protection relay was thereby connected to a different winding than the SCADA measurement system. The main reason for such a design is that the most accurate measurement is required for the usual operational area up to the rated current. Furthermore, for currents several times higher than the permissible values (i.e. which occur during short circuits) saturation of the current transformer has to be avoided, which would give the wrong current value to current protection devices.

Almost simultaneously, where the SCADA system registered a value of 1,989 A, the relay, which gets the measured value almost instantly, noticed a current above 2,080 A at 14:04:20.907.

Behaviour of current transformers in case of over current



I_1 primary current

I_2 secondary current

I_{1N} rated primary current

I_{2N} rated secondary current

Figure 1.11: Behaviour of current transformer in case of over current

Although there seems to be a difference in the measurements between metering and protection circuits due to the use of different secondary windings of current transformer and different equipment, Figure 1.11 shows that for current values between 120–130 % of rated current, the difference in the measurements is negligible (values on the abscissa between 1.2–1.3).

The reason for this apparent difference is that the relay gets the measured value almost instantly, whereas the measurement in the SCADA system comes periodically. Due to the local communication concentrator unit in the substation, the data is submitted only periodically, i.e. every 4 seconds, to the SCADA system. Just in case the measured value changes instantly more than 10 %, the value is delivered immediately (even if this was not the case in this situation). The value may fluctuate within the 4 seconds, but the last measured value will always be sent. Furthermore, the SCADA system trend is only refreshed every 10 seconds. Because of this, the operator can only see updates every 10 seconds, no matter if the value is already available in the SCADA system.

Because of the refreshing rate of the SCADA system, the operators could not see the last value of 1,989 A. The last reported value, when the busbar coupler was still closed, was 1,922 A at 14:04:16. As the busbar coupler finally opened at 14:04:26, the timespan was far too short for the operators to directly react to this last increase. Therefore, the measurement and refreshing delay in the SCADA system was not crucial for the incident in that specific regard. It should, however, be noted that this knowledge, i.e. a certain, possible as yet-acknowledged deviation from the last acknowledged value, should have been incorporated in the assessment of the situation in the time before the incident.

1.2.3.3 Further evaluation of increase in flows after 14:00

The mentioned increase in flows should be further analysed. During the period 13:30 to 14:00, a gradual increase in flow through the particular busbar coupler was realised and a significant change was observed from 14:00 to the initial event at 14:04.26, when the busbar coupler opened (see the next chapter for further description). In this regard, the area control errors (ACEs) of the different countries and areas are analysed further.

Regarding the ACE, Figure 1.12 shows the sum of the ACE for all countries south of the split line. The maximum ACE of approx. 600 MW is not unusual, but it is unusual that the average ACE between 3:00 and 14:00 was around 110 MW – apparently there was a constant positive area control error which could not be returned to 0 over a long time. The mean ACE over this period of time for the individual Load Frequency Controller (LFC) areas is shown in Figure 1.13. It is obvious that Macedonia and Montenegro in particular have a positive offset in their ACE values, but most other areas also have a slight positive offset, an overall total of 110 MW.

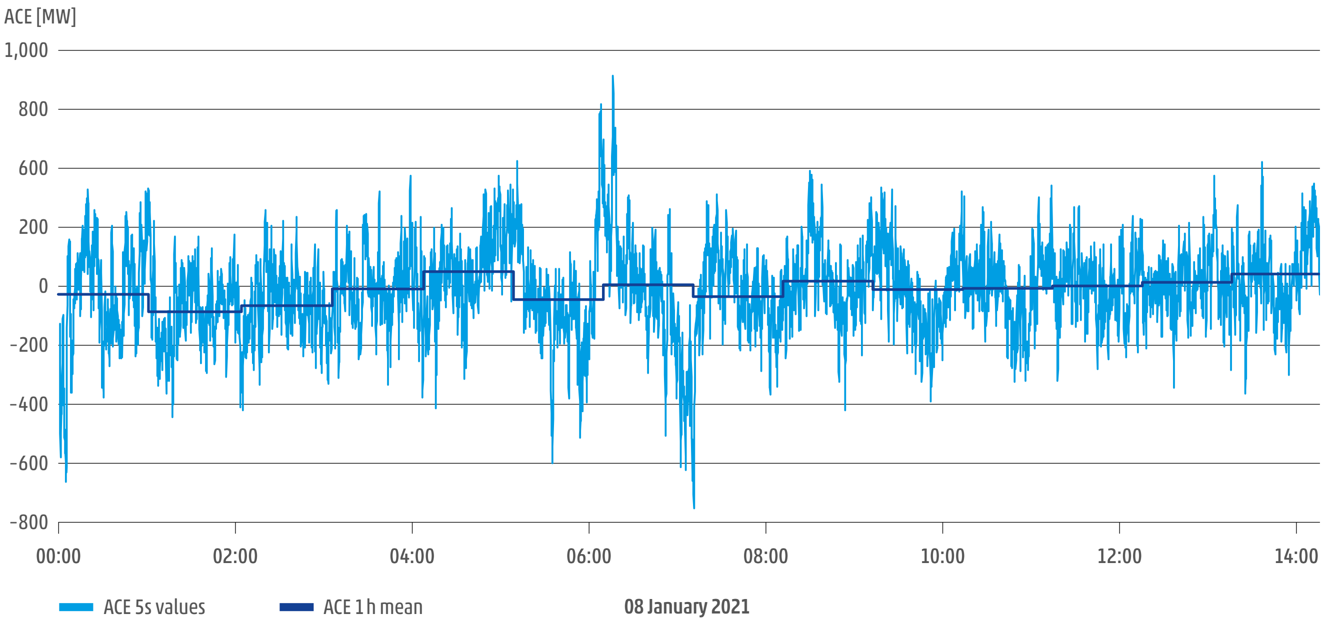


Figure 1.12: Sum of the ACE values of all LFC areas south of the split line on the 08 January before the split

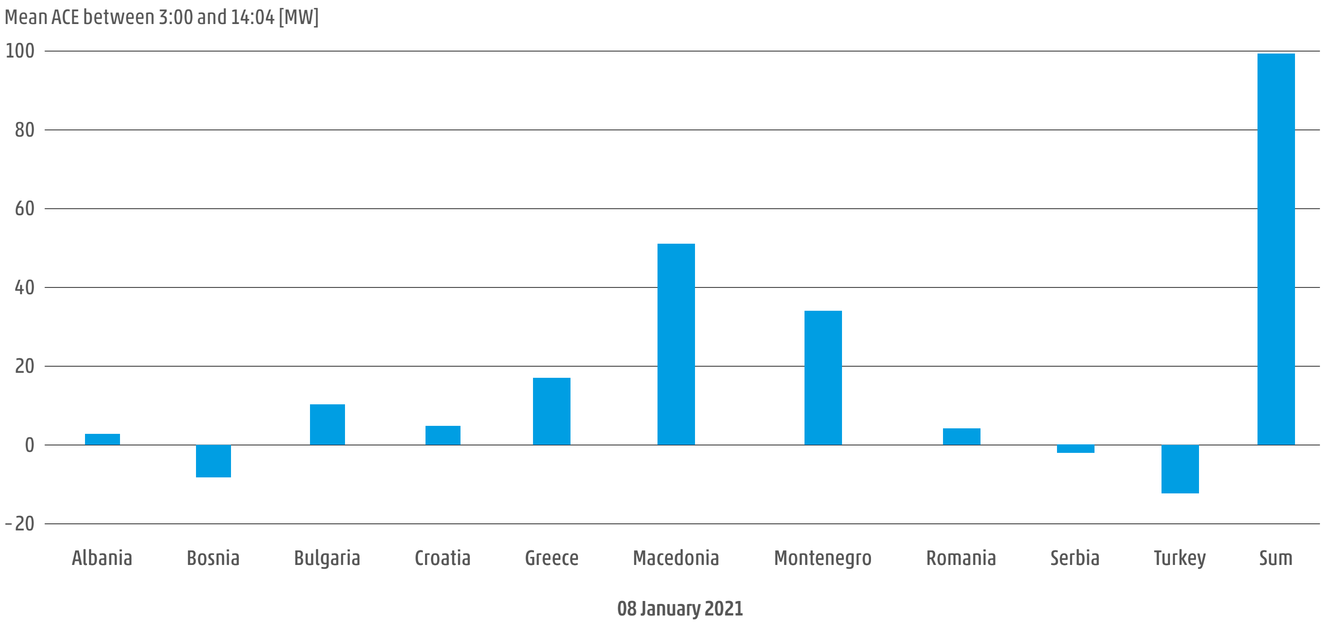


Figure 1.13: Average ACE values of each LFC area in the hours before the system split

Right before the system split happened, a significant increase in the ACE values of the southern part can be seen in Figure 1.14. At 13:30, the ACE was approx. 0 MW, and then increased up to 450 MW around 14:00. In this regard, the total ACEs of the south-east area and the north-west area were analysed, shown as a zoom-in in Figure 1.14 and Figure 1.15. In this regard, Croatia and Romania are added to the north-western area, as this illustrates the increase of flow in a clearer manner.

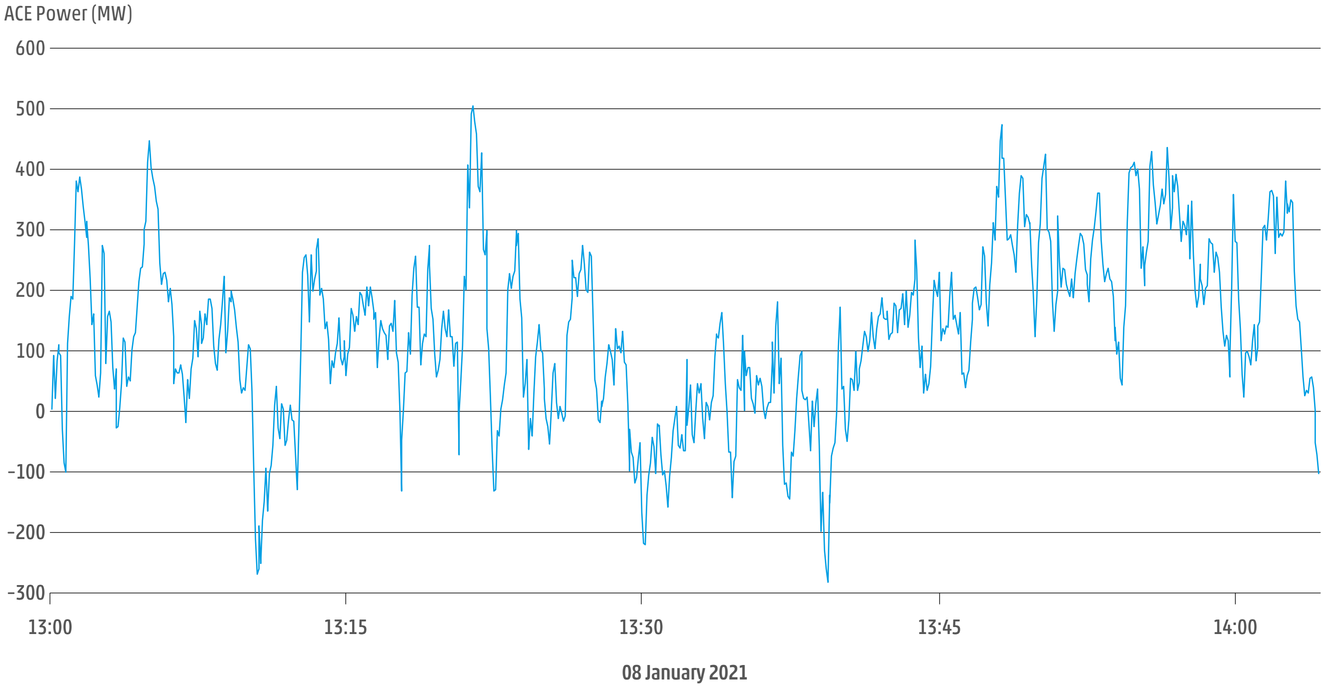


Figure 1.14: ACE of South-East area (without Croatia and Romania)

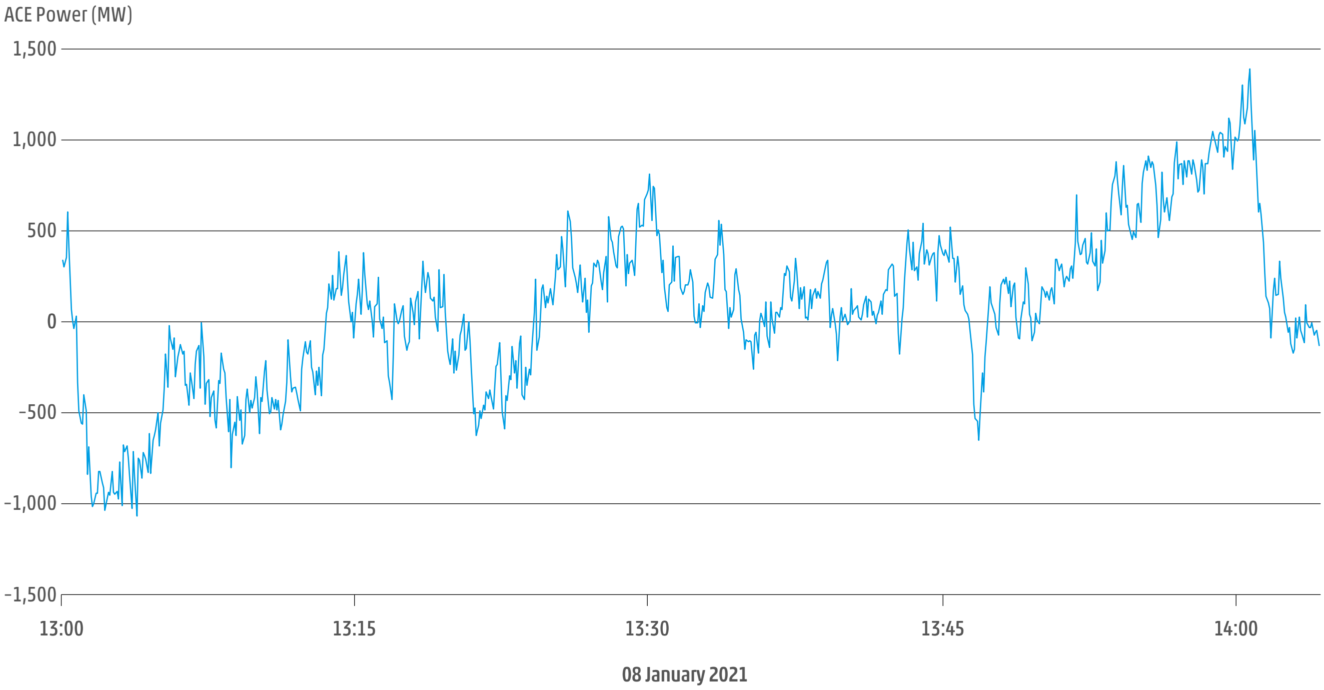


Figure 1.15: ACE of North-West area (including Croatia and Romania)

When combining ACE in the north-west area, the results yield a positive ACE of approx. 1,400 MW at 14:00, but this decreases very sharply to 0 MW until 14:02. In contrast, the ACE of the south-east area increases until around 14:03. The very sudden variations and the positive ACE in south-east area are considered to have contributed to the observed flow changes during the period from 14:00 – 14:04.

The preview processes Day-Ahead Congestion Forecast (DACF) and IDCF in the operational planning phase did not indicate flows that would cause an overloading of any monitored system element, as was elaborated previously. However, it could be observed that the physical flow on the borders during the period from 13:45 – 14:00 deviated from the market schedules. If for instance, a flow-corridor between BA » HR » SI » IT is considered, a flow deviation of approx. 450 MW – 539 MW compared with market schedule is obtained, which exceeds the allocated Net Transfer Capacity (NTC) values on single borders by more than 50 % (for instance at the border BA » HR).

If the market schedules of the determined set of borders north of the split line (i.e. HR » SI, HR » HU, RS » HU, RO » HU and RO » UA) are totalled, the result is a summed market schedule of 3,077 MW from 13:00 – 14:00. It can, however, be observed that the average physical flow was around 3,417 MW from 13:00 – 14:00 and thus constitutes a difference of approx. 340 MW between market schedules and physical flows. That difference might be understood by two factors: Firstly, the MONITA DC link (Italy to Montenegro) was rescheduled at 09:25 on 08 January 2021 and left to additional flows of ~220 MW through the AC-system of the Balkan-peninsula and, secondly, the ACE for the south-east region was constantly positive at around 120 MW during that hour.

Similarly, the difference for the time span between 14:00 – 14:04:30 can be obtained: the average physical flow was around 3,870 MW in these minutes, whereas the corresponding market schedules totalled 3,182 MW and are thus approx. 700 MW over. The present difference of approx. 340 MW from the hour before was thereby still in place, whereas the market schedule was raised approx. 100 MW further (3,077 MW to 3,182 MW). In addition, the market schedule of the MONITA link increased by approx. 80 MW, whereas its controlled set point remained unchanged. Finally, the ACE increased to a maximum of 380 MW, which yields an addition of approx. 260 MW compared with the previous hour.

The mentioned differences are summarised in Table 1.3 below.

In that regard, several careful conclusions have to be drawn. The mentioned differences in the operation of a meshed AC grid are not uncommon and are a complex combination of deviations in all parameters in the power system.

The analysis of ACE deviations for the individual Control Blocks during the above period, for instance, did not indicate any specific abnormal situation. Most Control Blocks across CE Synchronous Area (SA) had an ACE of normal size during this hour shift.

A further focus should be on the rescheduling of the MONITA-DC-link. It should be noted that the rescheduling was done in line with the agreed procedures among the involved TSOs. The rescheduling on the MONITA DC link (Montenegro » Italy) on 08 January 2021 at 09:25 reduced the flow on the DC link and similarly increased the flow in the AC grid by 223 MW. The involved TSOs approved this rescheduling as no N-1 problems were identified. At 14:00, the market schedule on the MONITA DC link increased to 400 MW – in turn progressively increasing the rescheduling to 300 MW in 15 min and increasing the flow in the AC grid South-East Europe (SEE) » Central-West Europe (CWE) in total with 300 MW. However, due to the complex power distribution in the AC grid, the rescheduling of 300 MW (14:00) from the DC link to the AC grid was distributed over the entire grid. Calculations based on the 14:00 IDCF model indicate that 80 MW was passing through Ernestinovo and as such contributed as a minor part of the registered deviation on the flow on the busbar coupler itself.

However, the observed differences in total underline the fact that the present capacity calculations and market schedules in the area do not fully reflect the physics of the power system.

	Absolute Value 13:00 – 14:00	Difference to Market Schedule	Absolute Value 14:00 – 14:04:30	Difference to Market Schedule
Market Schedule	3,077 MW	–	3,182 MW	–
Reschedule MONITA-link	–	+220 MW	–	+300 MW
ACE-Error	–	+120 MW	–	+380 MW
Physical Flow	3,417 MW	SUM +340 MW	3,870 MW	+680 MW

Table 1.3: Differences between market schedules and physical flows for 13:00 – 14:00 and 14:00 – 14:04:30

Recommendation concerning Reliability Margins

ID	Recommendation	Justification	Responsible
Capacity calculation			
R-4	It shall be **assessed** if the Transmission Reliability Margins (**TRM**) and the Flow Reliability Margins (**FRM**) are sufficient to cope with sudden high overloading.	Real-time variations in the power system are covered by TRM in NTC calculations and Flow Reliability Margins (FRM) in FB Market Coupling. A sudden increase of Area Control Errors was identified as one of the critical factors contributing to the event. With regards to the establishment of several European Balancing Platforms in the course of the next 12 months (IGCC, PICASSO, MARI) it shall be assessed whether the current approach for the determination of margins (TRM, FRM) is sufficient.	TSOs of the CCRs

1.3 Review of coordinated security analysis

1.3.1 General aspects of coordinated security analysis

In the daily operation of the transmission grid, it has to be ensured that the loading of the grid assets is within the allowable limits and that the system can also withstand an outage of grid assets. To guarantee this, coordinated security analysis are performed the day before the operation (day-ahead), during intraday as well as in real-time. The coordinated security analysis in day-ahead as well as during intraday are performed with the support of the Regional Security Coordinators (RSCs), whereby a common platform / tool environment is used among the RSCs and TSOs to analyse the results of the coordinated security analysis. During real-time, each TSOs uses his own SCADA system to analyse the grid situation and to conduct coordinated security analysis.

In Europe, six RSCs support the coordinated security analysis during day-ahead and during intraday. Figure 1.16 displays which TSO in Europe uses the services of which RSC(s).

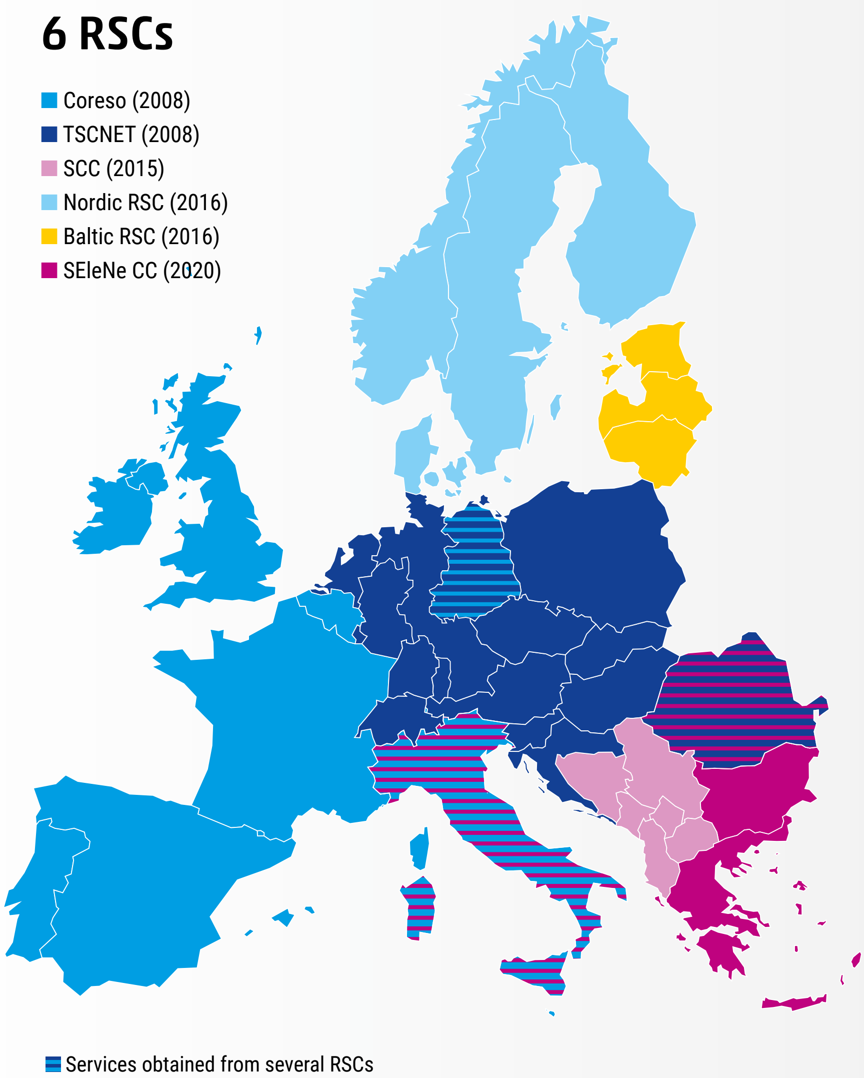


Figure 1.16: Overview of RSCs and corresponding TSOs in Europe.

Day-Ahead coordinated security analysis

In the day-ahead operational planning phase, the day-ahead individual grid models Individual Grid Models (IGMs) are generated by the individual TSOs after the gate closure of the market. The day-ahead IGMs contain all relevant information as day-ahead market results, schedules of power plants and of the High Voltage Direct Current (HVDC) system, renewable energy forecast, load forecast, planed outages and all already decided RAs. These IGMs are then scaled according to the day-ahead exchange programs provided in the VULCANUS platform and merged into common grid models (CGMs) by the responsible RSC for all hours of the day ahead during the DACF business process. That task is performed on a rotational basis by the RSCs. For the RSCs TSCNET and Coreso, the creation of the CGMs is started on the day before system operation when all DACF IGMs are available and validated (around 6 pm). The merging of the IGMs in CGMs thus creates a complete model of the respective synchronous area so that the DACF is calculated on the model of the synchronous area as a whole.

By using DACF CGMs, the security assessment calculation in n & n-1 cases are performed in the DACF process. In the event of congestion, available RAs must be prepared and checked. RAs, which have an impact on neighbouring grids, have to be coordinated with concerned TSOs / RSCs. After the application of the proposed RAs on the DACF CGMs, all relevant overloads should be eliminated in the DACF process.

In the CEE & CWE area, TSOs and RSCs can exchange all the relevant information to the DACF process and to other participants at the Daily Operational Planning Conference (DOPT). The DOPT normally takes place at 9 pm on the day before the system operation. At the DOPT, it must be clearly stated if a proposed Remedial Actions (RA) is acceptable for the represented concerned TSO/RSC. In the event of any objections, an explanation must be provided. All relevant information shall be recorded and reported in the DOPT-reports.

Intraday security coordinated security analysis

Different to the DACF process, the IDCF process runs on an hourly basis in intraday. IDCF IGMs are created by the individual TSOs each hour based on up-to-date topology and also include all relevant information such as intraday market results, schedules of power plants and of the HVDC system, renewable energy forecast, load forecast, planed outages and all already decided RAs for all remaining hours of the day.

During the IDCF process, the IDCF IGMs are scaled according to the intraday exchange programmes and merged into CGMs by the responsible RSCs, following which the Security Assessment calculation is performed for all the remaining hours of the day. The merging of the IGMs in CGMs thus creates again a complete model of the respective synchronous area so that the IDCF is also calculated on the model of the synchronous area as a whole.

Based on the results obtained from the calculation of the RSCs, TSOs shall then verify the results and check if the RAs agreed in the DACF process or previous IDCF run are sufficient to solve congestions. If not, additional RAs need to be prepared. In the event of any impact on the neighbouring grids, RAs must be coordinated with concerned TSOs/RSCs.

At the request of one or more TSC TSOs, an Intra-day Operational Planning Teleconference (IDOPT) can be organised by the TSCNET operators. IDOPT could be triggered by a significant change in the forecasted grid situation during intraday or a Multilateral Remedial Action (MRA) request.

Real-Time coordinated security analysis

In real-time, a coordinated security analysis is performed in the local SCADA system of the TSOs. When performing operational security analyses, each TSO shall, in the N-Situation, simulate each contingency from its contingency list and verify that the operational security limits in the (n-1) situation are not exceeded in its control area. Such a contingency list shall include all the internal (inside the TSO's control area) and external (outside the TSO's control area) contingencies that can endanger the operational security of the TSO's control area.

For this reason, a so-called observability area, larger than the TSO's control area, must be determined and monitored. This observability area contains the own grid, interconnectors and the grid of neighbouring TSOs with relevant influence on the own grid elements. A TSO has to adopt a model of the external observability area in the SCADA system with all relevant electrical parameters. Topology information (switching state) and measurements are received in real-time.

The common methodology "Coordinated Security Assessment (CSA) Methodology" in accordance with Article 75 of the SO GL defines how to determine a TSOs observability area.

In the event of congestions in the n-1 calculation, RAs have to be activated as soon as possible for compliance with the (n-1) criterion (Preventive Remedial Actions [PRA]). In the event that the permanent admissible transmission loading (PATL) of equipment is violated but there is also a transitory admissible transmission loading (TATL) which is not violated, there might exist a timeframe of several minutes within which the TSO is able to prepare and activate a remedial action in a timely manner – e.g. change of Phase-Shifting Transformers (PST) settings, manually or automatically (Curative Remedial Actions [CRA])- to prevent any limit violations in the system. RAs which have an impact on neighbouring grids have to be coordinated with concerned TSOs. After the occurrence of a contingency there should be no limit violations in the transmission system, because the TSO has to comply with the (n-1) criterion and has activated either PRAs or CRAs. If a TSO is not able to comply with (n-1) criterion, meaning that at least one contingency from the contingency list leads to a violation of the TSO's operational security limits, even after the activation of RAs, the TSO has to set 'alert state' in the ENTSO-E Awareness System (EAS). If there is at least one a violation of a TSO's operational security limits in N state, the TSO has to set an 'emergency state' in EAS.

1.3.2 Regional coordinated security analysis

1.3.2.1 General aspects of future regional coordinated security analysis

On 04 December 2020, ACER approved the Methodologies for Regional Operational Security Coordination (ROSC) for Core Capacity Calculation Region (CCR) and SEE CCR in accordance with Article 76 (1) of the SO GL. The methodologies cover the year-ahead, day-ahead and intraday regional operational security coordination within CCRs and shall be implemented in two steps. According to the ROSC methodology, the first implementation step will at least fulfil day-ahead regional operational security coordination. The second implementation step has a go-live window no later than 04 June 2025. Furthermore, according to CSAM, an inter-CCR coordination shall be established which complements the regional methodologies especially also at the borders of the CCRs. The ROSC methodology, including the inter-CCR-coordination, will guarantee a common view on the grid and its constraints as well as a coordinated determination of RAs. Therefore, RSCs will perform CCR-wide hourly regional security assessments and run Remedial Action Optimisations regarding current limit violations on regional and on inter-CCR level at dedicated time slots in Day-Ahead and Intraday. The outcome can be analysed by TSOs and complemented with local assessments on further limitations regarding voltage, stability or short-circuit. Furthermore, grid configurations not able to model properly in the grid models can be analysed during those assessments. Based on these assessments, TSOs have the right to reject proposed RAs by RSCs, propose alternatives and request a re-run of the optimisation considering their objections.

As a foundation for guaranteeing the security of the grid, the market coupling plays an important role which is, in turn, linked to the determination of the cross-border capacities. In some regions (or sub-regions), a load flow based approach is already used for this purpose, which will become mandatory for all CCRs in the future under CACM[1] (Art. 20(1)). With this approach, capacity is limited to grid constraints in the form of maximum flows on network elements. Despite grid constraints, however, a minimum margin on network elements must be maintained for cross-border capacity, according to Clean Energy Package (CEP). Furthermore, to reflect constraints that cannot be transformed efficiently into maximum flow on network elements such as voltage, stability or short-circuit issues, CACM Art. 23(3) allows TSOs to apply allocation constraints which have to be respected during capacity allocation. Another possibility to reflect further constraints is given to TSOs by the possibility to perform own validations of the cross-zonal capacity and reduce capacity for reasons of operational security.

1 Except if it can be proven that the coordinated net transmission capacity approach is more efficient than the flow-based approach.

Recommendation concerning coordinated capacity calculation

ID	Recommendation	Justification	Responsible
Capacity calculation			
R-5	The NTC calculation shall be performed in a coordinated manner in each Capacity Calculation Region. The **coordinated NTC calculation** has to consider existing **stability limits**.	A regional approach is a way to examine the situation holistically so as to overcome the shortcomings of coordination that occur with the application of only the bilateral approach. Dynamic stability limits can only be seen by analysing the wider region.	TSOs of the CCRs

1.3.2.2 General aspects of regional coordinated security analysis in the affected region

The relevant RSCs for the System Split analysis are TSCNet and SCC. These two RSCs are currently providing daily security analysis to the TSOs in the area. TSCNet performs tasks related to Eles (Slovenia), HOPS (Croatia), MAVIR (Hungary) and Transelectrica (Romania), and SCC performs tasks related to EMS (Serbia), NOSBIH (Bosnia and Herzegovina), CGES (Montenegro), MEPSO (North Macedonia), OST (Albania) and IPTO (Greece). SEleNe CC, who will perform tasks related to IPTO (Greece), ESO-EAD (Bulgaria), TERNA SpA (Italy) and Transelectrica (Romania), is at present in the implementation phase and preparing for operation in July 2021.

The current TSCNET CSA assessment is based on the model of the complete synchronous area of Regional Group Central Europe (RGCE), as was described above. Regardless, it is focused on identifying constraints within TSC subregion. The stated TSC subregion includes the MAVIR, HOPS and Transelectrica areas; however, the monitoring of contingencies in the neighbouring areas (NOS BiH, EMS, etc.) as well as their impact on the TSC area is limited and based on the individual request of TSC TSOs.

For the purpose of security assessment, all SCC TSOs are obliged to deliver two input files:

- Contingency list – containing all the elements that a certain TSO wants to be simulated as outages in DACF and IDCF processes,
- Monitoring list – containing all the elements that a certain TSO wants to be monitored during the security assessment in DACF and IDCF processes.

In those lists, SCC-TSOs are not limited on number of elements, type of elements, type of contingency, etc. They are allowed to include single or multiple outages of lines, transformers, generators, shunts or any combination of mentioned elements. The majority of outages are actually single outages, but there are also cases of multiple outages due to operational needs or specific network configuration and representation in Union for the Coordination of Transmission of Electricity (UCTE) models. In addition, it is expected that SCC – TSOs include some elements from their neighbouring systems at least in their Contingency list, but also into their Monitoring list. Each SCC – TSO is responsible for maintaining its Contingency and Monitoring lists and for announcing in advance if some major changes are expected. All the lists from TSOs are merged by SCC in one joint Contingency and Monitoring list with TSOs flags. Although it is the responsibility of TSOs to maintain them, in SCC there is a daily crosscheck between reference DACF Common Gird Model (CGM) (CGM for 1030) and joint lists prior to the triggering of the security assessment. If some differences are detected, they are updated by operators in the shift based on internal algorithm. After the process is done, TSOs for which differences were detected are informed and asked to confirm/reject the changes proposed.

Both TSC and SCC provide a security analysis based on the merged UCTE data models in the Day-Ahead (DA) and Intra-Day (ID) timeframes (DACF and IDCF) as described above. The RSC thereby rely on the IGMs provided by the TSOs, for whom the RSCs provide their services. The used UCTE standard data models, however, have several limitations. One limitation, which proved crucial in the course of the event on 08 January 2021, was the representation of substations as one node, i.e. neglecting the detailed representation of several busbars and busbar couplers.

The calculations, therefore, did not identify whether an overloading of this equipment should be expected. Chapter 1.4 provides a recommendation as a further detailed analysis.

At present, there is no established formal cross-regional coordination of security analysis between TSCNet and SCC as a normal daily routine. However, the operational practise is that coordination is made in situations where calculations indicate critical situations in the area. Furthermore, there is no coordination between SCC and Selene – CC regarding CSA. The CSA process in general is, however, not under risk because currently, SCC calculations cover a wide area of surrounding TSOs. Therefore, SCC considers almost the whole HOPS system, half of MAVIR's system, and parts of the Transelectrica, ESO and TEIAS systems, as required by TSOs service users of SCC. Regardless, the development and implementation of dedicated CSA methodology is not mandatory for non-EU TSOs in SEE and thus SCC.

To conclude, CSA adaption is based on CCR regional modules". The development and implementation of Coordinated Capacity Calculations (CCC) and CSA methodologies is foreseen on the CCR level as well as the coordination and cooperation on these meters with neighbouring CCRs. If some part of synchronous area is not covered by any CCR (as is now the case for the non-EU part of the SEE network), that has an influence not only on system security in that part of the synchronous area but also on the system security of neighbouring TSOs, which belongs to Core and SEE CCRs.

Recommendation concerning implementation of observability area

ID	Recommendation	Justification	Responsible
Modelling and execution of (n-1) calculation			
R-6	**Monitor the implementation of** the common approach to determine and update **the observability area**.	The analysis of the incident emphasises the importance of the accuracy of operational security analysis across all timeframes. The implementation of an adequate observability area serves as an important contribution to this.	ENTSO-E

Recommendation concerning CSA and CCC in SEE

ID	Recommendation	Justification	Responsible
Coordinated Processes in South-East Europe			
R-7	The possibility of developing a more **sustainable solution for CCC and CSA for non-EU TSOs in the Balkans area and between these TSOs and neighbouring EU TSOs** should be assessed in order to increase the system security and ensure a proper level of TSOs cooperation.	Currently non-EU TSOs in the Balkans area do not belong to any CCR, despite the flows within them and within neighbouring EU TSOs having an influence on the CCC in both the Core and SEE CCRs. The capacity calculation is usually left to bilateral agreements without a proper coordination among the different borders (both non-EU and EU) and this impacts the system security of the entire SA.	TSOs and NRAs

1.3.2.3 Regional coordinated security analysis before the incident

During the DACF process on 07 January 2021, there was no clear indication of special operational circumstances for the business day 08 January 2021. For the timestamps 13:30 and 14:30, there were no base case overloads detected, and the highest N-1 constraint was an overloading up to 110 % for the transformers in Sandorfalva (Hungary) if the parallel transformer trips and up to 103 % for the transformer in Iernut (Romania) if the line Iernut – Gadalin trips. For the DACF, the N-1 constraints on internal elements up to permanent admissible value of 120 % are considered as non-critical (compared with Chapter 1.3.4.2). During the DOPT, APG and TenneT D shared that they would implement a bilateral redispatch to resolve remaining constraints. Apart from that, there was no other indication that anything special is expected in the concerned grid on the following day.

Similarly, during the IDCF process, there was no clear indication as to the extraordinary situation. There was no noticeable difference in the load flow distribution compared to the DACF results. Transelectrica was not yet participating in the IDCF process and the grid situation further in the south-east direction was out of scope of the TSC Operator, according to the CSA task as being based on CCR.

Post event analysis has shown that during the day, the net position of certain countries such as Spain, France, Portugal and Germany changed in the direction of the higher import of Spain, caused by extreme weather conditions. TSCNET only became aware of the system separation after analysing the IDCF model for 14:30, which did not converge. The data pointed to an unusual configuration of substation Ernestinovo and only after the TSC Operator contacted the HOPS operator was TSC Operator informed of the special event.

1.3.3 Security calculation at HOPS

(n-1)-calculations at HOPS are performed several times in the operational planning and operations phase, which includes the consideration of different aspects. This regards mainly the time horizon of the respective processes as well as their specific characteristics.

Therefore, the general process-related aspects are explained first, whereas the analysis of the forecasting security calculation and the real time security calculation is presented thereafter.

1.3.3.1 General process-related aspects

In the system operation planning phase, during the HOPS IGM creation, an initial contingency analysis is performed. After the merged CGM is received back, it is checked again to determine if there are any (n-1) violations. In case violations are detected, remedial actions are implemented through the model improvement phase to get a congestion free model. The IGM created by HOPS contains 400, 220 as well as the 110 kV voltage level network because the HOPS control area is connected with NOSBiH and ELES control areas via the 110 kV network. Due to the large extension of the model, the results shown by AMICA[2] are considered very trustworthy. The disadvantage is that multi-busbar systems are not modelled correctly as several nodes in HOPS IGM, but instead are modelled as one node. Therefore, it is currently not possible to perform an automatic (n-1) analysis for busbar coupler outages or overloads in the HOPS forecasting process. Even if it is possible to adapt the model manually regarding a particular concerned busbars or busbar coupler in order to do this analysis, this is not feasible for all substations at a time, as the HOPS general forecast models lack this granularity. Regardless, the outage of individual busbars can be simulated as a simultaneous outage of several elements connected to the busbar.

During the real time operation phase, on-line and of-line calculations can be done. Off-line models and calculations can be used for additional security analysis. The disadvantage of using these off-line calculations is that they depend on the quality of the IDCF models sent by the TSOs, and changes that may occur between the sending of the IDCF model and real time are not automatically included.

Normally, during real time operation, contingency analysis is by default performed automatically in the SCADA system and in DAM software[3]. Contingency analysis is performed in consideration of the relevant contingency list. This contingency list consists of ordinary contingencies (loss of every single network element in the HOPS

2 AMICA is a tool used by TSOs whose RSC is TSCNET for coordinated security analysis.

3 DAM uses data acquired by SCADA for EMS purposes, it is more user-friendly than SCADA and tailor-made for use in HOPS control centres and is widely used at HOPS for different calculations.

control area and external contingency list) and the loss of any double circuit line in the HOPS control area, which are regularly monitored as exceptional contingencies. However, neither of these two systems does automatic (n-1) analysis related to busbar coupler outages. It is possible in the SCADA system to use the off-line study mode and to do (n-1) calculation related to busbar coupler outages. The disadvantage of these systems is that in the case of busbar couplers, as well as in other cases, the external model used for calculation is limited by the current extent of HOPS' observability area, and the results obtained through (n-1) analysis are thus not always trustworthy. The extent of the observability area is determined in accordance with Article 5 and Annex I of the Methodology for coordinating operational security analysis (CSAm). This means that a year-ahead CGM developed in accordance with Article 67 of the SO GL was used to determine the elements whose influence factor is higher than that provided by the allowable range prescribed in Annex I of the CSAm. HOPS has taken the minimum allowable influence factor, which means that the HOPS observability area is the largest possible in accordance with the provisions of the CSAm (the HOPS observability area is shown in Figure 1.17). This approach for security calculation works well if the full RG CE model is used. However, if calculations are done in SCADA on a model that includes only the accordingly determined observability area, significant errors occur in (n-1) analysis, especially in parts near the edges of the model. Chapter 1.4 provides a recommendation as a further detailed analysis, conducted by a team of legal experts regarding SO GL.

In addition, although HOPS receive measurements and indications from the observability area, due to some missing measurements (production on generator injection in TERNA, tap positions for OLTC in CGES), some smaller parts of the observability area are removed from the state estimator and consequently from the power flow and N-1 calculations. These measurements are removed to not degrade the quality of the calculations, i.e. to increase state estimation reliability. Accordingly, adding additional measurements and knowledge of power system models is crucial for quality calculations because, according to the conducted analysis, equivalent models as alternatives are not an optimal solution for ensuring accurate and reliable results.

Accordingly, higher quality results (calculation results which match the actual situation better) are for lower voltage levels, more distant from the edge of the observability area. This fact, as well as the fact that the 110 kV network does not have such a cross-border impact, influences the usual procedure whereby off-line N-1 calculations in the AMICA system for real time operation are used for calculations in the area around the substation Ernestinovo.

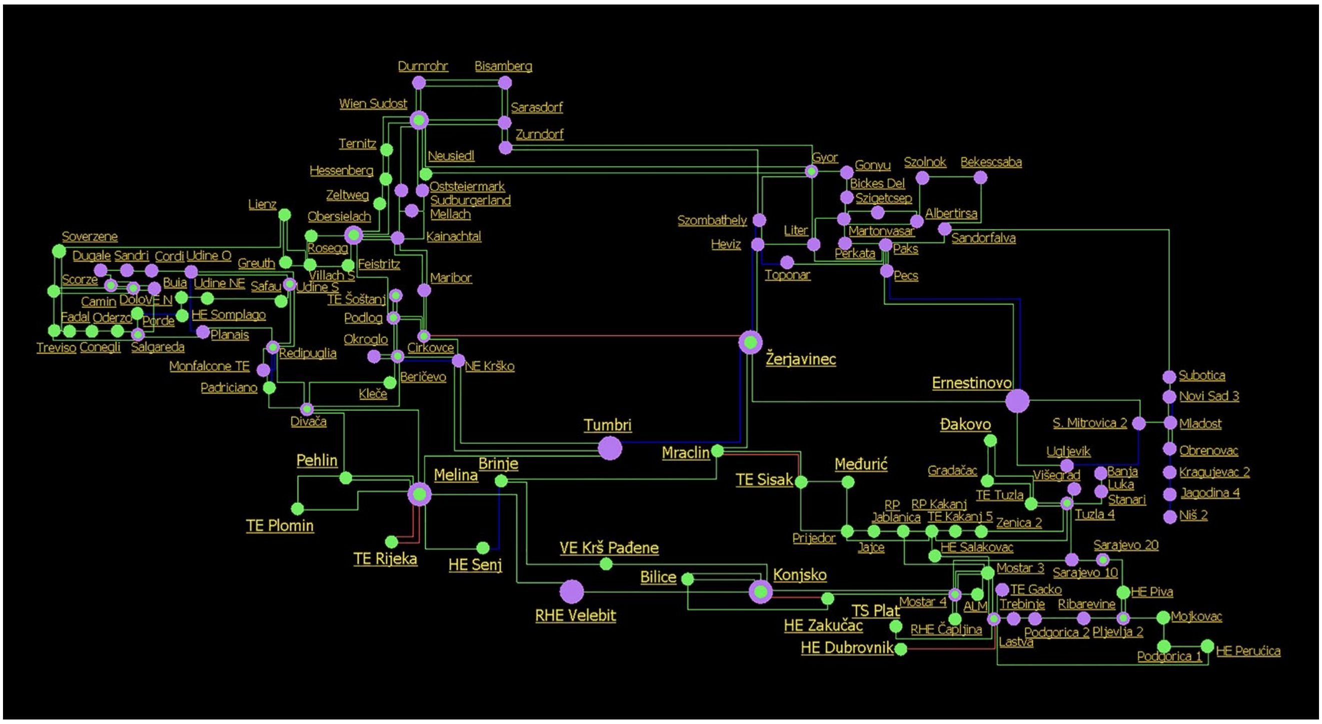


Figure 1.17: HOPS Observability Area

During the IDCF, as well as during real time operation, N-1 contingency simulations are performed. The tripping of the busbar coupler was not identified by HOPS as an ordinary contingency pursuant to the methodology for coordinating operational security analysis. Therefore, the tripping of the busbar coupler was not included as a possible event in the n-1 contingency simulations in DACF, IDCF or in real time. Chapter 1.4 provides a recommendation as a further detailed analysis.

Furthermore, the power flow value on the busbar coupler for the case of a trip of a transmission line had to be calculated manually by HOPS in the IDCF by considering the power flow on the transmission lines and the transformers at the SS of Ernestinovo. Neglecting the power flow on the transformers TR1 and TR2, the power flow of the busbar coupler would correspond to the sum of the power flow on the lines of Ernestinovo (HR) – Pecs 1 (HU) and Ernestinovo (HR)–Žerjavinec (HR).

The manual calculation of the power flow on the busbar coupler for the case of a trip of a transmission line was performed by HOPS with the IDCF data set for the hour 13:00 – 14:00. The trip of the 400 kV line from Novi Sad – Subotica led to the worst case loading of the busbar coupler. In case of a trip, the expected power flow on the busbar coupler resulted in a power flow of 1,370 MW and a current of 1,930 A, respectively. The value was still within the permitted limits.

Further data regarding the local load flow situation in EMS and Transelectrica control area is given in the Annexes.

Recommendation concerning modelling and execution of (n-1) calculation

ID	Recommendation	Justification	Responsible
Modelling and execution of (n-1) calculation			
R-8	It should be mandatory to **include** outages of any transmission elements (incl. **busbar couplers**) **in the contingency lists** in the event of a cross-border effect, if they are protected by overcurrent and over-/under-voltage protection devices. A TSO's SCADA system and the modelling of the respective system elements in the IGMs across all timeframes must allow for the simulation of such contingencies.	The inclusion of the tripping of the busbar coupler in Ernestinovo in the contingency list of HOPS would have allowed an earlier identification of the (n-1) violation. At neighbouring TSOs, operators would have been more aware of the effects of a contingency of the busbar coupler in Ernestinovo on their grid. The probability of a tripping of the busbar coupler is significantly increased when the busbar coupler is protected by an overcurrent protection. Therefore, it is recommended to include the busbar coupler in the contingency list, if it is protected by an overcurrent protection.	All TSOs

Recommendation concerning detail of data model

ID	Recommendation	Justification	Responsible
Modelling and execution of (n-1) calculation			
R-9	When **creating IGMs**, all TSOs shall model the grid in such a way that the power flow limits of all relevant grid elements can be assessed. This includes the **modelling of busbar couplers** (for instance as branches with low impedance) in case they are subject to relevant power flow limits (e.g. resulting from overcurrent protection) and may also include **modelling additional parts of the distribution system**. In particular, the topology of the substations shall clearly	It is required to keep the power flow limits within the operational security limits after the occurrence of a contingency from the contingency list. Modelling the transmission network in a suitable manner is a prerequisite to ensure this in the operational planning processes.	All TSOs

1.3.3.2 Forecasting security calculation

As discussed above, the (n-1) analysis related to the busbar coupler could not be done in the operational planning phase as, at that time, the HOPS DACF models considered all busbars as one node. However, for the purposes of this post-incident analysis based on the forecasting models, the DACF- and IDCF-models were adapted only for SS Ernestinovo so that a contingency analysis could be performed also for the outage of the busbar coupler. The analysis was done using the merged DACF model in AMICA for the timestamps 13:30 and 14:30, while all values are referenced to their individual protection setting. For instance, that yields a current of 2,080 A for the busbar coupler. A complete list of the results can be found in the Annexes.

A brief summary shows that in the:

» base case, the maximum load on any element at 13:30 is 70.3 %, at 14:30 is 70.2 %;

» (n-1) case for the outage of busbar coupler in Ernestinovo, the maximum load is on the line Novi Sad – Subotica, at 13:30 is 84.3 %, at 14:30 is 83.2 %;

» (n-1) case for the outage of the line Novi Sad – Subotica, the maximum load is on the busbar coupler in Ernestinovo, at 13:30 is 84.5 %, at 14:30 is 85.1 %;

» (n-2) case for the outages of the busbar coupler in Ernestinovo and the line Novi Sad – Subotica, the maximum load is on the 220 kV overhead lines Timisoara – Resita 1 & 2, at 13:30 is 92.8 %, at 14:30 is 92.9 %.

It can be concluded that no violation was detected in the day ahead.

A similar off-line analysis was completed using the merged IDCF model. A complete list of results can be found in Annex 1.3.3.3.

A brief summary shows that in the:

» base case, the maximum load on any element at 13:30 is 73,8 %, at 14:30 is 74 %;

» (n-1) case for the outage of busbar coupler in Ernestinovo, the maximum load is on the line Novi Sad – Subotica, at 13:30 is 91,6 %, at 14:30 is 92 %;

» (n-1) case for the outage of the line Novi Sad – Subotica, the maximum load is on the busbar coupler in Ernestinovo, at 13:30 is 94,1 %, at 14:30 is 94 %;

» (n-2) case for the outages of the busbar coupler in Ernestinovo and the line Novi Sad – Subotica, the maximum load is on the 220 kV overhead lines Timisoara – Resita 1 & 2, at 13:30 is 99 %, at 14:30 is 99.2 %.

It can be concluded that only for the (n-2) case some lines are highly loaded.

1.3.3.3 Real-time security calculation

Finally, (n-1) analysis is completed in SCADA, using real time data. This analysis is completed in the study mode of HOPS SCADA for the same cases as for the off-line calculations. The results are shown in the Annexes, though only for some of the network elements. Other elements are outside of observability area, so for these elements the calculation cannot be completed. In addition, for the same reason, the state estimator could not estimate any solution for the (n-2) case.

As the system separation occurred at 14:04, it is illogical to study the time stamp 14:30; therefore, a calculation was made for 14:00.

A brief summary shows that in the:

- » base case, the maximum load on any element at 13:30 is 80.5 %, at 14:00 it is 81.8 %;
- » (n-1) case for the outage of busbar coupler in Ernestinovo, the maximum load is on the line Novi Sad – Subotica, at 13:30 is 127.4 %, at 14:00 is 130,3 %;
- » (n-1) case for the outage of the line Novi Sad – Subotica, the maximum load is on busbar coupler in Ernestinovo, at 13:30 is 128.6 %, at 14:00 is 131.3 %.

It can be seen that (n-1) violations are detected for the loss of the 400 kV Novi Sad – Subotica which overloads the busbar coupler in substation Ernestinovo) and vice versa for the loss of the busbar coupler in Ernestinovo the 400 kV line Novi Sad – Subotica is overloaded.

This happens for two reasons:

- » slightly higher load on all transmission elements in real time than in the IDCF model;
- » limited model used in the HOPS SCADA.

The limitations of the model used in the HOPS SCADA can best be illustrated by comparing the calculations made by using the merged IDCF models (AMICA) containing the network of the whole synchronous area and the calculations made by using the limited model in the SCADA for the time stamp 13:30. Table 1.4 below shows that when using the merged IDCF models, the power flow through the busbar coupler increases from 73.8 % (1,077 MW) to 94.1 % (1,370 MW), which is an increase of 20.3 % (293 MW), for the loss of the 400 kV line Novi Sad – Subotica. Using the limited model in the SCADA, the power flow through the busbar coupler increases from 80.5 % (1,188 MW) to 128.6 % (1,897 MW), which is an increase of 48,1 % (709 MW). This would mean that almost all power flow from 400 kV line Novi Sad – Subotica (920 MW) spilled over to the substation Ernestinovo, which does not correspond to reality.

Similar, but not so pronounced, results apply to the opposite situation for the loss of the busbar coupler – the 400 kV line Novi Sad – Subotica increases from 63.3 % (848 MW) to 91.6 % (1,204 MW), i.e. (+356 MW) calculated in AMICA and while using the limited model in SCADA, increases from 76.3 % (920 MW) to 127.4 % (1,480 MW), i.e. (+560 MW), which is an increase of 28.3 %.

Based on this comparison, it can be concluded that using a busbar coupler in the (n-1) analyses based on the model used in HOPS SCADA would likely have indicated the looming overload, so that remedial actions might have been taken in time.

	time stamp 13:30 AMICA						time stamp 13:30 SCADA					
	base case (MW, %In)		(n-1)-case for the outage of busbar coupler in Ernestinovo (MW, %In)		(n-1)-case for the outage of the line Novi Sad - Subotica (MW, %In)		base case (MW, %In)		(n-1)-case for the outage of busbar coupler in Ernestinovo (MW, %In)		(n-1)-case for the outage of the line Novi Sad - Subotica (MW, %In)	
Substation Ernestinovo busbar coupler	1,077	73.8	N/A	N/A	1,370	94.1	1,188	80.5	-	N/A	1,897	128.6
400 kV line Novi Sad - Subotica	848	63.3	1,204	91.6	N/A	N/A	920	76.3	1,480	127.4	-	N/A

Table 1.4: The results of contingency analysis made in AMICA (merged IDCF model) and SCADA (model acc. observability area)

1.3.4 Comparison between DACF, IDCF and RT

A comparison between the different time stamps can be obtained based on different calculations. Below, two different ways are presented: First, an analysis based on HOPS forecasting processes. Second, a post-incident analysis by SCC.

1.3.4.1 Comparison based on HOPS forecasting security calculation

The power flows in the HOPS network are predicted beginning on the day before the delivery using the DACF process. Furthermore, the power flows are updated and checked regularly by the IDCF with newer data available. During real-time operation, an n-1 contingency calculation is performed every minute using the SCADA system of HOPS. The result is a list of n-1 violations.

In Table 1.5, the forecasted IDCF values of the hours from 13:00–14:00 and 14:00–15:00 for the most important transmission network elements that affect the flows in SS Ernestinovo are compared (see Figure 1.17 for the location of transmission network elements). In addition, the value of the Real-Time Snapshot (RTSN) made at 13:30 is depicted in Table 1.5 and compared to the IDCF values.

The match between the IDCF values of the power flows and the actual flow for 13:30 was relatively good and the only mismatch was the flow over the busbar coupler of approx. 100 MW (compare with 150 A or 4.8 % of over-current protection setting). From the comparison of IDCF values, it can also be seen that the power flows on the grid elements were not predicted to change significantly from the hour 13:00–14:00 to the hour 14:00–15:00.

Furthermore, in Table 1.6, the same values are shown in amperes. The values in amperes are used for the following description of facts.

From Table 1.6, it can be concluded that the mismatch of the actual power flow on the busbar coupler compared to the forecasted value was approximately 150 A at the time of 13:30.

Power Flow (MW)	Busbar coupler	Ernestinovo – Žerjavinec	Đakovo – Gradačac	Đakovo – Tuzla	Ernestinovo – Ugljevik	Ernestinovo – S. Mitrovica	Ernestinovo – Pecs 1	Ernestinovo – Pecs 2	Žerjavinec – Heviz 1	Žerjavinec – Heviz 2
IDCF 13:00–14:00	1,076	344	-94	-132	-568	-510	730	0	0	345
IDCF 14:00–15:00	1,078	355	-96	-135	-563	-516	723	0	0	350
IDCF 13:00–14:00	1,076	344	-94	-132	-568	-510	730	0	0	345
RTSN at 13:30	1,180	409	-83	-129	-619	-604	779	0	0	306

Table 1.5: Comparison of forecasted and realised flows near SS Ernestinovo (in MW)

Current (A)	Busbar coupler	Ernestinovo – Žerjavinec	Đakovo – Gradačac	Đakovo – Tuzla	Ernestinovo – Ugljevik	Ernestinovo – S. Mitrovica	Ernestinovo – Pecs 1	Ernestinovo – Pecs 2	Žerjavinec – Heviz 1	Žerjavinec – Heviz 2
IDCF 13:00–14:00	1,517	485	-133	-186	-801	-719	1,029	0	0	486
IDCF 14:00–15:00	1,520	500	-135	-190	-794	-727	1,019	0	0	493
IDCF 13:00–14:00	1,517	485	-133	-186	-801	-719	1,029	0	0	486
RTSN at 13:30	1,664	577	-117	-182	-873	-852	1,098	0	0	431

Table 1.6: Comparison of forecasted and realised currents near SS Ernestinovo (in A)

1.3.4.2 Post-incident analysis by SCC

The existing data models and calculation models in daily use for DACF or IDCF calculations did not indicate any risk of n-1 overloadings, either from the TSCNET calculations nor from SCC calculation. The data below are based on further calculation from SCC, which has been done after the incident for an in-depth analysis. The model assumptions for this calculation are explained in the Annexes.

Table 1.7 shows the comparison of the base case (BC) results between the RTSN, IDCF and DACF processes. In that regard, the original created CGM for the hour 14:00 – 15:00 was used for gathering the DACF and IDCF results, whereas the real time results have been obtained based on a snapshot CGM from 14:00. The used Imax is thereby defined as the permanent admissible current on the device. As a basis for this table, all 400 kV and 220 kV elements loaded over 70 % in the RTSN CGM after load flow (LF) calculation are listed. Calculations cover the TSOs in the separation area (RS, BA, HR, HU and RO). To achieve a better insight of the system state, all 400 kV lines connected to the SS Ernestinovo as well as internal EMS 400 kV RP Mladost – Sremska Mitrovica 2 are also included (loaded less than 70 % in the RTSN CGM). Please note that the busbar coupler in the SS Ernestinovo was not available in the DACF/IDCF CGMs but only in the RTSN (it was not either available here initially but was manually added as (HERNES11 HERNES12 1) as explained above). The last three columns show the absolute differences (%) between the RTSN, IDCF and DACF values.

Name	Type	Area 1	Area 2	Voltage	Imax [A] SN	Imax [A] IDCF, DACF	Sn [MVA]	Monitoring SCC	Loading [%] SN	Loading [%] IDCF	Loading [%] DACF	Delta [%] (SN - IDCF)	Delta [%] (SN - DACF)	Delta [%] (IDCF - DACF)
HERNES11_HERNES12_CKT_1	Sw.	HR	HR	400	1,920	-	-	NO	104.83	-	-	-	-	-
RARA1D5_RARAD22_CKT_1	Tr.	RO	RO	110-220	-	-	200	NO	98.69	91.7	90.6	6.99	8.09	1.1
RTRGJ22_RUREC22_CKT_1	Ln.	RO	RO	220	978	978	-	NO	88.43	65.54	62.62	22.89	25.81	2.92
RPARO22_RTRGJ22_CKT_1	Ln.	RO	RO	220	978	978	-	NO	88.38	65.18	62.51	23.2	25.87	2.67
JSRBOB51_JSRBOB2_CKT_2	Tr.	RS	RS	110-220	-	-	150	YES	85.78	74	72	11.78	13.78	2
JSUBO311_XSA_SU11_CKT_1	Ln.	RS	XX(HU)	400	1,599	1,920	-	YES	85.46	57.09	49.72	14.11	21.48	7.37
MSAFA_11_XSA_SU11_CKT_1	Ln.	HU	XX(RS)	400	1,599	1,599	-	YES	85.06	68.46	59.6	16.6	25.46	8.86
RPDF222_RRESI22_CKT_1	Ln.	RO	RO	220	960	960	-	YES	83.82	75.82	73.38	8	10.44	2.44
RPDF212_RRESI12_CKT_1	Ln.	RO	RO	220	960	960	-	YES	83.82	75.82	73.38	8	10.44	2.44
RRESI22_RTIMI22_CKT_1	Ln.	RO	RO	220	960	960	-	YES	79.3	71.58	69.18	7.72	10.12	2.4
RRESI12_RTIMI12_CKT_1	Ln.	RO	RO	220	960	960	-	YES	79.3	71.58	69.58	7.72	9.72	2
MPAKS_11_MPERK_11_CKT_1	Ln.	HU	HU	400	1,999	1,999	-	YES	77.7	73.47	69.02	4.23	8.68	4.45
HKONJS2_HZAKUC2_CKT_1	Ln.	HR	HR	220	780	780	-	NO	76.9	69.43	73.06	7.47	3.84	-3.63
JNSAD312_JSUBO311_CKT_1	Ln.	RS	RS	400	1,920	1,920	-	YES	75.75	62.62	57.24	13.13	18.51	5.38
RHASD22_RPEST12_CKT_1	Ln.	RO	RO	220	978	978	-	NO	75.22	55.98	53.13	19.24	22.09	2.85
HMRACL2_HZERJA2_CKT_1	Ln.	HR	HR	220	780	780	-	NO	74.69	51.62	55.68	23.07	19.01	-4.06
RBARU22_RPARO22_CKT_1	Ln.	RO	RO	220	978	978	-	NO	74.44	54.97	52.35	19.47	22.09	2.62
MGONY_11_MGONYE11_CKT_1	Ln.	HU	HU	400	866	866	-	NO	72.84	62.64	62.38	10.2	10.46	0.26
RUREC41_RUREC22_CKT_1	Tr.	RO	RO	400-220	-	-	400	NO	73.02	37.54	35.4	35.48	37.62	2.14
HERNES11_XER_PE11_CKT_1	Ln.	HR	XX(HU)	400	1,920	2,001	-	YES	66.98	48.52	41.2	15.75	23.07	7.32
HERNES12_XUG_ER11_CKT_1	Ln.	HR	XX(BA)	400	1,920	1,920	-	YES	53.63	40.64	38.2	12.99	15.43	2.44
HERNES12_XER_SM11_CKT_1	Ln.	HR	XX(RS)	400	1,920	1,920	-	YES	51.28	38.27	34.73	13.01	16.55	3.54
HERNES11_HZERJA1_CKT_1	Ln.	HR	HR	400	1,920	1,920	-	YES	37.27	27.9	27.8	9.37	9.47	0.1
JRPMLA12_JSMIT211_CKT_1	Ln.	RS	RS	400	1,920	1,920	-	YES	44.46	34.86	31.65	9.6	12.81	3.21

Table 1.7: Comparison of RTSN(SN), IDCF and DACF results on Base case scenario

It can be concluded that between the IDCF and DACF there are no significant differences.

The maximum recorded differences (IDCF – DACF) are:

- » the internal EMS line 400 kV Novi Sad 3 – Subotica 3 (5.38 %);
- » tie-line between EMS and MAVIR 400 kV Subotica 3 – Sandorfalva (7.37 % and 8.36 % depending on the parts observed);
- » tie-line between HOPS and MAVIR 400 kV Ernestinovo – Pecs (line 1) (7.32 %).

This part of the grid in real-time was critical but those loadings in the IDCF were still below 70 %.

On the other side, differences between RTSN and IDCF
On the other side, differences between RTSN and IDCF
are much higher (up to 35 %). Several lines are highly loaded in real-time SN, in particular several 220 kV lines in Romania, but below of the admitted limits. For instance, not all TSOs deliver accurate IDCF IGMs, so that for the specific purpose the DACF IGMs have to be used. More detailed analyses may be performed in this area.

The above analysis illustrates that the IDCF data models are deviating substantially from the RTSN models, which render the IDCF models less reliable as a basis for real-time decisions.

It should also be noted that the BB coupler in Ernestinovo (inserted in the model) in the SN analysis was loaded at 14:00 to 104.83 % (related to an Imax of 1,920 A). N-1 calculations on the RT SN data model (which include the model improvements and the Busbar coupler in Ernestinovo) identified significant overloads over several lines in an outage of the busbar coupler (data not presented in the Report).

Two particular overloaded lines are of interest:

- » 400 kV Subotica 3 (RS) – Sandorfalva (HU) – (142 %)
- » 400 kV Subotica 3 – Novi Sad 3 (EMS internal) – (114 %)

The data model for Subotica 3 (RS) – Sandorfalva (HU) needs checking, as it was the 400 kV line Subotica 3 – Novi Sad 3 (an EMS internal line) that actually tripped on over-current protection relay.

Recommendation concerning forecast quality

ID	Recommendation	Justification	Responsible
R-10	Assess and improve the forecast quality, particularly the IDCF quality, to **reduce** the **difference of results of IDCF and real-time calculations**.	The present process for IDCF data model creation is not standardised. A high-quality IDCF is essential for a secure system operation.	ENTSO-E

1.3.5 Evaluation of security calculation

Deficiencies in modelling and the execution of the (n-1) calculation greatly restrained the correct assessment of the situation before the system separation as well as the timely application of appropriate countermeasures.

The tripping of the busbar coupler (as Critical Outage) in Ernestinovo was not included in the contingency lists of HOPS neighbouring TSOs (busbar coupler was not modelled in HOPS IGMs) and was thus not adequately calculated in DACF, IDCF and Realtime. As the probability for contingencies of busbar couplers is generally very low, this is technically appropriate under most circumstances. However, as an overcurrent protection device was activated for the bus coupler in Ernestinovo, the non-inclusion in the contingency list no longer seems adequate from a technical perspective.

Operators at HOPS would have realised earlier that the (n-1) criterion was not met in their responsibility area in the event of the tripping of the busbar coupler in Ernestinovo, if this contingency had been included in HOPS's contingency list. On EMS's side, operators would have been more aware of the effects of a contingency of the busbar coupler in Ernestinovo on the transmission line Novi Sad – Subotica, if it had been included in the contingency list. However, it must be considered that in the actual chain of events, Novi Sad – Subotica did not trip after the sole tripping of the busbar coupler but after the tripping of the busbar coupler as well as the 400/110 kV transformers in Ernestinovo. Even if EMS had accounted for the tripping of the busbar coupler, this would not have guaranteed withstanding the actual multi contingency in Ernestinovo (i.e. overload of 400/110 kV-transformers in Ernestinovo) which in turn was, under no circumstances, to be accounted for by EMS in their contingency list.

In addition to the effects of tripping of the busbar coupler in Ernestinovo on other grid elements, the effects of other contingencies on the busbar coupler itself (as Critical Branch) should have been monitored. As there were obvious power flow limits to be maintained for the busbar coupler in Ernestinovo due to the overcurrent protection, the effects of other contingencies on this busbar coupler must have been monitored according to Article 32 of SO GL. Although in the actual chain of events no such contingency occurred, it is obvious that the power flow limits of the busbar coupler in Ernestinovo cannot have been maintained in the event of other contingencies from the HOPS contingency list before it ultimately tripped due to overcurrent without the occurrence of any preceding contingency. According to this, the requirements of Article 32 of SO GL have not been fulfilled by HOPS, which ultimately led to the system separation.

The inadequate execution of the (n-1) calculation in real time was mainly caused by the shortcomings of the SCADA system of HOPS which did not allow for the automatised calculation of all relevant contingencies. The inadequate execution of (n-1) calculation in DACF and IDCF was mainly caused by the unsuitable modelling of the busbar coupler in Ernestinovo in HOPS' IGMs. The tripping of the busbar coupler in Ernestinovo as well as the effects of other contingencies on this busbar coupler could not be automatically calculated in DACF and IDCF as the busbar coupler was not explicitly modelled. Although UCTE-DEF does indeed not provide an ideal solution for modelling busbar couplers, best practice for modelling busbar couplers in this format is modelling them as lines with very low impedance. This is applied by several TSOs across Europe and allows busbar couplers to be considered in an appropriate manner.

1.4 Further legal aspects

In the course of the work of the ICS Expert Panel, several legal aspects could not be clarified totally due to their immense complexity in regard to the compliance with SO GL and associated methodologies.

That covers, for instance, a further detailed analysis of the requirements regarding the observability area and its level of detail. Thereby, both the respective TSO as well as its neighbouring TSOs have to cope with the according obligations. Further requirements of SO GL also cover the data-exchange between TSOs as well as the inclusion of transmission assets in the contingency list. In addition, the dynamic stability analysis and its use in operational planning is under question. For further clarification in this regard, both regulators, i.e. ACER and NRAs, as well as ENTSO-E, will provide a team of legal experts to clarify these open points after the report is finalised.

Recommendation for further legal analysis

ID	Recommendation	Justification	Responsible
R-11	Carry out a detailed analysis of the technical issues highlighted in the report to verify that the relevant TSOs comply with the SO Regulation and associated methodologies concerning the safeguarding of the operational security, and, if necessary, propose an action plan to improve the consideration of the legal requirements.	The SO Regulation and the associated methodologies lay down several legal obligations for TSOs in order to safeguard the operational security. Rules on power flow, contingency analysis, dynamic stability management, and data exchange are complexly intertwined, so it is necessary to carry out a detailed analysis to verify that the relevant TSOs comply with the SO Regulation and associated methodologies, and to propose any necessary corrective measures.	Assessment team of legal experts, composed of both regulators as well as ENTSO-E.

2 Dynamic behaviour of the system during the incident

2.1 Sequence of events

The sequence of events was reconstructed based on Wide Area Monitoring System (WAMS) measurements and with protection device recordings, which both possess precise Global Positioning System (GPS) time stamps.

The sequence of events is detailed in Table 2.1. Furthermore, the related separation could be reproduced with the assistance of a dynamic model, which was initially prepared with the individual model snapshots delivered by all CE TSOs.

No	TSO	delta/s	trip time	substation 1	substation 2	voltage/kV	Comments
1a	HOPS	0	14:04:25.9	Ernestinovo		400	busbar coupler overload protection
1b	HOPS	2.6	14:04:28.0	Ernestinovo		400/110	Overload protection of both 400/110 kV transformers
2	EMS	23	14:04:48.9	Subotica	Novi Sad	400	overload protection 20 s 2nd zone
3	TRANS	26	14:04:51.9	Paroşeni	Târgu Jiu Nord	220	distance prot. starting zone 2.4 s
4a	TRANS	27.9	14:04:53.8	Reşiţa	Timişoara	220	dist. prot. 0.4 s
4b	TRANS	27.9	14:04:53.8	Reşiţa	Timişoara	220	dist. prot. 0.4 s, breaker L1 failure
5	NOS BiH	28.2	14:04:54.1	Prijedor	Međurić	220	dist. prot. out-of-step protection
6	NOS BiH	28.2	14:04:54.1	Prijedor	Sisak	220	dist. prot. out-of-step protection
7	HOPS	28.3	14:04:54.2	Melina	Velebit	400	dist. prot. zone 3
8	TRANS	28.3	14:04:54.2	Mintia	Sibiu	400	distance prot. power swing cond.
9	HOPS	28.5	14:04:54.4	Brinje	Padene	220	dist. prot. zone 1
10	TRANS	28.6	14:04:54.5	Gădălin	Iernut	400	distance prot. power swing cond. zone 2 0.4 s
11	TRANS	28.7	14:04:54.6	Sibiu Sud	Iernut	400	dist. prot. zone 3 reverse 0.6 s
12	TRANS	28.7	14:04:54.6	Autotransf 400/220	Roşiori	400/220	dist. prot. power swing cond.
13	TRANS	42.6	14:05:08.5	Iernut	Câmpia Turzii	220	dist. prot. zone 2 power swing conditions
14	TRANS	42.7	14:05:08.6	Fântânele	Ungheni	220	dist. prot. zone 2 power swing conditions

Table 2.1: Sequence of events

The tripping of the first three elements (1a, 1b and 2, in the first 23 seconds) occurred during a situation of extremely high-power flows (approx. 5.8 GW) from the South-East area of the CE power system towards the North-West area. The flow of 5.8 GW is calculated by summing the individual active power flows at 14:00 over the fifteen transmission system elements which tripped. However, based on the complex structure of the Romanian transmission system (a system which meshed operation between transmission and sub-transmission level) in the vicinity of the Iernut substation, there were three transmission system element trips (#10, #12, #13) which are not directly part of the separation line itself.

The initial tripping of the busbar coupler in Ernestinovo led initially to the redirecting of the busbar coupler flow through the two 400/110 kV transformers in Ernestinovo. The two 400/110 kV transformers subsequently tripped and shifted the power flows to the neighbouring transmission lines. In the course of the incident, the CE power system was subsequently split up in a cascading manner into two areas over an additional time frame of approx. 20 seconds.

It should be noted that this sequence of events reflects only the separation of transmission lines in the extra high voltage transmission system. In the parallel operated so-called sub-transmission system, approx. 15 additional lines at the 110 kV voltage level tripped and are not included in this table. They were disconnected automatically by their dedicated protection systems due to their operation in parallel with the transmission system. Indeed, the sub-transmission system is not able to carry the same power as the transmission system, consequently in similar cases that path becomes immediately highly-overloaded.

The exact locations of the tripped elements in the high voltage transmission system are depicted in Figure 2.1. It can be clearly seen that the resulting separation line crosses at least four European transmission system operators, namely HOPS, NOS BiH (Bosnia and Herzegovina), EMS and Transelectrica. As a result of the cascade, the CE power system was divided into two main areas. The corresponding resulting separation line is presented in Figure 2.2.

Figure 2.1: Geographical location of main tripped transmission system elements

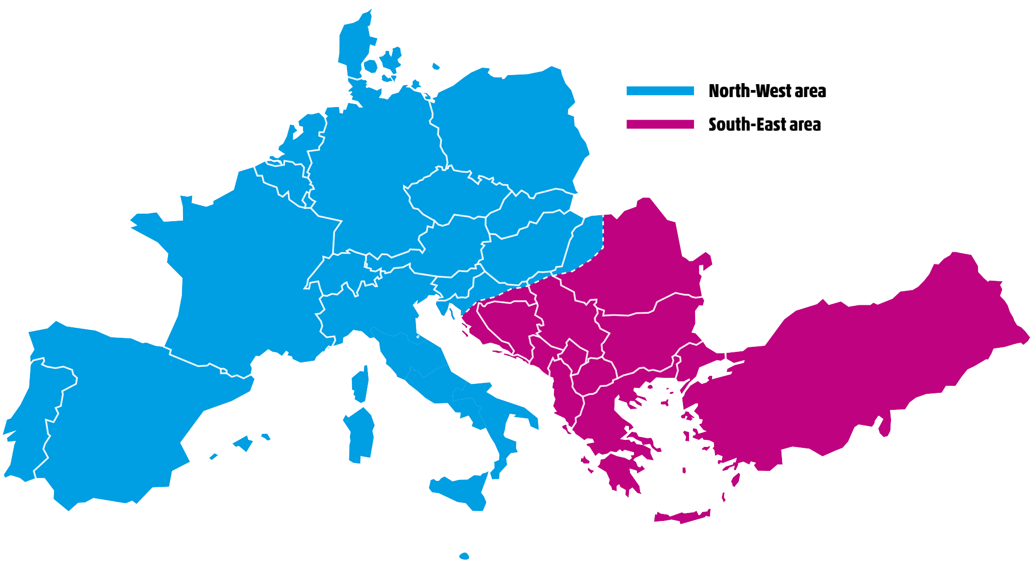


Figure 2.2: Resulting two synchronous areas after the system split

2.2 Dynamic stability margin

In the graph below, event #1 is the trip of the busbar coupler in Ernestinovo and event #2 is the Serbian line trip. The Phasor Measurement Unit (PMU) recordings included in Figure 2.3 explain how the separation occurred. The first three substations (blue) are in the western area and the second three (red/orange/yellow) are in the eastern area.

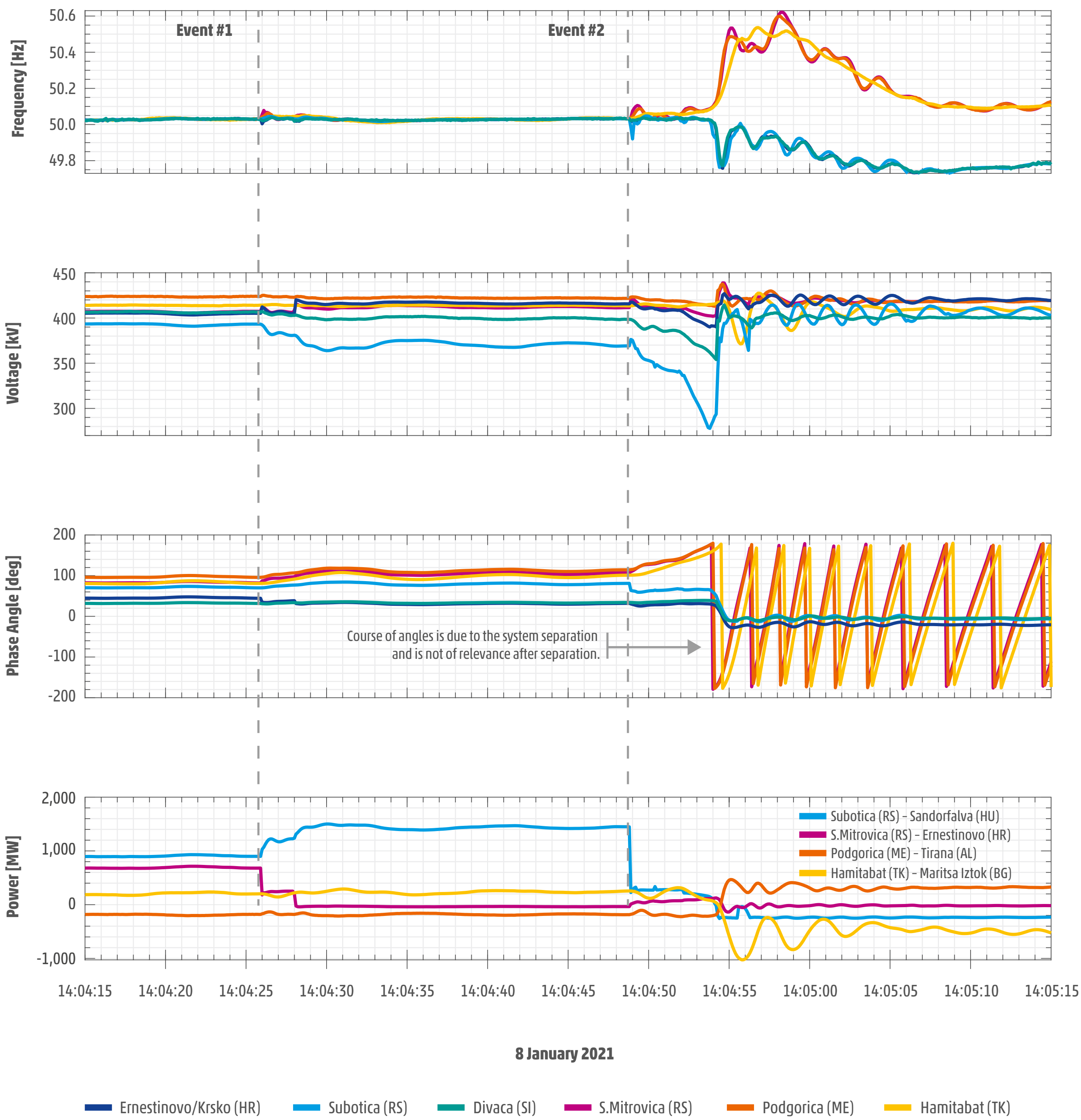


Figure 2.3: Frequencies, voltages, voltage phase angle difference and active power of selected transmission lines (reference for voltage phase angle difference is Lavorgo [CH] substation)

By analysing the selected recordings in detail, the following conclusions can be made:

» Based on the high east–west power flow, the phase angle differences show that before the first event, the system was already operating close to the point of angular instability, with voltage phase angle differences of close to 90 degrees between Western Europe (Switzerland) and Eastern Europe. After the separation of the two areas due to the asynchronous operation, a permanent voltage phase angle difference shift between the corresponding substations can be observed.

» The frequencies show that the opening of the busbar coupler in Ernestinovo substation at 14:04:25.9 (event #1) already had a visible impact on the overall system stability. The small oscillation stabilised before the overload of the second element.

» After the trip of the second element #2, namely the Subotica-Novi Sad transmission line at 14:04:48.9, the entire system reached a point of no return (i.e. the system reach a limit of stability. Only before reaching this limit could the system be saved; after crossing this border/limit no secure/stable way back is possible), and the two areas started to separate from each other due to angular instability.

» The separation phenomena were characterised by:

- A very fast voltage collapse at all substations close to the line of separation,
- A rapid increase of the voltage phase angle difference between the two areas, and
- A gradual difference in the frequencies of the two areas – the frequency was increasing in the South-East area and decreasing in the North-West area.

This transient drove the system into two separate synchronous areas, whereby the South-East area was in overproduction and the North-West area suffered a power deficit. The effect of the unbalance is depicted in the frequency trends, which show an excess in the South-East area and an underfrequency transient in the North-West area of the system. The rapid stabilisation of the system frequencies in both areas was achieved thanks to the activation of several system protection schemes in both areas.

It should be noted that the state-of-the-art transmission system protection devices separated the CE system into two areas by tripping line by line, thereby saving the system from more instabilities and related serious damage.

By extracting relevant cross-border active power flows from the EAS database for the time window 14:00–15:10, the related situation is reflected in a comprehensive manner. By summing up the power flow over the dedicated borders (HOPS – ELES, HOPS – MAVIR, EMS – MAVIR, TEL – MAVIR, TEL – UA_WPS) directly before and after the system separation at 14:05 CET, the flow over the separation line can be verified. The analysis is shown in Figure 2.4.

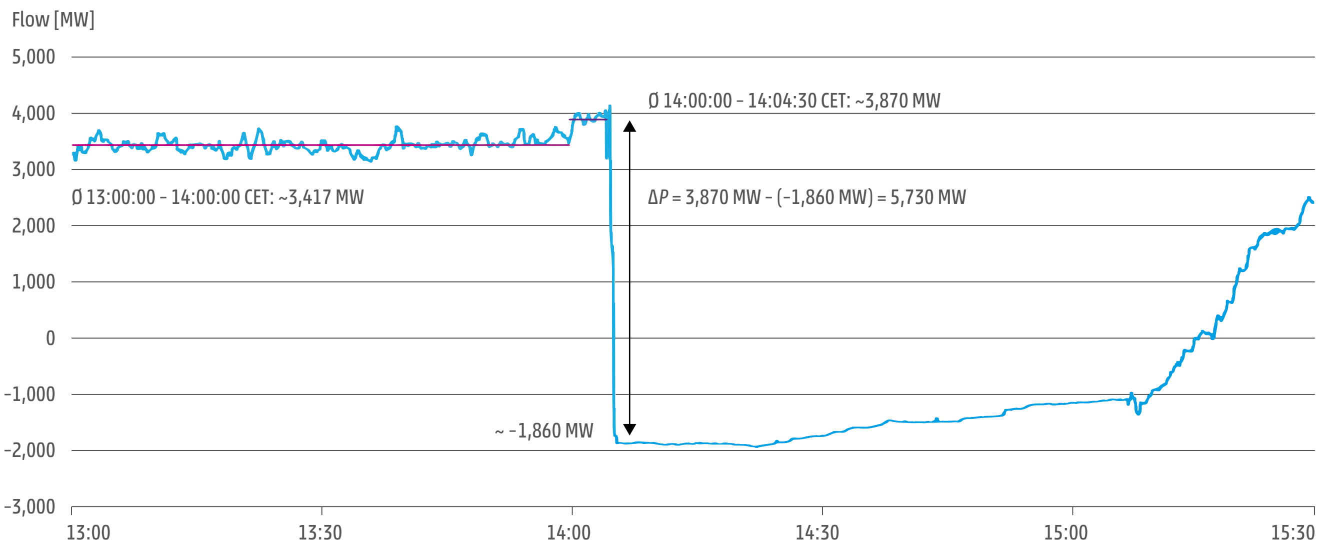


Figure 2.4: Sum of flows over dedicated borders and delta active power flow for system separation

From 13:00 – 14:00 CET, the average sum of active power flow across the dedicated borders is relatively constant at approx. 3,417 MW. As discussed in Chapter 1, this value increases to approximately 3,870 MW on average from 14:00:00 – 14:04:30 CET. Directly after the system separation, the active power flow is inversed to approximately –1,860 MW, resulting in a total delta of approximately 5,730 MW.

As illustrated above, after the system separation, the flow does not go down to 0 MW but instead moves from an export situation to an import situation of 1,860 MW. This is because the cross border active power flows do not exactly match the system separation line. The total change in power flow of 5,730 MW (3,870 + 1,860 MW) is evidence of the pre-event high active power flow on that interface which is, in fact, one of the root causes of the system separation. This is discussed further in section 1.2.1.3.

The individual active power flows over each border are presented further in the Annexes.

2.2.1 Behaviour of protection devices

In the electrical systems, protection devices are the first line of the defence strategies; protections are directly connected to the circuit breaker and no device can be interposed to block or limit their action. The aim of protection is to avoid or prevent as much as possible damage to people and devices; the requirements for a protection system are: selectivity (the ability to isolate only the faulty or overloaded part of a system), speed (the faster the action, the greater the probability of limiting risk and damage), reliability (because it is a "silent sentinel" that operates only in the rare case of fault or overload), sensitivity (the protection must be capable of always detecting the minimum level of fault to operate).

The most used protections in transmission networks are:

- **Distance protections:** the protection measures the voltage and the current, calculating their ratio. If a fault occurs, the calculated ratio is below a reference value.
- **Overcurrent protections:** the protection measures the current flowing through the protected device. If this flow exceeds a predefined threshold, after a certain time delay, the protection trips.
- **Differential protections:** the protection measures the current entering and exiting from the protected element, calculating the difference between the two. If fault occurs, this difference is different from zero.

There is no general rule for protecting electrical devices in substations; in particular, manufacturer's recommendations may impose a limit on the current flowing inside the device without exceeding a certain value for a definite time. Since many different constraints do not allow the affected device to be immediately replaced, a possible solution could be to protect it with an overcurrent protection to avoid exceeding these conditions.

The activation of the overcurrent protection led to the system separation, and thus the behaviour of different protection devices is analysed in greater detail in this section.

The following chapters analyse the coherency between trip by protections and settings in order to evaluate the correctness of intervention; when required, the setting tables of protections are reported to give a direct and pragmatic confirmation of general evaluation.

To assist the reconstruction of protection operation, the following information sources are used:

- **Event recording:** coded messages acquired by the protection with a time stamp that report all the "logical steps" that the relay follows before commanding the circuit breaker opening (trip).
- **Oscillo recording:** a very high sampling recording that permits the reconstruction of what the protection "sees". It is possible to express the recorded variables in two main ways: instantaneous values or root mean square (RMS) values. These are typical conventions proper adopted to demonstrate a particular concept to the reader.
- **X/R diagram:** A plot adopted by a specific protection of lines (Distance Protection). The protection calculates the ratio between voltage and current, obtaining a number that can be projected on two axes, namely X and R.

The protection settings tables help to explain the following concepts:

- **Main 1:** the principal (or unique) protection of the substation bay.
- **Main 2:** the backup and concurrent protection device of the same substation bay (a standard approach adopted in order to improve the selectivity and availability of the protection system). It operates in parallel with Main 1.
- **Prot. Functions:** This is the ANSI (ANSI /IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations) code that identifies the specific protection function.
- **Setting value:** the value that, in the event of excess, will cause the trip.
- **Time:** an intentional delay aimed at evaluating the persistence of tripping conditions.

2.2.1.1 Ernestinovo substation protection settings

At 14:04:20.907, based on the collected data, the maximum current threshold setting on the protection of Ernestinovo 400 kV busbar coupler was exceeded and the busbar coupler tripped 5 seconds later at 14:04:25.9; this is in agreement with the need to protect the integrity of the asset from damage caused by the excess of current flow. Table 2.2 reports the setting of protection and threshold/delay data; the event log of protection confirms 4.999 s as the tripping time.

Main 1			Main 2			
Prot. functions	Set value	Time	Model	Prot. functions	Set value	Time
51/51N	2,080 A	5.0 s				
50/50N	8,000 A	2.0 s				

Table 2.2: Ernestinovo busbar coupler protection settings

2.2.1.2 Ernestinovo transformers 400/110 kV protection settings

The trip of the busbar coupler forces the flow of the two 300 MVA power transformers to exceed the overload protection (namely I 51 protection), that trips after 2 seconds. The oscillo-recording confirms the values read by the protection as 79 A before the busbar coupler trip and 910 A after the busbar coupler trip; therefore the protection tripped triggered by an overload of approximately 160 %.

The Figure 2.5 shows the current flowing in one out of two power transformers measured on High Voltage (HV) level (400 kV), confirming a high overload that justifies the current relay trip.

SS Ernestinovo 400 kV	Main 1			Main 2		
	Prot. functions	Set value	Time	Prot. functions	Set value	Time
TRAFO ATR1 300 MVA	51N (400 kV side)	432 A	5,0 s	51N (110 kV side)	1,900 A	2,0 s
TRAFO ATR2 300 MVA	51 (400 kV side)	560 A	2,0 s	51 (110 kV side)	1,950 A	2,0 s
	51 (110 kV side)	1,900 A	2,0 s	51N (neutral point)	1,500 A	5,0 s

Table 2.3: Ernestinovo Transformers 400/110 kV protection settings

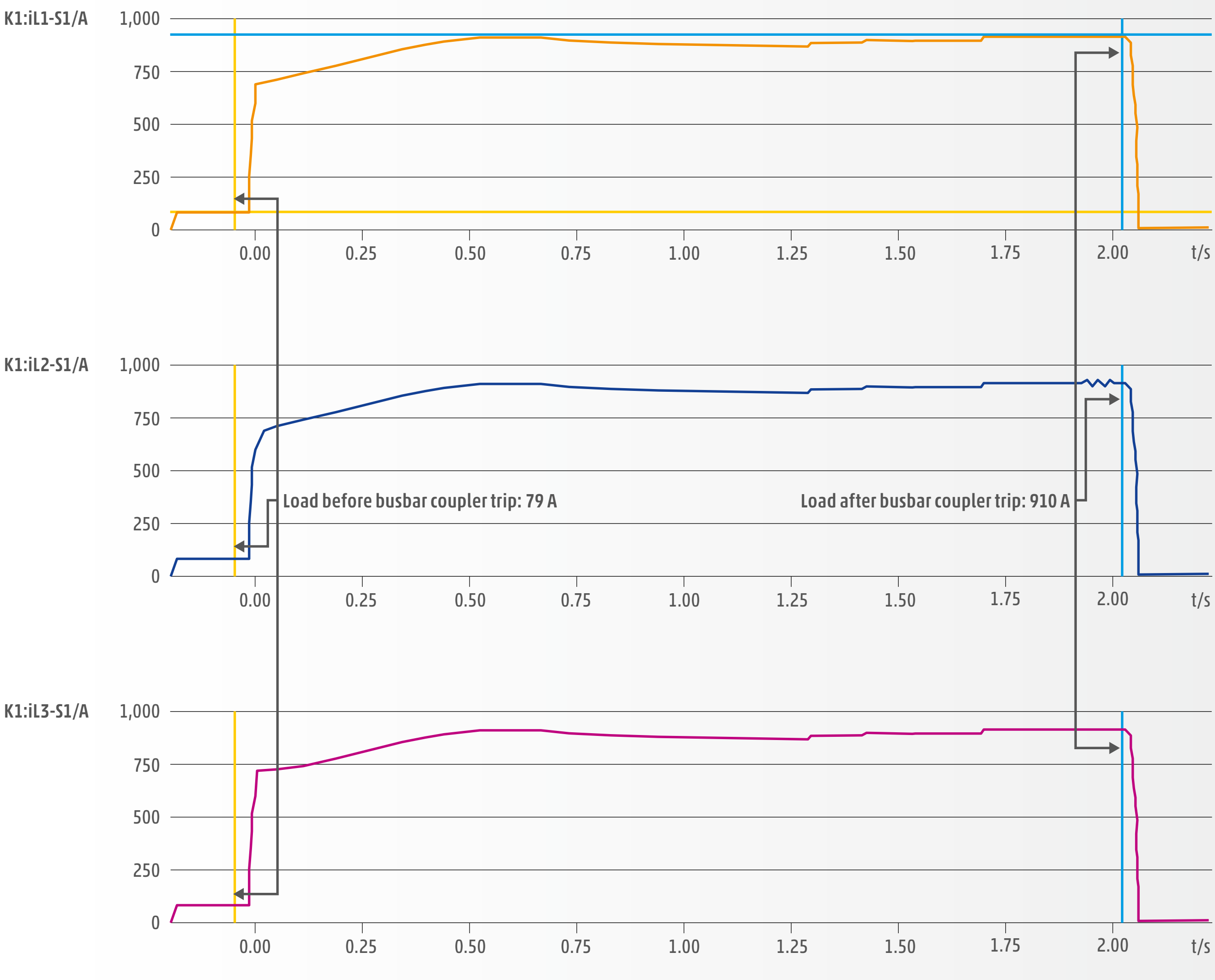


Figure 2.5: Ernestinovo transformers 400/110 kV protections oscillo recordings (RMS values)

2.2.1.3 Novi Sad – Subotica transmission line protection

The settings of the overload protection scheme of the 400 kV Subotica-Novi Sad line are:

Step 1:

» Protection function 51
» Set value: 1,920 A
» Time: 20 min

Step 2:

» Protection function 51
» Set value: 2,300 A
» Time: 20 sec

The first step is set to allow for the protected elements to be temporally overloaded for maximum 20 minutes at 120 % of the rated load, which is sufficient time for the operator to reduce the current. The set value of the second step can only be reached for a very short time (max 20 seconds) to avoid damaging the protected elements.

At 14:04:48.09, the 400 kV Subotica-Novi Sad line tripped due to an overload protection scheme, step 2.

2.2.1.4 Paroseni – Targu Jiu Nord transmission line protection

At 14:04:51.09, 220 kV Paroseni – Targu Jiu Nord line was tripped by distance protection (electromechanical type) in starting zone after 2.4 s. The starting zone criteria adopted by the device is a threshold in current (A), so the trip is an overload detected by the protection. The following figure shows the differences in characteristics between electromechanical and digital protection devices. In principle the digital protections (with load-encroachment characteristics) can be considered more stable in case of overload (due to more flexibility and selectivity) compared to the electromechanical devices.

Even if the electromechanical protection devices were retrofitted with digital devices, it would still not have changed the sequence of events due to the system being close to the "no return" point.

The oscillation recording shows clearly the starting and subsequent trips.

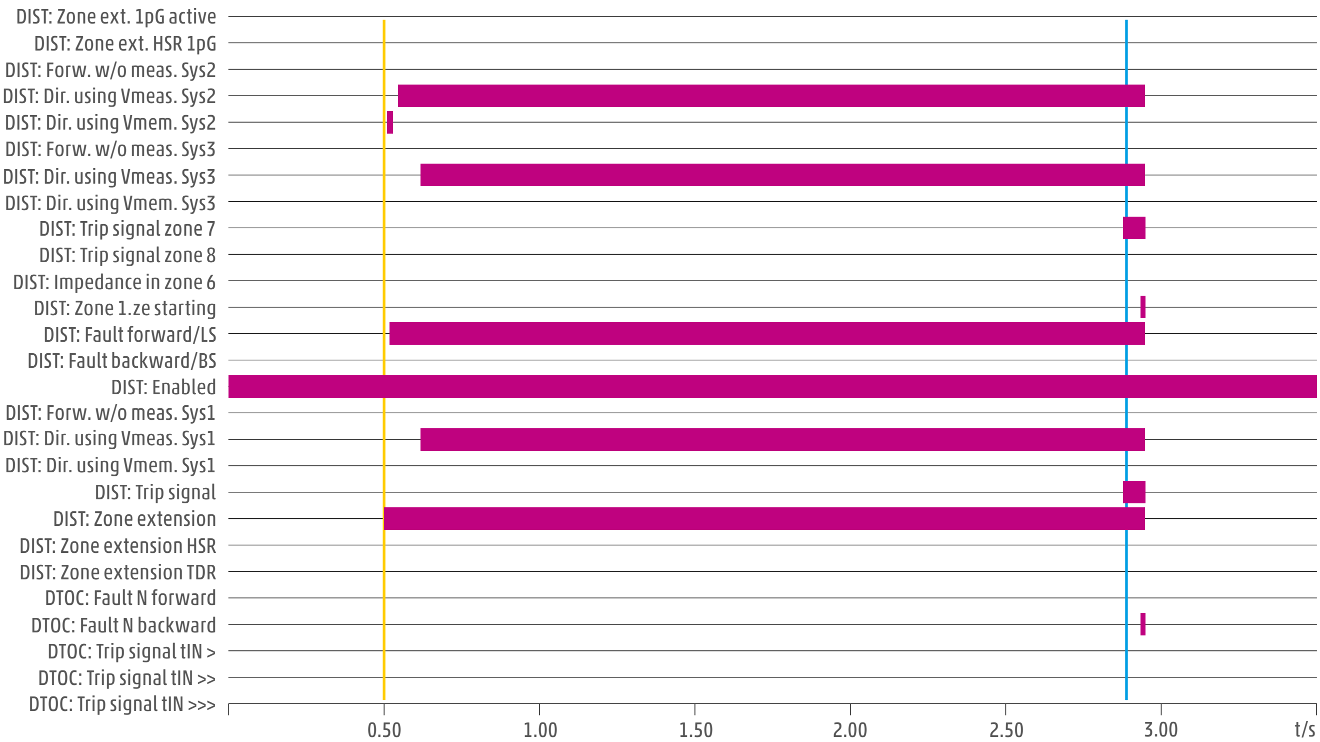


Figure 2.6: Paroseni-Tirgu Jiu protection device recordings (internal signals event recording)

2.2.1.5 Resita – Timisoara transmission line protection settings

At 14:04:53.08, the 220 kV Lines Resita-Timisoara 1 & 2 line were tripped in Resita; both protections released the trip after 0.4 s. It should be noted that the trip of the Timisoara 2 line occurred with the failure to open the Phase 1 pole, which led to the intervention of Breaker Failure after 120 ms (it is common practice for protection schemes to also consider a set of malfunctions if, e.g. circuit breakers do not open all three phases in a certain time interval).

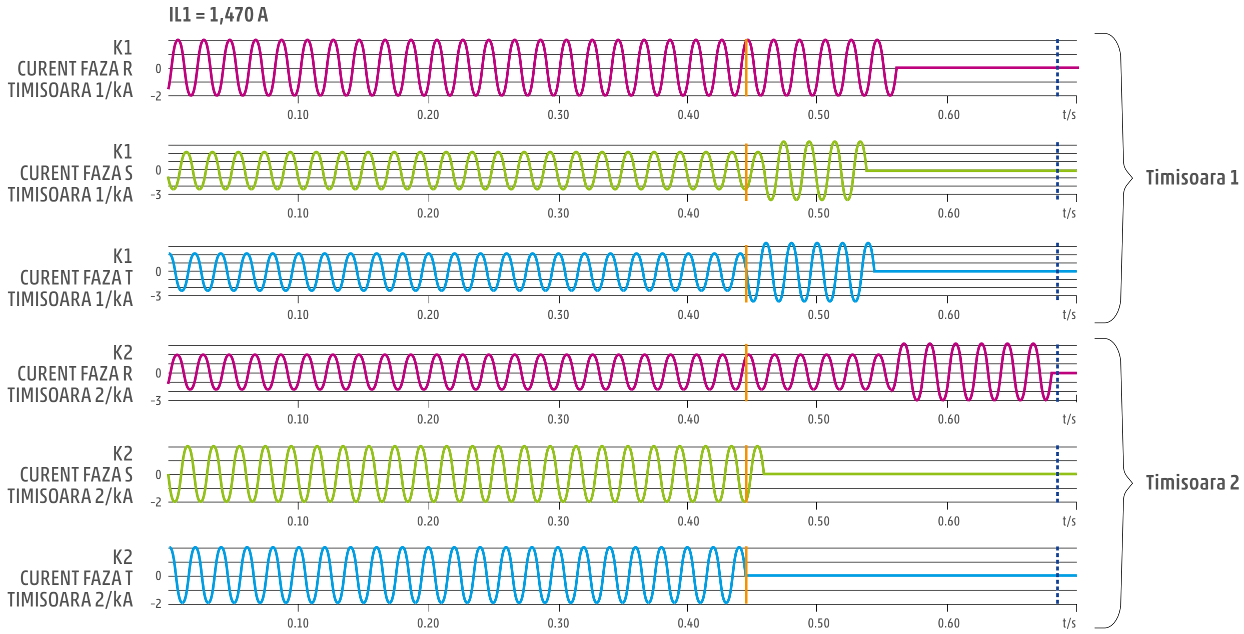


Figure 2.7: Resita-Timisoara protection device oscillo recordings (instantaneous values)

2.2.1.6 220 kV Meduric – Prijedor and Sisak – Prijedor line protection

At 14:04:54.080, the 200 kV Meduric – Prijedor and Sisak – Prijedor lines tripped in SE Prijedor; the starting zone commands the trigger of CB. No transient recording available for Sisak – Prijedor line available. The oscillo of Meduric – Prijedor confirms the start and opening of circuit breaker after 60 ms.

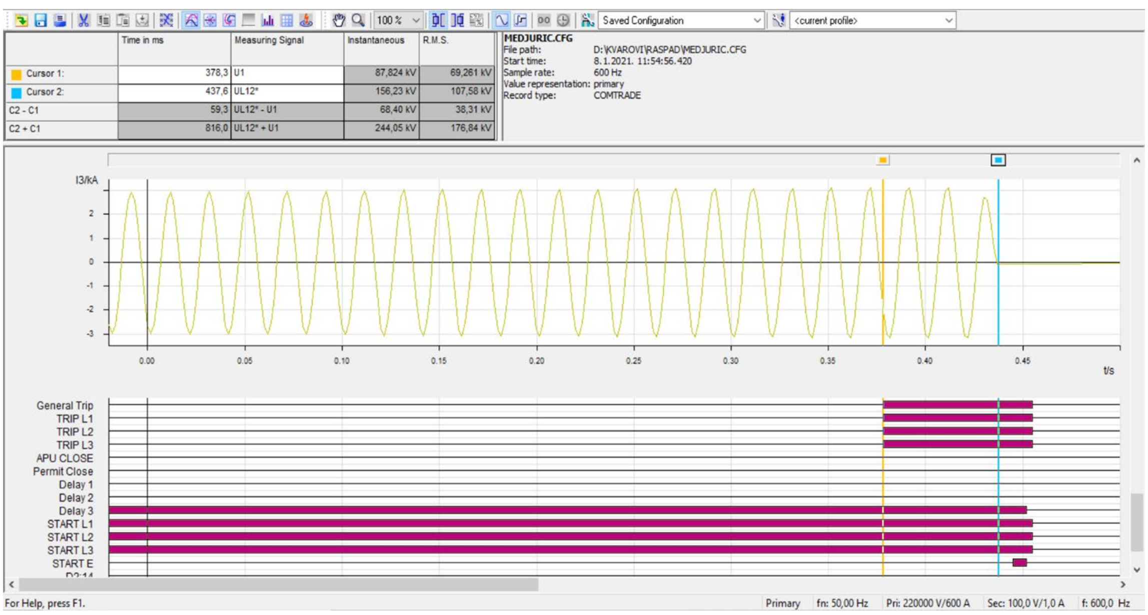


Figure 2.8: Meduric - Prijedor protection device recording (oscillo instantaneous values and internal signals event recording)

2.2.1.7 400 kV Mintia – Sibiu and Gadalin – Iernut and Iernut-Sibiu lines protection

At 14:04:54.56, the ongoing separation between the two systems is definitive (i.e. after passing the stability limit – the point of no return – there is no other option for separating the two systems). The protections see a fault in the first zone. Although the power swing block (protection device option which delays the triggering in the event of oscillation detection) was not active, this function cannot avoid the separation but only delays it.

Figure 2.9 is a R/X graph where R represents resistance and X represents reactance. The blue line shows how during the transient, all the relay zones for tripping were crossed. Each point is a different time instant of the impedance measured by the protection and projected on the R and X axes. The orange sag indicates the path of the impedance that the protection calculates during the transient; when this impedance enters zone 1 and 2, the protection "sees" a fault and correctly trips in order to limit damage to the system. The arrow in the figure indicates the "direction" of the impedance dynamically entering the protection characteristic protected zones.

The digital protection recordings of one of the last tripped lines very effectively reflects the high transients which occur in parallel with the occurrence of angular instability, see Figure 2.10.

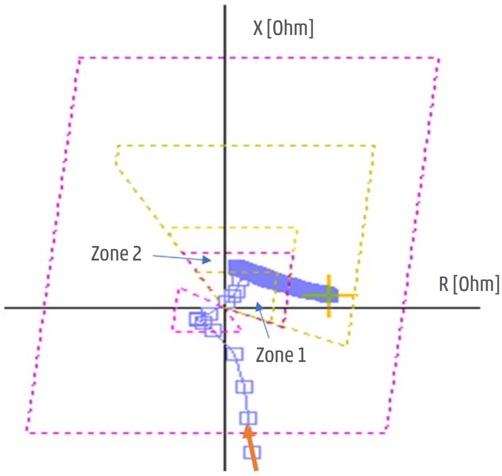


Figure 2.9: Mintia – Sibiu protection device X R diagram (real recording)

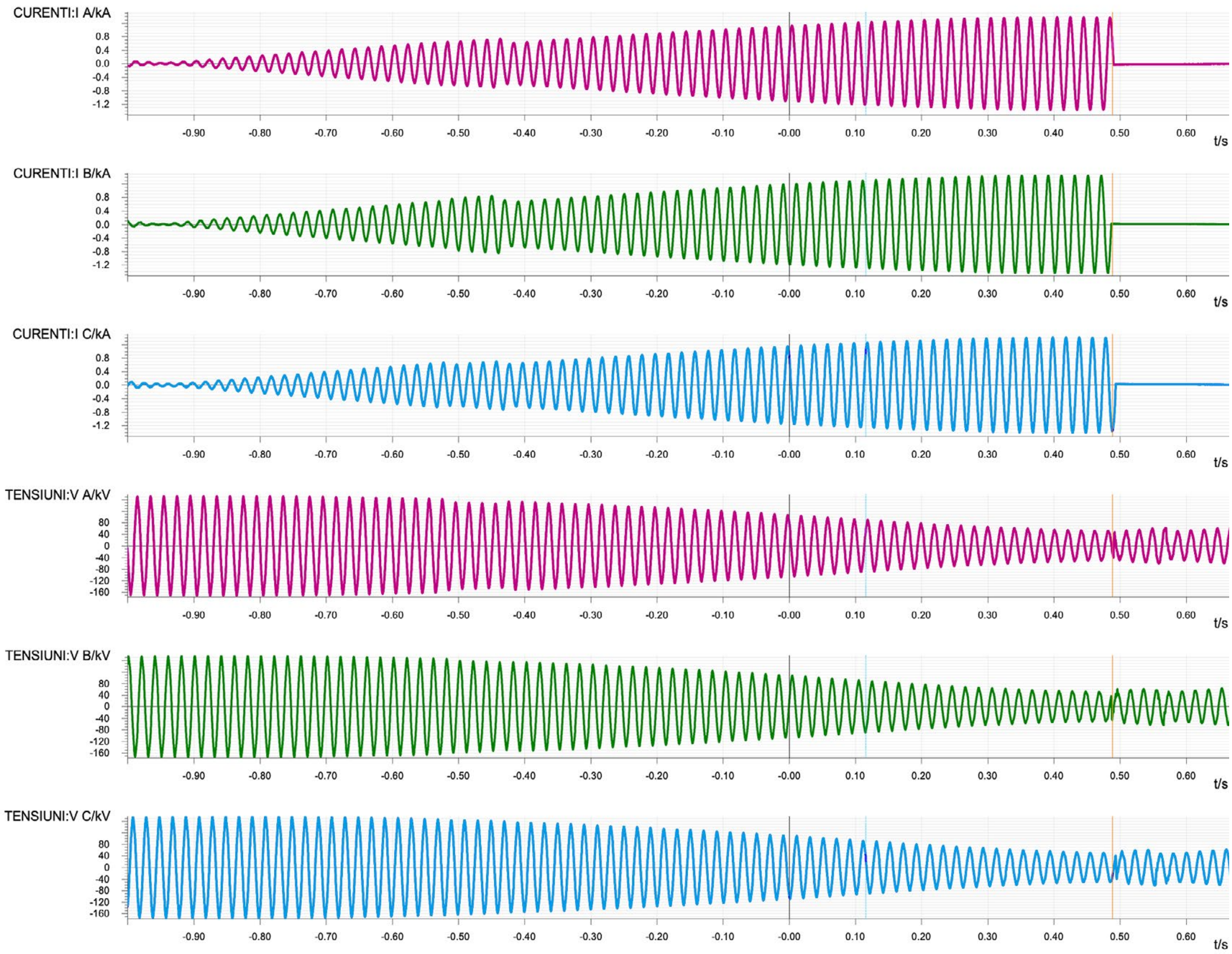


Figure 2.10: Trip of Iernut-Cimpia Turzii overhead line

2.2.2 Analysis

2.2.2.1 Dynamic behaviour of the system during the incident

Based on the heavy active power flow over the cross-borders section as previously presented in section 1.2, a very high voltage phase angle difference between the South-East and North-West part of the CE power system occurred. By using the merged snapshot of 14:00 and by performing the corresponding load flow calculation, the following Figure 2.12 was created, which illustrates the dramatic increase of the voltage phase angle difference around the separation. The calculations and Figure 2.12 reflect a voltage phase angle difference of approximately 80 degrees (the limit of angular instability). It is worth noting that the difference in voltage phase angle corresponds well with the boundary between the two equivalent centres of inertia for the East and West areas. The Centre of Inertia concept is a way to describe the entire electrical grid that is composed of thousands of generators, with only two "large" equivalent generators coinciding with the East and West Europe systems.

This approach enables a powerful simplification of the real behaviour of the system, which is extremely useful for understanding the physical concepts behind the reconstructed phenomena. To make an analogy with tectonic theory, if we represent the East and West grids like two plates, the stability is guaranteed until the forces that try to diverge them are properly compensated; this compensation is given by the equilibrium between the power transmitted between the two areas and the capability of the lines to carry it. A measure of the stress of transmitting the power is the so-called phase angle difference of voltages; when the angle exceeds a certain critical value, the effect on the system is similar to the friction between two tectonic plates: there is a fracture boundary in the most stressed point. Similarly, there is an "electrical fracture boundary" where the voltage angle difference is higher.

This evidence confirms the existence of a potential critical section due to the initial angular behaviour. Indeed, the risk of separation is always located there, where the electrical distance from two centre of inertia is the highest.

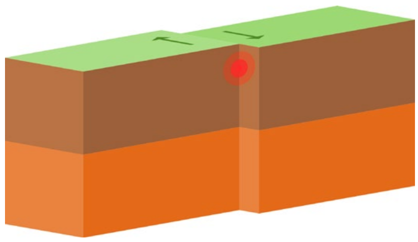


Figure 2.11: The "centre of inertia" concept – analogy with tectonic theory

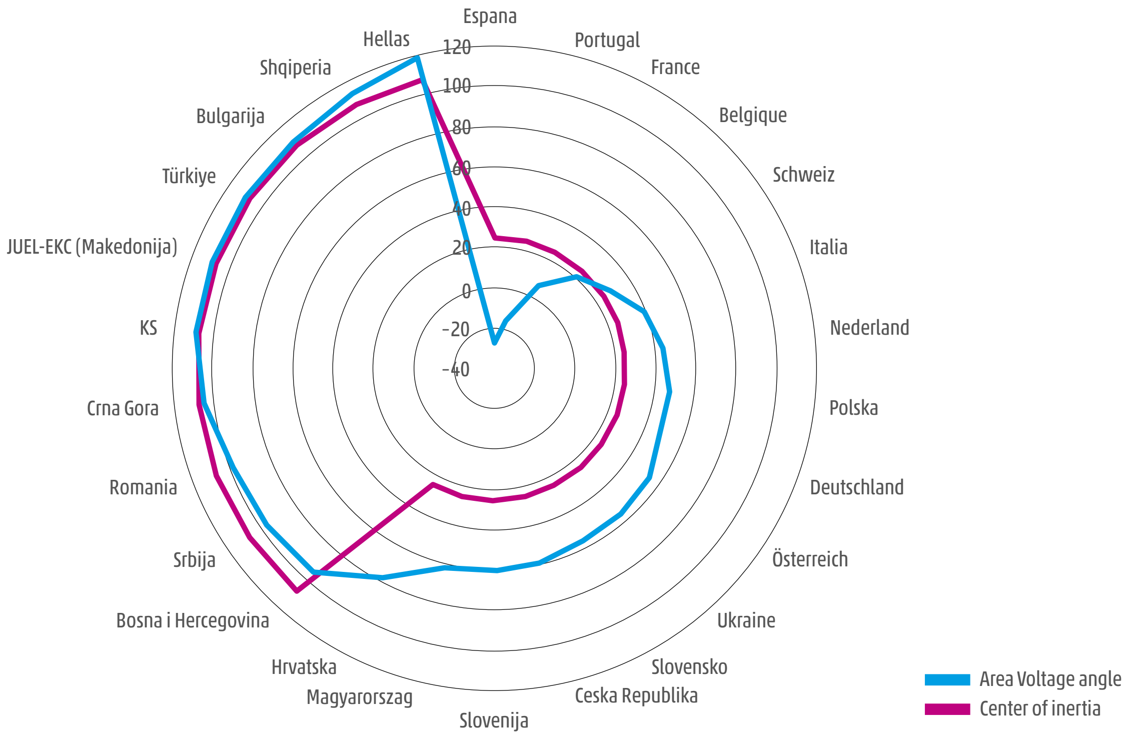


Figure 2.12: Steady-state voltage phase angles across CE power system, 08 January 2021 at 14:00

» Starting from the joining of the TSOs snapshots, the blue curve represents the mean angle over the 400 kV level

» Each angle is representative of a single TSO system

» The orange curve is the angle of the centre of inertia of the two equivalent clusters (EAST and WEST)

» The angle difference of the two clusters is around 80° in agreement with real measurements

The power system transient behaviour was reproduced by dynamic model calculations, considering two different approaches. With a detailed bus-branch dynamic model, based on the steady-state configuration (given by the merged snapshot file for 14:00), the individual steps of separation were simulated to analyse the exact protection equipment triggering and activation. In fact, the steady-state model was extended by the individual dynamic power system elements as generators, AVRs and governors based on the experience and tools available for CE power system model setup. Figure 2.13 illustrates the simulation results obtained with the detailed dynamic model. In Figure 2.13, in order to compare the results of simulation with real measurements, the following parameters are selected: the angle difference between Hamitabat and Soazza (the same locations as measurements from WAMS) and the frequency in three main locations: Soazza, Hamitabat and Ernestinovo.

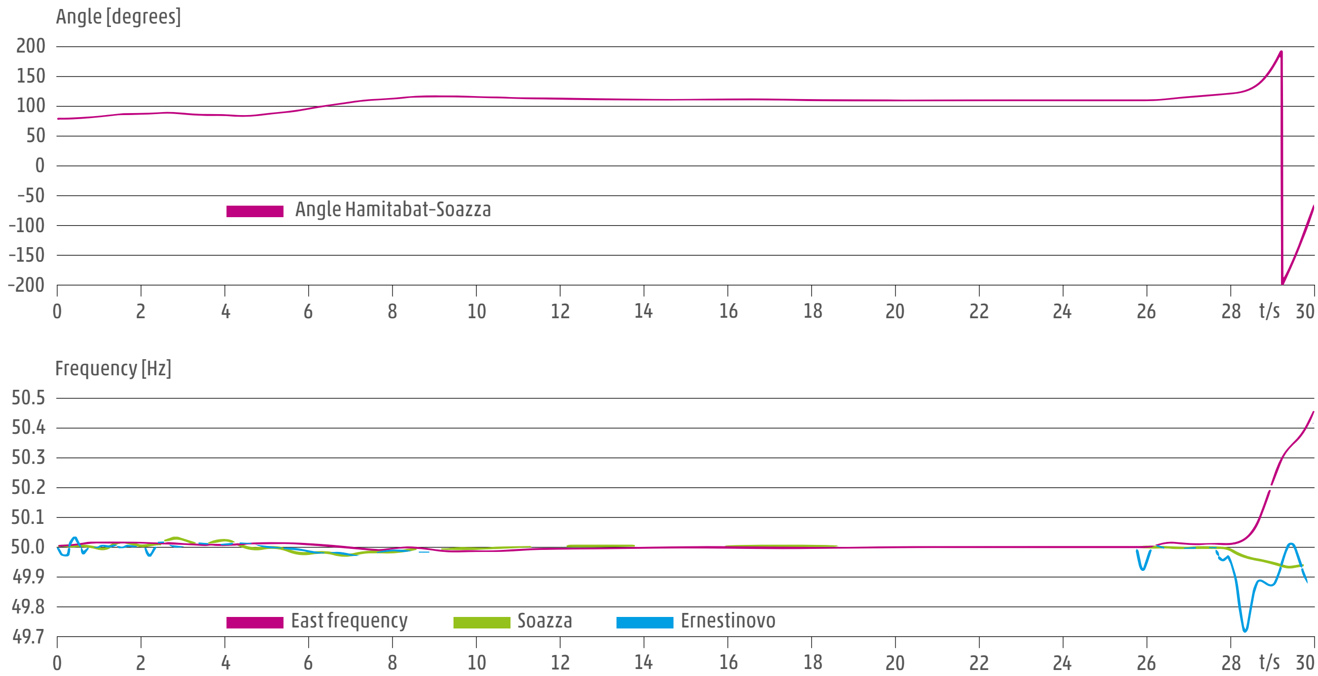


Figure 2.13: Detailed dynamic model calculation results (voltage phase angle and frequencies)

These results show:

» Very good dynamic correspondence following a crosscheck with WAMS measurements

» Same no return point as measurement recordings

» After no return point (visible different system frequencies) simulated protections trip due to transient instability

» After no return point in the event of no protection simulation West and East loss step

Figure 2.14 demonstrates the ability of this model to "reproduce" the distance protection activations, which were all very similar after crossing the point of no return; Figure 2.14 also shows the impedance trajectory seen by the Prejedor Sisak protection. Here, once again, the following observation is important: after the no return point, the impedance trajectory due to the asynchronism of the two systems collapse into the starting zone or the first zone of the distance protections. This is a typical behaviour that comes from dynamic simulation.

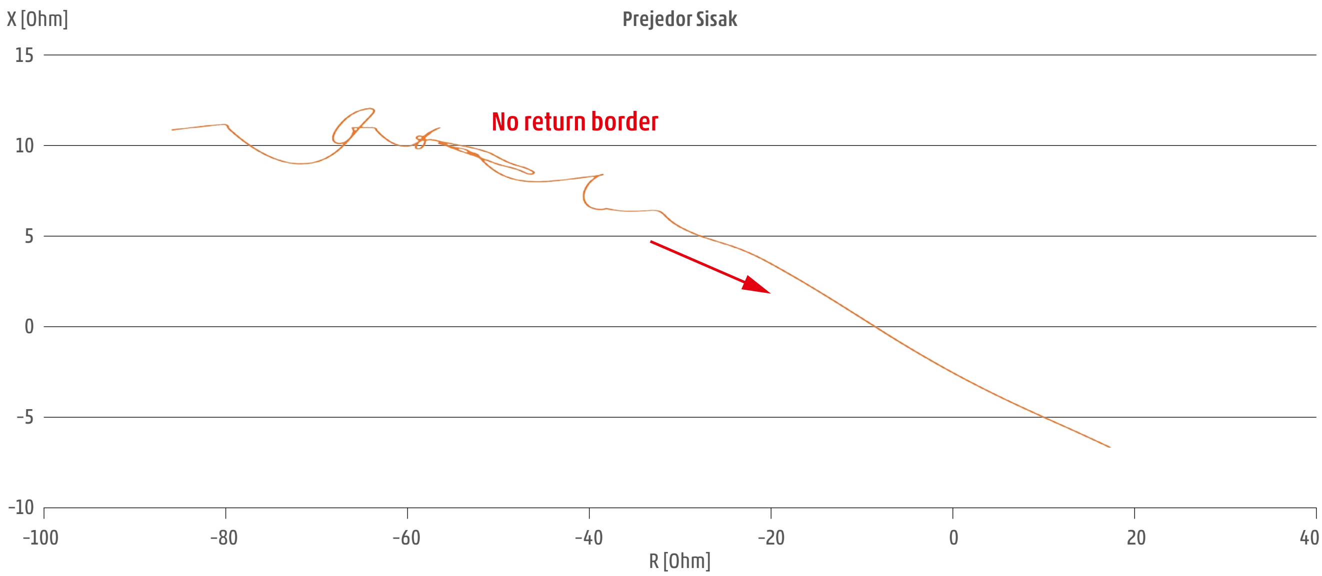


Figure 2.14: Simulation of distance protection activation X-R Diagram

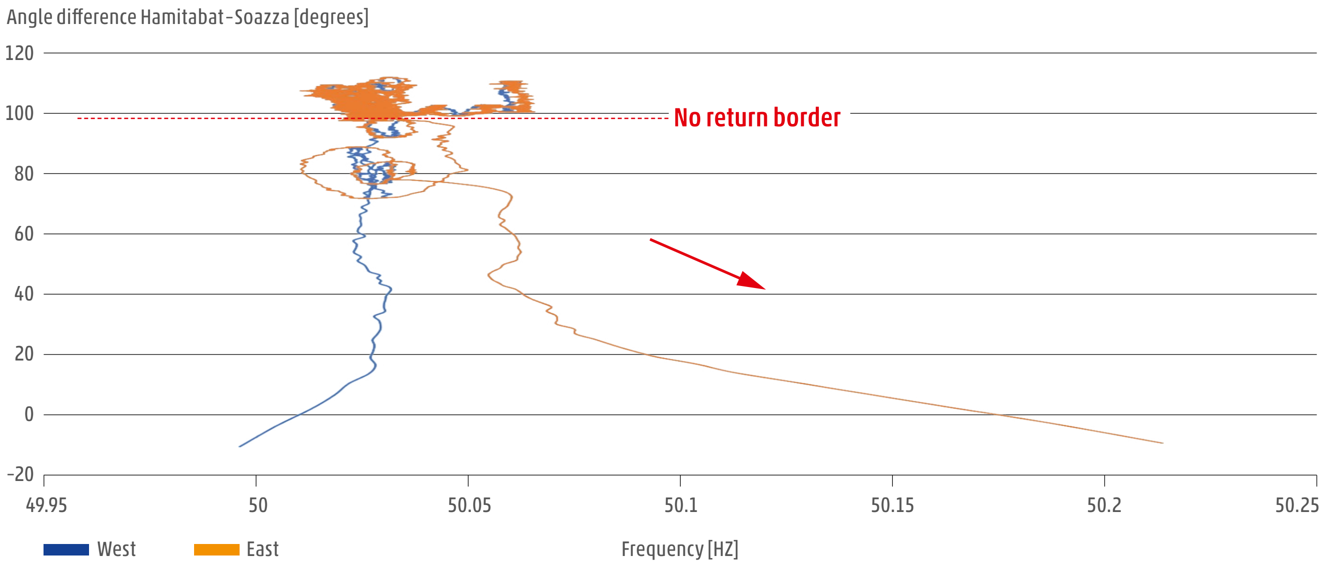


Figure 2.15: Illustration of the Point of no Return by using WAMS measurements

The detection of the point of no return was also performed by compiling the available WAMS measurements of two PMUs, one from each of the separation areas. Figure 2.15 above (space trajectory representation) clearly shows how the no return boundary between the two equivalent systems results in asynchronism.

With another dynamic model (a single busbar model developed using information from the ENTSO-E Transparency Platform), another set of dynamic model calculations were performed. Figure 2.16 compares the single busbar model with the PMU measurements.

The related single busbar model has the advantage that its handling and parametrisation is much simpler compared to the detailed model. The single busbar model can still reproduce an accurate mean system frequency behaviour and, therefore, confirm the main dynamic system behaviours, e.g. system inertia, primary control activation etc.

As shown in Figure 2.16, the South-East simulation, compared with WAMS recordings, shows a very good correspondence during first swing; The North-West simulation, on the other hand, is "faster" during the first swing due to the effect of the interarea mode of this side of system. In any case, with reference to the mean frequency behaviour, the model is adequate.

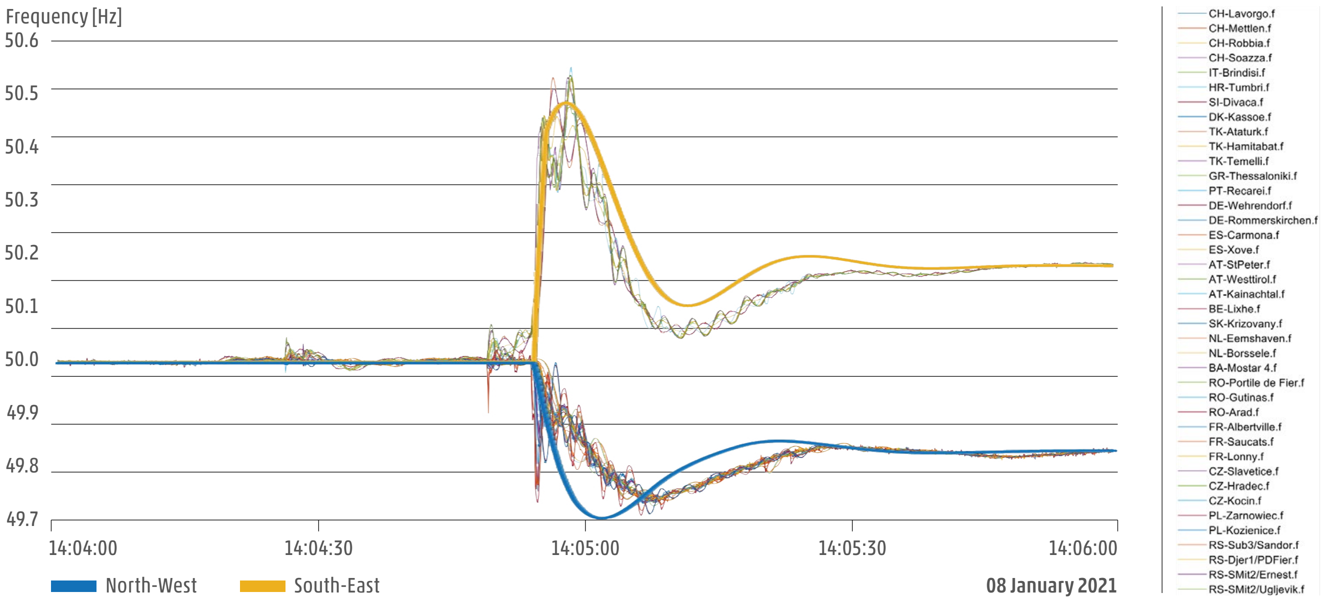


Figure 2.16: Simulation results of the single busbar model and comparison with PMU measurements

It is important to note that no critical inter-area oscillations were observed in none of the areas in no time window – damping was always satisfactory, as shows in Figure 2.17.

The main parameters behind this dynamic model are summarised in Table 2.4.

		Unit	Nord West	South East	Total
System load		GW	326	70.5	**396.5**
Power imbalance		MW	6,000	6,000	-
Power generation:	PV	GW	13	1	**14**
	Wind	GW	21.4	4	**25.4**
	Gasa	GW	73.3	5.3	**78.6**
	Others	GW	218.3	60.2	**278.5**
2021-01-08 14:30:00		seconds	12.4	10.2	-
2021-01-08 14:45:00		seconds	11.1	9.5	-
2021-01-08 15:00:00		%/Hz	2	2	-

Table 2.4: Simplified one busbar model main parameter (Load and generation data are based on the ENTSO-E Transparency Platform information)

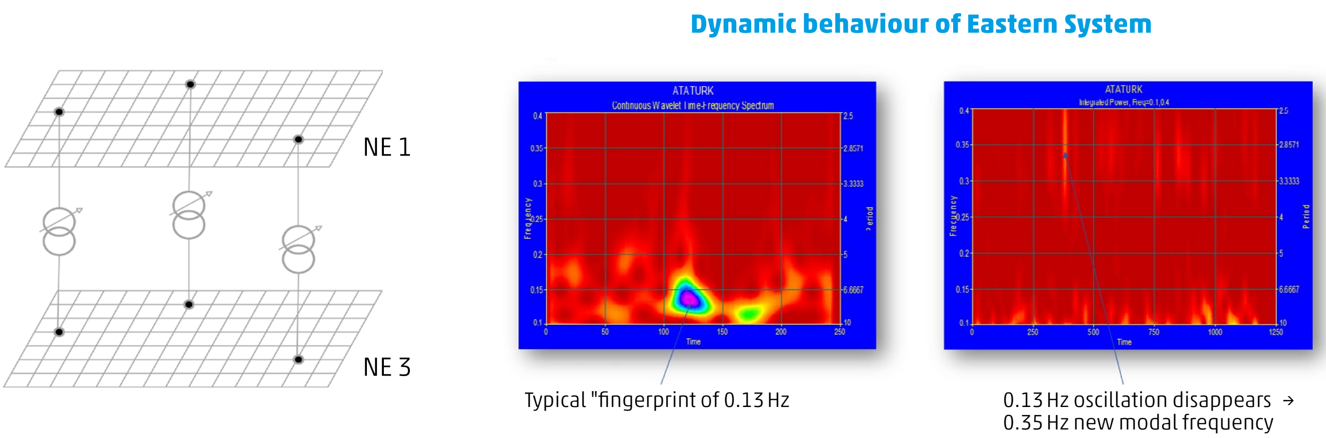


Figure 2.17: Dynamic behaviour of Eastern system (measurements)

2.3 Recommendations

Following the analysis, two main recommendations are proposed

It should be noted here that the system inertia is an important source of active power support in the first few seconds before FCR is fully activated. In light of future developments, such a decreasing amount of synchronous generators in the system and thus a decrease of potential system inertia, frequency support might be on a critical path in this regard. Therefore, measures must be identified to prevent a further reduction of the total system inertia.

ID	Recommendation	Justification	Responsible
R-12	For critical transmission system corridors, the **stability margin** must **be assessed in operational planning and real-time operations**. Furthermore, **operators** must be **trained** in the field of dynamic stability.	On the day of the incident the system was close to the dynamic stability limit. Usually the stability is not assessed in detail during operational planning and real-time operation. Therefore, methods for the assessment have to be developed. The calculations and measurements (PMUs) of the voltage-phase angle differences can serve as indicators for a potential system stability limit. The application of these methods shall be coordinated and used by all TSOs of a synchronous area.	Regional Group Continental Europe TSOs in coordination with relevant NRAs and ACER
R-12.1	Consider the **dynamic stability in the short-term studies**. As part of this recommendation, it could be useful to study the best practices of the Nordic and UK groups. The goal is to have a pragmatic and secure approach to obtain quick-wins, including how to incorporate potential stability constraints in the capacity calculation process		
R-12.2	Reasonably ensure that the weakest points of the network have been studied and that appropriate measures are taken (e.g. PST installations, NTC limit). To do so, the use of historical and statistical flow and temperature charts could be very useful. The objective is to transform certain risk scenarios (after analysing the split-lines) into clear instructions for the operators to avoid potential incidents of this type in the future.		
R-13	Due to the future decrease of conventional power generation sources and a corresponding **reduction of the system inertia, compensational measures** must be identified and implemented where identified.	Considering future developments, the frequency support by system inertia is on a critical path. Therefore, biennial inertia studies need to be duly carried out in accordance with Article 39 (3) of the SO GL.	TSOs

3 Frequency Support and Analysis

3.1 Frequency Containment and activation of automatic system defence measures

Frequency Containment Reserves (FCR) are designed to stabilise the system frequency and are not dimensioned to prevent deviations outside the n-1 criterion (reference incident of 3,000 MW in CE). Additional TSO secondary system defence measures are in place in CE, as per their required system defence plans, to support the transmission system and to minimise impacts on consumers for larger system events (outside the n-1 criteria).

These TSO system defence measures include individual automatic special protection schemes (namely either the disconnection of pump storage hydro power during pumping mode or the reduction of industrial loads with dedicated interruptible contracts) and wider Emergency Power Control (EPC) support from other synchronous areas via the connected HVDC links. These particular system defence measures are mainly activated in the frequency range of 49 Hz to 49.8 Hz and are not included in the normal FCR dimensioning process in CE. Further additional TSO system defence measures (Low Frequency Demand Disconnection schemes (LFDD)) exist between the frequency range of 47.5 Hz to 49 Hz and are in place to further protect the transmission system in CE. TSOs also have special protection schemes in place due to the system design which activate based on transmission system loading (not frequency) to ensure operational security limits are not violated. Section 3.1.1 provides a summary of the FCR activation on 08 January 2021 and is analysed further in Section 3.3. Sections 3.1.2 and 3.1.3 detail the system defence measures which were activated on 08 January 2021. FCR response has been significantly supported with the help from the two interruptible contracts (FR and IT) as well as from the support from the other synchronous areas via the connected HVDC links.

In addition, the fairly high inertia in both areas have supported the system within the first few seconds. For the South-Eastern, area the significant disconnection of generation units (even if not conforming) have also helped to stabilise the system on a not-too-high over-frequency level. The disconnection of generation and loads is discussed further in Section 3.2.

3.1.1 Frequency Containment Reserves

Due to the significant frequency deviation, all generation units which participated in the primary control either decreased (South-East) or increased (North-West) their power generation accordingly and as expected. In addition, by exceeding the 200 mHz limit, a high number of generation units changed their control mode to emergency control and contributed accordingly to the process of frequency stabilisation by either activating additional reserves in the North-West area or decreasing their generation in the South-East area.

As detailed in Section 3.3, Table 3.4, there was approximately 3,280 MW of FCR activated in the North-West area and 617 MW activated in the South-East area. The individual TSOs FCR contribution is based on the individual TSOs detailed reporting (Annex 3.1). Each TSO has provided recordings (steady-state values) from the FCR deployment for the key time window 14:05 – 14:06 CET. To summarise, the overall response of FCR in the CE synchronous area during the incident shows that several TSOs have delivered more primary reserve than requested. As the frequency deviation exceeded 200 mHz generation units activated emergency contributions as required by the Commission Regulation (EU) 2016/631 Article 11 (5.a.i) and Article 15 (2). Individual TSO FCR contributions are analysed further in Section 3.3.

3.1.2 Activated system protection schemes

South-East area

After the system separation, the frequency in the South-East area increased with a Rate of Change of the Frequency (RoCoF) of 300 mHz/s (deduced from the frequency measured at the centre of inertia and is a mean value for the complete area) and reached a maximum value of 50.6 Hz.

The Turkey Interconnected Electrical System operates in synchronous parallel mode with the ENTSO-E CE synchronous area via the 400 kV overhead lines Hamitabat – Maritsa (Bulgaria) Line-1, 400 kV Hamitabat – Maritsa (Bulgaria) Line-2 and 400 kV Babaeski – Neo Santa (Greece). After the system separation, an internal Special Protection Scheme (SPS) in Turkey in the Marmara region (Annex 3.2) activated which prevented an overload on the important Bandirma – Bursa corridor by shedding 975 MW of power generation. This situation helped to stabilise the frequency as more than half of the production units were in the TEIAS LFC block. The Marmara SPS is designed to prevent a local blackout risk in the Marmara region of Turkey. Condition 2 of the Marmara SPS was met as the flow on the overhead line Bandirma – Bursa suddenly increased to more than 35 % of its initial value and trip signals were subsequently sent to Bandirma (570 MW generation) and Icdas (405 MW generation) as per the SPS design. The activation of the Marmara SPS reduced the frequency rise and RoCoF but simultaneously increased the import further and even temporarily overloaded the interconnection between Turkey and the ENTSO-E CE synchronous area (prior to the event Turkey was exporting approximately 750 MW to the CE synchronous area but started importing approx. 3 GW after the separation and the activation of the SPS in Marmara).

There is also a special protection scheme in the Hamitabat substation which sheds load from transformers in the region to prevent the European connection lines from being overloaded due to large generation losses in the Turkish network. Likewise, in the event of consumption losses that may cause overloads on the lines, the SPS will send a trip signal to generation units. The Hamitabat SPS worked as designed and did not react as the conditions to trigger it were not met (the Hamitabat SPS is only triggered if the interconnection overload conditions occur for >3.5 seconds, which was not the case).

North-West area

After the electrical separation, the frequency in the North-West area decayed very quickly, with a RoCoF of 60 mHz/s (deduced from the frequency measured at the centre of inertia and is a mean value for the complete area) and reached a minimum value of 49.74 Hz. A further frequency decrease was arrested by the activation of the automatic frequency-dependent French system defence plan (approximately 1,300 MW) and the automatic frequency-dependent Italian system defence plan (approximately 400 MW). Both systems disconnected industrial loads and are regulated by dedicated national contract agreements, and are not included in the CE FCR procurement process.

This rapid action immediately arrested the frequency decrease in parallel with the primary and secondary frequency control. The disconnection of interruptible load in France and Italy is shown in Figure 3.1 and Figure 3.2. The interruptible load in Italy and France was reconnected at 14:47 CET and 14:48 CET respectively.

Both the French and Italian interruptible services are triggered by frequency thresholds. The Italian scheme is also triggered by events (e.g. tripping of lines or system dynamic issues). The interruptible services are integrated in the TSOs system defence plans which are in place to prevent/ease the consequences on the system of potential multiple events or cascading events at the national or pan European level (in accordance with the Network Code Electricity Emergency and Restoration (NC ER) Articles 11(4)(c), 11(5)(a) and Article 12 (4)). Typical response times are not comparable with conventional market services (i.e. FCR) because the activation is significantly faster and not obtainable with any other currently available countermeasures. The intervention on 08 January 2021 was correct in terms of performances and effectiveness and reconnection was instructed by the Control Rooms once system conditions were considered sufficiently stable.

Both the Italian and French schemes act directly on interruptible loads which are commanded via the instantaneous opening of circuit breakers by a remote order sent to a dedicated Remote Terminal Unit (RTU). Both TSOs manage the order via a remote central system. The order instruction criteria are slightly different because France instructs it automatically by the central system monitoring the frequency whereas Italy's central system adopts a cyclical "arming" action, monitoring not only the frequency but also system topology and dynamic security assessment calculations. In Italy, when a critical monitored event occurs (i.e. the trip of an interconnection line) the RTU monitoring the line intercepts the event and sends direct instructions to all the load shedding RTUs, which ensures an immediate response.

Interruptible services are in place to cope with unexpected and short terms events that cannot be solved

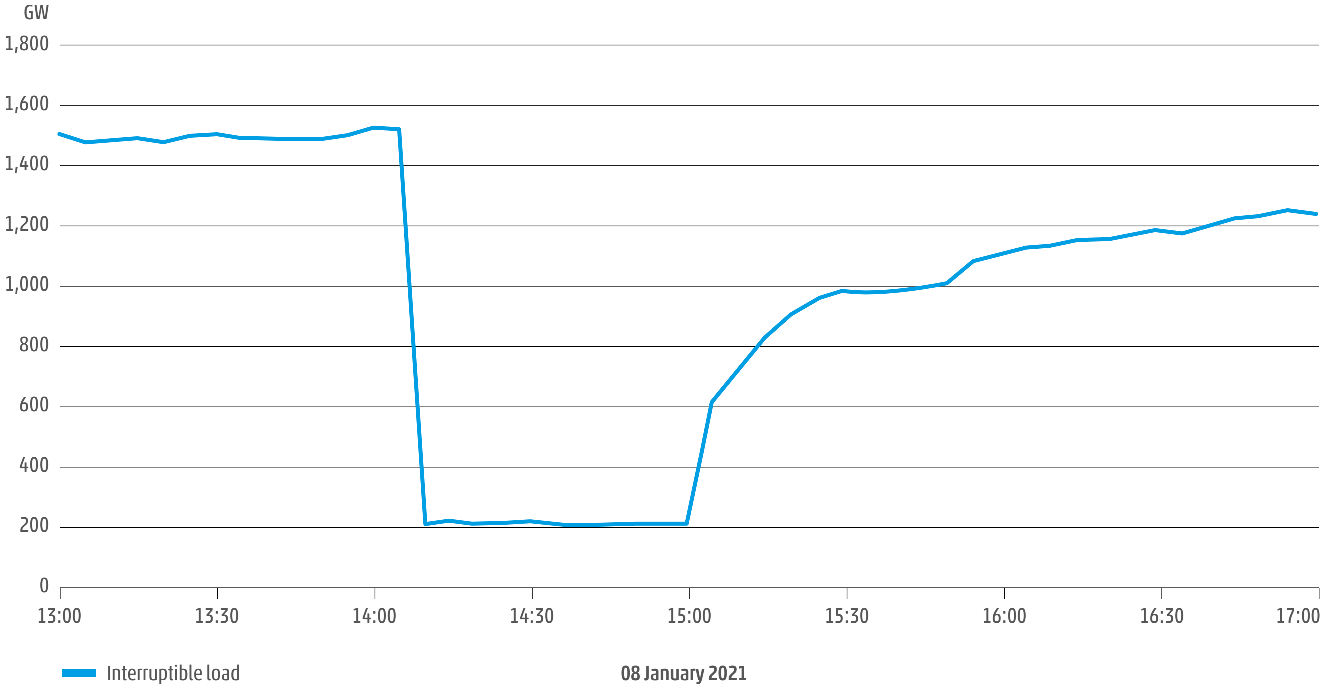


Figure 3.1: Interruptible service load activation in France

Figure 3.2: Interruptible service load activation in Italy

by the activation of ancillary services such as FCR or Frequency Restoration Reserve (FRR). The purpose of this service is to face, control and resolve severe grid security issues (e.g. severe dynamic grid transients due to loss of interconnection with foreign countries, cascade tripping of lines, unsecured generation losses [> dimensioning requirement]). These transients require a reaction in an extremely short timeframe (200 ms) which can be ensured only by interruptible resources. Moreover, it is worth noting that, due to its features, this service cannot be classified as a conventional frequency response tool because it is triggered only by strong frequency deviation events due to severe outages (that cannot be compensated by balancing resources) and other possible events such as overloads, protection trips or unexpected topological changes. Therefore, it cannot be included in the definition of "balancing" set out in Article 2 (10) of Regulation (EU) 2019/943 but rather falls within the framework of the Emergency and Restoration Code as an emergency measure integrated in the system defence plan.

The Italian and French schemes are constantly checked at national level and communicated to ENTSO-E, where experts evaluate periodically the coherency of all CE system defence plans and, when necessary, recommend actions and settings modifications. The consistency of the TSO system defence measures is also checked by the Regional Security Centres as per the requirements of the Commission Regulation (EU) 2017/2196, Article 6 (3).

In Italy, the interruptible services are procured through competitive auctions for 3-years product, one-year product and 3-months product. In France, an annual tender is organised.

3.1.3 Support from other synchronous areas

Thanks to the frequency support over HVDC links, the North-West area received 535 MW of automatic supportive power from the Nordic synchronous area and 57 MW from Great Britain (GB). Figure 3.3 shows the change of power on the Nemolink cable between GB and Belgium. The other HVDC cables (between GB and CE) capable of delivering frequency support (IFA2, BritNed) were not in service at the time of the event. At the time, as the total amount of support provided from GB was relatively small and within the GB dynamic frequency response requirements, there was no noticeable impact on the GB frequency.

The frequency support provided by Nemolink on 08 January 2021 was provided via the Limited Frequency Sensitive Mode (LFSM) of operation and is only available if capacity remains post market closure (there is no reservation of capacity for this support). The support is a technical requirement of the GB Grid Code [1] and is also in place to support compliance with the (EU) 2016/14472 Article 13 (3), Article 39 (4) & (7). The TSO who provides the support is responsible for managing any imbalance due to the support given and the support is not part of the FCR procurement process. It is in place to support exceptional events outside normal operation and is not supposed to be frequently used.

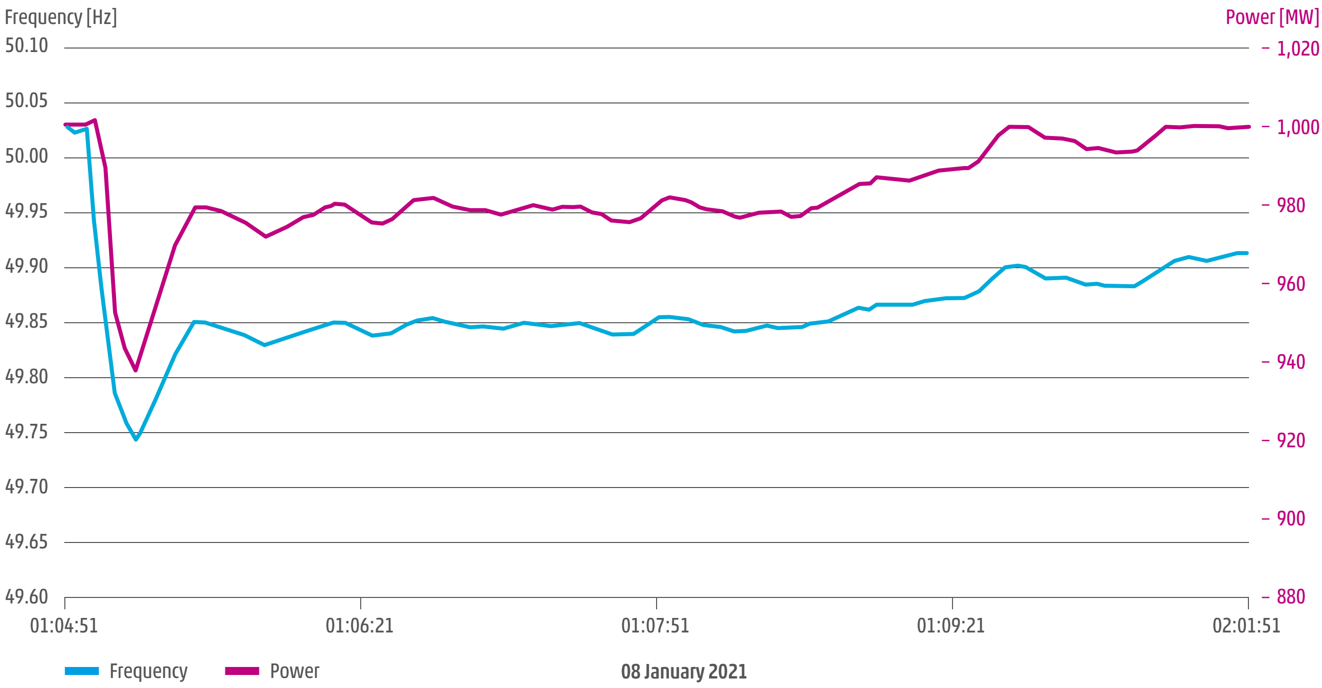


Figure 3.3: Frequency in the North-West area and active power on the NEMO HVDC link between GB and Belgium

Limited Frequency Sensitive Mode – underfrequency (LFSM-U) and Limited Frequency Sensitive Mode – over-frequency (LFSM-O) are, respectively, the frequency responses for low and high frequency excursions. The Nemo Link is capable of automatically responding to frequency deviations via LFSM in the connected AC networks of NGESO (GB) and ELIA (Belgium) by adjusting the transmission of active power. The active power response is driven by the frequency deviation on the AC side of the requesting converter. The response following a predefined frequency droop (MW/Hz) is maintained as long as the security criteria fixed at the converter on the other side of the cable (the providing converter) are satisfied. If the security threshold on the providing converter is reached, the support is immediately frozen. Finally, the support is cancelled as the providing converter is reducing the support in power from the LFSM service back to 0 MW. To meet the legal connection requirements, interim LFSM settings were put in place on Nemolink when it was commissioned in January 2019.

The settings implemented in both (requesting) converters are summarised in Table 3.1:

	Herdersbrug Converter (Belgium)	Richborough Converter (GB)
Droop (s%) – see below the formula	5 %	3 %
Threshold f1 for activation of LFSM-U	49.9 Hz	49.50 Hz
Threshold f2 for activation of LFSM-O	50.1 Hz	50.4 Hz
Maximum Power response ΔP_{max}	450 MW	450 MW

Table 3.1: Nemolink LFSM Interim Settings

The droop equation is defined as following:

$$\frac{\Delta P}{P_{max}} = \frac{100}{s\,[\%]} \times \frac{\Delta f}{50}$$

Where Δf is the frequency deviation beyond the activation thresholds f1 and f2 and P_{max} is 1,000 MW (activation is capped to ΔP_{max})

In the case observed on 08 January, the frequency deviation Δf went down to –150 mHz., leading to an active power variation of up to (100 × 15) / (5 x 50) × 1,000 = 60 MW

Activation of the LFSM function can only result in active power reduction, therefore the only possible activation scenarios are summarised in Table 3.2:

Power flow	LFSM-O availability	LFSM-U availability
BE » UK	UK	BE
UK » BE	BE	UK

Table 3.2: LFSM Activation Scenarios

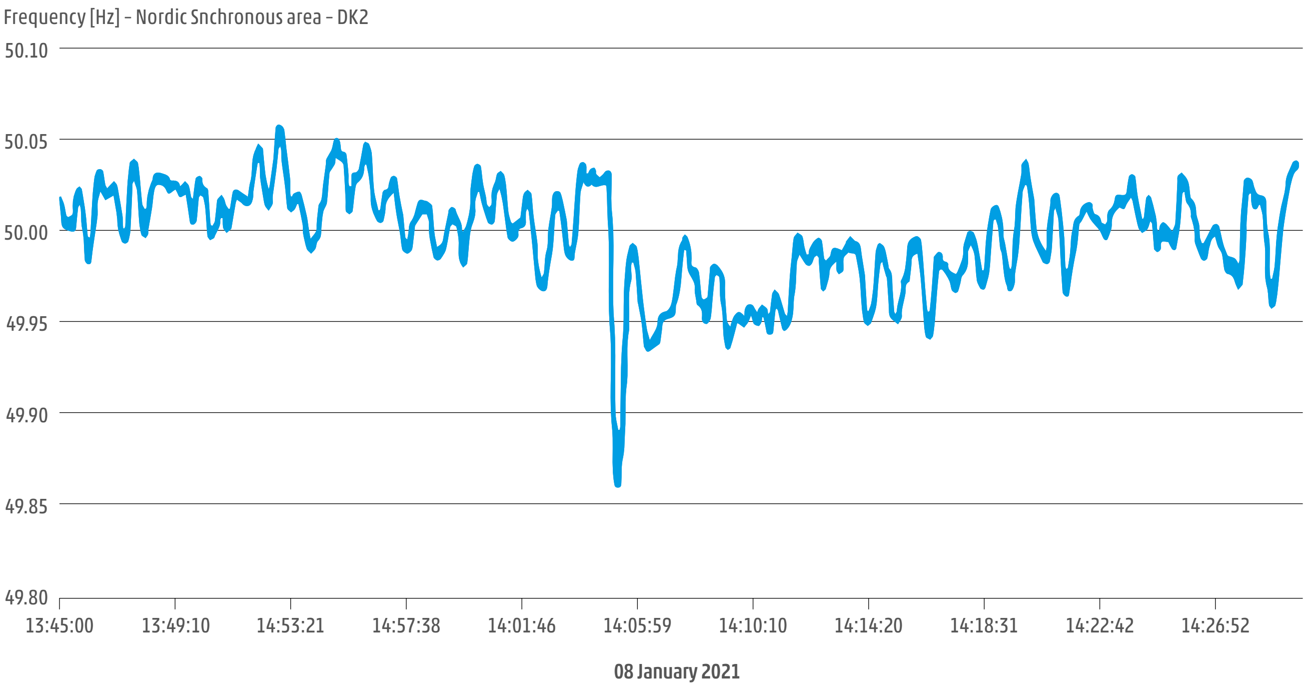


Figure 3.4: Nordic synchronous area frequency during the CE system separation.

During a LFSM activation on one side, if the frequency thresholds of LFSM-U or LFSM-O are triggered as well on the other side, the following provisions are applicable:

- Automatic freezing of the support (active power response is frozen)
- Nemolink immediately removes the support returning to the original active power setpoint using the normal operation ramping rate (100 MW/min)
- Nemolink calls both TSOs to inform the removal of the support

ENTSO-E published a mutual frequency support framework [2] in February 2021 which focuses on the ways in which current and future mutual frequency support as a defence mechanism can be implemented safely and securely over the HVDC links between synchronous areas. The framework defines the setting of limits for mutual frequency support over HVDC between synchronous areas and will harmonise the implementation of LFSM for the CE, Nordic and GB synchronous areas and replace some existing EPC services over the next 5 years. The current settings in the Nemolink converters do not allow both activation and freeze thresholds to be set independently and for security reasons the thresholds are set equal and, in some cases within the FCR frequency range. The settings will be aligned within the parameters and timeframe of the published ENTSO-E mutual frequency support framework.

The Nordic area helped from three directions: Skagerak (Norway – Denmark West) with 270 MW, Kontiscan (Sweden – Denmark West) with 215 MW and Kontek (Denmark East – 50 Hz (Germany)) with 50 MW. As can be seen in Figure 3.4, the HVDC EPC from Nordic to CE influenced the Nordic frequency by a maximum of 180 mHz. The frequency was below 49.90 Hz for approximately 20 seconds.

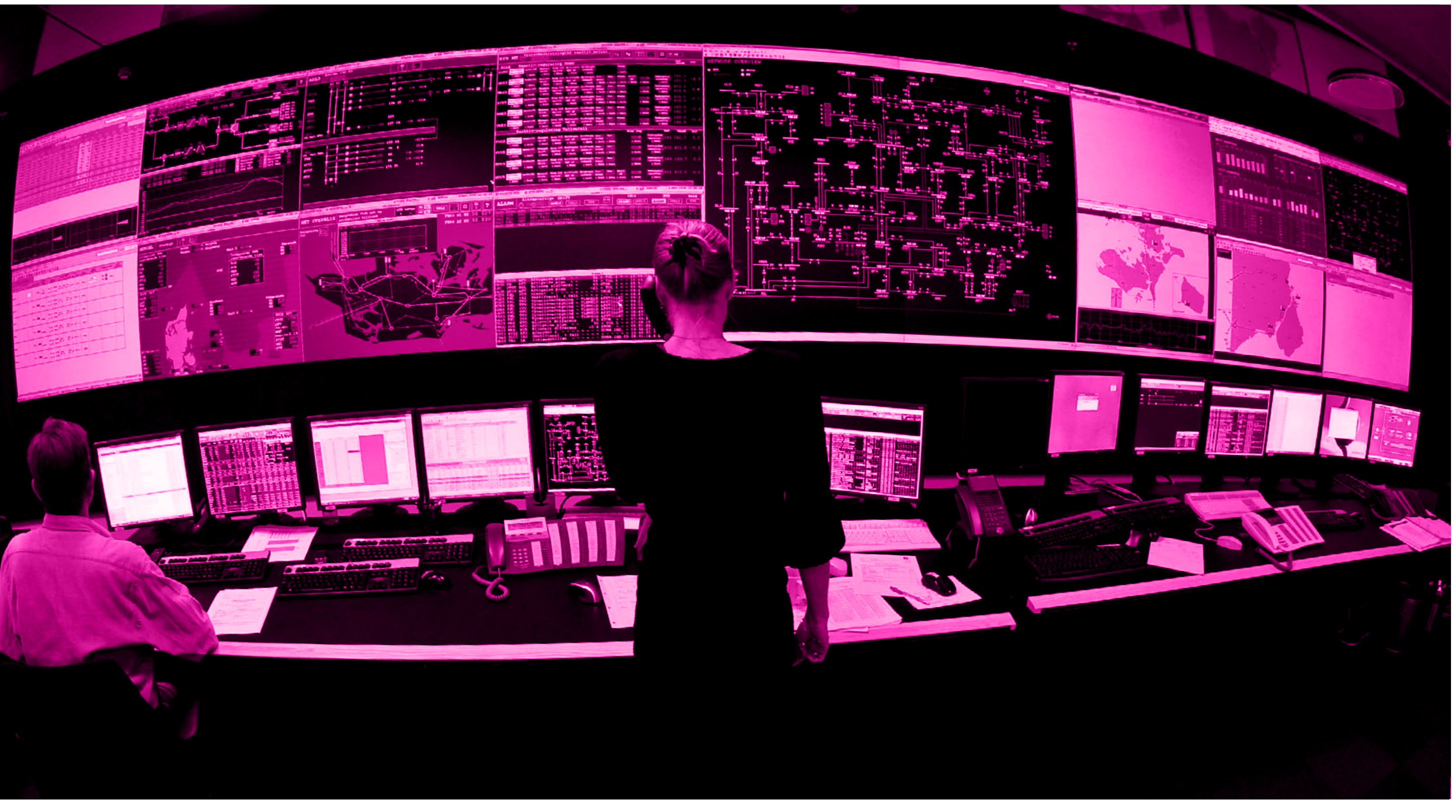
The EPC response on the HVDC links from the Nordic synchronous area to/from the Continental Synchronous Area are based on the following principles:

- No reservation for EPC power exchange, i.e. EPC support is realised only when there is free available capacity on the interconnector. For Kontek EPC, volume response may take advantage of the short-term overload capability on the cable;
- EPC on Nordic interconnectors are not included in the calculation of FCR capacity allocation for CE Synchronous Area TSOs;
- The EPC volume response and droop response are automatic and depending on frequency settings compared to actual frequency. Two frequency thresholds triggered an EPC response on 08 January 2021:
  - 49.85 Hz triggered 30 MW (100 MW/sec) on Kontiscan (SE » DKW);
  - 49.80 Hz triggered an additional EPC response on Kontiscan (SE » DKW, 185 MW, 20 MW/sec), Skagerak (NO » DKW, 270 MW 20 MW/sec) and Kontek (DKE » 50 Hz, 50 MW, 10 MW/sec);
- The EPC response is manually ramped down in accordance with frequency normalisation;
- The transferred EPC power is remunerated as imbalance and settlement agreed accordingly.

On 08 January 2021 at 14:05, capacity was available in the direction Nordic » CE for the maximum agreed EPC on Kontiskan, Skagerak and Kontek. Therefore, a maximum of 535 MW was supplied to the CE system between 14:05 and 14:15. Manual reduction of the EPC response was gradually initiated at 14:15.

The EPC response caused a frequency drop in the Nordic area with a maximum of 180 mHz. The Nordic Synchronous area FCR contained the deviation within the normal Nordic frequency deviation band after 20 seconds.

The CE synchronous area is also connected to the Baltic states and Russian synchronous area with one HVDC link, LitPol, (Lithuania to Poland). Currently, there are no contractual arrangements in place for mutual frequency support over this cable.



3.2 Disconnection of generation units and loads

Commission Regulation (EU) 2016/631, Article 13 (1) and Commission Regulation (EU) 2016/1388 Article 12 (1) state the requirements for generation and demand facilities in relation to frequency stability.

Table 3.3 shows the minimum time periods for which a new power-generating module[1], a new transmission-connected demand facility, a new transmission-connected distribution facility or a new distribution system[2] has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network.

Synchronous area	Frequency range	Time period for operation
Continental Europe	47.5 Hz - 48.5 Hz	To be specified by each TSO, but not less than 30 minutes
	48.5 Hz - 49.0 Hz	To be specified by each TSO, but not less than the period for 47.5 Hz - 48.5 Hz
	49.0 Hz - 51.0 Hz	Unlimited
	51.0 Hz - 51.5 Hz	30 minutes

Table 3.3: Requirements for generation and demand facilities in relation to frequency stability

For all the existing facilities, instead, different standards apply based on the national regulatory framework: the national competent authority may, in fact, extend the above standards also to existing units (either partially or completely) or to keep the requirements already in place before the implementation of Commission Regulation (EU) 2016/631 and of Commission Regulation (EU) 2016/1388.

Several generation units and loads disconnected during the system separation and several of these facilities showed non-national grid code conform behaviour (since the relevant regulatory framework applicable to them, either because new facilities subject to Commission Regulation (EU) 2016/631 and of Commission Regulation (EU) 2016/1388 or because existing facilities with specific standards defined at national level, doesn't allow for a disconnection in that situation). The detailed reasons for each individual disconnection will have to be investigated in greater individual detail and in a dialogue with the affected generation companies, Distribution System Operators (DSOs) and TSOs, as for more severe events, non-conform disconnection might be crucial.

3.2.1 Disconnection of generation units or loads close to the separation line due to high transients

Due to the high transients of voltage and frequency, a significant number of generation units and industrial or domestic loads were disconnected in both areas. The detailed breakdown of generation and load disconnection by country is presented in Section 3.3. The RoCoF at the centres of inertia in the North-Western area was −60 mHz/s and in the South-Eastern area +300 mHz/s (RoCoF values are deduced from the frequency measured at the centre of inertia and is a mean value for the complete area). Both values were quite far from the current considered critical limit of 1 Hz/s (for higher RoCoF values most of the current devices and schemes which protect the power system are too slow to react).

1 According to Article 4 of Commission Regulation (EU) 2016/631 (RfG NC)

2 According to Article 4 of Commission Regulation (EU) 2016/1388 (DC NC)

South-East area

Due to extreme voltage and frequency variations close to the separation line, 988 MW of generation connected to the transmission system was disconnected (388 MW in Croatia, 600 MW in Bosnia and Herzegovina), including 60 MW which was reported to have disconnected from the distribution system. The total load tripped in the South-East area was 184 MW (163 MW in Romania and 21 MW in Croatia); mainly connected to substations close to the separation line and therefore tripped because of the high transients.

North-West area

Due to the close proximity to the separation line and because of the related high transients in voltage and frequency, 348 MW of generation was tripped in Romania. The total load disconnected in this area due to extreme transients was 48 MW (28 MW in Romania and 20 MW in Hungary).

3.2.2 Disconnection of non-conforming generation units, loads or transmission elements far from the separation line due to frequency deviations

Unfortunately, several automatic disconnections took place, even very far from the system separation line, based only on the system frequency deviation which was, in both areas, outside the normal operation range of ±200 mHz. The detailed breakdown of generation and load disconnection by country is presented in Section 3.3.

South-East area

3,292 MW of generation tripped unexpectedly in the South-East area (Bulgaria 187 MW, Greece 1,350 MW, Serbia 600 MW, Turkey 1,155 MW) because of the over-frequency (in excess of 300 mHz). 587 MW of non-conforming dispersed embedded generation in the distribution system is included in the 3,292 MW total. A disconnection of 50 MW of load was also reported in Bulgaria.

There was a fairly significant generation disconnection in the South-Eastern area particularly in Turkey (1,155 MW) and in Greece (1,350 MW). Those two systems were quite close to becoming the third or even fourth areas with fairly serious subsequent system balances as both countries were exporting prior to the event but, immediately after the separation, they became highly importing areas. As illustrated in Annex 3.1, the Turkish system balance changed from approx. 700 MW export to approx. 2,600 MW import after the system separation. The Turkish interconnection to CE was temporarily overloaded and the SPS operated at Hamitabat (further detailed in Section 3.1.2). In addition, 1,155 MW of generation disconnected in Turkey. The Greek system balance changed from approx. 1,150 MW export to approx. 1,200 MW import, and the Greek system had 1,350 MW of generation disconnect.

North-West area

Due to incorrect frequency protection settings, in total 620 MW of generation tripped unexpectedly far from the separation line due to the decrease in frequency to 49.74 Hz. This generation disconnection was dispersed geographically in the North-West area (Austria 284 MW, Czech Republic 19 MW, Poland 5 MW, Portugal 170 MW, Slovakia 130 MW, Switzerland 11.6 MW) and contributed further to the decrease in frequency. 341 MW of distributed generation with a non-conforming disconnection setting (49.8 Hz) is included in the 620 MW total. 14 MW of load was also reported to have disconnected in the Netherlands due to an incorrect frequency setting.

The loss of the HVDC link between Santa Llogaia (Spain) and Baixas (France) was a consequence of the system separation and not one of the causes. It occurred due to an erroneous protection parametrisation of the auxiliary sources on the French side which had a frequency disconnection setting of 49.75 Hz. 1,400 MW of coordinated countertrading between France and Spain was necessary to cope with the tripping of the FR–ES HVDC link. The setting has subsequently been reset to avoid future tripping.

Recommendations

ID	Recommendation	Justification	Responsible
Non-grid code conform disconnection of generation and loads			
R-14	For the TSOs, where a **non-conform disconnection** of generation and loads occurred during this incident, each TSO must **review the cause with generation companies and DSOs** and **derive corrective measures** to avoid the non-conform disconnection in the future. Progress of the corrective measures will be monitored by ENTSO-E and ACER.	It is to be assumed that for the case of more severe events and related higher frequency deviations, the percentage of disconnected power will be much higher and will lead to a more severe system disturbance.	TSOs to implement ENTSO-E and ACER to monitor
Frequency stability evaluation criteria for RoCoF			
R-15	Given that system separation events occur on rare occasions, it is reasonable to use the recorded dynamic behaviour of the system (including the implemented interruptible load schemes) when evaluating frequency stability evaluation criteria for the synchronous zone of Continental Europe and to verify the dynamic stability models accordingly.	RoCoF values of – 60 mHz/s and +300 mHz/s were measured in the north-western and south-eastern areas, respectively. These values and related transients confirm the limit value of 1 Hz/s as a pragmatic sustainable RoCoF reference for the system. System separation events can serve as a valuable input to define normative incidents to be used in the dynamic system studies.	ENTSO-E

3.3 Frequency Containment Analysis

3.3.1 Frequency support during the system separation

By considering the most critical time window, namely 14:05 – 14:06 as illustrated in Figure 3.5, the frequency response of each CE TSO system was analysed in detail by compiling the related Wide Area Monitoring Measurements (WAMS) and the ENTSO-E awa EAS recordings, as well as the detailed data for FCR activation received from each CE TSO individually.

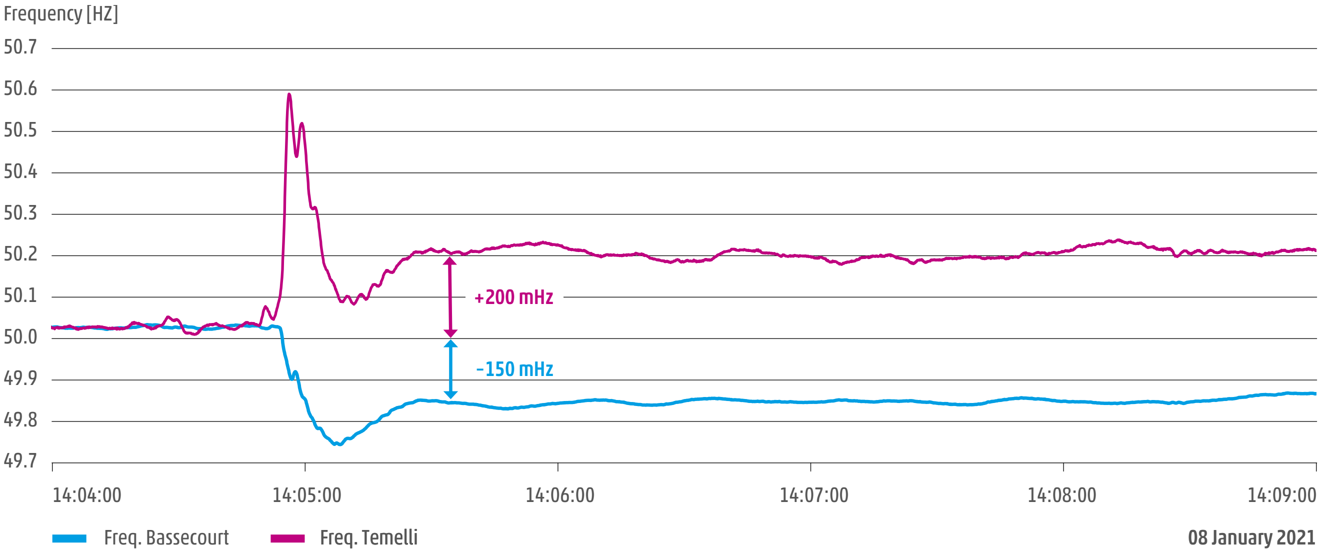


Figure 3.5: Frequencies of the decisive minutes before and after the event

As illustrated in Figure 3.6, after the separation in the North-Western area, a sudden active power deficit of approximately 5.9 GW occurred. Similarly, for the South-East area there was a resulting power surplus in the same magnitude, as shown in Figure 3.7.

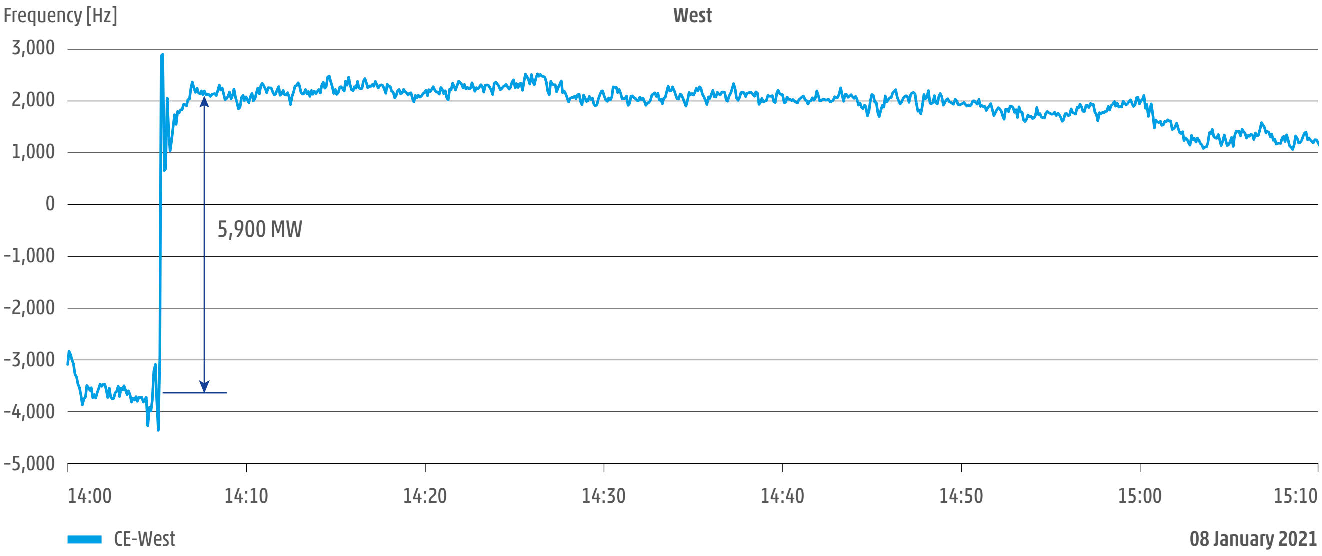


Figure 3.6: North-West area Balance

However, based on the fact that those figures were obtained by simply summing the related TSOs system balances, the exact numbers might differ as, for example, Romania was separated into two parts.

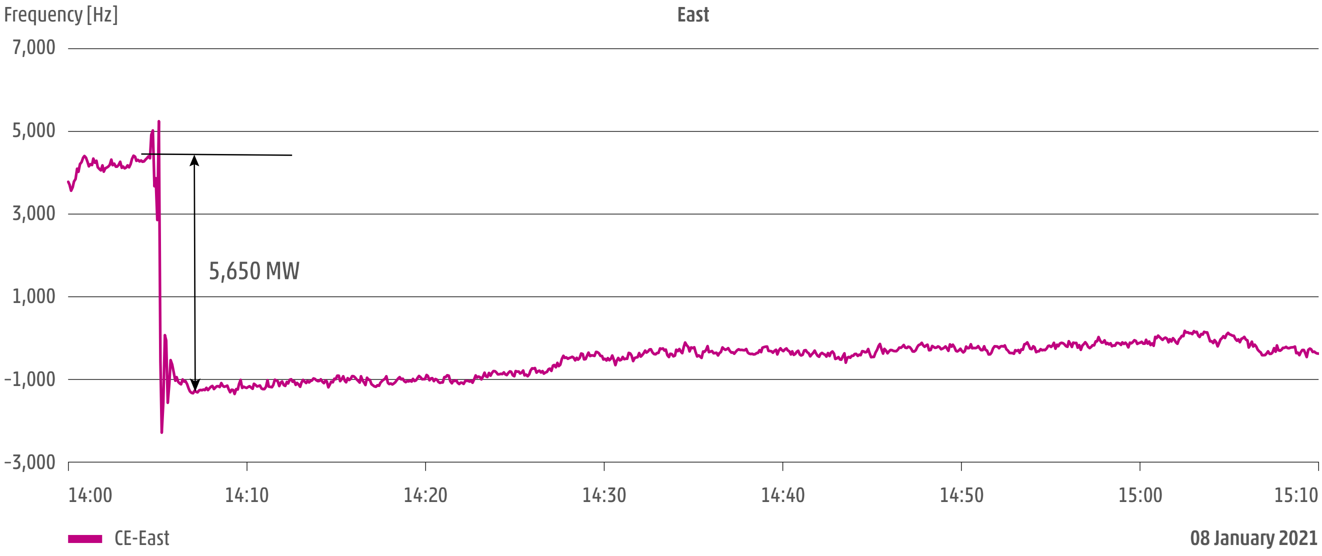


Figure 3.7: South-East Area Balance

Between 14:05 and 14:06, the very first and fast responses was given by the special system protections schemes triggered in France and Italy by disconnecting industrial loads at 49.8 Hz 1,280 MW and at 49.75 Hz 382 MW respectively as well as the EPC from GB with 57 MW and from the Nordic power system with 497 MW correspondingly, see Figure 3.8.

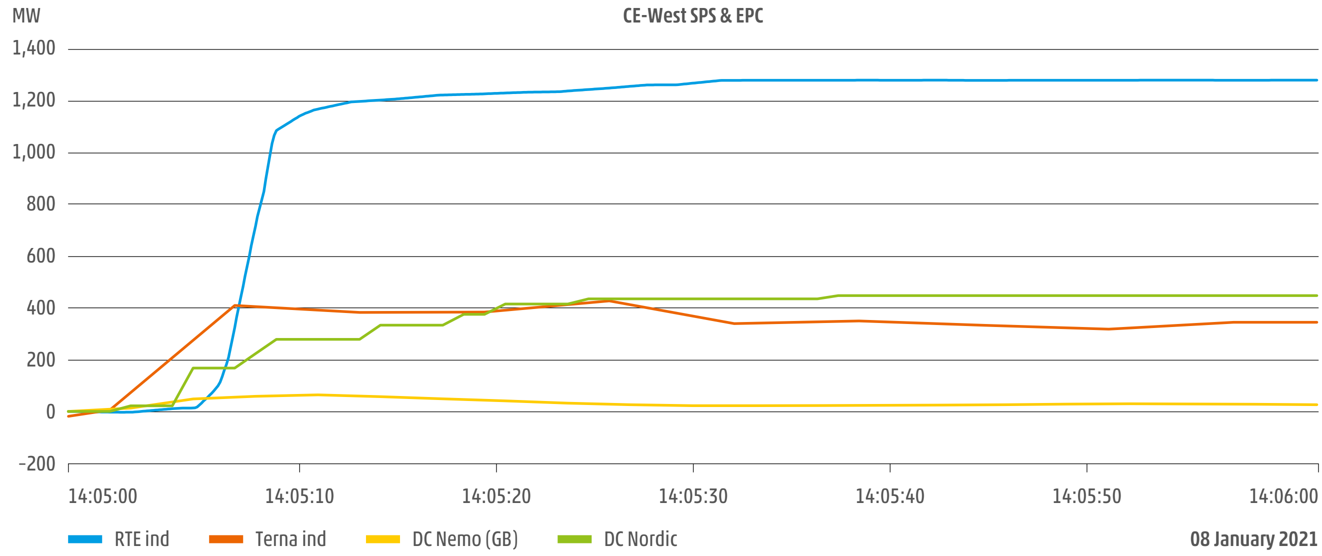


Figure 3.8: SPS and EPC support for the North-West area between 14:05 and 14:06 (EPC excludes 50 MW Kontek contribution)

In the next Figure 3.9, the contributions of the very fast control – SPS & EPC as well as all the individual FCRs activated reserves of the North-Western area are summed up together.

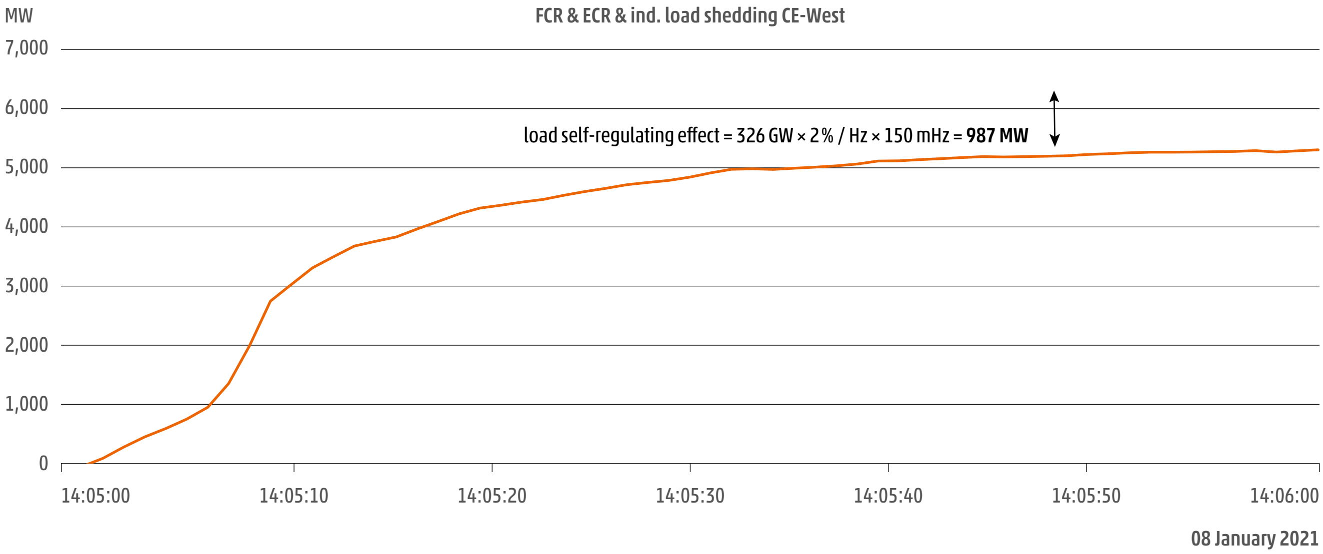


Figure 3.9: North-East area activated reserves and active power contributions

It can clearly be seen how the total power deficit was covered within the critical time window of one minute between 14:05 and 14:06. On the top, the load self-regulating effect is also depicted. This is due to the lower frequency which all rotating loads are "seeing" and consuming consequently less power. Of course, in the overall balance the additional generation trips as well as load shedding will have to be considered.

Finally, it will have to be accepted that it is not possible to acquire all single contributions as e.g. a certain contribution also from lower voltage levels not reported to the TSOs etc.

However, Table 3.4 below illustrates all the generation and loads which tripped as well as all the individual TSOs contributions. The TSO FCR desired values (noted as setpoint values) are listed next to the practically measured values. The total setpoint 1,862 MW refers to the required FCR activation for a 150 mHz deviation (steady-state requirement) for the North-West TSOs based on their k factor. 507 MW refers to a 200 mHz requirement for the equivalent South-East TSOs.

Table 3.4 shows there was approximately 3,280 MW of FCR activated in the North-West area and 617 MW activated in the South-East area. The individual TSOs FCR contribution is based on the individual TSOs detailed reporting (Figure A2-1 – Figure A2-73 in Annex 3.1). Each TSO has provided recordings (steady-state values) from the FCR deployment for the key time window 14:05 – 14:06 CET. The incident shows that several TSOs have delivered more primary reserve than requested.

In addition, the TSOs from Austria, Belgium, Switzerland, Germany, France, the Netherlands, Slovenia and West Denmark currently procure their FCR in a common market (FCR Cooperation*). The FCR Cooperation works currently with daily auctions with 4-hour symmetric products. The auction takes place every day and applies for the next delivery day. The FCR Cooperation is organised with a TSO – TSO-model, whereby the FCR is procured through a common merit order list where all TSOs pool the offers they received. The interaction with Balancing Service Providers (BSPs) and the contracts between the TSOs and BSPs is handled on a national basis along with the responsibility of delivery. Table 3.5 details the FCR Cooperation obligations against the measured values.

Furthermore, as the frequency deviation exceeded 200 mHz generation, units have activated emergency contributions as required by Commission Regulation (EU) 2016/631 Article 11 (5.a.i) and Article 15 (2).

Area	TSO	FCR		EPC / SPS	Fig.	Gen. disc.	Load disc.
		setp.	meas				
North-West	50Hertz		186	50			
	Amprion		148				
	TenneT_DE		115	447			
	TransNetBW		5				
	DE*	418	454		1,2,3,4		
	APG*	43	50		5,6,7	284	
	CEPS	64	100		8,9,10	19	
	ELES*	11	25		11,12,13		
	ELIA*	20	35	57	14.15.16		
	Energinet*	15	15		17.18.19		
	HOPS NW	11	8		20,21		21
	Mavir	28	30		22,23,24		20
	PSE	118	175		25,27,27	5	
	REE	285	390		28,29,30		
	REN	38	148		30,31	170	
	RTE*	495	600	1,280	32,33,34		
	SEPS	14	5		35,36	130	
	Swissgrid*	53	311		37,38,39	11.6	
	TenneT_NL*	28	34		40,41,42		14
	Terna	221	900	382	43,44,45		
	Transelectrica NW					348	28
	Total / MW	**1,862**	**3,280**	**2,216**	**46**	**967.6**	**83**
	Total / MW	**FCR meas & EPC & SPS**	**5,496**				
South-East	CGES	3	37		47,48,49		
	EMS	34	48		50,51,52	600	
	ESO EAD	37	31		53,54,55	187	50
	HOPS SE					388	
	IPTO	47	160		56,57,58	1,350	
	MEPSO	6	9		59,60		
	NOS BiH	13	10		61,62	600	
	OST	6	12		63,64		
	TEIAS	304	160	975	65,66,67	1,155	
	Transelectrica SE	57	150				163
	Total / MW	**507**	**617**	**975**		**4,280**	**213**
	Total / MW	**FCR meas & EPC & SPS**	**1,592**				

Table 3.4: Detailed CE power system balance overview

Country	Standard Volume	After Cooperation	150 mHz adaption (setpoint)	Measured
Austria	71	57	43	50
Belgium	87	27	20	35
Switzerland	67	71	53	311
Germany	562	557	418	454
France	508	660	495	600
Netherlands	114	37	28	34
Slovenia	15	15	11	25
Denmark (West)	20	20	15	15
Total	**1,444**	**1,444**	**1,083**	**1,524**

Table 3.5: FCR Cooperation obligations vs measured values

3.3.2 Frequency support and stability in case of system separation

By analysing the frequency behaviour immediately after the system separation, it means that for the first few seconds, the following conclusions can be made:

- » The system coped well with the enormous power deficit (North-West area) or power surplus (South-East area) of roughly 6 GW.
- » The sharp blocking of further frequency increase/decrease and higher/lower steady-state deviation in both areas is based on the fast activation of related system protection schemes in both areas, the frequency support over the HVDC links of GB and from the Nordic power system, and a significant amount of power plant disconnection in the South-Eastern area.
- » The deployment of FCR deployed by all CE TSOs has finally stabilised the frequencies in both areas.
- » After the further analysed contributions, the total power deficit was almost completely covered at 14:06 – the remaining deficit being due to the load self-control contribution.
- » Based on the significant inertia in both areas, the RoCoF was fairly moderate, with +300 mHz/s for the South-East area with an imbalance ratio of 6 GW/70 GW = 8.6 % and −60 mHz/s for the North-West area and an imbalance ratio of 6 GW/326 GW = 1.8 %.
- » Directly after the system separation the Monita HVDC cable remained connected to both the South East and North West areas with the agreed flow of 100 MW from Montenegro to Italy. Similarly, the 500 MW HVDC cable between Greece and Italy remained in service. As the North West and South East areas were now two asynchronous systems it would have been beneficial for the frequencies in both areas if the HVDC control systems for these cables were designed to detect the frequencies at both ends of the cables and then automatically change the flow to support the frequencies (reducing the high frequency in the South East area whilst increasing the frequency in the North West area).

Recommendations

ID	Recommendation	Justification	Responsible
Frequency support and stability			
R-16	Evaluate for future scenarios if the available fast-acting power support is sufficient, the point when a certain power transfer between power system regions exists and a system separation occurs.	If the power transfer between power system regions becomes higher, the fast-acting power reserves will have to be complemented with additional fast support beyond the classical FCR reserves. This could be either coordinated and geographically balanced special protection schemes including disconnection of contractual industrial loads and/or EPC (emergency power control, functionality of DC converters) from other synchronous areas. Otherwise, the last measure according to the defence plan in the case of underfrequency is the disconnection of demand.	ENTSO-E
System Defence Plans			
R-17	CE TSOs should assess the impact of system defence plan measures between 49.8 Hz and 49 Hz, as set up by different TSOs, in order to determine any adverse cross-border impact under different emergency state scenarios. Equally, TSOs should aim to harmonise these measures so as to attain a gradual frequency response and a level playing field (similar to the automatic low frequency demand disconnection scheme).	Substantial automatic frequency-dependent system defence plan measures were triggered in France and Italy, which significantly supported the system frequency on the north-west area. These measures currently trigger first during the large frequency drops, which raises the question of whether a level playing field exists (in relation to activation criteria and compensation) in the CE SA. Equally important is the question of whether such measures when activated under different scenarios (e.g. system separation) could generate any adverse load flow patterns across different regions, further exacerbating the system conditions.	ENTSO-E
Frequency support from embedded HVDC cables			
R-18	The automatic control of embedded HVDC systems, which remain connected between two asynchronous areas after a system separation, should be assessed to support frequency management procedures where it is technically possible.	An automatic modification of the transmitted active power infeed of embedded HVDC systems directly after a system separation can positively assist the frequencies in both areas and in addition can help to reduce the amount of manual actions that may be necessary during such events.	ENTSO-E and TSOs

References

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

[2] ENTSO-E, "Operational Limits and Conditions for Mutual Frequency support over HVDC," February 2021

4 TSO Coordination

4.1 Manual countermeasures and system stabilisation in individual areas

During and following the event, several system states were activated by affected TSOs, as illustrated in Table 4.1. This allowed all TSOs in Europe to become aware of the seriousness of the event. In addition, the coordination centres set the alarms for frequency deviations, whereby coordination centre (CC) North set the alarm for the confirmation of the frequency deviation in North-West Europe, and CC South set the alarm for the frequency deviation in South-East Europe.

TSO	Country	Type of alarm	Message(s) set	Time of activation	Reason
CC North	North & West Europe	alert (yellow)	Frequency Degradation	14:05:03	FRQ |df| >100 mHz for t > 5 min
CC South	South-East Europe	emergency (red)	Frequency Degradation	14:10:11	FRQ |df| >200 mHz
APG	Austria	alert (yellow)	Frequency Degradation	14:16:43	Due to frequency Deviation
ELES	Slovenia	alert (yellow)	Frequency Degradation	14:20:02	The frequency degradation which occurred after the system split. Other incidents were not detected at that time
EMS	Serbia	emergency (red)	Critical Event	15:01:53	One of the criteria for activation of the message EMERGENCY is "system split – at least one asynchronous system involving more than 1 TSO"
HOPS	Croatia	alert (yellow)	Flow Constraint Voltage Constraint Short-circuit Current Constraint	14:53:00	Because of N-1 violation, flow constraint and frequency deviation It is crucial to note that due to stressed situation, NCC dispatchers did not have sufficient time to think about properly messaging the EAS set
NOS	Bosnia Herzegovina	emergency (red)	Frequency Degradation Loss of Tools/Facilities N Violation	14:17:20	Frequency higher than 200 mHz Video wall and workstation in dispatcher centre was disconnected There is at least one violation (frequency) of a TSO's security limits with consequences for neighbouring TSOs, even after the effects of Remedial Actions
OST	Albania	alert (yellow)	Frequency Degradation	14:26:16	The Dispatchers sent the message due to the first notification in SCADA System for over-frequency. In the OST power system, we did not observe any other event following the frequency alarm
RTE	France	emergency (red)		14:49:23	
Transelectrica	Romania	emergency (red)	Critical Event	14:24:51	Based on the very complex impact and phenomena within the system (high frequency deviation + overloads & trips + voltage oscillations and power swings + split of the network + load & generation loss and real emergency situation), more than one condition from the emergency state definition was obtained

Table 4.1: EAS alarms in CE

EMS then acted as frequency leader in the separated South-East area to coordinate the return of the system to 50 Hz. This allowed the resynchronisation to take place as soon as possible. Amprion acted in the same manner as the frequency leader in the North-West area due to its role as Synchronous Area Monitor (SAM). Each area subsequently took appropriate actions on its control means, mostly on the production side, to create a balanced area.

4.1.1 North-West area and neighbouring synchronous areas

Frequency management

The CCs Amprion and Swissgrid in their role as SAM detected the frequency drop and the long-lasting frequency deviation in the North-West area. The CCs informed all TSOs via the Frequency State traffic lights in EAS. Although the criteria for Stage 2 of the "Extraordinary procedure for frequency monitoring and countermeasures in case of large steady-state frequency deviations" were not reached, Amprion, as the frequency monitor in odd months, proactively initiated the telephone conference between Swissgrid, RTE, Terna, REE and Amprion at 14:12 CET. This procedure is detailed further in Annex 4.1. In the telephone conference, the situation was analysed and assessed. Information about incidents and already activated automatic measures were shared. As the frequency in the North-West area was recovering and automatic measures such as FCR, Automatic Frequency Restoration Reserves (aFRR) and contractual load shedding in France and Italy appeared sufficient, the TSO came to the agreement that no further action was required to stabilise the frequency in the North-West area. The CCs decided to focus their investigations on the reasons for the system separation and to call the TSOs from the South-East area for more coordination. Furthermore, the CC monitored the frequency in the North-West area. They coordinated the successive withdrawal of measures and the return to normal state in the North-West area. Further details can be found in Chapter 4.2

Activation of production

Several TSOs applied measures (manual or automatic) regarding power generation units. There was automatic grid controller power activation due to high deviations from the planned schedules and further manual measures coordinated by telephone:

» CEPS: Defence service providing units (i.e. the majority of transmission-connected units and some distribution-connected type D units) switched to proportional speed control at 14:05:03 – 14:05:05. Their active power output followed the frequency.

» Amprion: Several hydropower plants synchronised between 14:05 and 14:07 for frequency restoration.

» CEPS returned units to active power control at their scheduled active power output between 14:29 and 14:39.

» APG (Austria) activated reserves manually to stabilise the frequency. Altogether, 564 MW contributed (ordered at 14:06 CET, activated at 14:15 CET), of which 284 MW was from the Austrian tertiary reserve and, in coordination with the German TSOs, an additional 280 MW from a common platform for manually activated FRR, operated by German and Austrian TSOs together.

» Transelectrica manually activated 878 MW during the frequency stabilisation period in its N – W split system based on the congestion management rules of the balancing market.

Further activation of power generation units is listed in Annex 4.2, Table A4-1.

Reconnection of load

Interruptible load was allowed to reconnect at 14:47 CET in Italy and at 14:48 CET in France. Table 4.2 shows the reported reconnection of load in the North-West area between 14:04 and 16:00 CET, whereas Table 4.3 and Table 4.4 show the actions on grid topology and the reconnection of grid elements.

Time	TSO	Load (place or name)	MW
14:04 - 14:06	MAVIR	Close to Sandorfalva and Bekescsaba substations	20
14:04 - 14:17	HOPS	SS Rab	6
14:04 - 14:17	HOPS	SS Nova Gradiška	15
14:28 - 16:00	Transelectrica	Close to the separation line in Romania	28

Table 4.2: Applied measures regarding reconnection of load

Actions on grid topology and reconnection of grid elements

Time	TSO	Grid topology change
14:09 - 14:48	PSE	Change of tap position of PSTs in Mikulowa (between 50 Hz and PSE) from 0 to -25
14:10	50 Hz	Change of tap position of PSTs in Vierraden (2 PSTs between 50 Hz and PSE) from 0 to -10
14:19 - 14:22	50 Hz	Change of tap position of PSTs in Vierraden (2 PSTs between 50 Hz and PSE) from -10 to -20

Table 4.3: Applied grid topology changes

Time	TSO	Reconnected element
14:09	HOPS	SS Nova Gradiška - TR1 and TR2 110/35 kV: opened
14:17	HOPS	110 kV Dunat - Rab
14:19	HOPS	110 kV Nova Gradiška - Međurić
14:19	HOPS	SS Nova Gradiška - TR1 110/35 kV: closed
14:23	HOPS	110 kV Međurić - Kutina
14:38	HOPS	400 kV Melina - RHPP Velebit
15:28	REE	HVDC 320 kV S.LLOGAIA - BAIXAS 1
17:17	REE	HVDC 320 kV S.LLOGAIA - BAIXAS 2
15:29	RTE	HVDC link France-Spain Baixas - Santa Llogaia n°1
17:15	RTE	HVDC link France-Spain Baixas - Santa Llogaia n°2

Table 4.4: Applied reconnection of grid elements

Countertrading/measures in the market

Furthermore, the following measures regarding market activities were applied by the TSOs:

» RTE and REE reported at 14:12 that coordinated countertrading of approx. 1,400 MW was activated to avoid overloading the 400 kV line Vic-Baixas after the loss of the HVDC link Baixas – Santa Llogaia nº1 and nº 2. As such, REE increased production and RTE decreased production as follows:

Time interval	TSO - TSO	Amount (MW)
14:05 - 14:45	RTE-REE	F > E from 3,400 to 2,000
14:45 - 15:35	RTE-REE	F > E from 2,000 to 1,700
15:35 - 15:45	RTE-REE	F > E from 1,700 to 2,000
15:45 - 16:00	RTE-REE	F > E from 2,000 to 2,300

Table 4.5: Applied measures regarding market activity

4.1.2 South-East area and neighbouring synchronous areas

Activation of production

The following TSOs applied countermeasures regarding the power generation units in their area. There was automatic grid controller power activation due to high deviations from the planned schedules and further manual measures coordinated by telephone:

- » NOSBiH excluded production manually in the amount of 350 MW (14:26 CET: –58 MW, 14:41 CET: –145 MW, 14:54 CET: –135 MW),
- » IPTO (Greece) called EMS at 14:16 CET. Because the frequency was higher than maximum steady-state frequency deviation, dispatchers agreed that the production of power plants in their control areas should be reduced in a coordinated manner,
- » After the call with IPTO, EMS also asked ESO EAD, Transelectrica and TEIAS (Turkey) to continue to reduce the production of power plants in the separated area with over-frequency.
- » Transelectrica manually activated more than 1,000 MW of downward regulation during the frequency stabilisation period in its South-East split system based on the congestion management rules of the balancing market. At 15:00 CET, some generation units were re-started (110 MW) to reach the resynchronisation condition of the South-East network area.

Further activation of power generation units is listed in Annex 4.2, Table A4-2. Applied grid topology changes and reconnection of grid elements are shown in Tables 4.6 and 4.7 respectively.

Actions on grid topology and reconnection of grid elements

Time	TSO	Grid topology change
14:06	HOPS	shunt reactor in 110 kV switchyard in SS Ernestinovo: opened
14:09	HOPS	TL 400 kV SS Konjsko – RHPP Velebit: opened
14:09	HOPS	RHPP Velebit – ATR 400/110/36,7 kV: opened
14:18	HOPS	HPP Peruća – Ag1 and Ag2: opened
14:28	HOPS	HPP Peruća – Ag1: closed
14:30	HOPS	HPP Peruća – Ag2: closed
15:09	HOPS	TL 400 kV SS Konjsko – RHPP Velebit: closed

Time	TSO	Grid topology change
15:09	HOPS	RHPP Velebit – ATR 400/110/36,7 kV: closed
15:24	HOPS	shunt reactor in 110 kV switchyard in SS Ernestinovo: closed
15:28	HOPS	SS Nova Gradiška – TR2 110/35 kV: closed
15:46	HOPS	TL 400 kV Ernestinovo – Pecs 2 (MAVIR): closed
14:24	Transelectrica	OHL 220 kV Iernut – Baia Mare 3 disconnected
15:16	Transelectrica	OHL 220 kV Iernut – Baia Mare 3 connected

Table 4.6: Applied grid topology changes

Time	TSO	Reconnected element
14:17	HOPS	WPP Zelengrad
14:33	HOPS	WPP Korlat
14:34	HOPS	WPP Krš Pađene
15:07	HOPS	SS Ernestinovo – Busbar coupler 400 kV
15:12	HOPS	OHL 220 kV Brinje – Krš Pađene
15:14	HOPS	TL 220 kV TPP Sisak – Prijedor (NOSBiH)
15:14	HOPS	OHL 110 kV Rab – Novalja
15:15	HOPS	OHL 220 kV Međurić – Prijedor (NOSBiH)
15:16	HOPS	SS Ernestinovo – AT1 400/110 kV
15:16	HOPS	OHL 110 kV Lički Osik – Otočac
15:22	HOPS	SS Ernestinovo – AT2 400/110 kV
15:26	HOPS	OHL 110 kV Nova Gradiška – Požega
15:26	HOPS	OHL 110 kV Slatina – Virovitica
15:33	HOPS	RHPP Velebit – AG1
15:12	NOSBiH	OHL 220 kV Prijedor 2 – Medjuric
15:13	NOSBiH	OHL 220 kV Prijedor 2 – TPP Sisak
15:10	Transelectrica	400 kV OHL Mintia – Sibiu Sud
15:12	Transelectrica	400 kV OHL Iernut – Sibiu Sud
15:12	Transelectrica	400 kV OHL Iernut – Gădălin
15:17	Transelectrica	220 kV OHL Iernut – Câmpia Turzii
15:17	Transelectrica	220 kV OHL Paroșeni – Târgu Jiu Nord
15:19	Transelectrica	220 kV OHL Timișoara – Reșița ck.1
15:23	Transelectrica	400 MVA, 400/220 kV AT Roșiori SS
15:24	Transelectrica	220 kV OHL Fântânele – Ungheni
18:04	Transelectrica	220 kV OHL Timișoara – Reșița ck.2
15:08	EMS	Switched on and loaded 400 kV OHL Subotica 3 – Novi Sad 3 in substation Novi Sad 3
15:20	EMS	Switched on and loaded 110 kV OHL Srbobran – Bečej
15:21	EMS	Switched on and loaded 110 kV OHL Vrbas 1 – Odžaci
15:21	EMS	Switched on and loaded 110 kV OHL Srbobran – Sremska Mitrovica 2
15:21	EMS	Switched on and loaded 110 kV OHL Srbobran – Novi Sad 3
15:22	EMS	Switched on and loaded 110 kV OHL Sombor 3 – Crvenka
15:23	EMS	Switched on and loaded 110 kV OHL Srbobran – Senta 1
15:23	EMS	Switched on and loaded 110 kV OHL Srbobran – Bačka Topola 2

Table 4.7: Applied reconnection of grid elements

Reconnection of load

A total load of 162.9 MW was successfully resupplied between 14:28 – 16:00 CET in the Romanian power system.

4.1.3 Activation of automatic frequency restoration reserves

Operation Modes of the Load Frequency Controller

The descriptions of the operation modes of the load frequency controller are documented in Synchronous Area Framework Agreement (SAFA) Annex 1 B-6.

In Normal Operation Mode, the load frequency controller input of the load frequency control area in which it is implemented is calculated as the sum of the Power Control Error and the Frequency Control Error.

$$LFC\ input_i = -\left(\sum_{j\in\Omega_i} (P^j_{T_{ph},i}) - P_{set} + K_i(f - f_{set})\right)$$

where Ω_i corresponds to the set of the tie-lines of the LFC area i, K_i is the K factor of the LFC area i.

In frequency control mode, the load frequency controller input of the LFC area in which it is implemented is equal to the frequency control error (the Power Control Error is omitted).

$$LFC\ input_i = -K_i(f - f_{set})$$

In Frozen Control Mode, the output of the load frequency controller of the LFC area in which it is implemented remains constant. Thus, the setpoint for the activation of aFRR remains constant and the area control error is not controlled.

$$S_{aFRR,i} = const.$$

According to SAFA Annex 5 C-4-1, in the event of frequency deviation higher than 200 mHz lasting more than one minute, individual Frequency Restoration Controllers have to be switched in Frozen Control Mode by direct manual or automatic actions or by other methods, relying on TSO devices or generating units devices.

SAFA Annex 5 C-18 asks to nominate a frequency leader when the frequency deviation is higher than 200 mHz for more than 15 minutes, following the criteria from Article 29 (3) of NC ER.

On the other hand, NC ER Art. 29 (1) requires, in the event of a synchronous area being split in several synchronised regions, that the TSOs of each synchronised region appoint a frequency leader. SAFA Annex 5 C-19 , in addition, defines that the frequency leader's Frequency Restoration Controller shall be switched to frequency control mode; the Frequency Restoration Controllers of the other TSOs of the synchronised region shall be switched to Frozen Control Mode.

North-West area – LFC Control Mode

The following TSOs reported the changes applied to their Load Frequency Controllers:

Time	TSO	LFC Mode changed to…
14:05:01	CEPS	Frozen Mode
14:11:36	CEPS	Normal (P/f)
14:05:02	Elia	Frozen Mode
14:11:40	Elia	Normal Mode
14:25:36	HOPS	Stopped Mode
15:18:25	HOPS	Normal Mode

Table 4.8: Applied changes to LFC mode

In the North-West part of the interconnection, the precondition from SAFA Annex 5 C-4-1 has not been fulfilled as frequency deviation was above 200 mHz for less than one minute. However, as the network split occurred, a frequency leader had to be appointed and the Frequency Restoration Controllers of the other TSOs of the synchronised region had to be switched to Frozen Control Mode. The appropriateness of switching all other TSO Frequency Restoration Controllers (except frequency leader) to Frozen Control Mode is discussed further in Section 4.1.4.

In the North-West part of the interconnection, in the role as SAM, Amprion acted as a frequency leader; however no official declaration as frequency leader was conducted. Almost all individual Frequency Restoration Controllers remained operational during the incident. Only two controllers (ELIA and CEPS) switched to Frozen Control Mode. The LFC controller in the HOPS LFC area uses frequency measurements from busbars in the North-West area. For this reason and to more easily control power plant production in the HOPS LFC area, the HOPS LFC controller was intentionally stopped.

South-East area – LFC Control Mode

The following TSOs reported the changes applied to their Load Frequency Controllers:

Time	TSO	LFC Mode changed to…
13:30:00	NOSBiH	Normal Mode
14:04:00	EMS	Frozen Mode
14:04:57	ESO	Frozen Mode
14:05:00	Transelectrica	From Normal (P/F) to Frozen Mode
14:06:00	IPTO	Frozen Mode
14:06:00	NOSBiH	Stopped Mode
14:13:04	TEIAS	Frozen Mode
14:24:43	ESO	Normal (P/f)
14:36:00	IPTO	Frequency Mode
14:43:36	TEIAS	Frequency Mode
15:09:00	IPTO	Normal Mode (P/F)
15:10:00	EMS	Normal Mode
15:10:00	TEIAS	Normal Mode
15:30:00	NOSBiH	Normal Mode
15:30:54	Transelectrica	From Frozen Mode to Normal (P/F)

Table 4.9: Applied changes to LFC mode

There was no influence of the aFRR as the large number of TSO LFC controllers were switched off manually or automatically ended in Frozen Control Mode in accordance with SAFA Annex 5 C-4.

In the South-East part of the interconnection, frequency deviation fulfilled criterion defined in SAFA Annex 5 C-4-1. Consequently, almost all individual Frequency Restoration Controllers were switched to Frozen Control Mode. They returned to normal operation mostly after the resynchronisation once the condition was met.

In the North-West part of the interconnection, the largest TSOs were in contact and well-coordinated, but it appears that the other TSOs required more information and coordination, at least concerning the eventual appointment of the frequency leader, the related coordinated change of Frequency Restoration Controller control modes and in the resynchronisation process.

In the South-East part of the interconnection, Transelectrica, following the criteria from Article 29 (3) of NC ER, should be appointed as the frequency leader, but due to system critical situation and network split it did not comply with the operational conditions to assume this responsibility. Therefore, EMS took the role of frequency leader.

TSO which went through the separation line had additional difficulties with Frequency Restoration Controllers as the units participating in LFC were in two separate areas. The awareness of dispatchers that its control area is split in two or more parts is of utmost importance.

4.1.4 Operation of LFC

LFC performance during the incident was satisfactory. It showed that the settings of individual Frequency Restoration Controllers were good, as almost all controllers followed the request from SAFA Annex 5 C-4-1 (in the event of a frequency deviation higher than 200 mHz lasting more than one minute, individual Frequency Restoration Controllers have to be switched in Frozen Control Mode). Controllers in South-East part of the network, where the precondition was fulfilled and frozen, and controllers in North-West part of the network, where frequency deviation was below the limit, remained operational.

On the other hand, according to NC ER Article 29 (1), in the case when a synchronous area is split in several synchronised regions, the TSOs of each synchronised region shall appoint a frequency leader. Frequency in the separated area from the network can be very sensitive and volatile. Depending on the size of synchronised region, even relatively small changes of production or load could lead to large frequency deviations, endangering the security, and may even lead to load shedding. Therefore, SAFA Annex 5 C-19 also defines that the frequency leader's Frequency Restoration Controller shall be switched to frequency control mode; the Frequency Restoration Controllers of the other TSOs of the synchronised region shall be switched in Frozen Control Mode. The intention here is to leave one TSO, usually the largest, to control frequency, which is a sensitive and difficult task in the case of a relatively small area. On the other hand, in the case of a large area it could become difficult or even impossible for one TSO to control the frequency. In the North-West part of the interconnection, the frequency leader was not officially appointed, and almost all individual Frequency Restoration Controllers remained operational during the incident. Only two controllers (ELIA and CEPS) switched their controllers to Frozen Control Mode. Although security of the system has not been endangered, it has to be concluded that the requirements from NC ER Art. 29 (1) and SAFA Annex 5 C-19 have not been fulfilled. Also, in the South-East part of the interconnection, the frequency leader has not been officially appointed. The largest TSO, Transelectrica, had to handle the large disturbance in their grid and could not assume the role of frequency leader, so EMS as TSO with eight borders and possibility to communicate with almost all TSOs in South-East part of the interconnection performed the role of frequency leader. As the size of the South-East area was too big for EMS frequency control capabilities, EMS did not put its Frequency Restoration Controller in frequency control mode. Instead, EMS coordinated the action of several TSOs, and, as a result of common effort, the frequency returned to the normal range.

It is recommended to examine all consequences of requirements from NC ER Art. 29 (1) and SAFA Annex 5 C-19. To freeze Frequency Restoration Controllers due to synchronous area separation could be the right or wrong decision, depending on the situation in the network. A more precise definition of network split is required. It is not the same if there are two or more similar areas and if a small part in a corner of the interconnection is separated from the network. The definition of "significant network separation" could be introduced, when the size or number of areas requires fulfilment of NC ER Art. 29 (1) and SAFA Annex 5 C-19 requirements. Because the North-West area was not really a separated area but rather the large part of RG CE, and one TSO with LFC in frequency control mode would not be able to control the frequency for this big area, it has to be checked whether this frozen mode for all TSOs and frequency control mode for one TSO is appropriate.

The EAS system already has a tool for detection of network split, based on 14 frequency measurements. It would be beneficial to transfer the network split signal created by EAS to the SCADA systems of all TSOs and to create a SCADA alarm. In addition, a TSO is going to face a lot of additional problems if the line of separation goes through its network. It could also be useful to develop a SCADA tool for detection of a local network split. For example, frequency measurements from all tie-lines could be compared in the SCADA system and in case of significant difference a system split alarm could be generated. If those alarms are collected on the interconnection level a more sophisticated system split detection tool could be available. These functionalities will be considered within the context of recommendation R-20.

4.1.5 Impact of IGCC during the incident

In the control areas which are part of the IGCC cooperation, any imbalances which occur are netted within the possible limits. Therefore, the IGCC process avoids the activation of aFRR due to the netting process and should not affect frequency as well as the balance between load and generation within the synchronous area. Theoretically, in the event of a of network split, a separation of the IGCC area could lead to a netting between two physically disconnected areas. Therefore, the imbalance would persist and no aFRR would be activated in both areas, even though this would be necessary.

On 08 January, the whole IGCC area was within the North-West area, except Croatia, which was partly separated due to the system separation. Before the incident, IGCC real-time transactions of Croatia were close to zero and went up slightly above 300 MW during the incident as illustrated in Figure 4.1. Therefore, it can be concluded that the IGCC did not affect the security of the network during the incident either in a positive or negative manner.

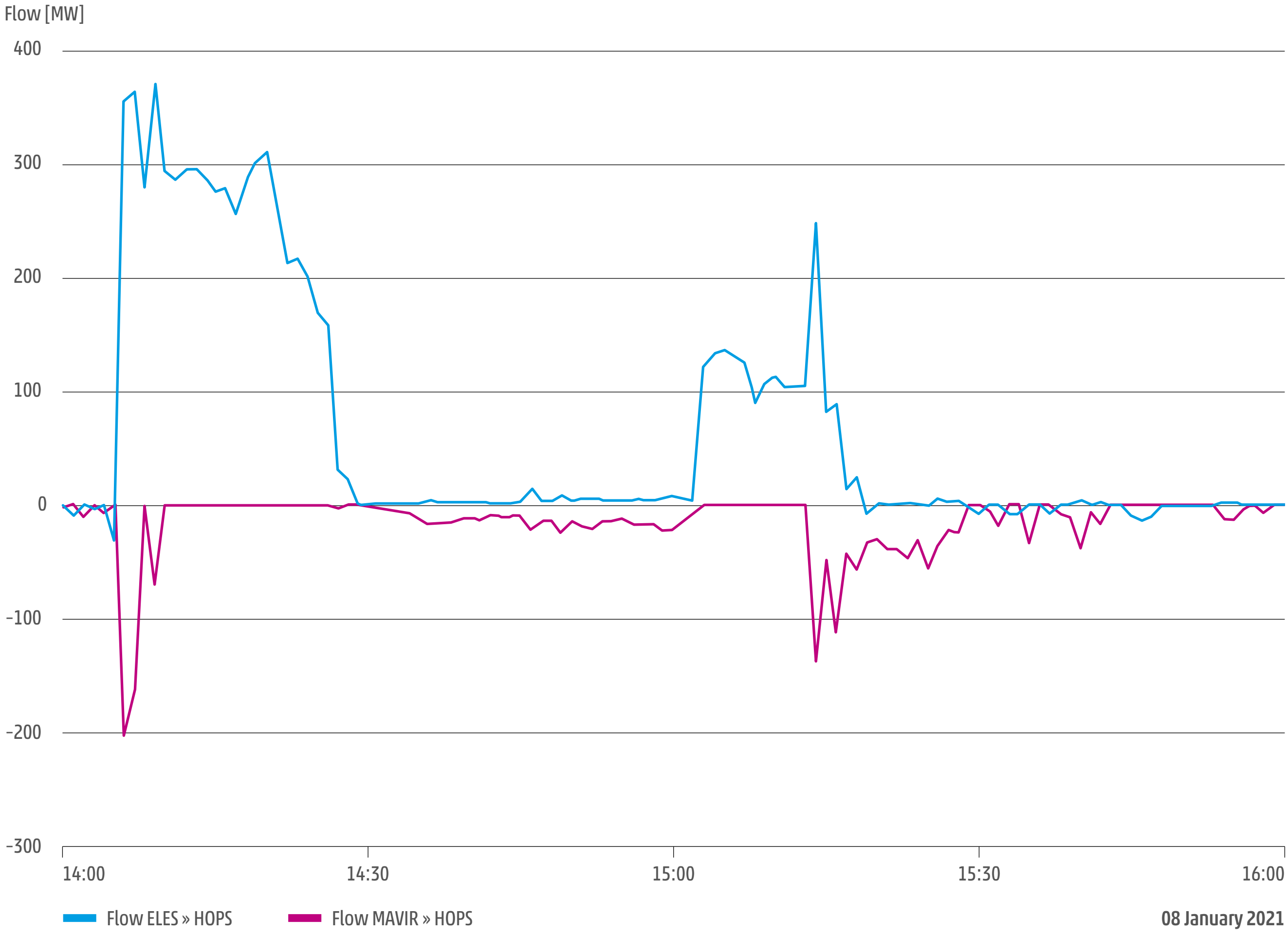


Figure 4.1: IGCC Flow: Slovenia » Croatia (blue line), and Hungary » Croatia (red line)

4.1.6 Operation of IGCC during system separation

On 08 January 2021, the IGCC platform remained operational during the incident period. IGCC operation did not affect the security of the network during the incident in a positive or in a negative manner as the whole IGCC area, except for a small part of the Croatian network, remained connected within the North-West area.

However, the operation of IGCC, or some other platforms for the cross-border exchange of reserves (PICASSO, MARI) during the network split could lead to significant imbalances in all parts of the network, if reserve is exchanged between TSOs in different areas. Procedures should therefore be considered to prevent energy interchange between separated parts of the network into the current and future platforms for the cross-border exchange of reserves.

ID	Recommendation	Justification	Responsible
Operation of IGCC during system separation			
R-19	Determine **procedures** for the imbalance netting as well as the exchange of reserve in case of a **system separation** for current and future **balancing platforms**, i.e. IGCC, PICASSO, MARI and TERRE.	If the power system is separated between two areas, any imbalance netting or exchange of reserve between both areas should be stopped. Otherwise, imbalances in the system will not be resolved and could lead to a larger disturbance of the system.	TSOs

4.1.7 Coordinated execution of manual measures (and automatic measures) in case of extraordinary disturbances

Overall, the execution of manual and automatic measures was effective. Nevertheless, the coordination of such measures can be improved. Not all measures were activated in coordination with the CCs. The activated manual measures affected the ACE values of the initiating TSOs and were thus partially counteracted by aFRR or IGCC netting.

4.1.8 Application of Articles 28, 29, 30 and 31 of the Electricity Emergency and Restoration Network Code

The NC ER is a regulation that came into force on 24 November 2017. Section 3 of Chapter III (Restoration Plan) of the NC ER is devoted to Frequency management and consists of following articles:

- Article 28 – Frequency management procedure;
- Article 29 – Appointment of a frequency leader;
- Article 30 – Frequency management after frequency deviation; and
- Article 31 – Frequency management after synchronous area split.

Article 28 (1) states that the frequency management procedure of the restoration plan shall contain a set of measures aiming at restoring system frequency back to the nominal frequency. Article 28 (2) defines that each TSO shall activate its frequency management procedure:

(a) in preparation of the resynchronisation procedure, when a synchronous area is split in several synchronised regions;

(b) in case of frequency deviation in the synchronous area; or

(c) in case of re-energisation.

During the 08 January 2021 incident, a system split (a) and a significant frequency deviation (b) were detected, so it is clear that the frequency management procedure had to be implemented.

According to Article 28 (3), the frequency management procedure shall include at least:

(a) a list of actions regarding the setting of the load frequency controller before the appointment of frequency leaders;

(b) the appointment of frequency leaders (further described in Article 29);

(c) the establishment of target frequency in the event of a bottom-up re-energisation strategy (this was not the case during the incident, so it is not commented on in this report);

(d) frequency management after frequency deviation (further described in Article 30);

(e) frequency management after synchronous area split (further described in Article 31); and

(f) the determination of the amount of load and generation to be reconnected, considering the available active power reserves within the synchronised region to avoid major frequency deviations.

The list of actions regarding the setting of the load frequency controller before the appointment of frequency leaders (Art. 28.3.(a)) is set in RG CE SAFA Policy on emergency on restoration (Policy 5, paragraph C-4, Frequency Management Procedure before the appointment of frequency leader according to Article 28 (3) of NC ER). In this paragraph, Policy 5 envisages the following actions relevant for operator's instruction:

In the event of frequency deviation higher than 200 mHz lasting more than one minute, individual Frequency Restoration Controllers have to be switched in Frozen Control Mode by direct manual or automatic actions or by other ways, relying on TSO devices or generating units devices (C-4-1).

After implementing actions described in C-4.1, TSOs are allowed to manually/automatically override the Frozen Control Mode output signal of Frequency Restoration Controllers to use theirs communication/signalling channels to power-generating facility to speed up the stabilisation of the system (C-4-4).

In the event of frequency deviation higher than 200 mHz lasting more than one minute, TSOs are allowed to manually and/or automatically activate additional reserve (e.g. (i) through starting/stopping pumped-storage power-generating facilities and/or (ii) activating Manual Frequency Restoration Reserves (mFRR) and/or (iii) decreasing/increasing the level of active power generation by activating extra FCR if available) to speed up the stabilisation of the system (C-4-5).

In Section 4.4.4, the actions performed in the South-East part of RG CE before the appointment of frequency leaders are presented. The conclusion is that Policy 5 was properly implemented (as there was a recorded frequency deviation higher than 200 mHz lasting more than 1 minute).

Before addressing the remaining articles, it must be noted that the subject of Article 28 (3) (f) is not further developed in either NC ER or in Policy 5. This means that the determination of the amount of load and generation to be reconnected during the system restoration is left to the dispatcher's experience. RG CE TSOs dispatcher training covers this issue extensively, and there is no need to define additional rules for this purpose.

Article 28 (3) is further developed in Article 29 which addresses the appointment of frequency leaders. According to Article 29:

» When a synchronous area is split into several synchronised regions, the TSOs of each synchronised region shall appoint a frequency leader (this was the case during the incident).

» When a synchronous area is not split but the system frequency exceeds the frequency limits for the alert state as defined in Article 18 (2) of Regulation (EU) 2017/1485, all TSOs of the synchronous area shall appoint a frequency leader.

» The TSO with the highest real-time estimated K factor shall be appointed as the frequency leader, unless the TSOs of the synchronised region, or of the synchronous area, agree to appoint another TSO as the frequency leader. In that case, the TSOs of the synchronised region, or of the synchronous area, shall consider the following criteria:

(a) the amount of available active power reserves and especially FRR;

(b) the capacities available on interconnectors;

(c) the availability of frequency measurements of TSOs of the synchronised region or of the synchronous area; and

(d) the availability of measurements on critical elements within the synchronised region or the synchronous area.

Currently, the majority of RG CE TSOs have no appropriate process or tool implemented in their control centres to assess and widely share the real-time estimated K-factors. If necessary, real-time K-factors can be estimated manually by the TSOs. In addition, in a scenario such as 08 January 2021, where a synchronous area was split in two relatively large areas, the K factor of an individual TSO is not the most determining factor for the nomination of a frequency leader. That is why these TSOs had to use points (a)–(d) to choose the frequency leader. In addition, the normal processes in relation to the role of the SAM and communication were important considerations in respect of choosing a frequency leader. The CC North (Amprion, who is also SAM and was responsible for frequency monitoring in January 2021) organised the communication and coordination with the TSOs in the North and West of Europe and with the CC South (Swissgrid). Swissgrid was responsible for communication and coordination with the TSOs in the South of Europe and with Amprion. In the South-East part, EMS coordinated and communicated with Swissgrid and the most relevant TSOs in the South-East (ESO, IPTO, NOS BiH, HOPS, Tranelectrica and TEIAS.

» Where the size of the synchronous area concerned and the real-time situation allow it, the TSOs of the synchronous area may appoint a predetermined frequency leader (for instance, some TSOs have in bilateral agreements predefined frequency leader according to annual K factor and this was also considered during the incident).

» The TSO appointed as frequency leader shall inform the other TSOs of the synchronous area of its appointment without delay. EMS agreed with most TSOs by telephone that it would perform the role of frequency leader as Transelectrica could not take the role. According to NC ER Article 29 (4) to (6), depending on the size of the synchronous area, a predetermined frequency leader may be appointed, and this frequency leader shall act as such until another frequency leader is appointed. According to SAFA LFC&R Policy B-3, the CCs fulfil the obligations of the SAM. In this role, they are responsible for frequency monitoring, the determination of system state with regard to the system frequency and coordination in the event of frequency deviations. Hence, the role of SAM in a normal state is very similar to the role of the frequency monitor. Considering that the frequency in the North-West recovered extremely quickly, Amprion acted as the frequency leader for the North-West area. In the future, all TSOs will be informed by the frequency leader of their appointment using the EAS Tool, as defined in SAFA Policy 5-C-17. This communication requirement will also be documented within a new RG CE resynchronisation procedure as per recommendation R-21.

» The appointed frequency leader shall act as such until:

(a) another frequency leader is appointed for its synchronised region;

(b) a new frequency leader is appointed as the result of the resynchronisation of its synchronised region with another synchronised region; or

(c) the synchronous area has been completely resynchronised, the system frequency is within the standard frequency range and the LFC operated by each TSO of the synchronous area is back to its normal operating mode in accordance with Article 18 (1) of Regulation (EU) 2017/1485 (during the incident we had the case c in place).

Next, Article 30, "Frequency management after frequency deviation" of the NC ER sets out the following rules:

- when a frequency leader has been appointed, the TSOs of the synchronous area, other than the frequency leader, shall as a first measure suspend the manual activation of FRR and replacement reserves;

- The frequency leader shall establish, after consultation with the other TSOs of the synchronous area, the operating mode to be applied on the LFC operated by each TSO of the synchronous area (Policy 5 further recommends in C-18-2 Frequency Restoration Controller for Frequency Deviation higher than 200 mHz: The frequency leader's Frequency Restoration Controller shall be switched to frequency control mode, the Frequency Restoration Controllers of the other TSOs of the synchronised region shall remain in (or, if not yet, manually switch to) Frozen Control Mode);

- The frequency leader shall manage the manual activation of FRR and replacement reserves within the synchronous area, aiming at regulating the frequency of the synchronous area towards the nominal frequency and considering the operational security limits defined pursuant to Article 25 of Regulation (EU) 2017/1485. Upon request, each TSO of the synchronous area shall support the frequency leader.

- In general, the TSOs followed the essence of the Article 30. It is worth mentioning that EMS acted as a frequency leader and had no capacity to keep the frequency restoration controller in the frequency control mode, but this was not a breach of Policy 5 as this is only a recommendation. The reasons for this are described in Section 4.4.4.

- The final article in relation to Frequency Management is Article 31 which is devoted to frequency management after the synchronous area split and has the following rules:

- When a frequency leader has been appointed, the TSOs of each synchronised region, with the exception of the frequency leader, shall as a first measure suspend the manual activation of FRR and replacement reserves (this is fully harmonised with Article 29, so if there is both, system split and frequency deviation, there is no collision).

- The frequency leader shall establish, after consultation with the other TSOs of the synchronised region, the operating mode to be applied on the LFC operated by each TSO of the synchronised region (this is also fully harmonised with Article 29).

- The frequency leader shall manage the manual activation of FRR and replacement reserves within the synchronised region, aiming at regulating the frequency of the synchronised region towards the target frequency established by the resynchronisation leader, if any, and considering the operational security limits (this part corresponds to Article 29). When no resynchronisation leader is appointed for the synchronised region, the frequency leader shall aim at regulating the frequency towards the nominal frequency. Upon request, each TSO of the synchronised region shall support the frequency leader (which was the case during this system split situation).

After deliberation of all articles relevant for frequency management in emergency operation, some conclusions regarding frequency management in system restoration can be made:

- Section 3 – Frequency management is well-structured and consistent;
- This part of NC ER is properly complemented by SAFA Policy 5;
- However, even though the frequency management and resynchronisation were carried out efficiently;
- The Frequency Management procedure is not easy to implement efficiently without proper tools and processes, due to its complexity:
  - The appointment of a frequency leader was not completed as set out by the NC ER, but the frequency leader functions were executed;
  - EAS was not used to inform all TSOs about the appointed frequency leader.
- There is no tool or procedure which can provide full guidance to TSOs' control room operators in the event of system separations. That is why it is necessary to investigate further upgrades of tools and procedures which could detect the characteristics of the pending disturbance and provide guidance to TSOs' control room operators in order to follow all the rules of the NC ER and SAFA Policy 5. These upgrades will be considered within the context of recommendations R-20 and R-21.

4.2 Resynchronisation process

This section presents the gathered data regarding the resynchronisation process. This section covers the preconditions of resynchronisation and preparatory actions as well as the resynchronisation sequence.

4.2.1 Preconditions for system resynchronisation

Thanks to the EAS, TSOs received information a short time after the disturbance that the Continental Synchronous Area had separated into two areas (Figure 4.2).

The control areas with an over-frequency are highlighted in red. A separate area with the TSOs HOPS, Transelectrica, NOSBiH, EMS, ESO, MEPSO, OST and IPTO can be identified (as can be observed from the frequencies, the colouring of OST is not correct in the figure because of an issue in the data handling failure in EAS).

More detailed information was available to the TSOs through WAMS (Figure 4.3) and SCADA/EMS.

The TSOs of the South-East area (EMS, HOPS, NOSBiH, MAVIR, ESO EAD, IPTO and Transelectrica) had a phone call with a briefing about every TSO system state. Affected TSOs (EMS, HOPS, NOSBiH, and Transelectrica) exchanged information about tripped elements in their networks to determine the line where the two parts of the Continental Synchronous Area had separated.

After the system separation, the South-East area had a high frequency, which was stabilised between 50.2 Hz and 50.3 Hz. The system operation of Transelectrica was largely influenced (significant challenges in both transmission and distribution grids, especially because the grid had to be operated for the two separated areas), and Transelectrica could not comply with the resynchronisation leader condition. Consequently, frequency regulation was done with the coordination of EMS with all the other TSOs in the South-East area. EMS agreed with ESO EAD, IPTO, HOPS, NOSBiH and Transelectrica to reduce the production of their power plants (HOPS and Transelectrica did this just in the higher frequency part of the grid). Furthermore, EMS asked ESO EAD if they could call TEIAS to also decrease their production. TEIAS agreed and reduced their production.

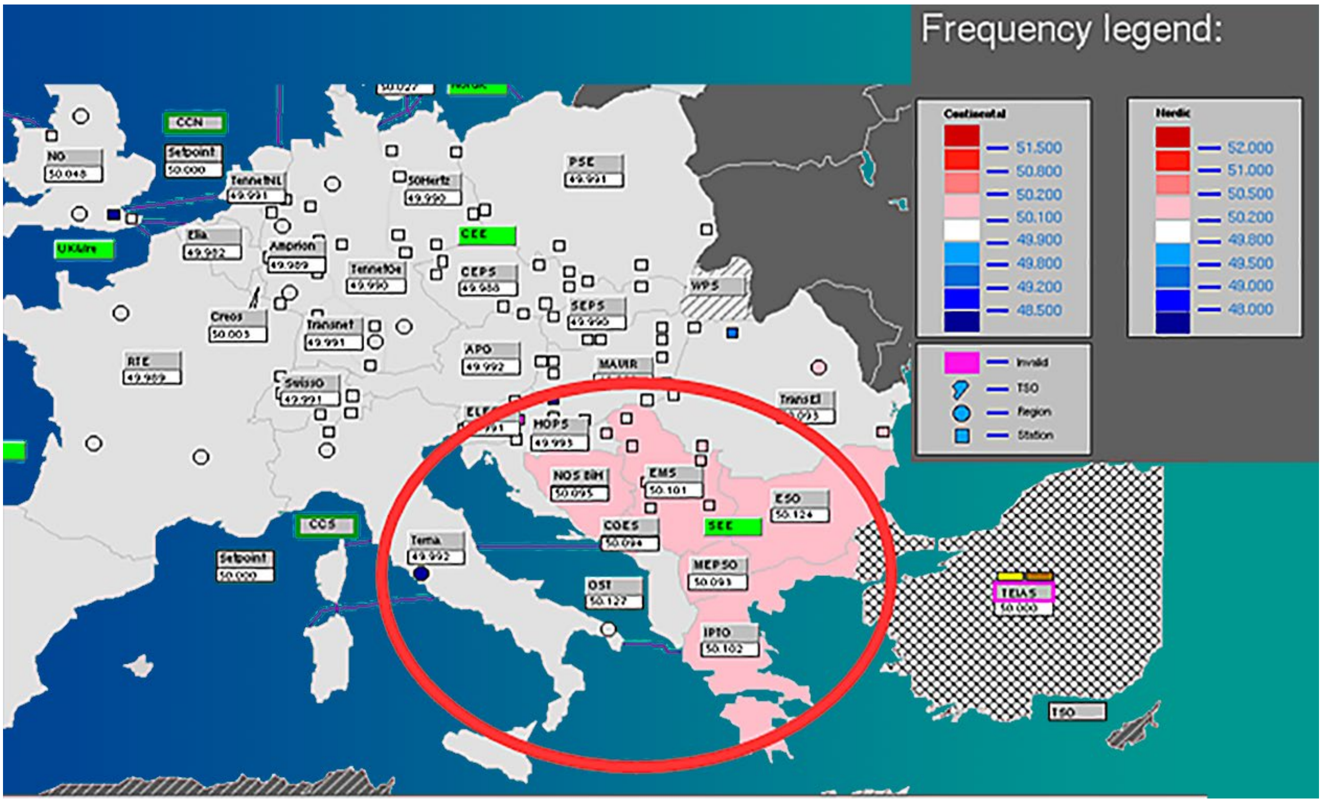


Figure 4.2: EAS overview of the CE Synchronous Area

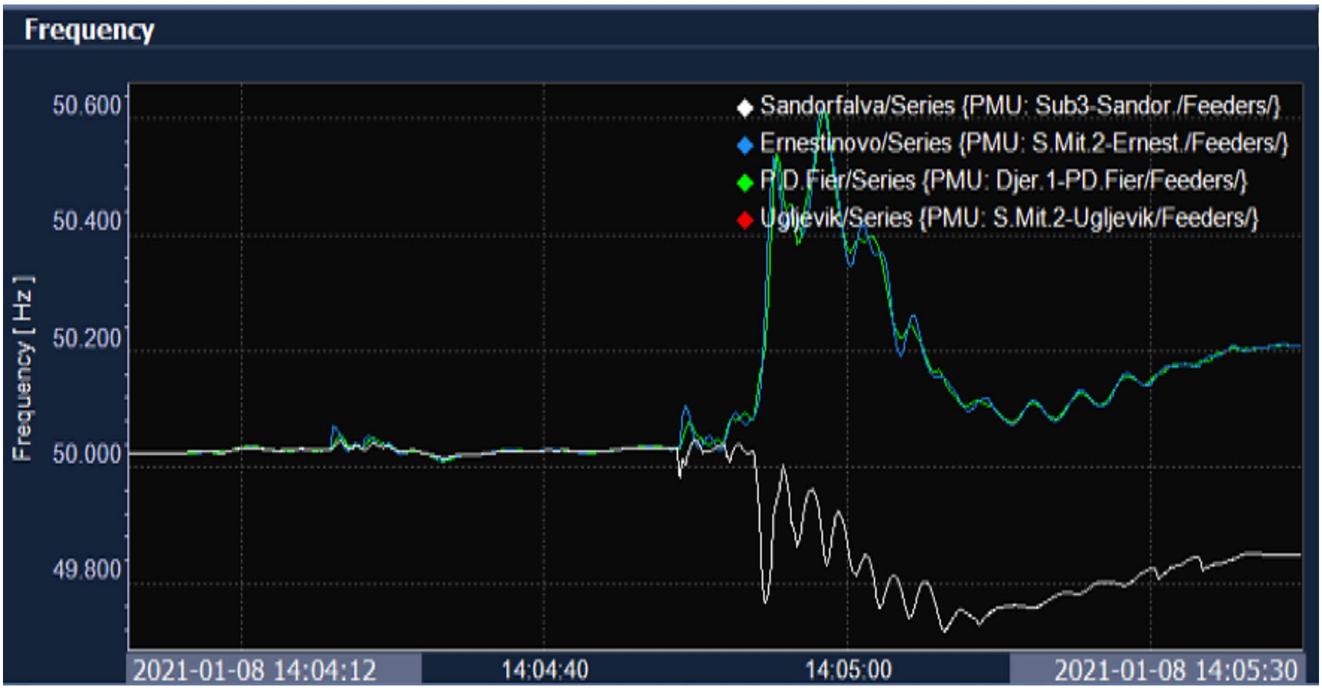


Figure 4.3: Frequency recording for Continental Synchronous Area at the moment of separation

The North-West area had a low frequency, which was stabilised around 49.96 Hz. Resynchronisation actions were performed in the networks of HOPS in Croatia, EMS in Serbia, NOSBiH in Bosnia and Hercegovina and Transelectrica in Romania.

The actions which allowed the resynchronisation can be grouped into the following phases:

» Preparatory actions

» Resynchronisation sequences

4.2.2 Preparatory actions

EMS, HOPS, and NOSBiH agreed during a conference call to the plan for resynchronisation as follows:

» To wait until the frequency difference between the areas is less than 100 mHz and shows a decreasing trend,

» To make three strong reconnection points connect in a short time,

» The first reconnection point would be a busbar coupler 400 kV in SS Ernestinovo (the busbar coupler in Ernestinovo has a synchro-check device and is more or less in the middle of the split line),

» The second reconnection point would be Overhead Line (OHL) 400 kV Novi Sad 3 – Subotica 3 (which is more or less in the middle of the split line, also providing a second strong connection in a relatively small area,

» The third reconnection point would be OHL 400 kV Konjsko – Velebit (last tripped 400 kV connection in HOPS[1]),

» To connect the other tripped OHLs in Transelectrica, HOPS, NOSBiH and EMS.

1 400 kV Velebit – Melina tripped, then 400 kV Konjsko – Velebit switched off, then Velebit – Melina switched on and finally Konjsko – Velebit switched on as third reconnection point

4.2.3 Resynchronisation sequences

To ensure the success of the resynchronisation plan, EMS and HOPS kept an open line during the resynchronisation sequences of the first three points. Thereafter, one EMS dispatcher was on the line with the HOPS dispatcher, the second EMS dispatcher was in communication with SS Novi Sad 3, and the third was on the line with the Transelectrica dispatcher. At the same time, except with EMS, HOPS dispatchers were in communication with regional dispatch centres Osijek (in charge of SS Ernestinovo) and Split (in charge of SS Konjsko and SS Velebit).

The resynchronisation sequences are listed below:

1. The busbar coupler 400 kV in Ernestinovo (HR) was switched on at 15:07:25,
2. Immediately after confirming that the first step was successful, OHL 400 kV Novi Sad 3 (RS) – Subotica 3 (RS) was switched on at 15:08:20,
3. Immediately after confirming that the second step was successful, OHL 400 kV Konjsko (HR) – Velebit (HR) was switched on at 15:09:38,
4. Transelectrica was informed that EMS, NOS BIH and HOPS had made reconnections, so the internal line connections in Transelectrica could be started,
5. Transelectrica switched on OHL 400 kV Sibiu Sud – Mintia at 15:10, and, subsequently, OHLs 400 kV Iernut – Sibiu Sud & 400 kV Iernut – Gădălin at 15:12,
6. HOPS and NOSBiH switched on the other tripped lines:
   - 220 kV Brinje (HR) – Pađene (HR) switched on at 15:12
   - 220 kV Sisak (HR) – Prijedor (BA) switched on at 15:14
   - 220 kV Međurić (HR) – Prijedor (BA) switched on at 15:15
7. Transelectrica proceeded to reconnect the rest of the tripped lines and transformers:
   - 220 kV Iernut – Baia Mare 3 at 15:16
   - 220 kV Iernut – Câmpia Turzii at 15:17
   - 220 kV Târgu Jiu Nord – Paroșeni at 15:17
   - 220 kV Reșița – Timișoara 1 at 15:19
   - AT 400 MVA – 400/220 kV Roșiori at 15:23,
8. EMS and HOPS proceeded to reconnect the tripped 110 kV OHLs.

Around 15:50 on the transmission lines, large loads of 400 kV Ernestinovo – Ugljevik and 400 kV Sremska Mitrovica 2 – Ernestinovo were observed, which were almost the same as before the disturbance. The level of the DC Link Monita was then changed in the CGES – Terna direction from 100 MW to 600 MW at 16:10 in coordination with Balkans TSOs and Terna.

After this coordinated action, there was a change in power flow on the tie-lines between EMS – HOPS and EMS – NOSBiH: 400 kV Sremska Mitrovica 2 – Ernestinovo (from approximately 700 MW to 600 MW) and NOSBiH – HOPS 400 kV Ugljevik – Enestinovo (from approximately 740 MW to 630 MW).

The frequency in CE during the resynchronisation process, based on the WAMS measurement of frequencies in the split areas (each measurement point with exact GPS time stamp, 50 msec resolution), is presented in Figure 4.4.

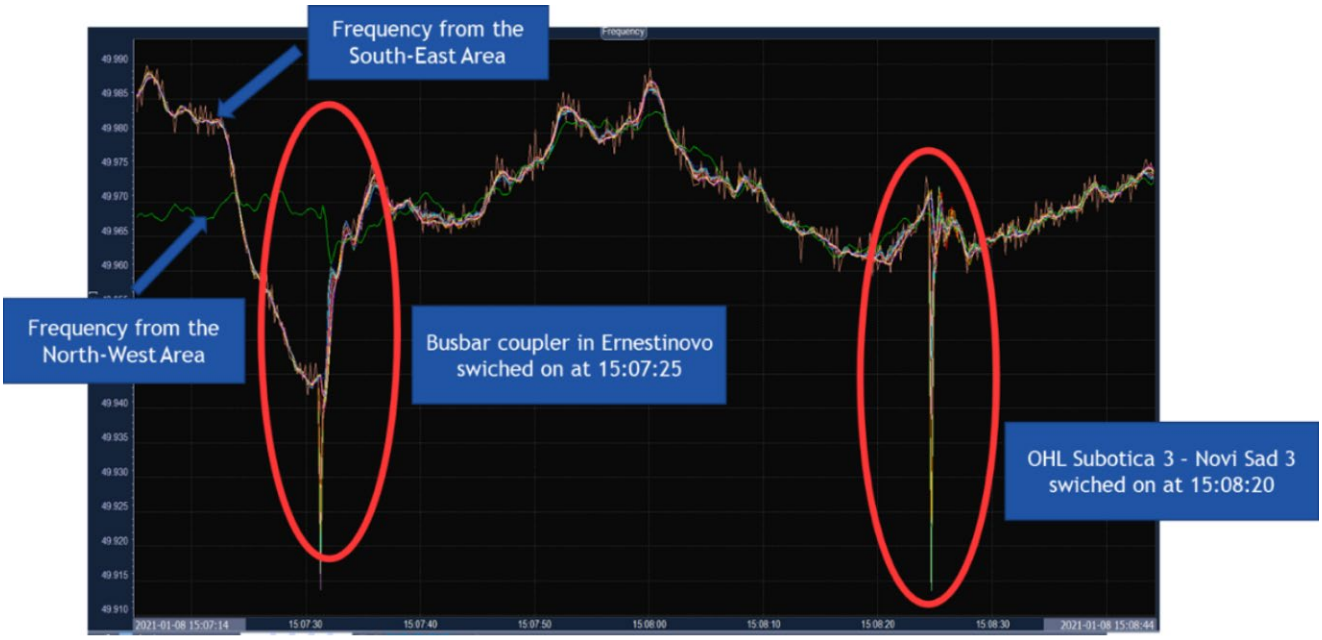


Figure 4.4: Frequency recording for the North-West and South-East areas during resynchronisation at two points

4.2.4 Procedure in the event of system separation and resynchronisation of separated grid areas

Overall, the resynchronisation of separated grid areas went well. Nevertheless, coordination and communication can be enhanced. Today, no common procedure in the event of a system separation has been established.

The current processes are more designed for restoration in black out cases. Not all of this can be transferred one-by-one to system separation events.

4.3 Communication of coordination centres/SAM and between TSOs

As communication between the CCs and the TSOs is of utmost importance for a reliable and stable system operation, this section presents the different contacts at the time of the incident between the CCs and the affected TSOs and amongst the TSOs. It also considers the coordination of data in EAS.

4.3.1 Between North and South CCs and the affected TSOs

08 January, 14:05 CET

The system separation caused large steady-state frequency deviations within the two disconnected areas of the CE Synchronous Area. In the North-West area, the frequency dropped from 50.02 Hz to 49.74 Hz, whereas the frequency in the South-East area jumped to 50.6 Hz. The deviations were detected by the local LFC Systems of the CC Amprion (CC North) and Swissgrid (CC South). For CC South, the "Emergency State" and the predefined message "Frequency deviation | Δf | > 200 mHz" was set automatically in the EAS.

08 January, 14:06 CET

During a phone call between the CCs, the frequency drop was verified and the first common analyses were started based on information from EAS. At this moment, the frequency deviation in the North-West area had decreased to 160 mHz under frequency. EAS provided the following indications:

- » High ACE value of IPTO → (Change from +50 MW → –1,950 MW),
- » High ACE value of REE → –1,267 MW associated with the quick increase of generation in the Spanish system in order to compensate the trip of the HVDC,
- » Temporary high ACE sum-values for CC North and CC South.

Based on this information, the CCs called their originally assigned TSO REE and IPTO to ask for more information. REE reported the disconnection of HVDC interconnectors between RTE and REE.

In addition, Terna informed Swissgrid (CC South) via phone that approximately 400 MW of contractual load had been automatically disconnected.

08 January, 14:10 CET

The trigger for Stage 1 of the CE Extraordinary Procedure was reached (Frequency deviation |Δf| > 100 mHz for a time period t > 5 min). For CC North, the "Alert State" and the predefined message "Frequency deviation |Δf| > 100 mHz for t > 5 min" was set automatically in EAS.

Due to the results of the common analysis and the critical nature of the situation, the CCs decided to launch Stage 2 of the CE Extraordinary Procedure proactively. This procedure is detailed further in Annex 4.1.

08 January, 14:12 CET

Amprion, as the responsible frequency monitor in odd months, activated the "extraordinary procedure" (50/100 mHz-procedure) Stage 2 phone conference with the involved TSOs (Amprion, Swissgrid, RTE, Terna, and REE). The TSOs shared the following available information:

- » Amprion reported the frequency drop, the trigger for the CE Extraordinary Procedure and results of the first short analysis,
- » RTE and Terna reported a contractual load shedding of 1,300 MW in France and contractual load shedding max. 400 MW) in Italy,
- » REE confirmed HVDC disconnection between RTE and REE,
- » RTE and REE reported that coordinated countertrading, approximately 1,400 MW, was activated to avoid overloading the 400 kV line Vic-Baixas after the loss of the HVDC link between Santa Llogaia (Spain) and Baixas (France). For that:
  - – REE increased production
  - – RTE decreased production

During the call, the CCs detected the probable system separation on the EAS frequency map. A separate area with the TSOs HOPS, Transelectrica, NOSBiH, EMS, ESO, MEPSO, OST and IPTO was indicated.

Due to the fact that the frequency deviation in the North-West area was decreased by primary control FCR and other automatic measures such as contractual load shedding and aFRR activation to less than 50 mHz and was still recovering, the five TSOs decided that, at that moment, no further measures were necessary to stabilise the frequency in the North-West area.

The CCs decided to focus their investigations on the reasons for the system separation and to call the TSOs from the South-East area.

In parallel, APG called an Amprion grid engineer and informed them that APG ordered reserves at 14:06 CET (as per Section 4.1.1) and that the LFC was modified with a controller offset to support the frequency.

Transelectrica and MAVIR mutually informed each other about networks state in their system. MAVIR noticed no outages, but Transelectrica generally informed about the difficult situation in their system.

08 January, 14:29 CET – 14:35 CET

Swissgrid called IPTO. The TSO confirmed the grid separation of the South-East area. At this time, the cause was estimated to be in the grid of Transelectrica. Swissgrid called EMS. The TSO also confirmed the system separation in the area of Serbia and Romania and reported production shedding due to over-frequency. The CCs kept in touch and shared all relevant information via phone.

08 January, approx. 14:40 CET

In a phone call between Amprion and APG, Amprion reported the system split and the results of the 50/100 mHz-procedure phone conference.

08 January, 14:43 CET – 14:51 CET

The CCs had several phone calls together and with Terna and RTE. The high ACE of RTE (approximately 3,500 MW), due to compensation measures for HVDC tripping, contractual load shedding, and the upcoming hour schedule change in France, was discussed. As the frequency had recovered and was very close to 50 Hz, the CCs agreed that RTE and Terna should start reconnecting the disconnected contractual load in maximum steps of 300 MW and that RTE should adjust the production in coordination with REE, which was adapted due to the tripping of the HVDC connection. The CCs would monitor the development of the frequency and contact the TSOs in case of degradation.

08 January, 14:51 CET – 15:06 CET

The CCs tried to get more information about the system separation and the activities in the South-East area.

Amprion called ESO and Transelectrica. ESO provided further information about the system separation. The cause was estimated by ESO operators in Romania.

08 January, 15:08 CET

The CCs got in touch and monitored the resynchronisation of the South-East area with the North-West area in EAS and their local LFC systems. After the successful resynchronisation, the CCs decided to contact the control areas with the highest ACE values (imbalances) in EAS (RTE, EMS and ELES) and to initiate the return to the original production plans and exchange programmes.

08 January, 15:11 CET – 15:23 CET

Swissgrid had several phone calls with TSOs in the CC South area (RTE, EMS and ELES). In the calls, information about resynchronisation was shared, and Swissgrid gave the TSOs the task of recovering the lost production, reducing imbalances and returning to original production plans and exchange programmes. RTE was also requested to proceed with the reconnection of the HVDC interconnectors.

08 January, 15:27 CET – 15:31 CET

Amprion had phone calls with MAVIR and Transelectrica and attempted to get more detailed information about the system separation, the resynchronisation and the current situation in the grid of the TSOs. Transelectrica deployed actions and measures to supply the lost load and recover the right generation schedule.

08 January, 15:47 CET

Swissgrid contacted RTE to ask for the status of the HVDC interconnectors and current production. RTE reported that they had returned to their original production plan, but the process of reconnecting the HVDC interconnector with REE was still ongoing. Amprion contacted APG and asked them to deactivate mFRR which was activated from APG to support the frequency.

08 January, 16:15 CET

Amprion, as responsible frequency monitor, activated the "extraordinary procedure" (50/100 mHz-procedure) Stage 2 phone conference with the involved TSOs (Amprion, Swissgrid, RTE, Terna, and REE). The conference was used to report the current status of the CE transmission system. The CCs reported on the successful resynchronisation, relayed that the situation had relaxed and that all TSOs were back in their normal state. The TSOs confirmed the normalised status. RTE and REE reported that the HVDC link between France and Spain was still out of service but that the reconnection process was ongoing. Amprion distributed a final report to the involved TSOs.

In the afternoon, Amprion sent a management information report via email to the ENTSO-E bodies RG CE Plenary, SOC and CSO SG.

4.3.2 Between affected TSOs in the South-East area and the border region

08 January, 14:05 CET

The operators of EMS observed a tripping of overhead line between two 400 kV/110 kV substations due to overcurrent protection and an outage of a power plant (400 MW). The WAMS indicated a high frequency deviation and islanding alarms were displayed. WAMS frequency measurements for two 400 kV/110 kV substations deviated from other frequency measurements in the EMS grid. At the same time, in the control room of HOPS, investigations began after the tripping of several elements in the grid of HOPS.

08 January, 14:08 CET – 14:15 CET

EMS called HOPS: Both TSOs confirmed a system separation. By considering data from SCADA/EMS, WAMS and EAS, the points of separation were assumed to be in the grids of the TSOs HOPS, EMS, Transelectrica and NOS BIH.

After the call, HOPS informed NOS BIH and ELES while EMS called MAVIR to inform them about the system separation and that two EMS substations were only supplied by the grid of MAVIR.

The Transelectrica and ESO EAD control centres mutually informed each other about the operational state of the network. ESO – EAD had no trips within their transmission network, but Transelectrica faced some multiple transmission and distribution lines outages.

ESO EAD informed EMS that the cause of the grid separation was estimated to be in the Romanian TSO (due to multiple outages in the grid of Transelectrica).

EMS called Transelectrica. At that moment in time, the control centre of Transelectrica was unable to answer because they were extremely busy with the sudden situation in their grid. Subsequently, EMS informed Transelectrica about outages of the line Subotica – Novi Sad and Transelectrica informed them of the difficult situation within their system and generation decreasing within over-frequency area.

08 January, 14:16 CET – 14:48 CET

Swissgrid called EMS. EMS confirmed the system separation and that Romania reported production and load shedding due to over-frequency.

IPTO called EMS. Due to the fact that the frequency was higher than maximum steady-state frequency deviation, the dispatchers agreed that they should coordinate to reduce the production of power plants in their control areas.

After the call with IPTO, EMS also asked ESO EAD, Transelectrica and TEIAS to continue to reduce the production of power plants in the separated area with over-frequency.

The power system operators (IPTO, ESO, HOPS, Transelectrica, CGES, NOSBiH) kept in touch and shared all relevant information.

In alignment with NOSBiH and EMS, HOPS shared a resynchronisation strategy in which, after a successful attempt, EMS would make a reconnection to MAVIR, and, along with NOSBiH, would try to align the frequency to meet resynchronisation parameters.

08 January, 14:55 CET – 15:04 CET

The power system operators agreed that the reconnection of grid separation should be done by switching on the 400 kV busbar coupler in SS Ernestinovo (HOPS), when the frequencies in both areas had approximated and were stable.

08 January, 15:06 CET

When conditions were met (the frequencies of the two areas approached each other), HOPS switched on the busbar coupler in SS Ernestinovo, and immediately afterwards EMS switched on the 400 kV OHL, and the connections with MAVIR were restored. The South-East area then reconnected with the North-West area. After a successful reconnection in substation Ernestinovo, HOPS relayed news of the successful reconnection to EMS and initiated the immediate reconnection of OHL 400 kV Velebit – Konjsko.

At the same time, EMS informed Transelectrica of the reconnections. Transelectrica began reconnecting transmission lines in their grid. After the resynchronisation and stabilisation of the system, the power system operators increased the production of the power plants in their grid to bring ACE values into desirable limits.

Subsequently, HOPS agreed with NOSBiH that the reconnection was sufficiently stable to continue with the 220 kV reconnection of the 220 OHL interconnectors in substation Prijedor (NOSBiH).

Due to the high flow perseverance in a northern direction, the OHL interconnector with MAVIR (Ernestinovo – Pecs 2) was switched on in alignment with MAVIR.

Swissgrid (CC South) called EMS. EMS shared information about the successful resynchronisation. Swissgrid requested EMS to recover the lost production, reduce imbalances and return to the original production plans and exchange programmes.

08 January, 14:15 CET – 16:10 CET

During the event, EMS, HOPS and NOSBiH had three conference calls for information and coordination:

On the first call, around 14:20 CET, it was agreed:

- » Frequency regulation of all TSOs in the South-East area should be in coordination with EMS,
- » Reconnection of the three points (busbar coupler 400 kV in SS Ernestinovo, OHL 400 kV SS N. Sad 3 – SS Subotica 3, and OHL 400 kV SS Konjsko – SS Velebit) should be made as soon as feasible.

On the second call, around 15:15 CET:

- » Successful resynchronisation was confirmed.

On the third call, around 15:50 CET:

- » After taking note that the loads on the transmission lines Ernestinovo – Ugljevik and Ernestinovo – S. Mitrovica 2 were almost the same as before the disturbance, in coordination with CGES and Terna, the programme on the Monita DC link was changed to improve the stabilisation of the system after resynchronisation.

4.3.3 Data representation in EAS

EAS was used successfully by TSOs during the system separation, quickly informing each other of the local grid situation and of the frequency levels in each separated area. Post event analysis of the use of EAS has highlighted the need for further additional information in EAS both before and during the event.

Prior to the event, the following additional information would have increased TSO situational awareness, enabling TSOs to take preventive action and reduce the risk of a significant event due to high cross-border flows and/or angular instability:

- » Cross-border flows (DACF, IDCF, Real-Time)
- » WAMS measurements (voltage phase angles, frequencies, etc)

Using this data and enhanced EAS functionality, additional alarms could be developed in EAS to warn operators in the event of significant deviations in voltage phase angles or of significant differences between physical and commercial flows.

After the system separation, individual TSOs set alarms in EAS to highlight the local TSO grid situation. TSOs manually entered their system state and subsequent messages in the EAS system. Not all TSOs entered relevant system information and, in some cases, the incorrect system state was set in EAS. The frequency alarms for each separated area were set automatically by the CCs. Further guidance and training should be developed to support TSO operators in such events and to ensure consistent use of EAS amongst TSOs. The following additional information and automatic alarms in EAS could also support TSOs in quickly identifying the location of a system split:

- » Logging of main events in the grid (for instance opening and closing of 380 kV breakers identified as critical branches)
- » Additional Frequency measuring points to support area detection
- » Automatic System split detection and alarming
- » Additional Frequency State – “System Split”

During the event, it would have been useful for TSOs to see in EAS certain actions and measures which were taken either automatically or manually by individual TSOs. In addition, existing EAS functionality should have been used to appoint both frequency and resynchronisation leaders. The availability of the following information in EAS would have increased the situational awareness, supporting TSO coordination in stabilising the system and in the resynchronisation process:

» System defence measures automatically activated by frequency transients

» Manually activated system defence measures

» TSO K-factors

» TSO frequency leader status

» TSO Resynchronisation Leader status

4.3.4 Communication during system separation between TSOs

Overall, the communication during the system separation between TSOs went well. Nevertheless, communication in such an extraordinary event is challenging; for example, coordination with a multitude of TSOs, making contact with affected TSOs and keeping all European TSOs up to date.

4.3.5 Application of Articles 32, 33 and 34 of the Electricity Emergency and Restoration Network Code

Article 32 of the NC ER sets out the requirements of the resynchronisation procedure. This procedure is applied when two separate synchronous areas need to be merged into one single synchronous area. As this is the first time the procedure has been applied since the entry into force of the regulation, it is useful to analyse whether the procedure has been carried out as prescribed. It is also useful to critically review the provisions of this Article and suggest potential improvements as a result of the practical experience from the actual resynchronisation which took place on 08 January 2021.

NC ER, Art. 32 prescribes the resynchronisation procedure of the restoration plan shall include, at least:

(a) the appointment of a resynchronisation leader;

(b) the measures allowing the TSO to apply a resynchronisation strategy; and

(c) the maximum limits for phase angle, frequency and voltage differences for connecting lines.

According to NC ER, Article 33 (1) prescribes the appointment of a resynchronisation leader for system restoration, when two synchronised regions can be resynchronised without endangering the operational security of the transmission systems. The frequency leaders of these synchronised regions shall appoint a resynchronisation leader in consultation with at least the TSO(s) identified as the potential resynchronisation leader and in accordance with NC ER, Art. 33(2). Considering this specific case, EMS performed the role of frequency leader and was one of the potential resynchronisation leaders.

Regarding the consultation on the potential resynchronisation leader, it is clear that only the TSOs through which the separation line passed could be considered: HOPS, EMS and Transelectrica. Unlike HOPS and EMS, which stabilised quickly after system separation and were not engaged in reenergising load, Transelectrica had major problems in its own network and could not take on the role of resynchronisation leader. Accordingly, HOPS and EMS considered which of them should be the resynchronisation leader.

NC ER, Article 33 (2) prescribes that the resynchronisation leader shall be the TSO that:

(a) has in operation at least one substation equipped with a parallel switching device on the border between the two synchronised regions to be resynchronised;

(b) has access to the frequency measurements from both synchronised regions;

(c) has access to the voltage measurements on the substations between which potential resynchronisation points are located; and

(d) is able to control the voltage of potential resynchronisation points.

In addition, according to NC ER, Art 33(3), where more than one TSO fulfils the previously mentioned criteria, the TSO with the highest number of potential resynchronisation points between the two synchronised regions shall be appointed as the resynchronisation leader, unless the frequency leaders of the two synchronised regions agree to appoint another TSO as resynchronisation leader.

HOPS was appointed resynchronisation leader as the busbar coupler in Ernestinovo in Croatia was equipped with a parallel switching device (where one busbar was in the North-West region and the other busbar was in the South-East region). In addition, there were two potential resynchronisation points between the two synchronised regions in the HOPS control area, whereas in the EMS control area there was only one (considering the 400 kV voltage level).

According to NC ER Article 33 (1) "Each frequency leader shall inform without delay the TSOs from its synchronised region of the appointed resynchronisation leader". EMS did it partially, using phone communication to inform the most affected TSOs and was also in frequent communication with Swissgrid about the coordination in the South-East area during the event. As per the normal communication process, Swissgrid and Amprion kept close communication throughout the event. EMS also communicated by phone to ensure that the dispatchers in the vicinity of resynchronisation point were fully aware of the planned resynchronisation. In the future, all TSOs will be informed by the resynchronisation leader of their appointment using the EAS Tool as is defined in SAFA Policy 5 C-23.

Finally, the applied resynchronisation strategy should be considered according to what is prescribed in the NC ER, Article 34:

1. Prior to the resynchronisation, the resynchronisation leader shall:

   (a) establish, in accordance with the maximum limits referred to in NC ER, Art. 32:

      (i) the target value of the frequency for resynchronisation;

      (ii) the maximum frequency difference between the two synchronised regions;

      (iii) the maximum active and reactive power exchange; and

      (iv) the operating mode to be applied on the LFC;

   (b) select the resynchronisation point, considering the operational security limits in the synchronised regions;

   (c) establish and prepare all necessary actions for the resynchronisation of the two synchronised regions at the resynchronisation point;

   (d) establish and prepare a subsequent set of actions to create additional connections between the synchronised regions; and

   (e) assess the readiness of the synchronised regions for resynchronisation, considering the conditions set out in point (a).

2. When carrying out the tasks enumerated in paragraph 1, the resynchronisation leader shall consult the frequency leaders of the involved synchronised regions and, for the tasks listed in points (b) to (e), it shall also consult the TSOs operating the substations used for resynchronisation.

3. Each frequency leader shall inform the TSOs within its synchronised region of the planned resynchronisation without undue delay.

4. When all conditions established in accordance with point (a) of paragraph 1 are fulfilled, the resynchronisation leader shall execute the resynchronisation by activating the actions established in accordance with point (c) and (d) of paragraph 1.

In relation to the target value of the frequency for resynchronisation and the maximum frequency difference between the two synchronised regions, it was clear that the North-West region, as a significantly larger region, had a relatively stable frequency close to 50 Hz, and that the preferred approach was to try and bring the South-East region's frequency to a slightly higher value than the frequency of the North-West region. This simplified the communication because HOPS, as a resynchronisation leader, could focus on communicating with only one frequency leader (EMS). It was agreed to try to achieve a frequency difference of no more than 100 mHz between the two regions prior to attempting resynchronisation. The low frequency difference meant that the active power exchange after resynchronisation would also be low. As there were low voltage differences between the regions before the resynchronisation, reactive power flow after the resynchronisation was also not expected and it was not further considered.

As discussed above, for the first resynchronisation point, the 400 kV busbar coupler in Ernestinovo was chosen because it has a parallel switching device and was close to the middle of the split line. As part of the resynchronisation strategy, the second resynchronisation point (or additional connection), the 400 kV overhead line Novi Sad 3 – Subotica 3, was chosen because it was also close to the middle of the split line, which provided a second strong connection in a relatively small area. Subsequently, the 400 kV circuit Konjsko – Velebit was agreed as the third resynchronisation point (or additional connection) as this was the last 400 kV corridor disconnected (outside Romania) during the separation.

As it is crucial for successful resynchronisation to quickly connect the regions in as many points as possible, HOPS dispatchers in the National Control Centre had open phone lines with the regional control centre in Osijek (in charge of control of Ernestinovo – first point), with EMS (in charge of 400 kV Novi Sad – Subotica – second point) and with the regional control centre in Split (in charge of control of 400 kV Konjsko – Velebit). The EMS dispatcher was simultaneously in communication with SS Novi Sad 3 and the Transelectrica dispatcher via telephone. It was thereby ensured that immediately after the confirmation of one resynchronisation step, the next one could be made. Immediately after reaching the necessary conditions (the frequency difference between regions below 100 mHz) the HOPS dispatcher gave the order to turn on the busbar coupler in Ernestinovo, initiating the resynchronisation sequence.

In addition to the NC ER, the requirements for the resynchronisation process are also described in the CE Synchronous Area Framework Agreement (through the Policy on Emergency and Restoration). The Policy defines, among others, parameters of resynchronisation (as required by Article 32 (c) of NC ER), recommended modes of LFC controller in case of restoration (including system split), the requirement to inform (via EAS) other TSOs of the appointment, and the resignation of role of frequency leader and/or resynchronisation leader. Through SAFA, these requirements are mandatory for all EU and non-EU TSOs. It can be concluded that the processes carried out took place mainly in accordance with both documents, except in the part of informing all TSOs. There was no systematic informing of all TSOs through EAS, but information was shared by bilateral/multilateral contact of TSOs directly involved in certain parts of the frequency management and the resynchronisation processes.

The following points should be considered for future events and within the current regulations:

- » The process of informing all TSOs of the appointment of Frequency/Resynchronisation Leader needs to be improved (including inter-TSO training for operators/dispatchers) and should be included in the EAS user tests. This event emphasises the importance of cooperation between TSOs on training to improve the knowledge and understanding of the operational procedures between TSOs in all operational states as per Article 63 of the SO GL;
- » For the appointment of the resynchronisation leader the NC ER prescribes that the potential resynchronisation leader must be able to control the voltage of the potential resynchronisation points. This is not of practical importance because without a uniform voltage profile along the resynchronisation line, which means in a wider area of both regions, the resynchronisation will likely be unsuccessful because large flows through the resynchronisation points are likely to occur immediately after the resynchronisation. In any case, parallel switching devices allow connection even at relatively larger voltage differences, so the problem is not local;
- » In this case, there were a total of five potential resynchronisation points between the two areas. Excluding those from Transelectrica (Romania), there were only three potential points and it was relatively easy to decide where to try to resynchronise the two areas. It is necessary to consider the determination criteria for more complicated cases;

- The resynchronisation process was simplified because the North-West region came into the standard frequency range relatively quickly and had a stable frequency, thus setting a frequency resynchronisation target value for the South-East region;

- The resynchronisation process was simplified because EMS was both a frequency leader and one of the potential resynchronisation leaders. In general, frequency leaders and potential resynchronisation leaders can be from many different TSOs and the communication procedure in relation to this selection must be prescribed in more detail;

- The maximum active power exchange as prescribed in NC ER (cf. Article 34 (1) (a) (iii)) cannot be determined as an absolute value expressed in MW. Only by achieving the smallest possible frequency difference before resynchronisation can a smaller active power exchange be achieved through resynchronisation points after resynchronisation;

- The maximum reactive power exchange as prescribed in NC ER (cf. Article 34 (1) (a) (iii)) cannot be determined as an absolute value expressed in MVar. Only by achieving the smallest possible voltage difference before resynchronisation can a smaller reactive power exchange be achieved through resynchronisation points after resynchronisation;

- The definition of emergency system state (Article 18 (3) (b) of SO GL) could be updated by adding a time threshold for frequency deviation;

- The rules to define the recommended modes of the LFC controller in the event of a situation such as 08 January 2021 need to be verified and if necessary updated;

- Last but not least, there may be a role for the RCCs with larger geographical coverage to assist the resynchronisation leader, if so requested by TSOs, in verifying and proposing the optimal sequence of additional connections between the synchronised regions.

Recommendations

ID	Recommendation	Justification	Responsible
Data representation in EAS			
R-20	Further **functionalities** based on the evaluation of the incident shall be implemented in the EAS system to further **improve the operator's** use of the EAS system in the event of system separation.	The incident has revealed further improvements of the EAS system, e.g. an automatic detection and alarm in case of system separation, inclusion of wide area monitoring system measurements (voltage-phase angles, automatic grid event detection, resynchronisation points, etc). In order to further improve the usage of the system, those functionalities must be identified and implemented.	TSOs & ENTSO-E

ID	Recommendation	Justification	Responsible
Region CE resynchronisation procedure			
R-21	In addition to the currently established legal framework and policies, the communication between a multitude of TSOs can be enhanced by the development of an RG CE common **procedure** for **resynchronisation** in case of **system separation** with two or more areas (but without larger areas without voltage). The appropriateness of the requirements of SAFA Annex 5 C-19 (TSO Frequency Control Modes) should be considered within the procedure.	Overall, the communication, coordination and resynchronisation of the separated grid areas during this event were successfully implemented. Nevertheless, in the event of larger or more difficult events, the coordination and communication between TSOs could be more complex and a new RG CE common procedure should be developed to support the system resynchronisation for such events. Additionally, to freeze frequency restoration controllers due to synchronous area separation could be the right or wrong decision and needs to be considered based on the actual system conditions at the time of the event (e.g. it may not be possible to control the frequency if one area in RG CE is very large and so only one TSO has the LFC in frequency control mode).	TSOs
Regional Coordination			
R-22	Even though the resynchronisation was successful and timely, ENTSO-E and TSOs could determine areas where the coordination of regional restoration could be strengthened if needed.	Due to the limited observability, the resynchronisation leader may face challenging situations when determining the sequence of additional connections between the synchronised regions. Relevant RCCs with larger offline geographical coverage could propose an optimal sequence of additional connections between the synchronised regions, if requested by TSOs.	ENTSO-E and TSOs

References

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

[2] ENTSO-E, "Operational Limits and Conditions for Mutual Frequency support over HVDC," February 2021

5 Market aspects

5.1 Market aspects of system conditions in Continental Europe

The overall pan-European flow pattern on the afternoon of 08 January 2021 reflected a special load situation. This situation was caused, on the one hand, by warm weather in the Balkan Peninsula as well as the Orthodox Christmas holiday on 06 and 07 January, leading to an overall lower demand than usual in some of these countries. On the other hand, countries in Central and South-Western Europe saw colder weather and corresponding higher loads.

5.2 Market aspects of system conditions in Balkan Peninsula

5.2.1 Generation and load (production of power plants and renewables, consumption, scheduled outages)

5.2.1.1 Production of power plants (running) and renewables (forecast and actual)

HOPS

The actual production of power plants correspond to the scheduled production in Croatia. In the hour from 13:00–14:00, before the system separation, the scheduled and actual productions are the following (in MW):

Type of power plant	Scheduled	Realised
Hydro power plants (HPPs)	1,470	1,428
Thermal power plants (TPPs)	462	463
Wind power plants (WPPs)	225	288
All other power plants	129	127
SUM	**2,286**	**2,306**

Table 5.1: Planned and actual production in Croatia from 13:00–14:00

In the hour from 14:00–15:00, during the system separation, the scheduled productions are very similar (in MW):

Type of power plant	Scheduled
Hydro power plants (HPPs)	1,420
Thermal power plants (TPPs)	462
Wind power plants (WPPs)	224
All other power plants	126
SUM	**2,232**

Table 5.2: Scheduled production in Croatia from 14:00–15:00

There are no power plants directly connected to SS Ernestinovo. One power plant in the vicinity is connected to the 110 kV network at SS Osijek 2. Nevertheless, this power plant was not in operation during the time of the system separation. During that time, approx. 30 MW of distributed energy resources were in operation in the proximity of SS Ernestinovo and operated at constant production (with mainly biomass or gas as the primary energy source).

EMS

The production of power plants in Serbia was implemented mostly successfully (slightly higher wind generation infeed), and in the hour before the separation (the hour from 13:00 – 14:00 on 08 January), the following are the scheduled and actual productions:

Type of power plant	Scheduled	Realised
Hydro power plants (HPPs)	2,040	2,060
Thermal power plants (TPPs)	2,835	3,076
Wind power plants (WPPs)	60	106
SUM	**4,935**	**5,242**

Table 5.3: Scheduled and realised production in Serbia from 13:00 – 14:00

In the hour from 14:00 – 15:00, after the incident, production was reduced as a consequence of the high frequency and surplus of generation in the SEE area. The following are the scheduled and actual productions:

Type of power plant	Scheduled	Realised
Hydro power plants (HPPs)	2,077	1,512
Thermal power plants (TPPs)	3,065	2,913
Wind power plants (WPPs)	73	159
SUM	**5,215**	**4,584**

Table 5.4: Scheduled and realised production in Serbia from 14:00 – 15:00 – after the incident

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Production of power plants (running) and renewables (forecast and actual)

Before the incident took place, the total production of power plants realised in Romania correspond to the scheduled production levels. However, the realised production of classical power plants was lower than scheduled due to wind power production that was higher than scheduled (see Table 5.7).

In the hour from 13:00 – 14:00, before the system separation, the scheduled and realised productions are the following (in MW):

Type of power plant	Scheduled	Realised
Nuclear power plants (NPPs)	1,390	1,359
Hydro power plants (HPPs)	3,325	3,159
Thermal power plants (TPPs)	2,978	2,701
Wind power plants (WPPs)A	961	1,376
Photovoltaic power plants (PV PPs)	45	34
All other power plants	59	77
SUM	**8,758**	**8,706**

Table 5.5: Scheduled and realised production in Romania in the hour from 13:00 – 14:00

After the incident, the total production of power plants realised in Romania was lower than scheduled due to the generation units that tripped or reduced their production as a response to the frequency deviations.

In the hour from 14:00 – 15:00, during the system separation, the scheduled and realised productions are the following (in MW):

Type of power plant	Scheduled	Realised
Nuclear power plants (NPPs)	1,390	1,294
Hydro power plants (HPPs)	3,337	2,376
Thermal power plants (TPPs)	2,996	2,356
Wind power plants (WPPs)	1,118	1,575
Photovoltaic power plants (PV PPs)	20	19
All other power plants	61	53
SUM	**8,922**	**7,672**

Table 5.6: Scheduled and realised production in Romania in the hour from 14:00 – 15:00

Hour	Total net exchange	Scheduled WPP	Realised WPP
01	599	205	266
02	530	144	67
03	522	105	9
04	435	80	1
05	388	67	1
06	4	67	12
07	-324	71	41
08	-694	100	101
09	-976	174	163
10	-851	301	312
11	-672	431	411
12	-476	574	756
13	-251	816	1,034
14	84	961	1,376
15	340	1,118	1,575
16	379	1,235	1,706
17	-92	1,339	1,815
18	-123	1,374	1,906
19	-39	1,328	1,905
20	122	1,252	1,794
21	357	1,164	1,828
22	725	1,107	1,741
23	722	1,020	1,660
24	820	977	1,656

Table 5.7: WPPs production on 08 January 2021 (scheduled, realised) and total net exchange (in MW)

5.2.1.2 Power plants not in operation/disconnected from the grid

HOPS

No forced outages or malfunction of any power plant was reported before the incident.

EMS

The following production units were not available due to planned outages: TPP Kolubara (four generators), TPP Morava (one generator) and TPP-HPP Novi Sad (one generator), for a total of 360 MW.

Transelectrica

The following production units were not available on 08 January 2021 because they were out of service for maintenance works: one unit at TPP București Sud and one unit at TPP Ișalnița – totalling 415 MW. Some others production units were out of operation for long-term works and were therefore not relevant to the incident.

5.2.1.3 Consumption

HOPS

The planned consumption in Croatia was very similar to the actual consumption. In the hour from 13:00–14:00, the planned consumption was 2,500 MW while the actual consumption was 2,519 MW. In the hour from 14:00–15:00, the planned consumption was 2,438 MW while the actual consumption was 2,432 MW.

EMS

Consumption was accurately forecasted. In the hour from 13:00–14:00, the planned consumption was 4,420 MW while the actual consumption was 4,496 MW. In the hour from 14:00–15:00, the planned consumption was 4,382 MW while the actual consumption was 4,595 MW.

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The planned consumption in the 14 hour (13:00–14:00) was 8,320 MW, whereas the realised consumption was 8,619 MW. The planned consumption for the 15 hour was 8,260 MW, whereas the realised consumption was 8,050 MW.

5.3 Capacity calculation

5.3.1 Regional capacity calculation

In the south-east area of the Continental Europe interconnection, as well as in the larger part of the central area, there is no coordinated capacity calculation in line with Regulation (EU) 2015/1222 for day-ahead and intraday market timeframes or Regulation (EU) 2016/1719 for yearly and monthly market timeframes. These methodologies and processes are now being implemented across different states.

Thus, the NTCs at all borders are calculated based on bilateral coordination with the neighbouring TSOs in accordance with the former Multilateral Agreement (MLA) Operation Handbook[1].

The TSOs of SEE region established a procedure for the creation of a common grid model for monthly capacity calculation.

Also, with regard to Energy Community Secretariat (EnCS), there is a common methodology for transmission capacity calculation approved by EU and non-EU TSOs in the region[2]. The prerequisite for coordinated capacity calculation and the implementation of a common methodology is the definition of the SEE capacity calculation region, or Shadow SEE CCR. However, this methodology has not been implemented by 'Energy Community states' in the area.

The NTC are calculated by each TSO on the regional common grid model of the respective border and harmonisation per border is based on the minimum value proposed by each of the partners.

The bilateral NTC calculation is conducted for the month ahead of time and takes into consideration exchange programmes from the ENTSO-E RG South-East Europe and ENTSO-E Regional Continental Europe common grid model with expected forecasted data and registered maintenance for the considered period. Base case exchange programmes in the merged model of South-East Europe are provided for the following countries: IT, SI, HR, RS, RO, HU, BG, GR, TR, ME, MK, AL, BA, UA, KS, and AT. The individual monthly model is elaborated for the third Wednesday of the month M, 10:30 CET.

The harmonisation of the base-case exchanges of SEE and model merging is performed by one of the involved TSOs in the area (TSO coordinator). The role of TSO coordinator rotates on a monthly basis according to an agreed yearly scheme.

The reference schedule (timeframe) for month (M) data exchange and NTC calculation is the following:

- **Days 15 – 20 (M-2):** exchange and harmonisation of forecasted net positions for month M in the south-east area of Continental Europe by a TSO coordinator.
- **Days 20 – 24 (M-2):** exchange of system models forecasted for month M by each TSO, in UCTE format (the details of the UCTE def data models and recommendations for improvements are described in Chapter 1).
- **Days 25 – 26 (M-2):** merging of the models and realisation of the interconnected south-east model. Sending of the merged SEE model to all partners.
- **Days 27 (M-2) – 3 (M-1):** NTC calculation by each TSO.
- **Day 5 (M-1):** NTC exchange between bidding zone border TSOs and harmonisation on minimum value; NTC values provided to the market upon completion of bilateral harmonisation processes.
- There is no coordination of NTC calculations between TSOs for several borders; instead, only individual TSOs consider the interactions of individual NTCs at their own borders.

1 https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/publications/entsoe/Operation_Handbook/Policy-4-v2.pdf

2 https://energy-community.org/dam/jcr:7ca112b6-44bf-44d7-ab5c-23575054bba8/EKC_shadow_CCR_122018.pdf

It is worth mentioning that for HOPS for the daily calculation at the HR-SI border uses customised monthly models and D-2 CF models that have recently been exchanged for DA FB CC preparations in the core region. However, for a correct daily calculation, a necessary condition would be the existence of a D-2 CF model for the whole region. As these models are not available, all TSOs still rely on the monthly calculations as described above. Although the most unfavourable situation is taken into account for monthly calculations, due to unplanned unavailability of transmission elements, NTC overestimation in the monthly process can occur. As described in Chapter 1, presently available models are not complete and do not have the same level of accuracy e. g. related to the inclusion of busbars in the models. Further elements and recommendations on this subject have been described in Chapter 1.

A disadvantage of the current approach is that the capacity calculation is not coordinated and performed sufficiently in advance. Day-ahead coordinated capacity calculation in line with Regulation (UE) 2015/1222 is under implementation in Core CCR with a go-live window in February 2022 and in SEE CCR with a go-live window in July 2021. Unfortunately, coordinated capacity calculation in SEE CCR will cover only two borders from the south-east area of Continental Europe, RO-BG and BG-GR. Capacity Allocation & Congestion Management (CACM) is not mandatory for non-EU TSOs and basic capacity calculations in SEE (which are still used for commercial purposes) are bilateral NTC calculations performed by neighbouring TSOs, using M-2 regional CGM harmonised among SEE TSOs. Therefore, a stronger and more detailed coordination at the level of RSCs (TSCNET, SCC and SELENE-CC) should be developed in the region, as soon as possible. Preconditions for stronger and more detailed RSCs coordination are harmonised methodologies and business processes in SEE for CCC. The concept of CCC is based on 'CCR regional modules' as well as coordination and cooperation on these matters with neighbouring CCRs (and RSCs). Currently, non-EU SEE TSOs do not belong to any CCR, and this issue has to be solved (possible options are the creation of either so-called Shadow CCR 10 or WB6 CCR) in order to implement the 'CCR regional modules' concept for the entirety of the Continental Europe Synchronous Area. Furthermore, the secure and reliable solution for coordinated capacity calculation in the south-east part of Continental Europe is the implementation of the flow-based approach and market coupling within the whole area. Further recommendations for work related to the coordination of capacity calculation have been proposed in Chapter 1.

5.3.2 National capacity calculation

HOPS

The transmission network of HOPS is connected to the neighbouring countries by the following lines:

- NOSBiH – two 400 kV, six 220 kV and eleven 110 kV tie lines
- MAVIR (Hungary) – four 400 kV tie lines
- EMS – one 400 kV and two 110 kV tie lines
- ELES (Slovenia) – three 400 kV, two 220 kV and three 110 kV tie lines

The NTCs at all borders are calculated in bilateral coordination with the neighbouring TSOs. For the calculation of NTCs, the ENTSO-E seasonal network models are used and adapted to the relevant month. The NTCs are calculated by each TSO of the respective border. The NTC values are compared and the smaller value is chosen as the final value. At the borders with Hungary, Serbia and Bosnia and Herzegovina, the values are calculated on a monthly basis, which means that the grid situation allowing for the lowest NTC value for that month is taken into account. At the border with Slovenia, values are calculated on a daily basis. HOPS also takes into account the specific layout/shape of the Croatian power system in the calculations, especially the location of the substation (SS) Ernestinovo, which is directly connected to three substations in the surrounding three countries, namely SS Pecs (MAVIR), SS Mitrovica (EMS) and SS Ugljevik (NOSBiH). This means that cross-border flows are highly interdependent at SS Ernestinovo.

The bilaterally agreed-upon NTC values for the entirety of 08 January 2021 are as follows:

- HR » BA: 1,000 MW; BA » HR: 1,000 MW
- HR » HU: 1,000 MW; HU » HR: 1,200 MW
- HR » RS: 500 MW; RS » HR: 600 MW
- HR » SI: 1,500 MW; SI » HR: 1,500 MW

The calculated NTC values as shown above also take into account the scheduled/planned outages as described further on.

EMS

EMS's control area is connected to the neighbouring areas with the following lines:

- NOSBiH — one 400 kV, one 220 kV and two 110 kV tie lines
- MAVIR – one 400 kV tie line
- HOPS – one 400 kV and two 110k V tie lines
- Transelectrica – one 400 kV and three 110 kV tie lines
- ESO EAD – one 400 kV and two 110 kV tie lines
- MEPSO – one 400 kV tie line
- CGES – two 220 kV and one 110 kV tie lines
- KOSTT – one 400 kV, one 220 kV and two 110 kV tie lines

NTC on all borders of the EMS bidding zone (except with KOSTT) is calculated in bilateral coordination with neighbouring TSOs, using a monthly model adapted to the planned disconnections for that month and taking the smaller value that each of the TSOs calculates.

In addition, in the calculations, EMS takes into account the specific position of TS Sremska Mitrovica 2, which is directly connected to two other control areas: SS Ernestinovo (HOPS) and SS Ugljevik (NOSBiH).

The bilaterally agreed-upon values for the whole day of 08 January 2021 were as follows:

- RS » HR: 600 MW; HR » RS: 500 MW
- RS » HU: 1,000 MW; HU » RS: 1,000 MW
- RS » RO: 800 MW; RO » RS: 800 MW
- RS » BG: 300 MW; BG » RS: 350 MW
- RS » MK: 300 MW; MK » RS: 250 MW
- RS » ME: 300 MW; ME » RS: 200 MW
- RS » BA: 600 MW; BA » RS: 500 MW

Transelectrica

Transelectrica's control area is connected to the neighbouring areas with the following lines:

- MAVIR – two 400 kV tie lines
- EMS – one 400 kV tie line and three 110 kV tie lines (usually disconnected and operated in radial topology only)
- ESO – EAD – four 400 kV tie lines (usually only three lines in operation and one circuit not energised)
- Western Power System – of Ukrenergo (Ukraine) – one 400 kV tie line

The NTC at all borders is calculated in bilateral coordination with neighbouring TSOs using the seasonal model adapted to the relevant month and taking the smaller value that each of the TSOs calculates.

At the borders with Hungary, Serbia, Ukraine and Bulgaria, the values are calculated on a monthly basis, which means that the most unfavourable situation for that month is considered.

Bilaterally agreed values of the NTC for the entirety of 08 January 2021 were as follows:

- RO » HU: 800 MW, HU » RO: 1,000 MW
- RO » RS: 800 MW, RS » RO: 800 MW
- RO » BG: 1,000 MW, BG » RO: 1,000 MW
- RO » UA: 200 MW, UA » RO: 400 MW

5.4 Day-ahead and intraday schedules

To understand whether market disturbances and interruptions occurred before, during and after the incident, data[1] for the borders on the separation line was collected and analysed for the period 06–10 January with a one-hour granularity. The use of multi-day data provides an insight into data trends, which serve as a basis to indicate any abnormal fluctuations on 08 January as compared to the other days. The primary focus of the analysis is the day-ahead and intraday markets – this includes cross-border commercial exchanges compared to the bilaterally agreed NTCs border by border, and weighted average volume prices on the national power exchanges.

The exchanges on the following borders are investigated:

- Romania (RO) – Western Power System of Ukraine (UA)
- Romania (RO) – Hungary (HU)
- Serbia (RS) – Hungary (HU)
- Croatia (HR) – Hungary (HU)
- Croatia (HR) – Slovenia (SI)

In this section, the data for 08 January is presented and analysed. The section is split into two sub-sections: 5.4.1. Comparison of day-ahead and intraday commercial exchanges with the bilaterally agreed NTCs for the above-mentioned borders, and 5.4.2. Comparison of day-ahead prices.

1 Data sources: ENTSO-E Transparency Platform, TSOs from HR, RS, RO, and National Power Exchanges of HR, HU and RO.

5.4.1 Comparison of day-ahead and intraday commercial exchanges with the bilaterally agreed NTCs

In the figures below (Figure 5.1 – Figure 5.2), day-ahead and intraday commercial exchanges between the bordering countries are plotted with the bilaterally agreed NTCs. The figures show the market situation on the day of the incident (hourly granularity). These figures serve to (1) determine whether there are any excessively aggregated exchanges or abnormal exchange fluctuations in either direction on both day-ahead and intraday markets, (2) compare market exchanges relative to the bilaterally agreed NTCs, and (3) indicate the presence of higher commercial exchanges in either direction, and, if the case, investigate the reasons why these commercial exchanges exceed the NTCs.

Border: Western Power System of Ukraine (UA) – Romania (RO)

Figure 5.1 below indicates that there are no commercial exchanges in the direction RO » UA, and just minor day-ahead exchanges in the direction UA » RO with an average value much lower in comparison to the 400 MW and 200 MW NTCs allowed in UA » RO and RO » UA direction, respectively. UA » RO day-ahead commercial exchange is stable in the hours before the incident and drops to 0 MW per hour in the time-period 15:00 – 21:00. In general, the market exchanges are much lower compared to the NTCs, and the trends do not indicate any market disturbances or interruptions that occurred in the hours before, during and after the incidents. The sum of day-ahead and intraday schedules in both directions does not exceed the NTC values as well; the values are much lower compared to the NTC values.

Day-ahead, intra-day commercial schedules [MW] vs. bilateral NTC values [MW]
Border: Western Power System of Ukraine (UA) – Hungary (HU), 08 January 2021

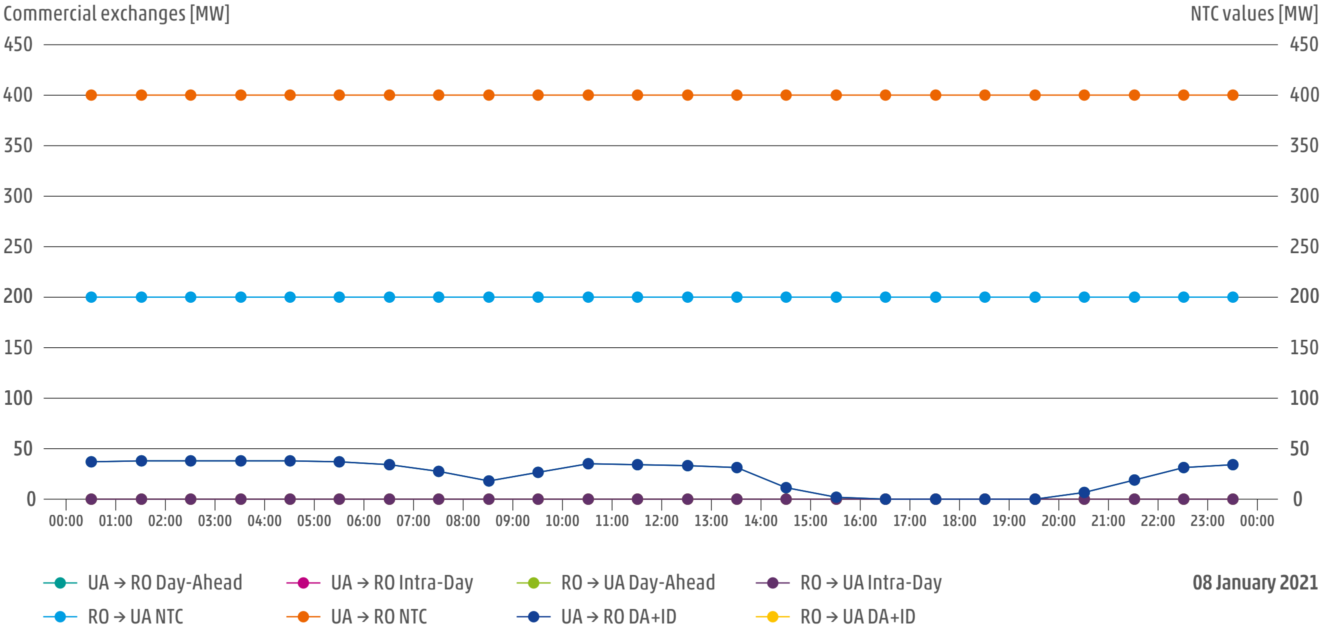

Figure 5.1: Commercial exchanges compared to bilateral NTCs: Western Power System of Ukraine (UA) – Hungary (HU)

Border: Romania (RO) – Hungary (HU)

Based on the trend observation in Figure 5.2 below, a high day-ahead exchange close to the RO » HU agreed NTC value of 800 MW is observed during the late-night hours (00:00 – 05:00) and after 11:00, as well as an increased intraday exchange in the hours 08:00 – 13:00. It is Important to indicate that the sum of day-ahead and intraday schedules does not exceed the NTC values, mainly in the direction RO » HU.

Day-ahead, intra-day commercial schedules [MW] vs. bilateral NTC values [MW]
Border: Romania (RO) – Hungary (HU), 08 January 2021

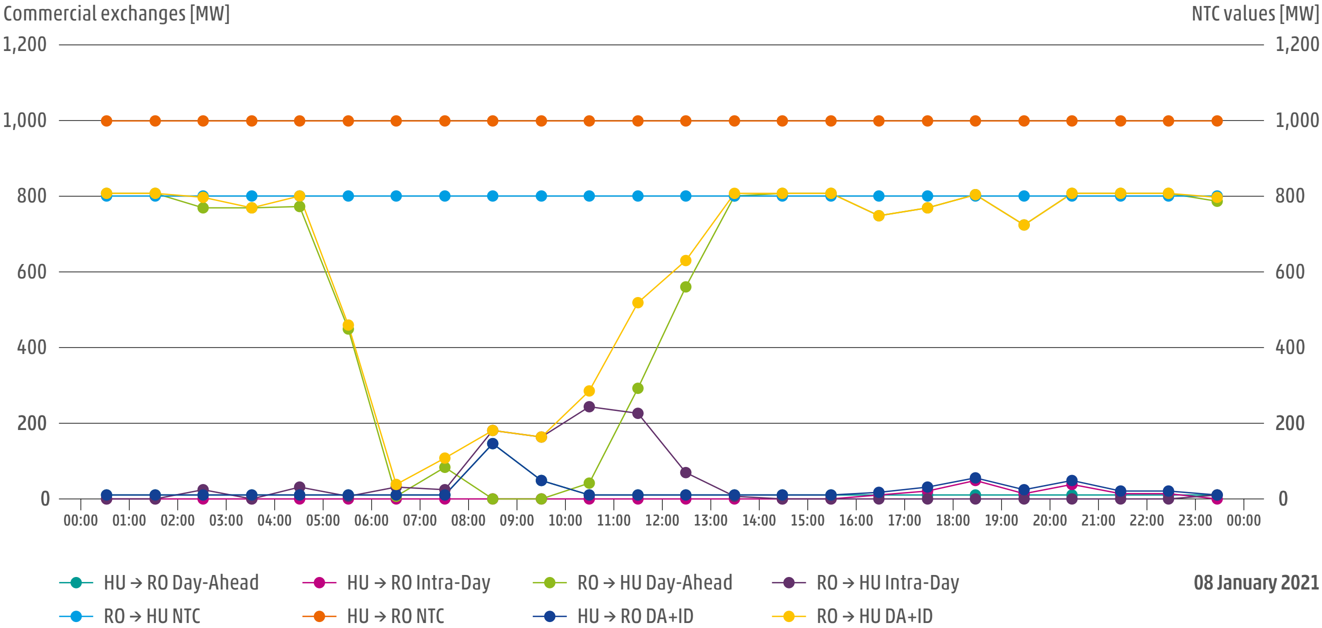

Figure 5.2: Commercial exchanges compared to bilateral NTCs: Romania (RO) – Hungary (HU).

One reason for such a high exchange could be a relatively low price in Romania compared to Hungary. Figure 5.11 in Sub-section 5.5.1. provides information on the difference in prices on the power exchanges. The prices in Hungary and Romania are broadly similar on all days from 06 – 10 January. In addition to this, the price comparison does not indicate any significant difference in the prices, but rather stable prices on all National Power Exchanges for the day-ahead market. Therefore, the hypothesis of a lower price in Romania compared to Hungary is not the reason for the aggregated flow. From an operational perspective, generation outages have also been investigated to determine whether there were any planned outages in Hungary in the hours with higher exchange. The planned time of generation outages in Hungary matched the time interval at which higher exchange occurs in the direction RO » HU.

Border: Serbia (RS) – Hungary (HU)

The bilateral NTC values for Serbia – Hungary are the same (1,000 MW per hour). Based on the trends shown in Figure 5.3 below, there is a consistent high day-ahead exchange in the direction RS » HU close to the agreed NTCs. It is observed that the sum of day-ahead and intraday schedules exceeds the NTC values in direction RS » HU; the maximum observed value of the sum is 1,144 MW. However, as is shown visually in the diagram, scheduled market flow in the direction HU » RS counteracts the excess. The intraday market flow in the direction RS » HU is accepted up to a netted flow that equals the NTC value. See Table 5.8 below.

Day-ahead, intra-day commercial schedules [MW] vs. bilateral NTC values [MW]
Border: Serbia (RS) – Hungary (HU), 08 January 2021

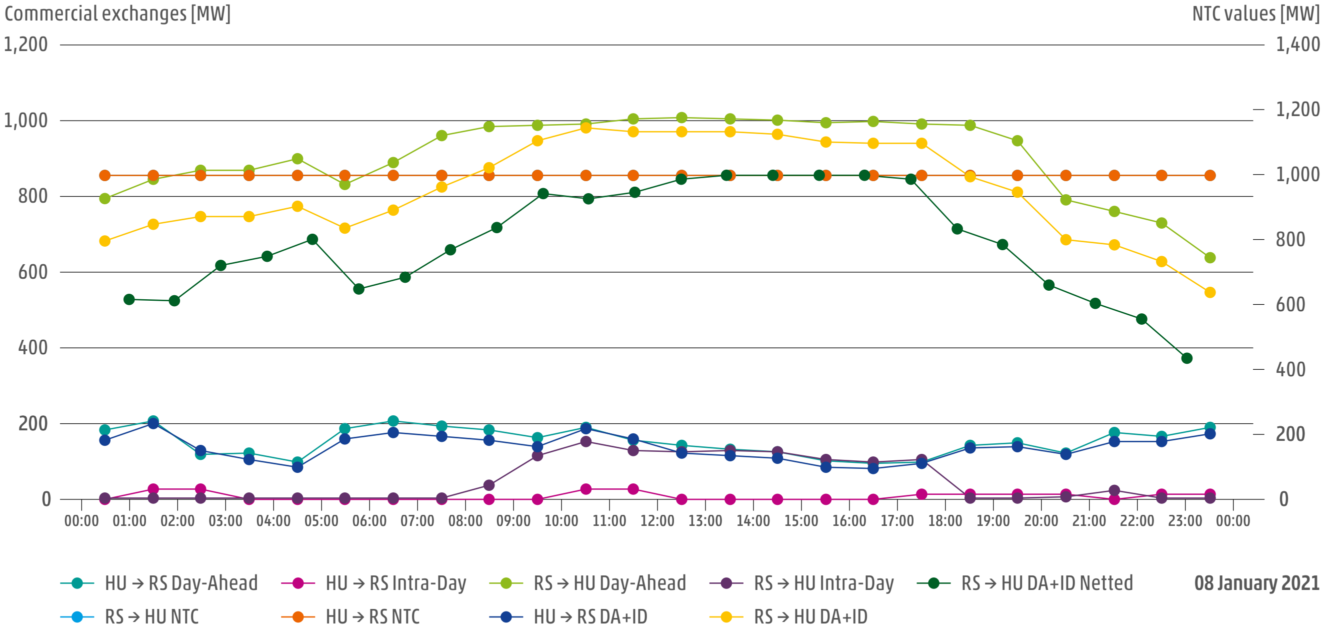

Figure 5.3: Commercial exchanges compared to bilateral NTCs: Serbia (RS) – Hungary (HU)

As already discussed in the case of Romania – Hungary, one reason for the high day-ahead exchange in direction to Hungary from the SEE neighbouring countries might be the planned generation outages in Hungary. In addition to this, the graph shown in Figure 5.3 above does not indicate any abnormal or unexpected fluctuations in the data trends and the commercial exchanges are consistent and without any major increases or decreases throughout the day.

2021.01.08	ID HU » RS	ID RS » HU	DA HU » RS	DA RS » HU	DA netted schedule RS » HU	DA + ID netted schedule RS » HU	NTC HU » RS	NTC RS » HU
H1	0	2	184	796	612	**614**	1,000	1,000
H2	29	2	206	846	640	**613**	1,000	1,000
H3	29	2	120	869	749	**722**	1,000	1,000
H4	0	2	123	869	746	**748**	1,000	1,000
H5	0	2	99	900	801	**803**	1,000	1,000
H6	0	2	187	833	646	**648**	1,000	1,000
H7	0	2	207	890	683	**685**	1,000	1,000
H8	0	2	194	961	767	**769**	1,000	1,000
H9	0	39	183	984	801	**840**	1,000	1,000
H10	0	116	162	989	827	**943**	1,000	1,000
H11	29	153	189	991	802	**926**	1,000	1,000
H12	29	129	157	1,006	849	**949**	1,000	1,000
H13	0	125	144	1,008	864	**989**	1,000	1,000
H14	0	128	134	1,006	872	**1,000**	1,000	1,000
H15	0	125	126	1,001	875	**1,000**	1,000	1,000
H16	0	105	101	996	895	**1,000**	1,000	1,000
H17	0	99	96	997	901	**1,000**	1,000	1,000
H18	14	105	97	992	895	**986**	1,000	1,000
H19	14	4	144	989	845	**835**	1,000	1,000
H20	14	2	150	946	796	**784**	1,000	1,000
H21	14	8	124	791	667	**661**	1,000	1,000
H22	0	23	178	760	582	**605**	1,000	1,000
H23	14	2	165	732	567	**555**	1,000	1,000
H24	14	2	189	637	448	**436**	1,000	1,000

Table 5.8: Market flows on directions RS » HU and HU » RS

Border: Croatia (HR) – Hungary (HU)

Similar to the trends observed in the RS – HU and RO – HU cases, a constantly high day-ahead exchange in the HR » HU direction is observable in Figure 5.4 below as well; however, it does not exceed the NTC limits. The sum of day-ahead and intraday schedules in both directions does not exceed the NTC values as well; most of the time the value of the sum is close to the NTC values but never exceeds them. The intraday exchange in this direction is similar to that of RS » HU and RO » HU. The trend of relatively high day-ahead commercial exchanges might also be influenced by the planned generation outages in Hungary.

Day-ahead, intra-day commercial schedules [MW] vs. bilateral NTC values [MW]
Border: Croatia (HR) – Hungary (HU), 08 January 2021

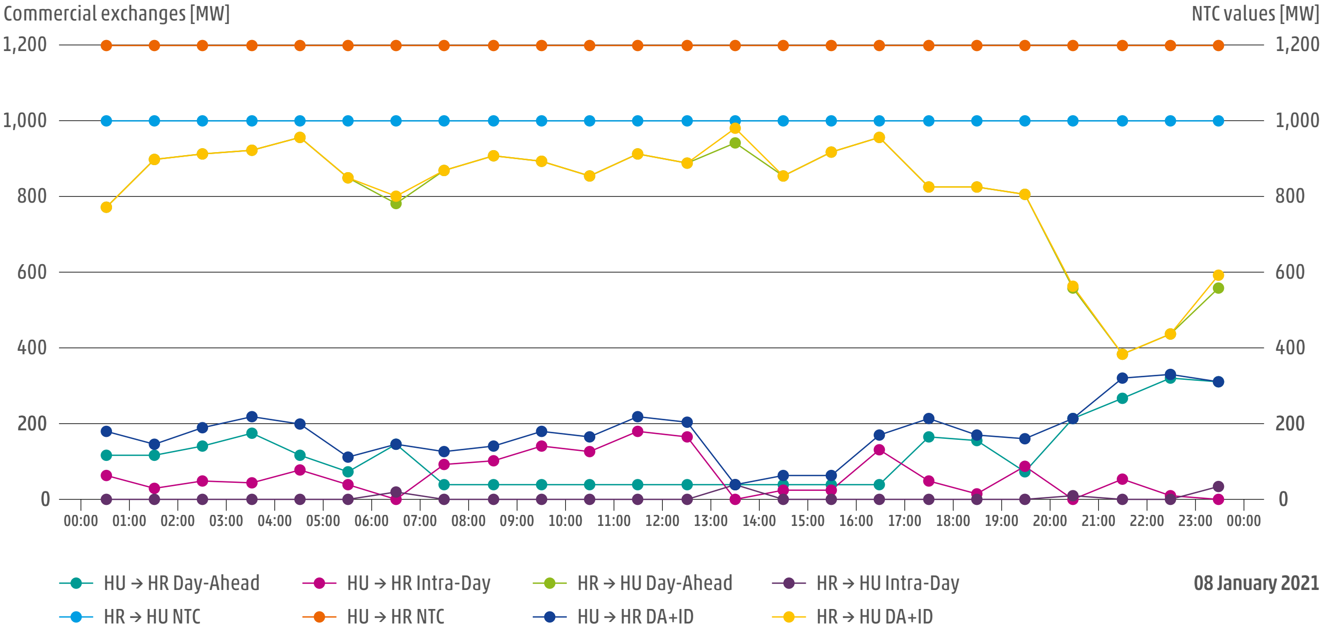

Figure 5.4: Commercial exchanges compared to bilateral NTCs: Serbia (RS) – Hungary (HU)

Border: Croatia (HR) – Slovenia (SI)

HR and SI are coupled, such that the bilateral NTC values are equal and of value 1,500 MW.

Based on the trends seen in Figure 5.5 below, there are some minor fluctuations in the day-ahead exchange trend in HR » SI direction; however, these fluctuations are not abnormal and are within accepted values. The NTC values are not exceeded on any of the markets in either direction. The sum of day-ahead and intraday schedules in both directions does not exceed the NTC values as well. Similar trends and day-ahead behaviour is observable on all days, with only a very minor increase of day-ahead values above NTCs observed from 02:00 – 05:00 on 09 January. However, the values drop throughout the day and the trend remains similar to that of the other days.

Another observation is that there are also minor increases in HR » SI intraday exchange during the day on 07 and 08 January, as compared to the other days. However, the values are still below the bilaterally agreed NTCs. These fluctuations in flow can be due to several reasons, including but not limited to the fact that the exchange to Slovenia depends on how much energy can pass further to Italy and Austria, which is limited by the Croatia-Slovenia exchange.

Day-ahead, intra-day commercial schedules [MW] vs. bilateral NTC values [MW]
Border: Croatia (HR) – Slovenia (SI), 08 January 2021

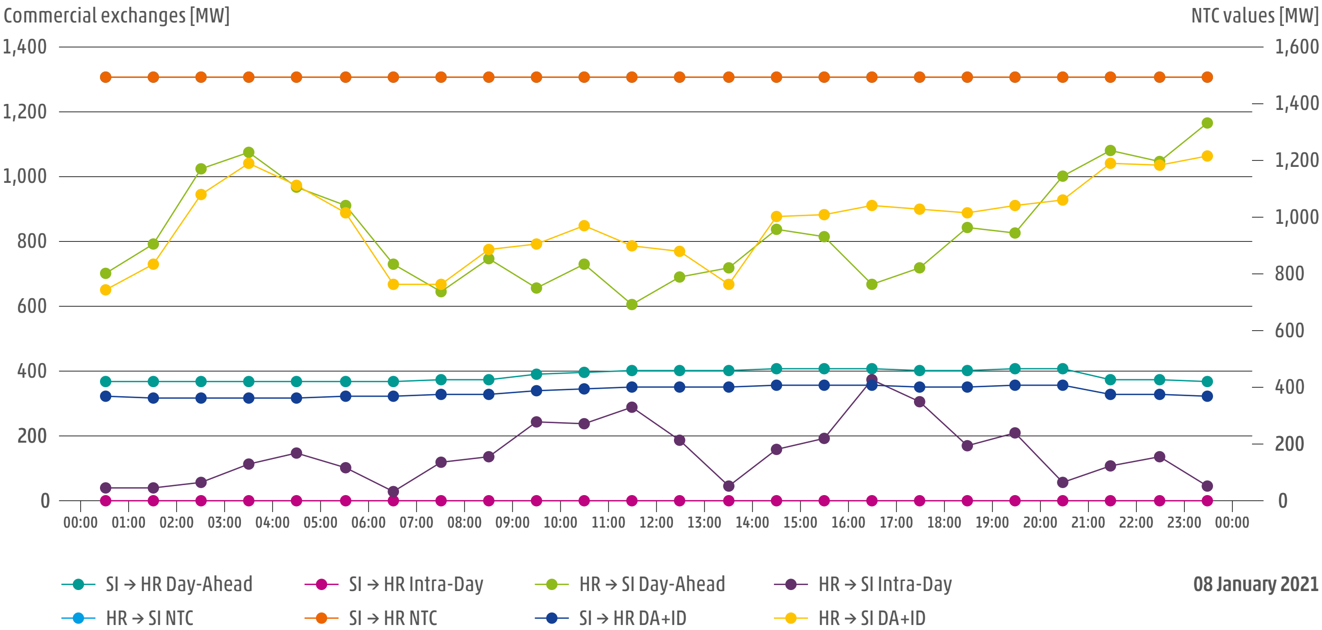

Figure 5.5: Commercial exchanges compared to bilateral NTCs: Croatia (HR) - Slovenia (SI)

Overall, the data analysis performed shows that the market did not experience any changes as a result of the incident. The data trends presented for the period 06 – 10 January highlight that all commercial exchanges on day-ahead and intraday markets did not exceed the bilaterally agreed NTC values on the borders of the separation line (with some minor exceptions on exchanges to Hungary with values equal to or slightly higher than the NTC values at specific hours). On all borders, in general, the sum of day-ahead and intraday schedules in both directions does not exceed the NTC values, except for the case of RS » RO. The results of the analysis performed do not highlight any abnormal market behaviour in the day-ahead or intraday markets on 08 January and on the rest of the days taken into consideration (all observed changes and fluctuations in the trends are within normal market variations).

5.4.2 Day-ahead schedules

Market schedules HOPS

The market schedules reflect a general trend in Continental Europe at the time: cheaper energy from a place of lower demand in the east (warm weather in the Balkan Peninsula, Orthodox Christmas) was sold to a place of higher demand in the west (cold wave, especially on the Iberian Peninsula).

The net exchange values for Croatia for 08 January 2021 are shown in Table A5-1 (Annexes). The market schedules show high imports to Croatia from Bosnia and Herzegovina and Serbia beginning at 08:00 in the morning. The net exchange during this time is close or even equal to the full NTC value. Furthermore, Croatia exports energy to Slovenia and Hungary during this time.

Market schedules EMS

Market schedules reflected a general trend in Continental Europe to obtain cheaper energy from a place of lower demand in the east (this day had warm weather in the Balkan Peninsula and it was the first day after Orthodox Christmas) sold at a place of higher demand in the west.

Therefore, market schedules were mainly from the east to the west, and net exchange values for 08 January 2021 are provided in Table A5-2 (Annexes).

Market schedules Transelectrica

Market schedules were more a result of long-term scheduled imports compensated by day-ahead and intraday scheduled exports entailed by Romanian wind generation than a consequence of the general trend depicted by the commercial power stream from the Balkan Peninsula to the north-west systems of Continental Europe interconnection. Within hours 14 (13:00–14:00) and 15 (14:00–15:00) the Romanian power system was relatively balanced, the net exchange was extremely low and the actual rate of NTC use was moderate. The exchange values on Transelectrica borders for 08 January 2021 may be found in Table A5-3 (Annexes).

5.4.3 Intra-day schedules around the time of the incident

This section analyses the system conditions in Continental Europe shortly before and at the time of the incident. The focus is on the development of flows from day-ahead market schedules and intraday market schedules to the measured flows.

The overall pan-European flow pattern on the afternoon of 08 January 2021 reflected a special load situation. This situation was caused, on the one hand, by warm weather in the Balkan Peninsula as well as the Orthodox Christmas holiday on 06 and 07 January, leading to an overall lower demand than usual in some of these countries. On the other hand, countries in Central and South-Western Europe saw colder weather and corresponding higher loads.

The differences in the actual market schedules for the two timestamps, 13:45 – 14:00 and 14:00 – 14:15 (Source: Vulcanus/Verification Platform), are shown in Figure 5.6. Higher differences are shown for the values between DE – FR, DE – NL, NL – BE, BE – FR, CH-IT, SI-IT and FR – ES. In most cases these differences are not unusual in terms of their magnitude and in relation to the size of the market areas. The net position in Italy is changing from 696 MW to 1,835 MW, which is significant but not extraordinary. This change is partly a result of the change in market schedule on the IT-SI border of total 324 MW (direction west), which is not extraordinary either. In the area of the system split, there are relatively small changes in the actual market schedules between the two timestamps considered. On the FR-ES border the usual deviation is very low. The unusual deviation observed in this case was caused by the countertrading performed after the system separation in order to cover the tripping of the HVDC link FR-ES.

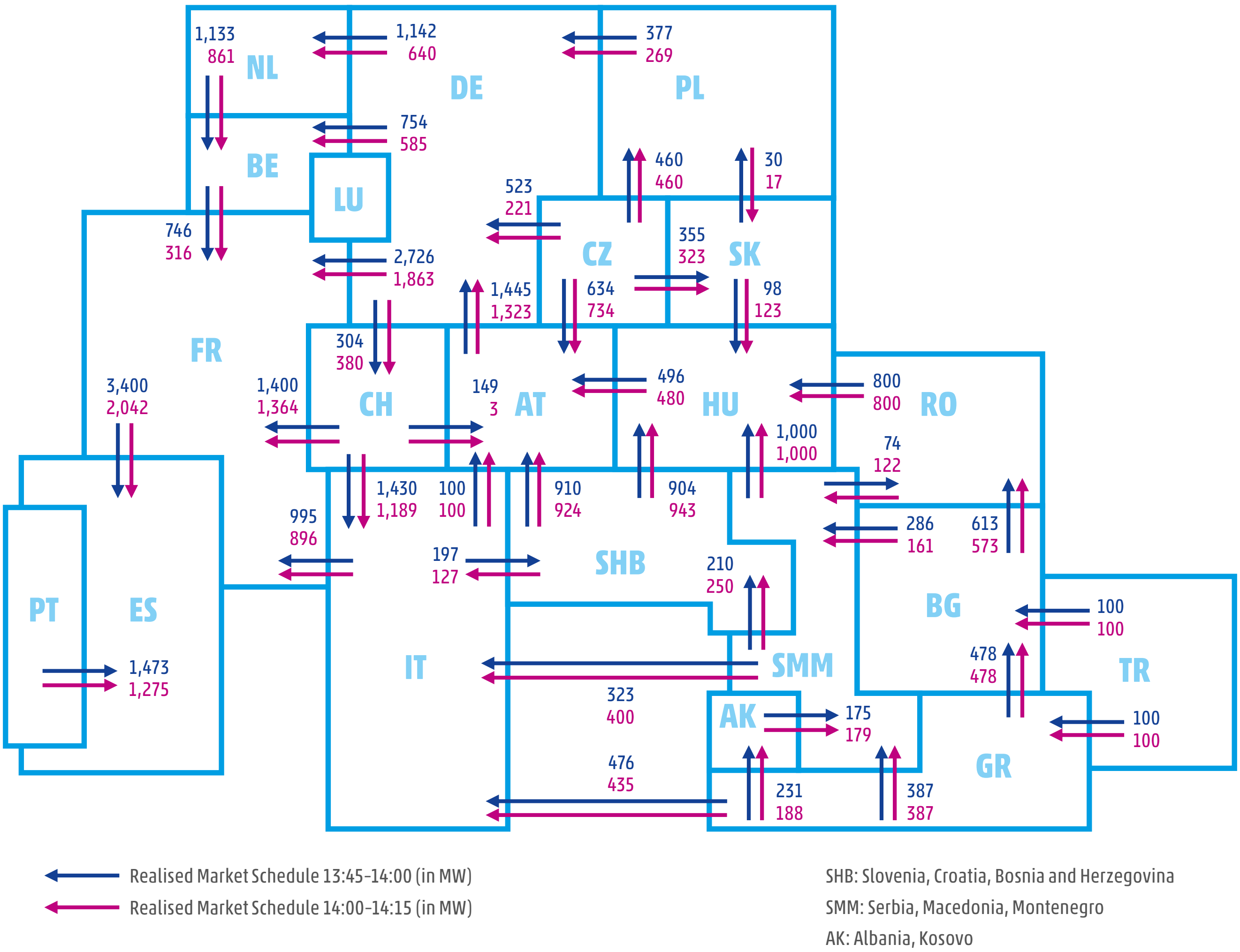

Figure 5.6: Comparison of realised market schedules (day-ahead + intraday)

To understand the impact of changes in market schedules (and flows) the comparison in Figure 5.7 below illustrates market schedules versus NTC for selected borders. In this overview it is visually demonstrated that the borders along the split line were highly loaded and using the full NTC, whilst other borders experienced changes in market schedules that were larger (f.ex. CH-IT with a change of 600 MW represent only approximately 20 % of the NTC).

The difference between the day-ahead market schedules and the actual market schedules for the timestamp 13:45 – 14:00 (Source: Vulcanus/Verification Platform) is shown in Figure 5.8. Overall, the differences between the day-ahead schedules and the actual schedules are relatively small. Larger differences are found for ES – PT and CZ – PL. In the area of the system split, all differences can be classified as relatively small.

In order to establish a better overview of the situation in the area of the system split, Figure 5.9 and Figure 5.10 show the same analysis in different resolutions, i.e. market flows are also presented at the level of Load Frequency Control (LFC) control areas. The market schedule changes from 13:45 – 14:15 are small (< 200 MW pr border). Notably, there is only a change on the SI-IT border from 197 MW import to 127 MW export; however, this is covered by generation in Slovenia and does not impact the flow on other borders.

Change in net positions for the LFC areas are included in the table below. It is shown visually that most LFC areas (except HU and XK) in the region have negative net positions (net export), which complies well with the combined large flow from SEE to CWE on 08 January. However, there are no significant changes in net position for any LFC area for the 13:45 – 14:00 or 14:00 – 14:15 market schedules – underlining the previous conclusion that sudden large market schedule changes at 14:00 did not contribute to the incident.

To understand the system conditions before the system split, a more detailed analysis is performed at the interconnectors between the affected countries in South-East Europe (Serbia, Croatia, Romania) and Central-West Europe (Slovenia, Hungary). The analysis of the flow towards Central-West Europe is performed by looking into the scheduled and total market flows in the hours 13:00 – 14:00, 14:00 – 15:00 and 15:00 – 16:00, on both 07 and 08 January. The day before the system separation is also considered in order to provide a comparison.

Table 5.9 and Table 5.10 provide information on the scheduled day-ahead market flows and the total market flows (Source: ENTSO-E Transparency Platform). The net values are considered in each case (i.e., RS » HU corresponds to the difference between RS » HU and HU » RS). For both 07 and 08 January, exports of comparable magnitude from the South-East European countries to Central-West Europe are observable. On both days the total market flows are slightly higher than the scheduled day-ahead flows. The most significant difference between 07 and 08 January is the partial shift of exports from HR » SI to HR » HU.

Realised Market Schedule vs Forecasted Transfer Capacity: 08 January 2021, 14:00 – 14:15 h

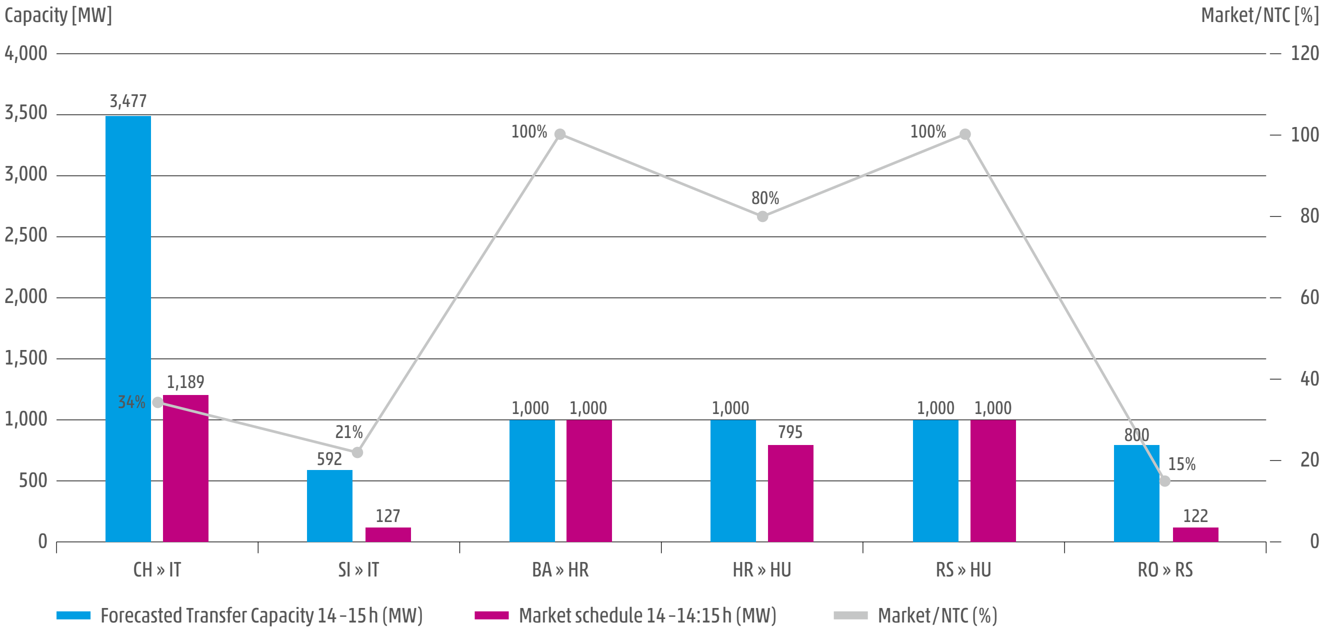

Figure 5.7: Market schedules versus NTC for selected borders

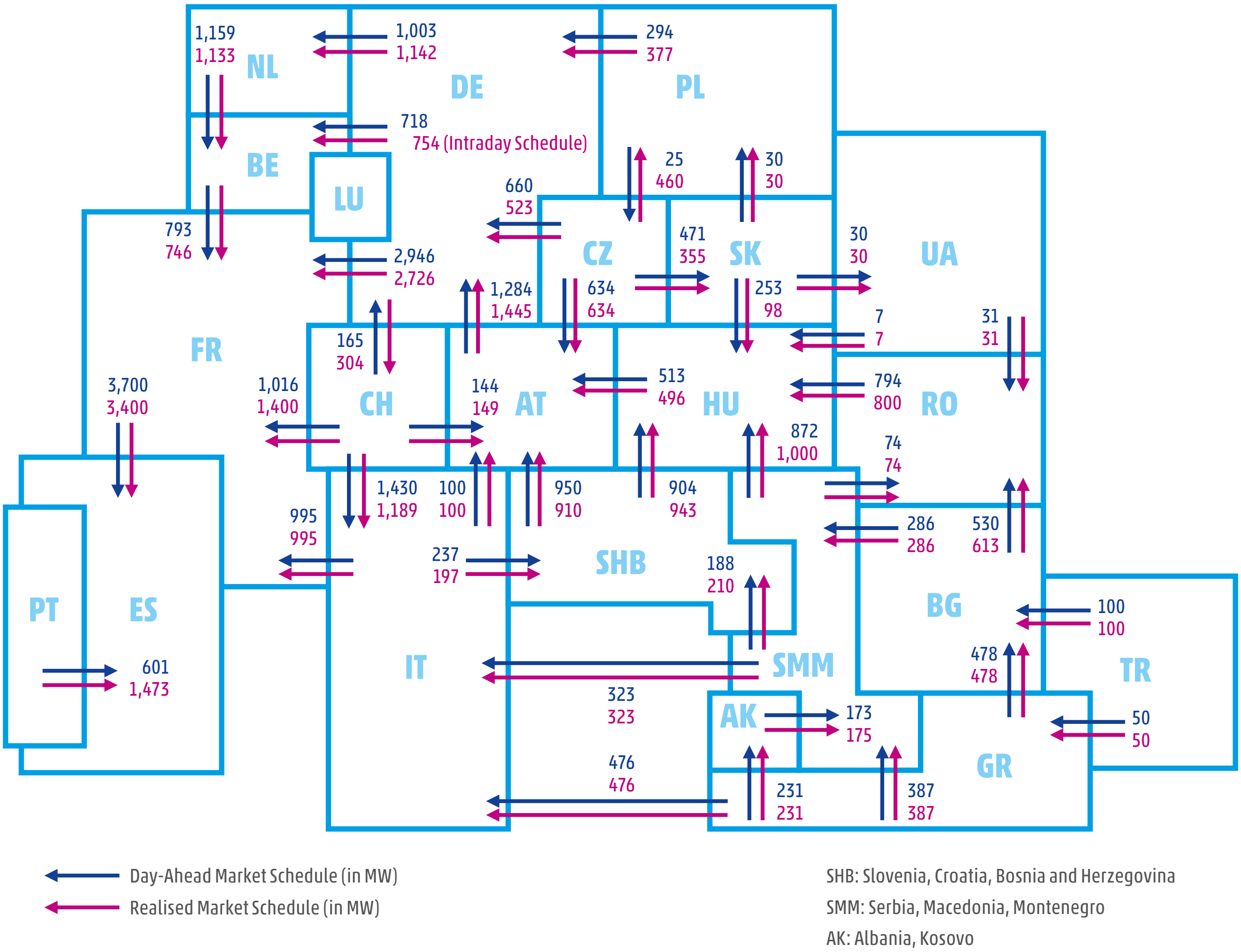

Figure 5.8: Comparison of day-ahead and actual schedules incl. intraday trades

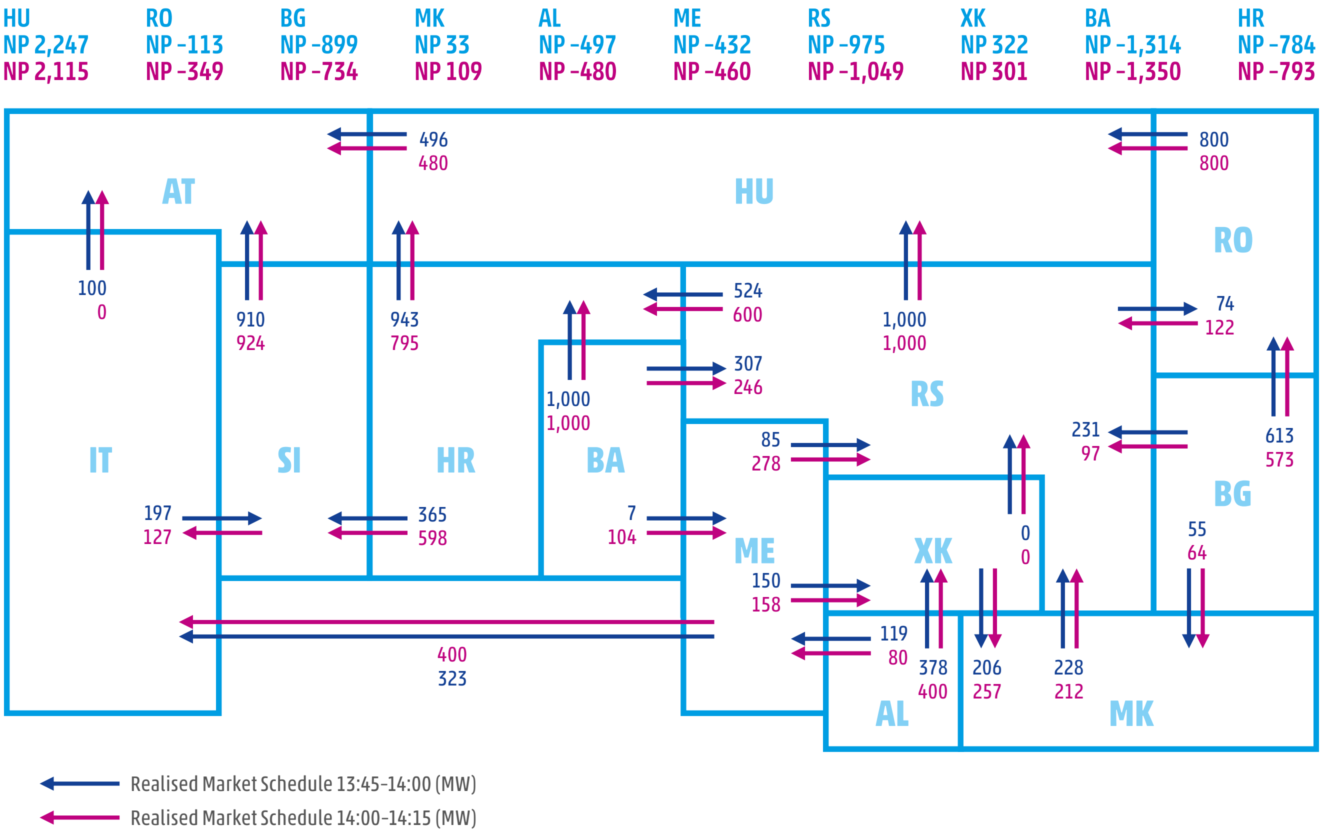

Figure 5.9: Comparison of actual market schedules in the affected region for relevant market units

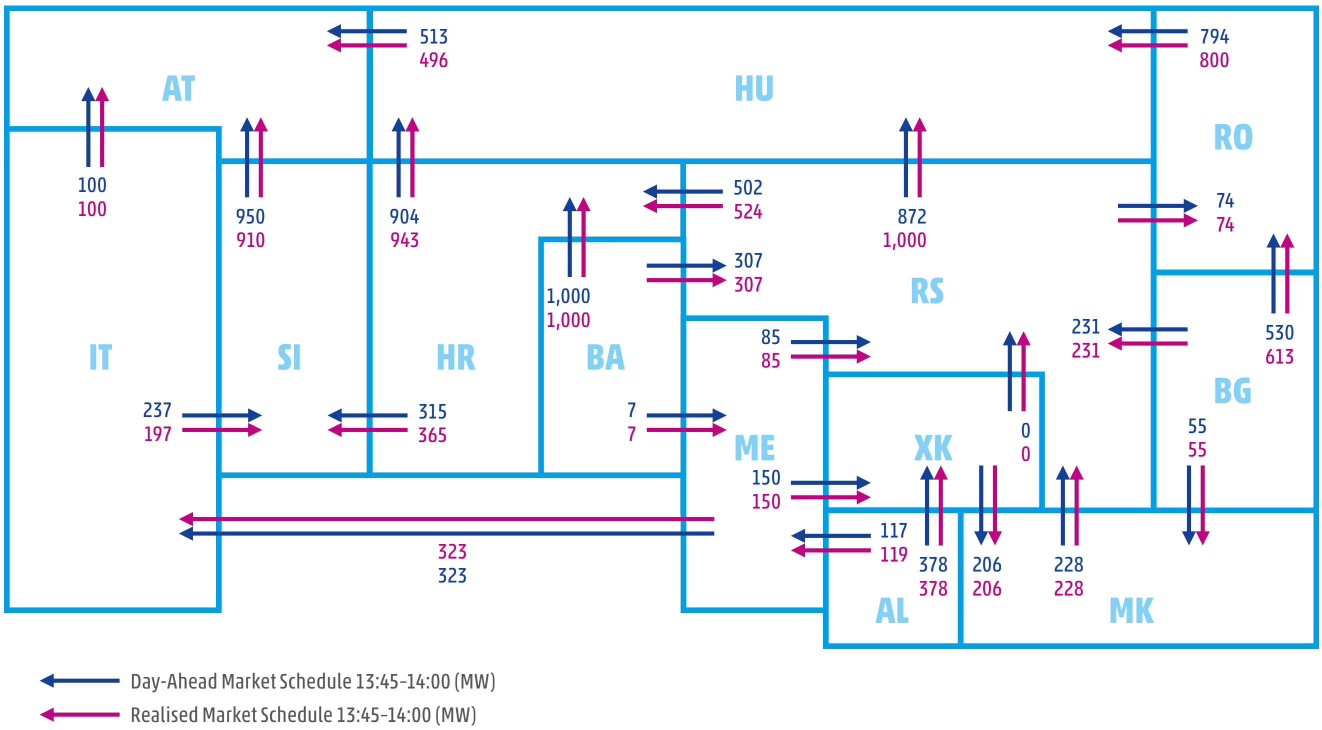

Figure 5.10: Comparison of day-ahead and actual schedules in the affected region for last market unit before the system separation

Scheduled day-ahead flow (MW)

Date	Time	RS » HU	RO » HU	RO » WPS	HR » SI	HR » HU
07 January	13:00 - 14:00	956	800	- 4	274	662
	14:00 - 15:00	960	800	- 2	323	701
	15:00 - 16:00	975	800	- 1	330	728
08 January	13:00 - 14:00	872	794	- 31	315	904
	14:00 - 15:00	875	800	- 11	434	819
	15:00 - 16:00	895	800	- 2	411	881

Table 5.9: Scheduled day-ahead market flows (net values)

Total flow (MW)

Date	Time	RS » HU	RO » HU	RO » WPS	HR » SI	HR » HU
07 January	13:00 - 14:00	1,000	799	- 4	676	581
	14:00 - 15:00	1,000	790	- 2	628	658
	15:00 - 16:00	1,000	800	- 1	592	733
08 January	13:00 - 14:00	1,000	800	- 31	365	943
	14:00 - 15:00	1,000	800	- 11	598	795
	15:00 - 16:00	1,000	800	- 2	606	857

Table 5.10: Total market flows (net values)

Summative flows (MW)

Date	Time	Day Ahead	Total	Delta
07 January	13:00 - 14:00	2,688	3,052	364
	14:00 - 15:00	2,782	3,074	292
	15:00 - 16:00	2,832	3,124	292
08 January	13:00 - 14:00	2,854	3,077	223
	14:00 - 15:00	2,917	3,182	265
	15:00 - 16:00	2,985	3,261	276

Table 5.11: Summative market flows (net values)

Table 5.11 shows the sum of the market flows from South-East Europe to Central-West Europe. Focusing on 08 January (Source: ENTSO-E Transparency Platform), there was a scheduled day-ahead export of 2,917 MW from South-East Europe to Central-West Europe from 14:00 – 15:00. The resulting total market flow is slightly higher at 3,182 MW. The comparison with 07 January shows that the flows on 08 January were slightly larger overall. In contrast, for 07 January, there is a larger delta between the total market flows and the scheduled day-ahead flows.

5.5 Day-ahead and intraday prices, 08 January 2021

5.5.1 Comparison of day-ahead market prices

An overview of the hourly price [EUR/MWh] per day from 06–10 January is presented for the day-ahead market to determine whether market prices were significantly lower in the SEE region when compared to the rest of Continental Europe (SEE prices are compared to those of France and Spain). The average daily hourly prices [EUR/MWh] per country for all days are shown in Figure 5.11 for the day-ahead market. Figure 5.12 illustrates the price trends on 08 January throughout the day as this information provides an insight into whether the difference in market prices is the main reason for increased electricity exports from SEE to the rest of Continental Europe. This comparison also serves as a basis to understand whether there were any price spikes or unexpected fluctuations in the hours before, during and after the incident. In this section, only the average daily hourly prices (06–10 Jan) and the price trends for 08 January are presented.

Figure 5.11 below illustrates the day-ahead average daily hourly prices in SEE countries, France and Spain, and shows that on average the prices in France and Spain are relatively higher than those of SEE countries.

The comparison indicates the following:

- On 06 January, prices in France are on average 28 % higher than in SEE countries, and prices in Spain are on average 29 % higher than in SEE countries
- On 07 January, prices in France are on average 22 % higher than in SEE countries, and prices in Spain are on average 28 % higher than in SEE countries
- On 08 January, prices in France are on average 13 % higher than in SEE countries, and prices in Spain are on average 23 % higher than in SEE countries
- On 09 January, prices in France are on average 12 % higher than in SEE countries, and prices in Spain are were on average 33 % higher than in SEE countries
- On 10 January, prices in France are on average 16 % higher than in SEE countries, and prices in Spain are on average 28 % higher than in SEE countries

The graph below illustrates the daily hourly prices [EUR/MWh] for Romania, Serbia, Hungary, Croatia, France, and Spain, thus providing an insight into how price trends changed throughout the day of the incident.

Day-Ahead Average Daily Hourly Prices [EUR/MWh]

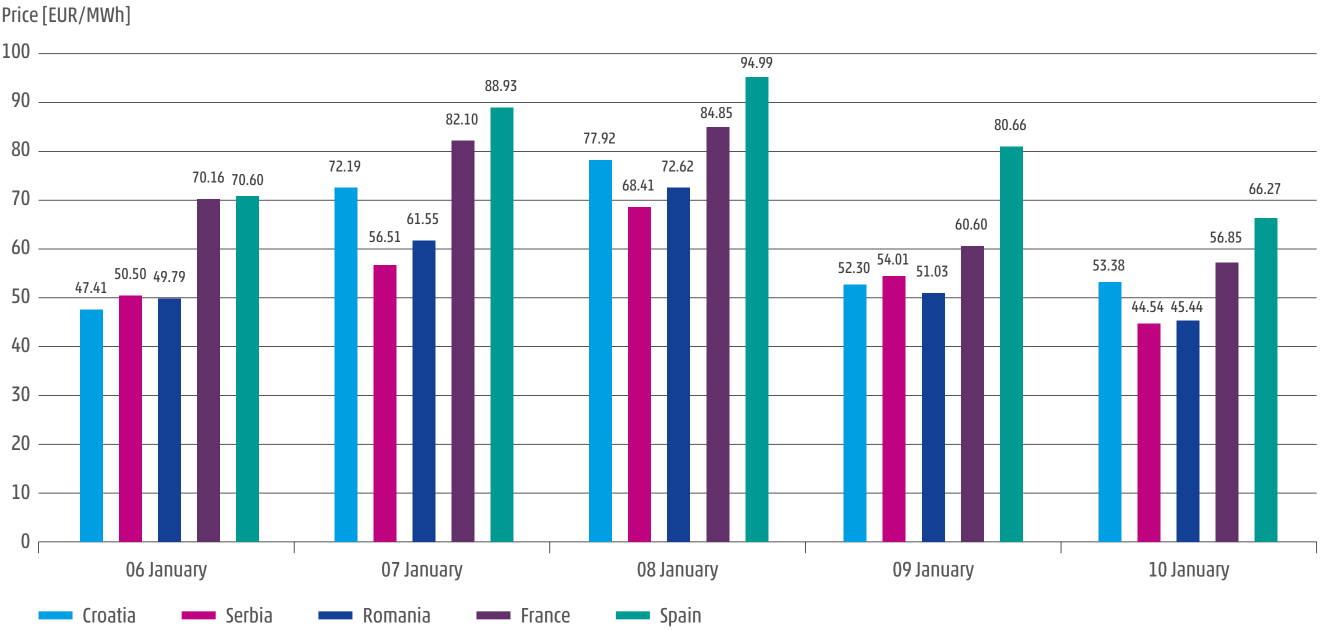

Figure 5.11: Day-ahead average daily hourly prices [EUR/MWh]

Figure 5.12 below indicates that price trends are continuous, without any abnormal fluctuations. The price trends behave in the same way for all countries – the price increases throughout the day due to an increase in electricity demand. It can be observed that the prices in the SEE region are relatively low when compared to those of France and Spain. There are two minor spike periods in France for 09:00 – 12:00 and 18:00 – 21:00; however, these are neither significant nor abnormal. The trends shown above do not indicate any disturbance or significant, sudden change of prices throughout the day. The same trends are observed for the other days, without any disturbance or change of price.

The comparison of day-ahead prices shows that the price trends in the SEE region were the same on all National Power Exchanges for the period 06 – 10 January. It is observed that the prices in France and Spain (which serve as representative example countries for the rest of Continental Europe) are relatively higher than those of SEE countries on all days. As there were no significant price spikes or drops in any country other than the relatively higher prices in CWE and South-West Europe (SWE), this observation indicates that the lower prices in SEE can be counted as the main reason for higher electricity flow transmitted from SEE to the rest of Continental Europe.

Intraday prices [EUR/MWh]: 08 January 2021

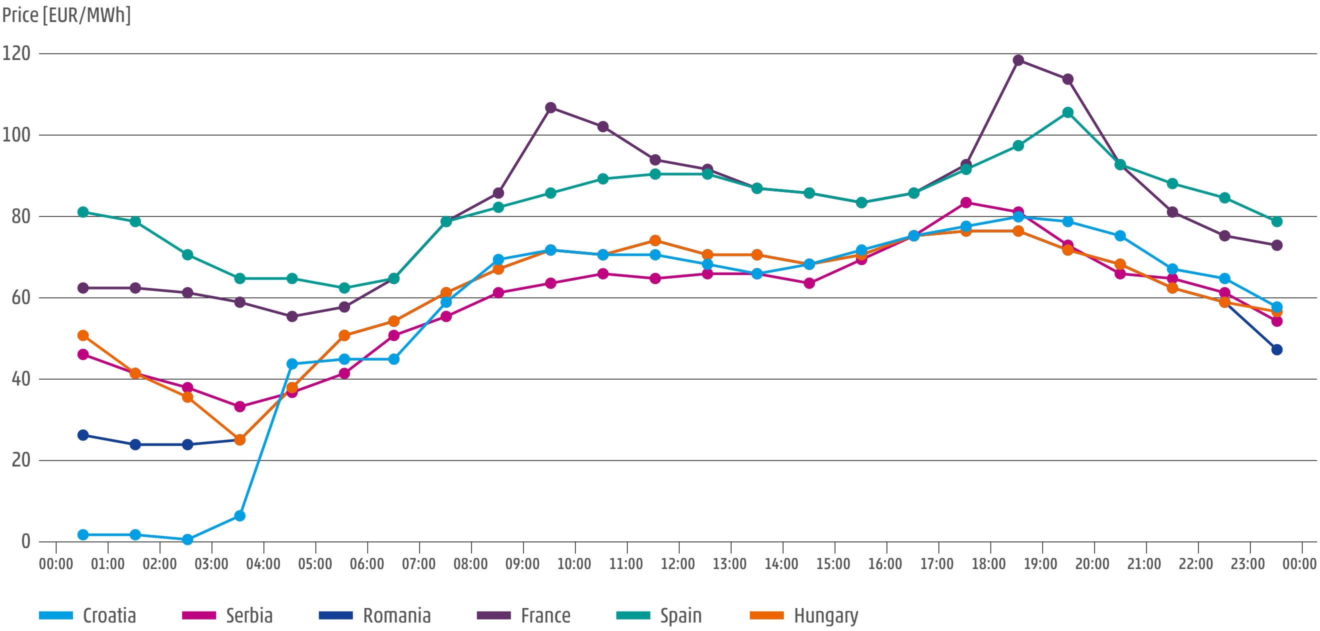

Figure 5.12: Comparison of day-ahead prices in SEE with other parts of Continental Europe

5.5.2 Comparison of intraday market prices

An overview of the volume weighted average hourly price [EUR/MWh] per day on the continuous intraday trading from 06–10 January is presented for the intraday market to determine whether market prices were significantly lower in the SEE region when compared to the rest of Continental Europe (SEE prices are compared to those of France and Spain). It is important to indicate that in Serbia there is no intraday market, and, therefore, Serbia is not taken into consideration for this part of the analysis. The average daily hourly prices [EUR/MWh] per country for all days are shown in Figure 5.13.

Figure 5.14 illustrates the price trends on 08 January throughout the day as this information provides an insight into whether the differences in market prices are the main reason for increased electricity exports from SEE to the rest of Continental Europe. This comparison also serves as a basis to understand whether there were any price spikes or unexpected fluctuations in the hours before, during and after the incident. In this section, only the average daily hourly prices (6–10 Jan) and the price trends for 08 January are presented.

The comparison indicates the following:

- On 06 January, prices in France are on average 27 % higher than in SEE countries, and prices in Spain are on average 32 % higher than in SEE countries
- On 07 January, prices in France are on average 28 % higher than in SEE countries, and prices in Spain are on average 46 % higher than in SEE countries
- On 08 January, prices in France are on average 27 % higher than in SEE countries, and prices in Spain are on average 35 % higher than in SEE countries
- On 09 January, prices in France are on average 14 % higher than in SEE countries, and prices in Spain are on average 33 % higher than in SEE countries
- On 10 January, prices in France are on average 9 % higher than in SEE countries, and prices in Spain are on average 20 % higher than in SEE countries

The graph below illustrates the daily hourly prices [EUR/MWh] for Romania, Croatia, France, and Spain, thus providing an insight into how price trends changed throughout the day of the incident.

Average volume intraday price [EUR/MWh] on the continous intraday trading

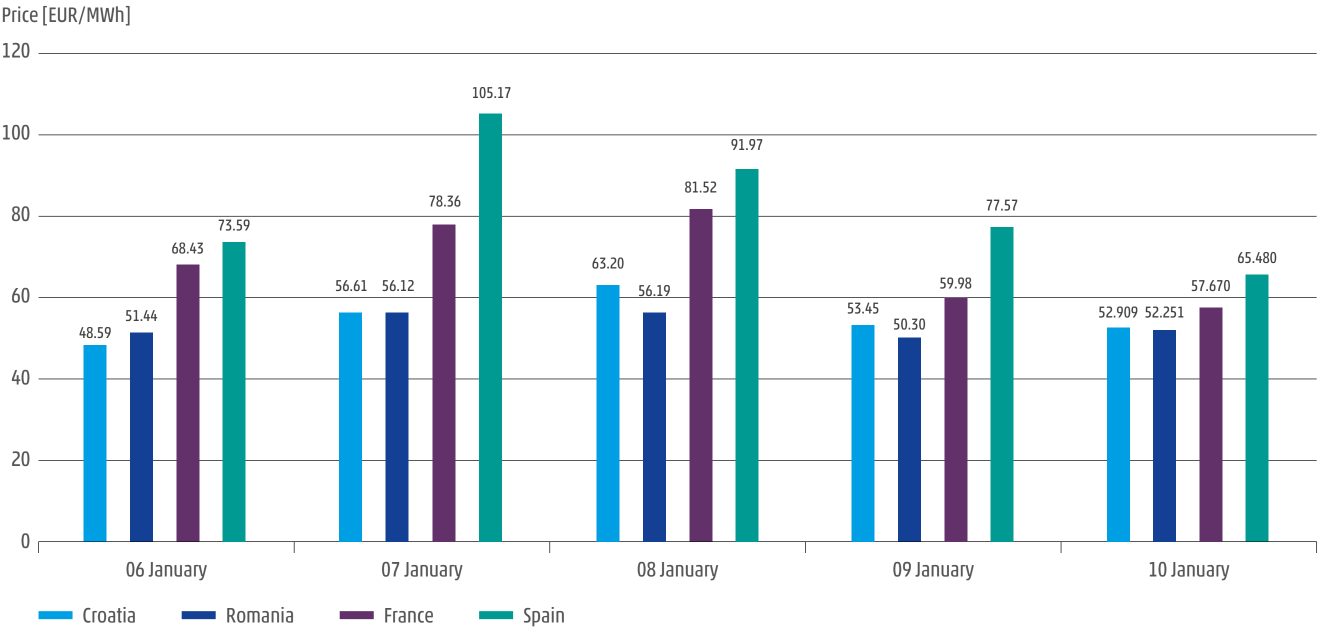

Figure 5.13: Intraday average daily hourly prices [EUR/MWh]]

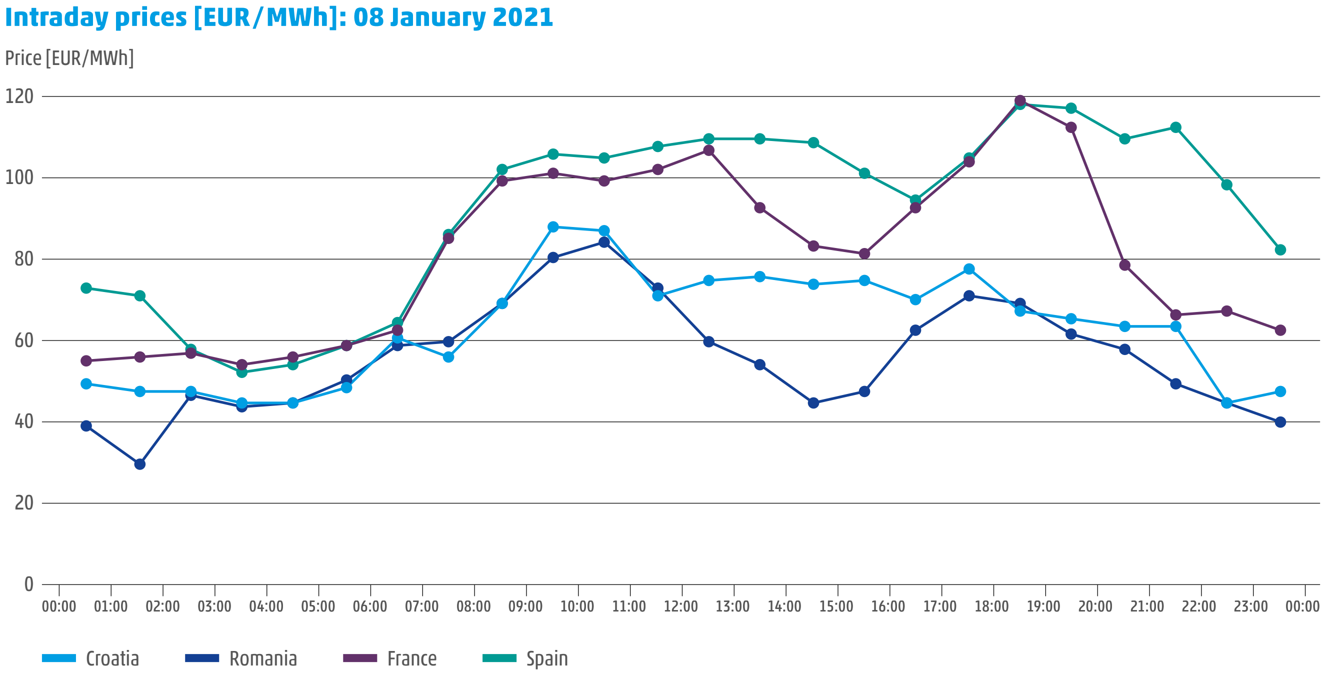

Figure 5.14: Comparison of intraday prices in SEE with other parts of Continental Europe

Figure 5.14 above indicates that price trends are continuous, without any abnormal fluctuations. The price trends behave in the same way for all countries – the price increases throughout the day due to an increase in electricity demand. It can be observed that the prices in the SEE region are relatively low when compared to those of France and Spain. At the time of the incident, and just before the incident, the prices in France experience a downward trend, while in Spain they are relatively higher for most of the day. The price increases in France after 17:00. These increases are not abnormal: 27 % and 35 % for France and Spain, respectively. The trends shown above do not indicate any major disturbance or significant, sudden change of prices throughout the day. The same trends are observed for the other days, without any disturbance or change of price.

The comparison of day-ahead prices shows that the price trends in the SEE region were the same on all National Power Exchanges for the period 06 – 10 January. It is observed that the prices in France and Spain (which serve as representative example countries for the rest of Continental Europe) are relatively higher than those of SEE countries on all days. As there were no significant price spikes or drops in any country other than the relatively higher prices in CWE and SWE, this observation indicates that the lower prices in SEE could be counted as the main reason for higher electricity flow transmitted from SEE to the rest of Continental Europe.

The general conclusion of both day-ahead and intraday price analysis is that all markets continued to operate as anticipated, both before, during and after the incident. In addition to the analysis performed, the TSOs from the affected SEE countries (Serbia, Bosnia and Herzegovina, Romania, and Croatia) were contacted after the incident and highlighted that no market activities were suspended at the time of the incident.

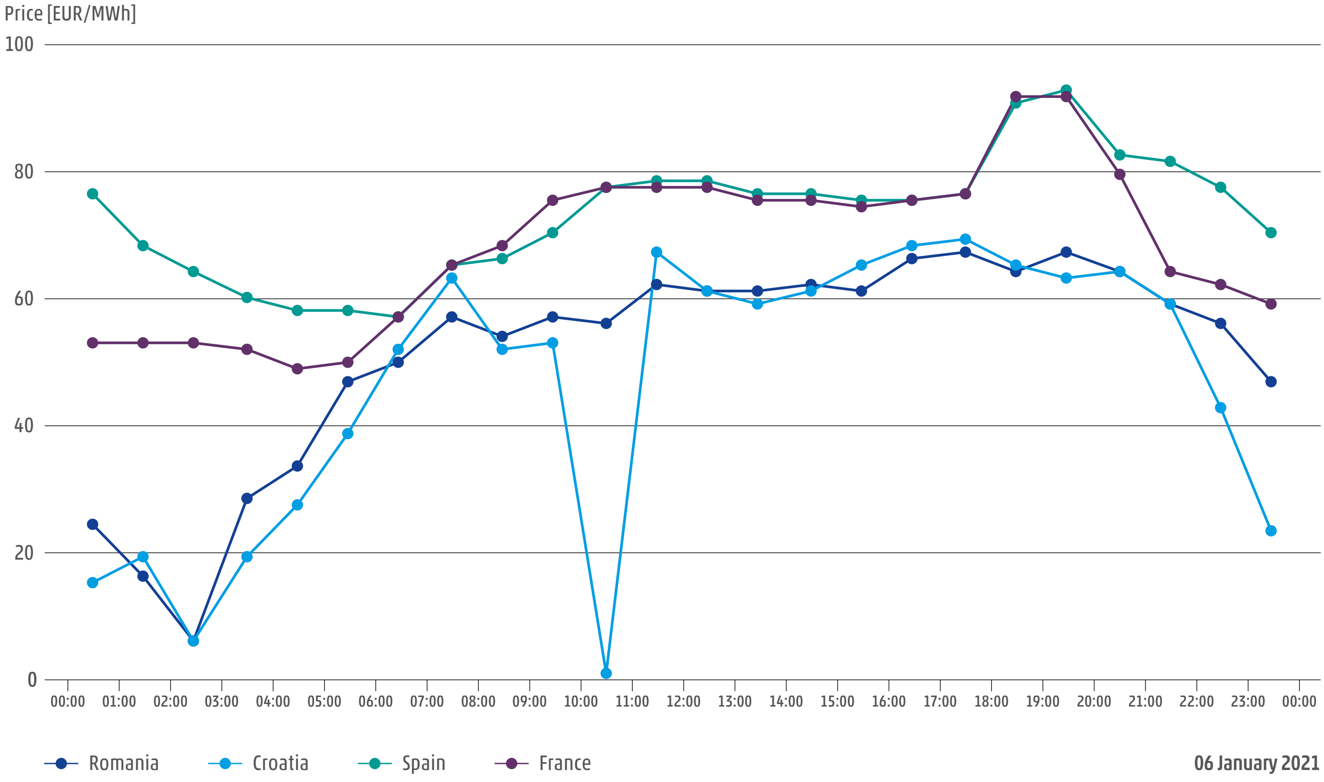

Figure 5.15: Intraday Price [EUR/MWh]: 06 January 2021

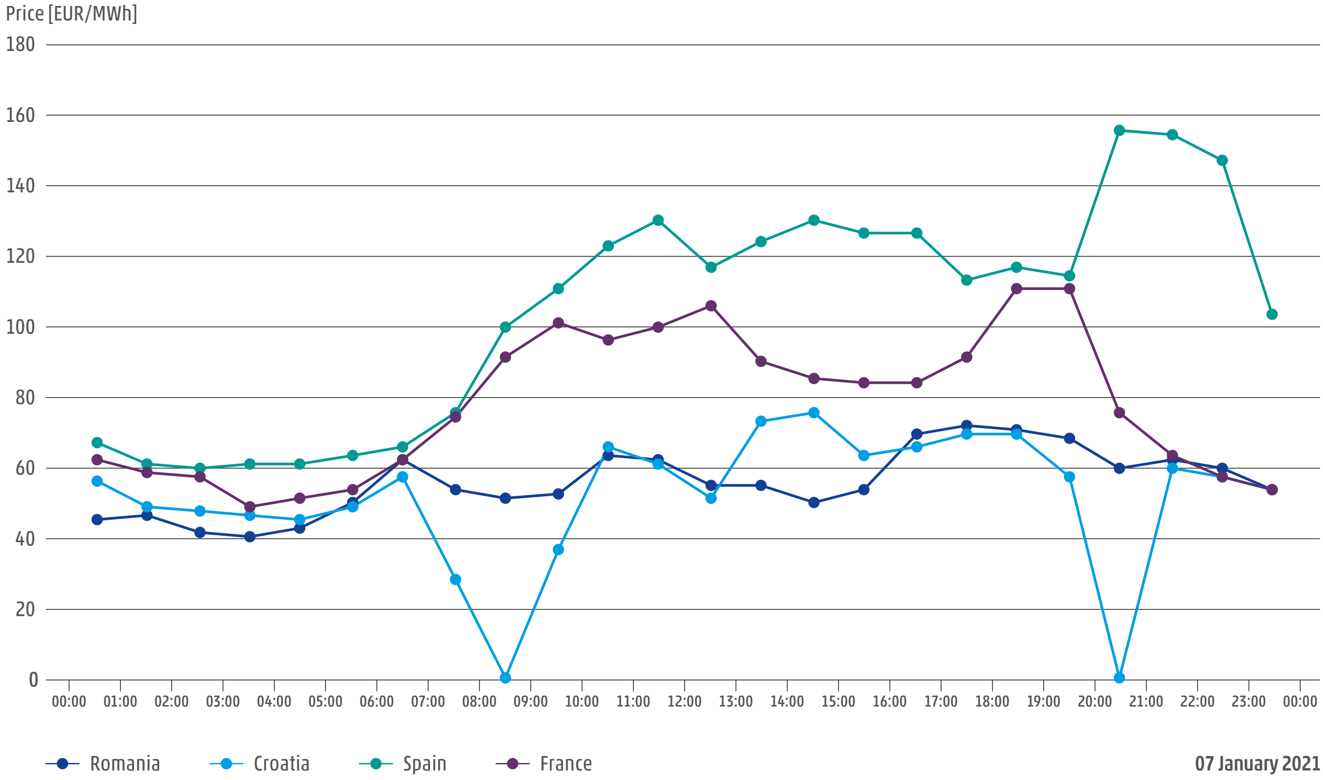

Figure 5.16: Intraday Price [EUR/MWh]: 07 January 2021

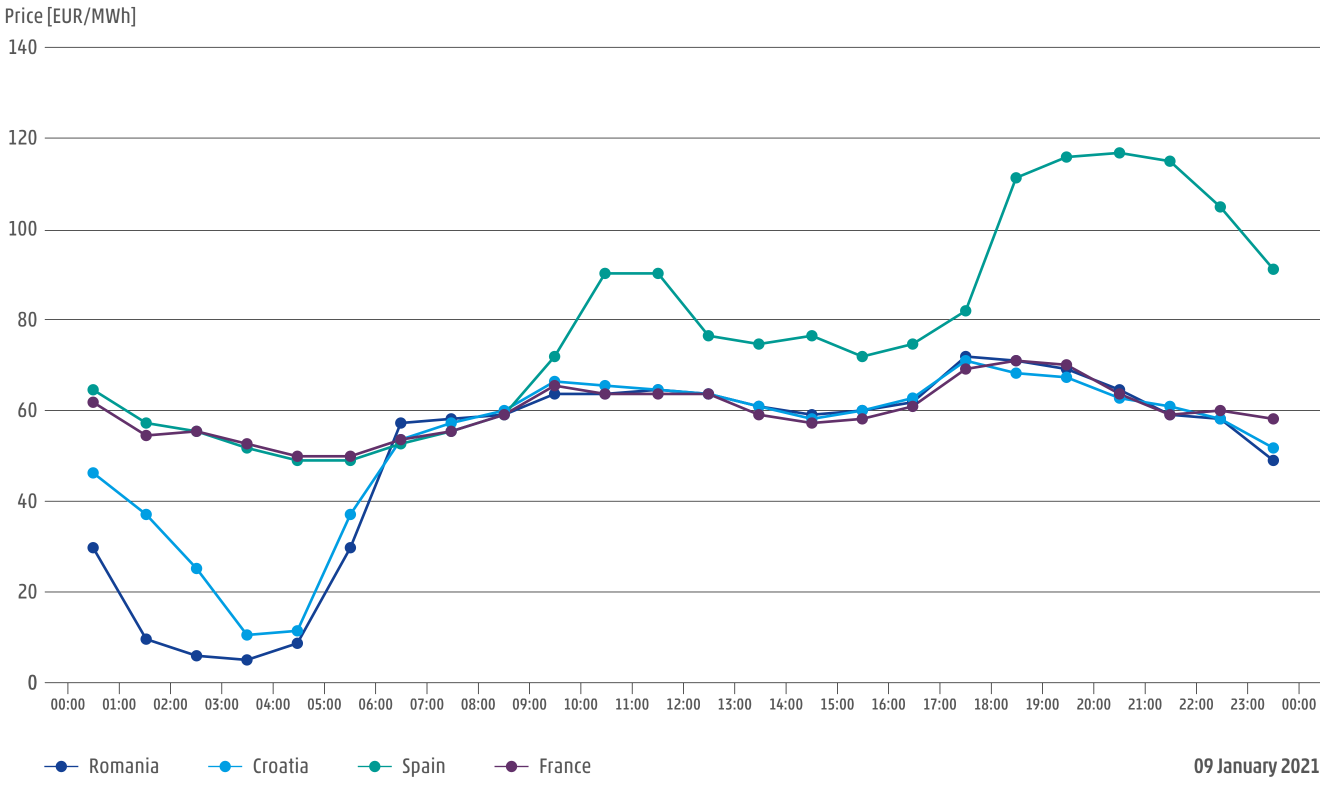

Figure 5.17: Intraday Price [EUR/MWh]: 09 January 2021

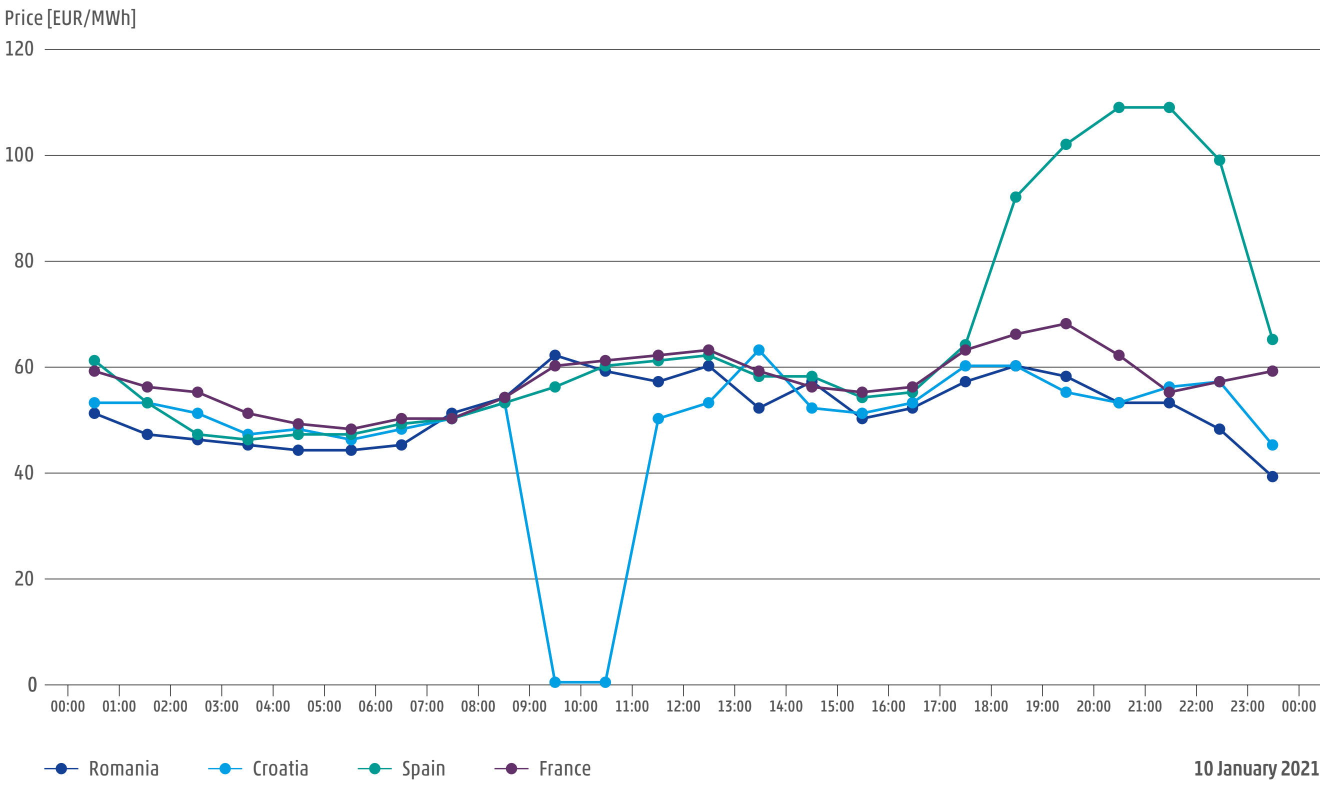

Figure 5.18: Intraday Price [EUR/MWh]: 10 January 2021

5.6 Market impact of the incident in selected areas

The incident caused an interruption in the power flow based on the day-ahead and intraday market schedules across the split-line. This caused a shortage in the CWE region and a surplus in the SEE region and comparable frequency deviations.

The shortage and deviations influenced the activation of the market-based FCR and FRR capacity in all areas, but additionally in some areas extraordinary measures were activated to bring the system conditions back to normal across the entire CWE and SEE regions. France, Italy, Romania and the Nordic area were impacted by extraordinary measures. The extraordinary measures and the contractual details for such measures are described in Chapter 4.

In order to investigate whether the incident had any impact on market platforms and activities, we have analysed the behaviour of the closer-to-real-time market platforms for the selected areas, where extraordinary (manual or automatic) measures were initiated. The selected areas are France and Italy due to the activation of contracted interruptible resources, the Nordic area due to significant EPC delivery to the CE region, and Romania due to the special situation of operating in two synchronous areas during the system split.

5.6.1 France

Intraday trading

The intraday trading volumes and prices are illustrated in Figure 5.19 below.

The data shows an increase in intraday trading in the hours after the incident. Whether this increase is caused by the incident or by other market activities cannot be verified. However, as is the case for other market activities, the intraday trading patterns and price levels do not indicate particularly large variations or shown any sign of particular gradients close to the time of the incident.

The intraday prices show a notable pattern as there is a decrease in intraday price levels despite the increase in traded volume in the hours 13–16. However, as this trend starts before the incident and continues after the incident, it cannot be plausibly linked to the incident.

Overall, it can be concluded that normal intraday market trading activities continued during and after the incident. Any impact of the incident on the intraday market volume and prices has not been identified in this analysis.

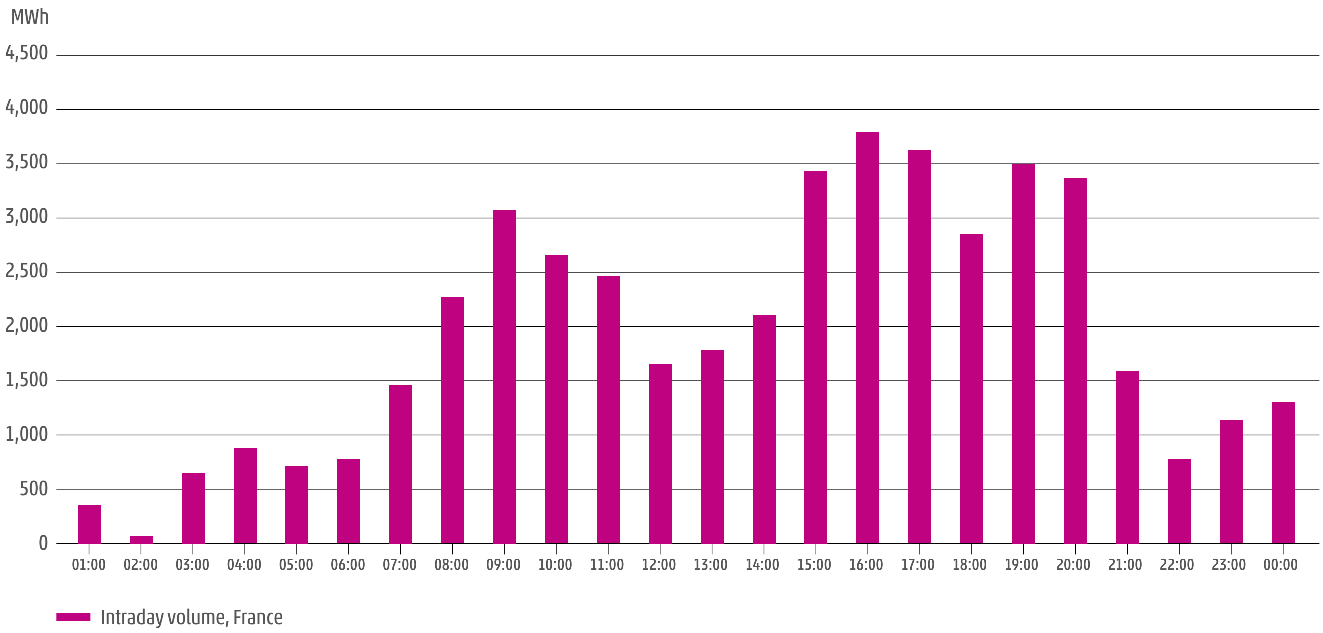

Figure 5.19: 08 January 2021 – Intraday volume, France

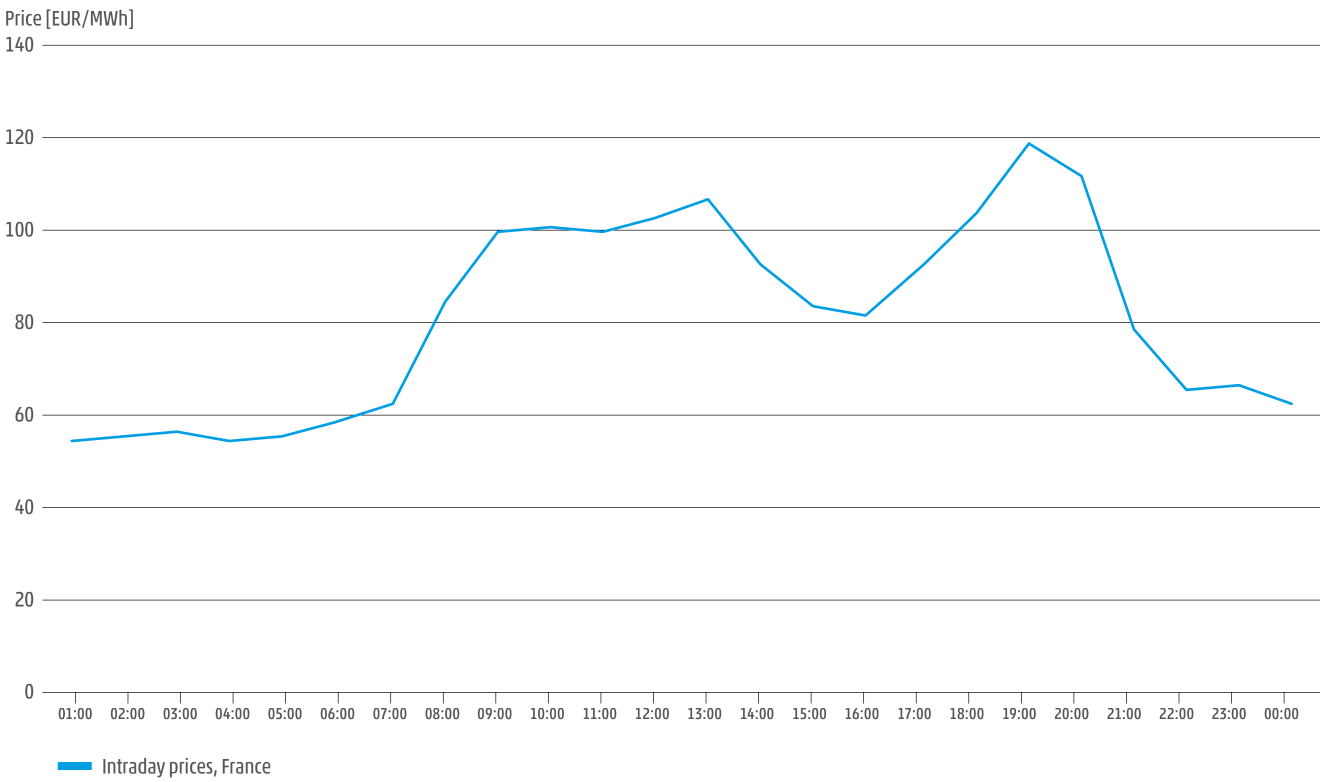

Figure 5.20: 08 January 2021 – Intraday prices, France

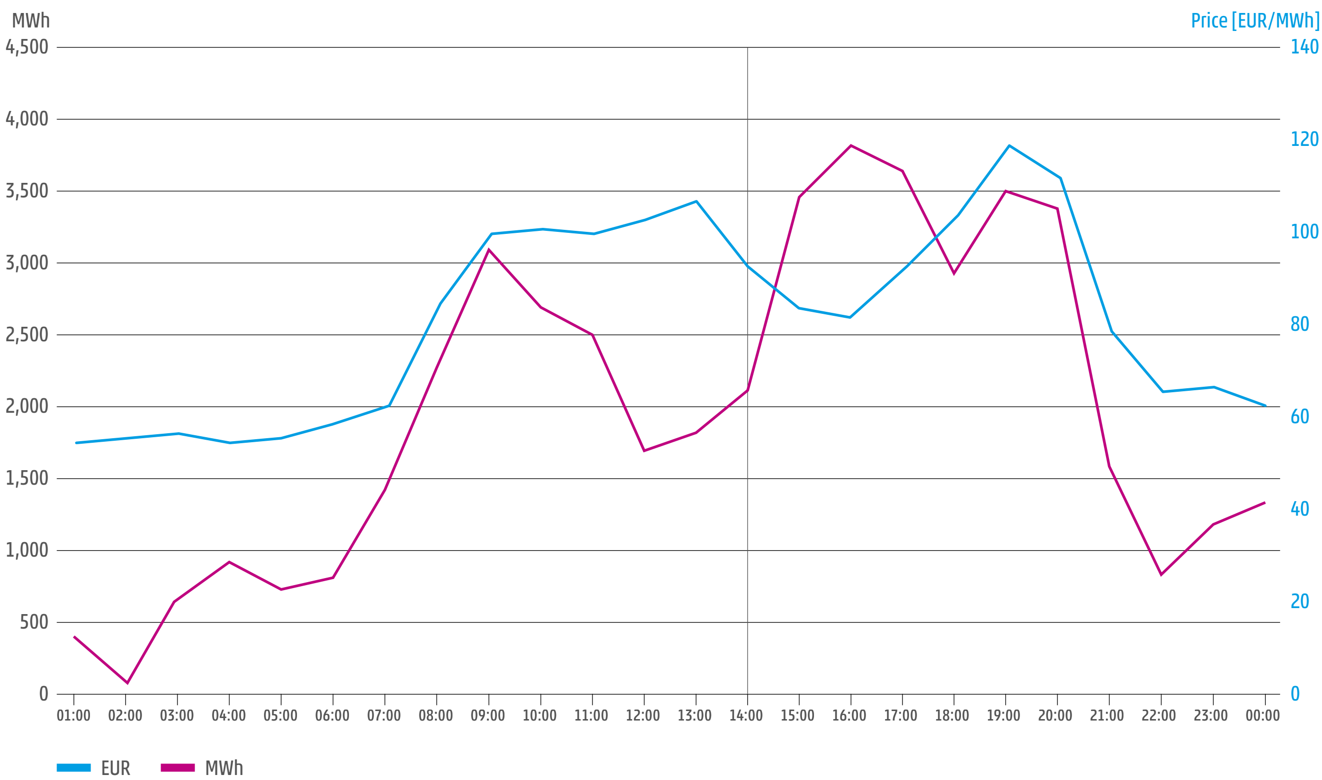

Figure 5.21: 08 January 2021 – Intraday trading, France

Balancing market, France

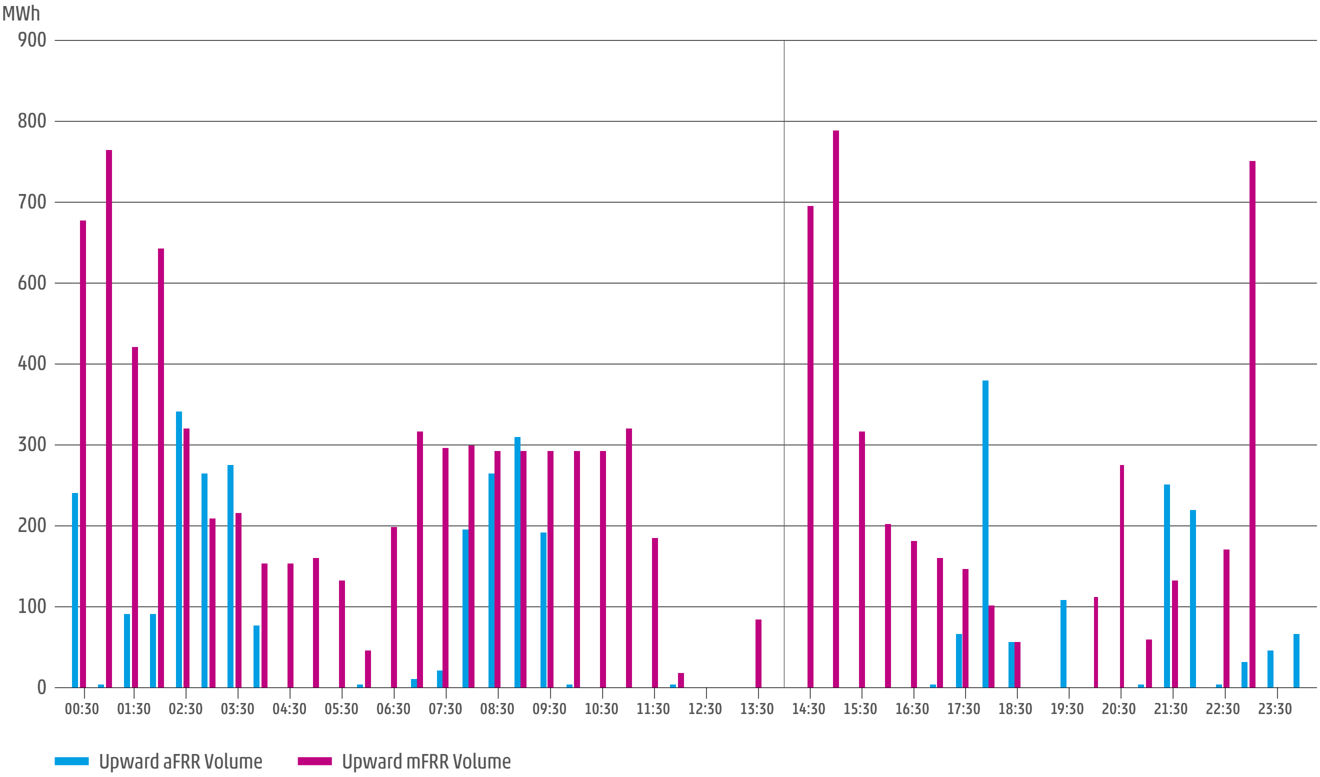

Figure 5.22: Upward FRR Volumes (MWh)

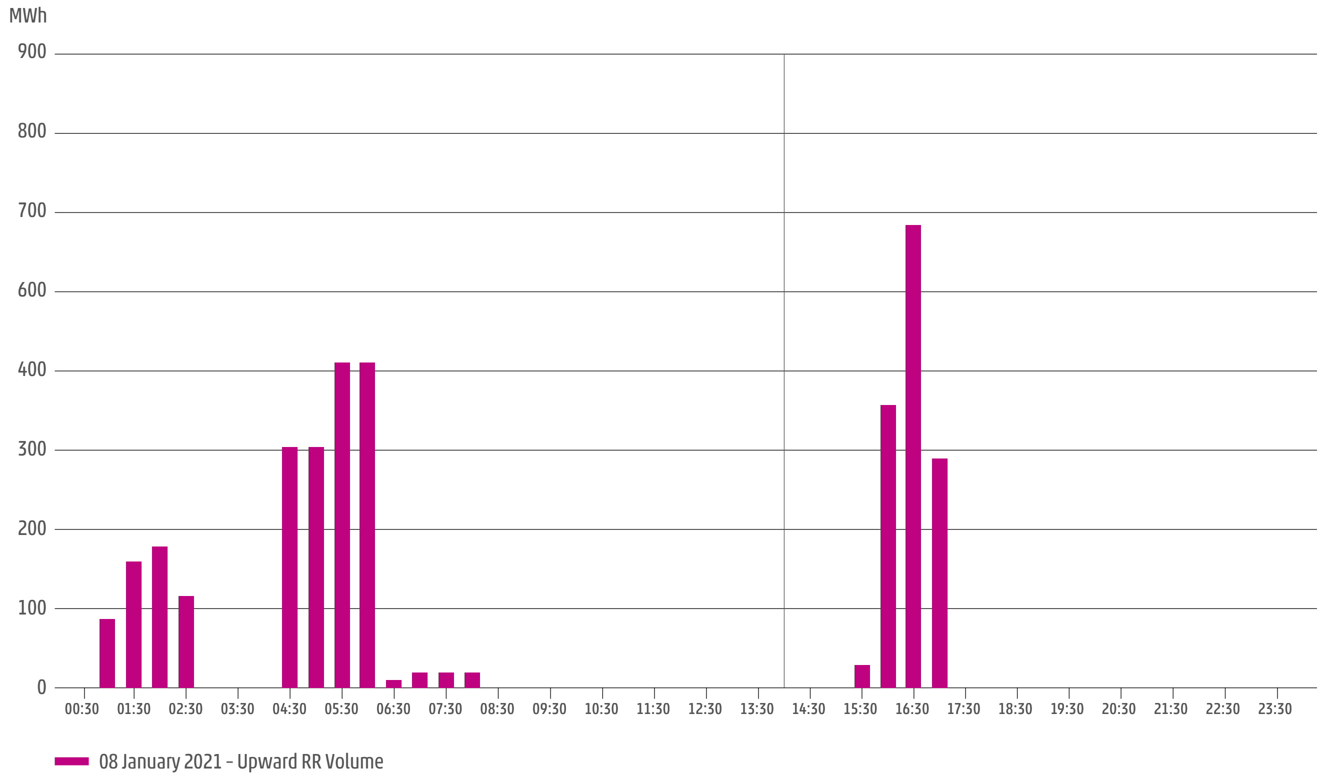

Figure 5.23: Upward RR Volume (MWh)

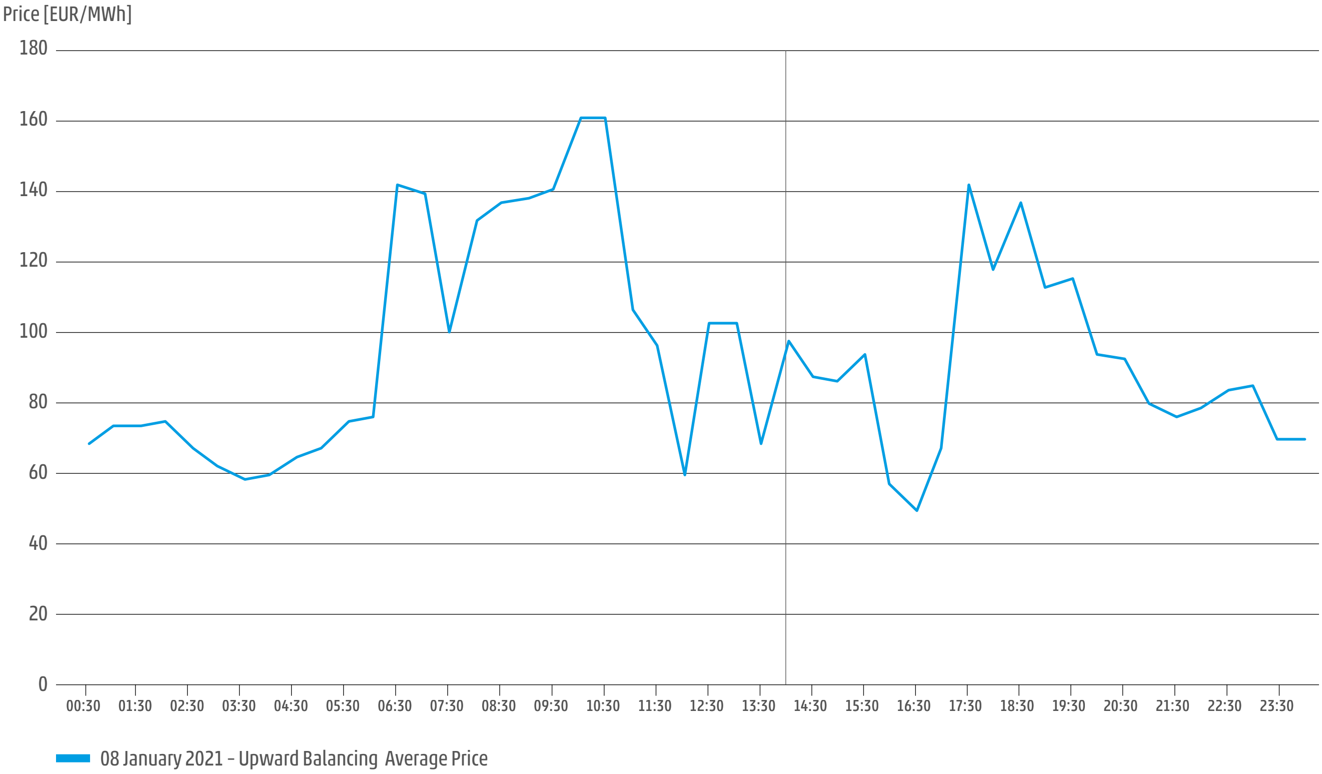

Figure 5.24: Upward Balancing Average Price (EUR/MWh)

The above analysis of balancing market volumes and prices on 08 January does not identify an impact of the balancing market activity of the incident at 14:05.

Countertrade, France

The HVDC interconnector between France and Spain tripped in connection to the incident as described in Chapter 2. To compensate for the XB imbalance countertrade was agreed

The countertraded volume (CT) with Spain on 08 January displayed in the report of 1,400 MW is correct but it corresponds to the first CT value established at 14:05. This value evolved afterwards until the end of the incident. It should be noted that a CT (300 MW) was already in place before the incident (see data below).

Volumes

Using the available data (MW for internal data, MWh for public data), there was 300 MW of CT in place at the time of the incident. The trip of the HVDC interconnector obliged an additional 1,400 MW of CT, giving a total value of 1,700 MW of CT (between RTE and REE) from 14:05–14:45.

To summarise

Total countertrading set up on 08 January between 13:00 and 17:00:

13:00–14:05	300 MW
14:05–14:45	1,700 MW
14:45–15:35	2,000 MW
15:35–15:45	1,700 MW
15:45–16:25	1,400 MW
16:25–17:00	1,600 MW

Remuneration of countertrade

The bilateral contract 'Cooperation agreement REE-RTE' specifies the rules of remuneration of countertrading between RTE and REE. This contract was updated in March 2021, with specific changes being made in the section concerning the sharing of countertrading costs between REE and RTE.

The costs and revenues of countertrading are shared 50/50 between REE and RTE, regardless of the location of the congested network element.

The costs (upward activation) and revenues (downward activation) of a countertrading action are calculated by multiplying the countertrading volume by the settlement price of the discrepancies (positive or negative depending on the direction of activation) of RTE and REE.

Contracted interruptible resources

RTE engages in annual contracting with industrial customers, which allows a percentage of their load to be triggered in 5 or 20 seconds in case of major system operation deviations (system frequency or system balance).

This opportunity was activated when the frequency dropped below 49,80 Hz in the CWE area.

The remuneration for such load shedding is fixed in the annual contract, independent of the activation.

The basis for the operational activation mechanisms and triggering limits for the interruptible resources have been described in Chapter 3.

5.6.2 Italy

Intraday market, Italy

The intraday market in Italy is complex and divided into 7 zones. The market is highly liquid with significant trading across the zones.

The total traded volume varies during the day. Without preparing a closer analysis, it shows visually that volumes and prices in hours 13–15 (around the incident) are closer to average figures than extreme figures.

From the analysis of intraday volumes and prices it is not possible to identify an impact of the incident on the intraday market behaviour in Italy.

Figure 5.25 and Figure 5.26 below illustrate the traded volumes and prices for 08 January 2021 for Zone M1.

From these diagrams, which illustrate the general trading situation in Italy, no impact of the incident at 14:05 on market behaviour can be deduced.

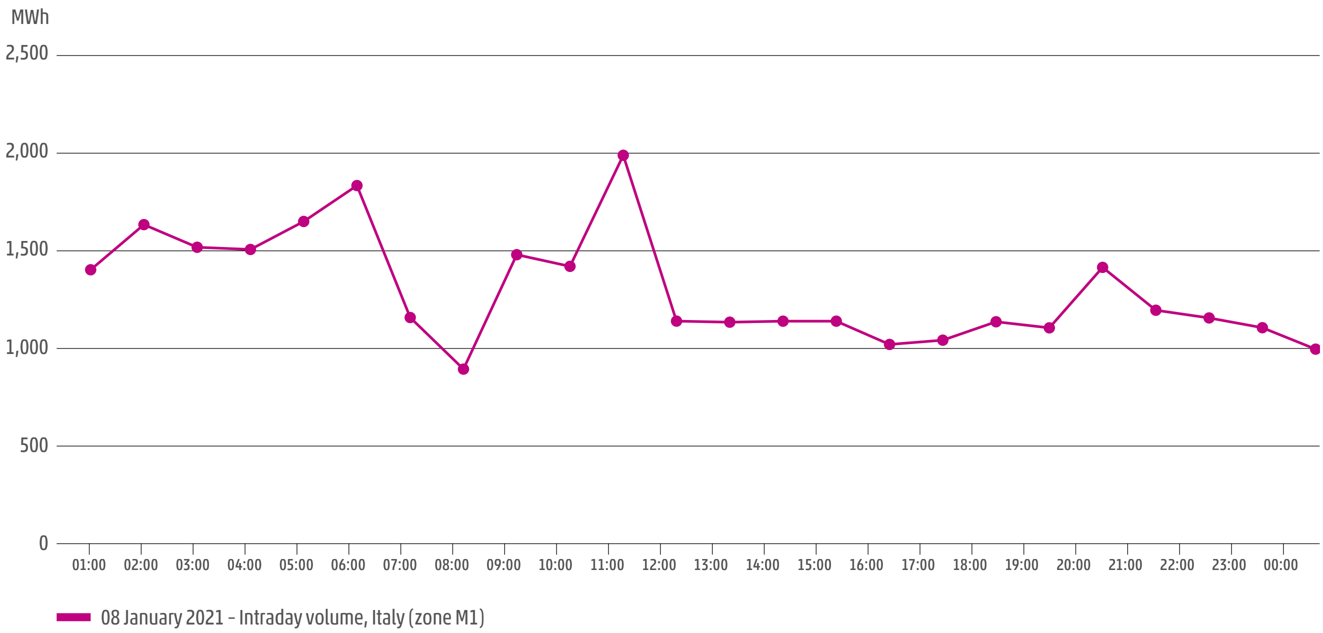

Figure 5.25: 08 January 2021 – Total hourly intraday trade, Italy, zone M1

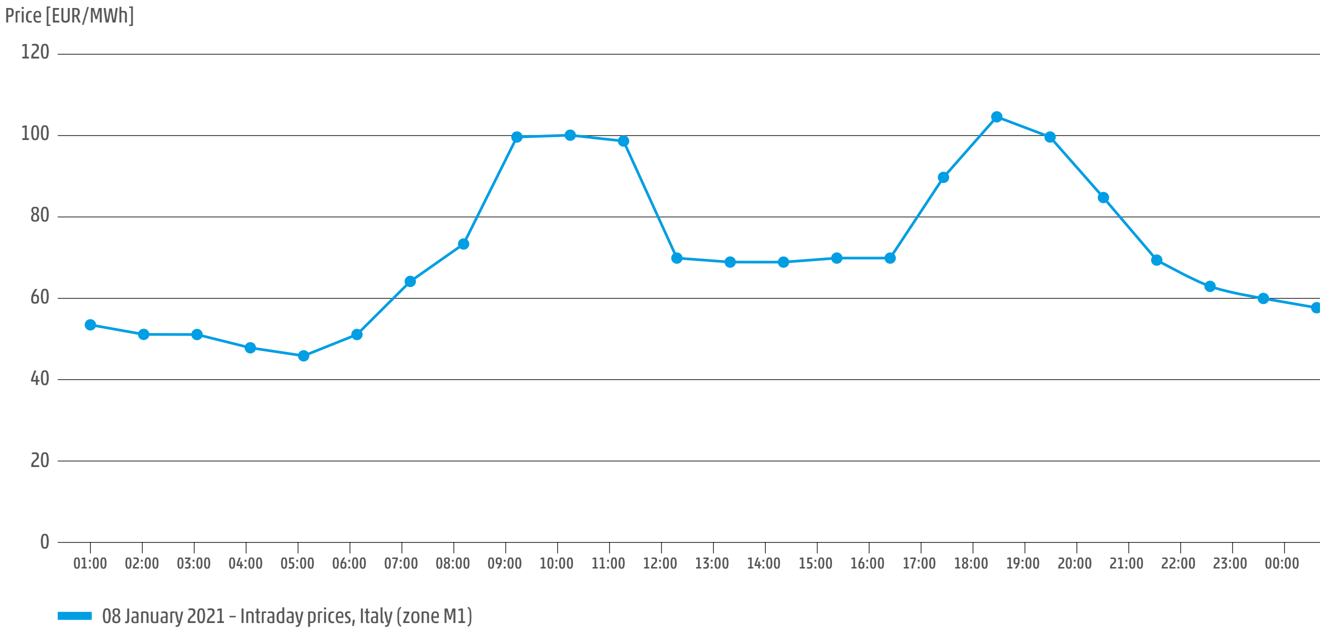

Figure 5.26: 08 January 2021 – Hourly intraday prices, Italy, zone M1

Balancing market, Italy

The balancing market in Italy appears to be entirely unaffected by the incident.

No upward regulation was activated. Rather, downward regulation was activated at unchanged prices. See Table 5.12 below for the relevant time period on 08 January 2021:

Date-Hour	Price Down [EUR/MWh]	Volume Down [MWh]	Price Up [EUR/MWh]	Volume Up [MWh]
13:00	-29	-679	0	0
13:15	-28	-651	0	0
13:30	-28	-634	0	0
13:45	-29	-571	0	0
14:00	-32	-444	0	0
14:15	-32	-428	0	0
14:30	-32	-399	0	0
14:45	-32	-398	0	0
15:00	-32	-415	0	0
15:15	-33	-571	0	0
15:30	-33	-695	0	0
15:45	-33	-640	150	13

Table 5.12: Balancing volumes and prices in Italy before and after the incident

Contracted interruptible resources, Italy

Interruptible resources in Italy are designed to cope with unexpected and short-term events that cannot be solved by the activation of ancillary services such as FCR or FRR. The purpose of this service is to address severe security issues of the grid. It enables the resolution of severe grid transients due, for example, to the sudden outages of interconnection lines with foreign countries

Italy's interruptible resources are procured through competitive auctions for three-year products, one-year product and three-month product. The interruptible service providers must bid, day by day, for the value of the load-shedding event and they are paid, in case of activation, at the price offered (pay-as-bid mechanism) up to a maximum value for the shedding event. The selection of offers is executed through a merit-order mechanism (from the lowest price to the highest).

Countertrade DC link Montenegro, Italy

A countertrading agreement exists between the TSOs of Italy and Montenegro (Terna and CGES).

During and after the resynchronisation process, an increase of power flow (500 MW) from SEE to CWE via the Monita DC link was agreed. This was established without countertrading.

In order to support the stabilisation of the reconnected areas, the change of the active power's set point on the HVDC Monita link to 600 MW was applied without any countertrading, because the aim was to reduce the loading on the lines connecting the two areas involved in the separation. The change of the set point on the Monita link (of course agreed beforehand among Terna, CGES and the other Balkan TSOs) enabled them to partially redirect the power flows from the south-east to the north-west of Europe through the Italian network. This measure helped to stabilise the Balkan network after the reconnection procedure.

Activation of countertrading between Italy and CGES would have counteracted the benefit expected from the measure above.

5.6.3 Nordic area

The Nordic Synchronous Area provided EPC (Emergency Power Control, fast frequency support) to the Continental Synchronous Area at a maximum total volume of 535 MW. This impacted the frequency in the Nordic Synchronous Area as described in Chapter 3.1.3: Support from other synchronous areas.

The EPC is activated automatically on the HVDC interconnectors between the Nordic area and the CE area. The impact of EPC in the CE area is fast support to restore the frequency. The impact in the Nordic area is similar to the loss of production of similar size.

In the Nordic area the EPC impacted the frequency and FCR reserves were activated fully, resulting in a loss similar to that of a production unit. The frequency drop in the Nordic area was contained within 30 seconds through the automatic FCR response. Remuneration of FCR is covered by the TSOs as capacity cost and supplied power.

The impact on the Nordic balancing market was not visible – it cannot from data be disclosed whether balancing reserves were activated to compensate for the EPC activation during the short timeframe of the EPC activation.

Therefore, no impact on the Nordic balancing market can be identified as a result of the incident.

5.6.4 SEE area (Romania)

During the system split, Romania was divided into two synchronous areas – the north-west area and the south-east area.

Therefore, system operation and market operation were difficult. However, no market activities were suspended during or after the incident. The market platforms delivered as expected, and reserves were provided as anticipated due to the deviations in frequency and balance in the areas.

North-west area

To restore balance and frequency, the following actions were taken in the FRR market.

After the network splitting at 14:05 (CET), in the north-west area have been upward activated in order to restore the frequency, an amount of 739 MW from FRR reserves as follows:

- 141 MW of the production units (three HPP units) that tripped at 14:05 were started up after the incident (the remaining 207,2 MW of the 348,2 MW that were tripped in the north-west area could not be started up);
- 598 MW of the other production units that were not in operation were also started up after the occurrence of the incident.

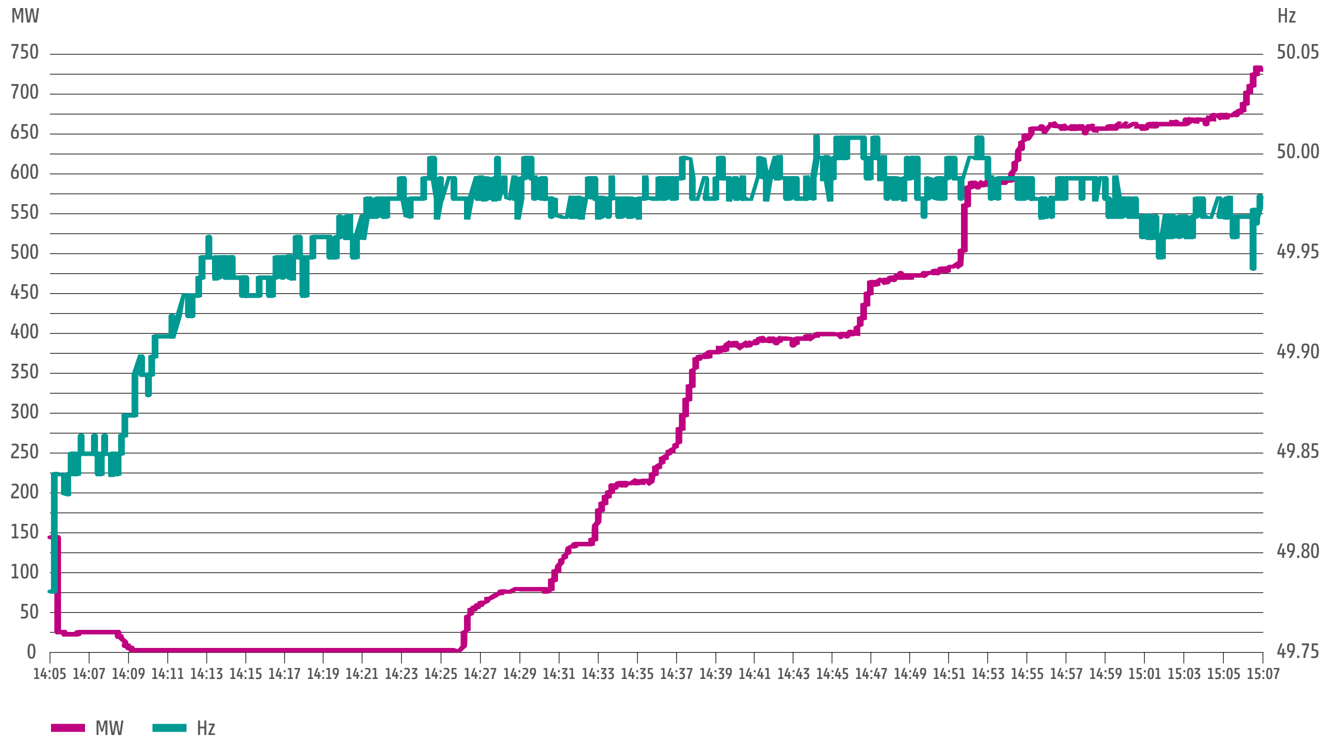

Figure 5.27: FRR up in north-west area 14:05 – 15:08 CET

South-east area

After the interconnection splitting at 14:05 (CET), in order to restore the system frequency, there was downward activation of a maximum amount of 1,288 MW from FRR reserves.

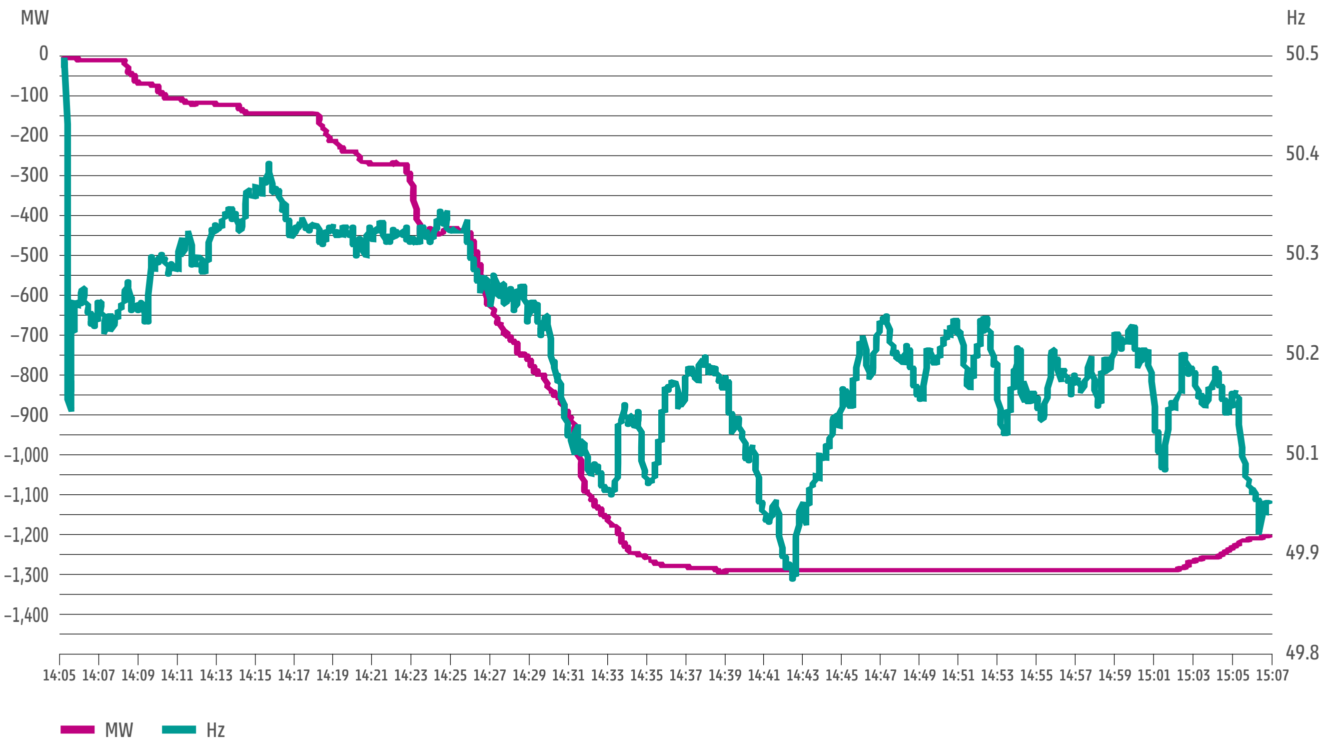

Figure 5.28: FRR up in South-East area 14:05 – 15:08 CET

Conclusion

Based on the legal framework, soon after the system separation in the power system of Continental Europe on 08 January 2021, a scale 2 investigation according to the Incident Classification Scale (ICS) methodology was launched in order to describe the course of the incident and its underlying causes. The presented final report provides several notable findings and insights. Its lessons, which have been derived in detail, are thus valuable and highly appreciated inputs that will help to prevent similar incidents in future power system operation. In regard to ongoing energy transition, a resilient and sustainable power system is required to guarantee a stable supply of electric power to all European citizens.

Summary

On Friday, 08 January 2021 at 14:05 CET, the Continental Europe Synchronous Area was separated into two areas (the north-west area and the south-east area) due to cascaded trips of several transmission network elements. This cascade of trips was initiated by the busbar coupler in the Croatian substation Ernestinovo. The substation was exposed to a high load flow, caused by a large flow pattern running from South-East to North-West Europe. That flow pattern totalled approx. 5.8 GW across the separation line at the time when the initial event took place. However, this high load flow, particularly on the busbar coupler, was not forecasted correctly in the different respective security calculations.

Directly after the initial trip at 14:04:25, power flows were dislocated due to the physical laws and thus caused the trips of further transmission elements due to overcurrent protection. It was determined in the investigations after the incident that the power system was already on the verge of angular instability before the initial event. After the first trips, the system thus became unstable, which caused further cascading trips. Finally, at 14:05:08 and thus 43 seconds after the initial event, the Continental European Power System was divided into two asynchronous areas. Due to the load flow pattern before the event, the north-west area had a power deficit of 5.8 GW, while the south-east area coped with the according surplus of power. This led to frequency gradients, peaking at 49.746 Hz in the north-west area and 50.6 Hz in the south-east area.

Based on the large frequency deviations in both areas, the automatic frequency containment reserves started to contribute power shortly after the system separation and thus stabilised the frequency soon afterwards. This was also a result of the further application of frequency support by automatic interruptible loads in France and Italy as well as through HVDC lines from the Nordic and GB power systems. Shortly after the separation, the affected TSOs as well as the coordination centres advised all TSOs with the guidance of the EAS. The frequency leaders Amprion (for the north-west area) as well as EMS (for the south-east area) then further coordinated the return of the frequency to 50 Hz. As this was obtained after approx. an hour, the resynchronisation process was started immediately by the affected TSOs, so that the Continental European Power System was resynchronised at 15:08.

Further investigations regarding the influence on the market do not reveal any impact. The markets continued to operate as planned before, during and after the incident and did not show any abnormal behaviour. Furthermore, market schedules did not exceed the agreed NTC values.

Derived recommendations

Based on the collected facts, the further analysis, and the subsequent derivation of main causes and critical factors, the expert panel outlined a number of recommendations.

In the chapter 'System conditions before the incident', recommendations have been made regarding the substation topology to enable the flow through a busbar coupler to be as low as possible. Recommendations have also been made regarding the set points of protection devices, which should be adapted according to operational security limits. The according alarm settings must be defined in a clear and consistent way, while certain operator actions might also be predefined. Furthermore, Transmission Reliability Margins and Flow Reliability Margins must be reviewed if both are sufficiently dimensioned to cope with future sudden overloading. A further significant impact for the incident was due to the security calculation. In that regard, transmission elements must be implemented in the contingency list if these elements have a significant effect and are protected by overcurrent and over-/under-voltage protection devices. The IGM of each TSO must further allow the assessment of power flow limits of all relevant grid elements. In addition, the forecast processes, mainly the intraday congestion forecast, must be improved to reduce differences with real-time operations. Moreover, the implementation of the observability area should be monitored for the security calculation in real time. Further considerations have also been made regarding the regional coordination, especially in SEE, which should perform the coordinated capacity calculation according to existing stability limits as well as the coordinated security assessment in a more sustainable way. While analysing the system conditions before the incident, several issues could not be solved in compliance with relevant codes, guidelines and methodologies, all of which should be obtained by a further detailed analysis after publication of the ICS final report.

In the chapter 'Dynamic behaviour of the system during the incident', two recommendations have been derived. The first relates to critical transmission system corridors: the stability margin has to be assessed in operational planning and real-time operations. Furthermore, operators have to be trained in the field of dynamic stability. A task force will work under the oversight of the RGCE to rapidly develop proposals to transform the results of dynamic studies into concrete operational actions. The second recommendation proposes that due to the future decrease of conventional power generation sources and a corresponding reduction of the system inertia, compensational measures must be identified and implemented where identified.

Following post-event analysis of the frequency support and generation performance, five recommendations are proposed in Chapter 3. Where there is a non-conform disconnection of generation or loads, each TSO must review the cause with the Generation Companies and Distribution Network Operators to avoid non-conform disconnections in the future. Based on the recorded dynamic behaviour of the system it is observed that the RoCoF values after the separation were within the generation withstand capabilities. The event will be used to evaluate frequency stability evaluation criteria for Continental Europe and to verify the dynamic stability models.

For higher power transfers between regions, the fast-acting power reserves may need to be complemented with additional fast support beyond the classical FCR. Future scenarios should be evaluated to determine whether the available fast-acting support is sufficient in case a system separation occurs. The TSO system defence plans should also be assessed in this regard to determine any adverse cross-border impacts under different emergency state scenarios and to ensure that the defence plans (including special protection schemes) are coordinated and geographically balanced to meet the system needs.

Even though the communication, coordination and resynchronisation were successful and timely, this event can be used to identify further improvements in coordination and communication between TSOs for large-scale events. From Chapter 4, procedures for the management of balancing platforms during system events should also be developed to avoid any unintended consequences which could lead to a larger disturbance of the system.

The European Awareness System was used successfully during the event but more functionalities should be developed to further assist TSOs in the sharing of operational data (pre and post fault) and coordinated actions. Furthermore, in addition to the currently established legal framework, a Region Continental Europe procedure for resynchronisation in case of system separation with two or more areas should be developed based on the experience of this event. Finally, in the future, coordination of regional restoration could be enhanced if it is deemed necessary by TSOs.

Overall assessment and conclusion

The provided final report of the ICS expert panel yields a comprehensive analytical overview of the Continental European system separation on 08 January 2021. After the incident, ENTSO-E and the European TSOs as well as ACER and NRAs started an intensive assessment of the incident in close collaboration.

The analysis has shown that the separation of the Continental European power system in two asynchronous areas led to significant frequency deviations in both areas. The impacts of the separation were visible in both areas through voltage and power oscillations. Primarily as a consequence of the fast and coordinated activation of stabilising measures like activation of frequency reserves, interruption of contractual agreed industrial loads and support from other synchronous areas, frequency degradation was automatically stabilised. Further manual measures then brought the frequency back to its nominal value of 50 Hz soon after the incident, so that the resynchronisation could take place over a duration of approx. one hour after the separation. In that timespan only a very small number of private and industrial loads could not be supplied, meaning that overall the incident had no major influence on the security of supply of European consumers. The system separation of 08 January 2021 was thus severe but not as serious as the system separation of 4 November 2006, where millions of consumers were affected.

Overall, the incident was handled in a better and more efficient manner than the split in November 2006, which was also due to the lessons learned from that system separation and consequent development of the binding legal framework at the EU level. The EAS, introduced right after the 2006 event, allowed the TSOs to be aware of the overall system states. Coordinated measures of the defence plans were activated quickly, which also allowed for the fast resynchronisation of the two asynchronous areas.

In addition, it was shown by the in-depth analysis that the large pan-European load flow and the subsequent low stability margin were crucial for the incident, which reveals an illuminating view on future power system conditions in Europe. With the ongoing energy transition, large and long-ranging power flows on the pan-European level will further increase in amplitude and occurrence. In this regard, power system operation must become sufficiently resilient to cope with unexpected disturbances and faults to guarantee an unchanged high security of supply of European customers. Therefore, sufficient security margins must be provided if increasingly high utilisations of assets are necessary to cope with the electrical energy transition. Power system operation will thus be further challenged, emphasising the importance of highly accurate security calculations. In all those regards, the ICS expert panel has provided numerous recommendations for further assessments and corresponding implementations. The implementation of these recommendations will thus help to prevent similar incidents in the future.

List of Abbreviations

A	Ampere(s)
AC	Alternating Current
ACE	Area Control Error
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserves
CACM	Capacity Allocation & Congestion Management
CB	Circuit Breaker
CC	Coordination Centre
CCC	Coordinated Capacity Calculations
CCR	Capacity Calculation Region
CE	Continental Europe
CET	Central European Time
CEP	Clean Energy Package
CGM	Common Grid Model
CSA	Coordinated Security Assessment
CT	Countertraded Volume
CWE	Central-West Europe
DA	Day-ahead
DACF	Day-Ahead-Congestion-Forecast
DC	Direct Current
DOPT	Daily Operational Planning Teleconference
DSO	Distribution System Operator
EAS	ENTSO-E Awareness System
EnCS	Energy Community Secretariat
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Emergency Power Control
FB	Flow-Based
FCR	Frequency Containment Reserves
FRM	Flow Reliability Margins
FRR	Frequency Restoration Reserve
GPS	Global Positioning System
GW	Gigawatt
HPPs	Hydro power plants
HV	High Voltage
HVDC	High Voltage Direct Current
ICS	Incident Classification Scale
ID	Intra-day
IDCF	Intra-day Congestion Forecast
IDOPT	Intraday Operational Planning Teleconference
IGCC	International Grid Control Cooperation
IGM	Individual Grid Model
LFC	Load Frequency Controller
LFDD	Low Frequency Demand Disconnection Schemes
LFSM	Limited Frequency Sensitive Mode
LFSM-O	Limited Frequency Sensitive Mode – Over-frequency
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency
mHz	Milihertz
MLA (Operation Handbook)	Multilateral Agreement (Operation Handbook)
MRA	Multilateral Remedial Action
MVA	Megavolt ampere
MW	Megawatt
NC ER	Network Code on Electricity Emergency and Restoration
NPPs	Nuclear Power Plants
NRA	National Regulatory Authority

NTC	Net Transfer Capacity
OHL	Overhead Line
PMU	Phasor Measurement Unit
PRA	Preventive Remedial Actions
PST	Phase-Shifting Transformers
PV PPs	Photovoltaic Power Plants
RA	Remedial Actions
RGCE	Regional Group Central Europe
RMS	Root Main Square
RoCoF	Rate of Change of Frequency
ROSC	Regional Operational Security Coordination
RSC	Regional Security Coordinator
RTSN	Real-Time Snapshot
RTU	Remote Terminal Unit
SA	Synchronous Area
SAFA	Synchronous Area Framework Agreement
SAM	Synchronous Area Monitor
SCADA	Supervisory Control And Data Acquisition
SEE	South-East Europe
SOGL	System Operation Guideline
SPS	Special Protection Scheme
SS	Substation
SWE	South-West Europe
TPPs	Thermal power plants
TRM	Transmission Reliability Margins
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity
kV	Kilovolt(s)
WAMS	Wide Area Monitoring System
WPPs	Wind Power Plants

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Publisher

The Expert Panel on the separation of the Continental Europe Synchronous Area of 08 January 2021

info@entsoe.eu
info@acer.europa.eu

Design

DreiDreizehn GmbH, Berlin
www.313.de

Images

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Publishing date

15 July 2021