» Continental Europe Synchronous Area Separation on 24 July 2021

ICS Investigation Expert Panel » Final Report » 25 March 2022

Main Report

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CONTENTS

1 INTRODUCTION

Background

On Saturday, 24 July 2021 at 16:36 CET, the Continental Europe (CE) Synchronous Area was separated into two areas due to cascaded trips of several transmission network elements. Specifically, the Iberian Peninsula, comprising the systems operated by REE and REN, was separated from the rest of CE. Immediately after the incident occurred, European Transmission System Operators (TSOs) began to resolve the situation, resynchronising the Continental European power system at 17:09 CET.

Continental Europe System Separation Task Force

In the immediate aftermath of the system separation, European TSOs, in close collaboration with ENTSO-E, decided to start a joint process to collect all relevant facts regarding the incident. This process was launched through the coordination of an ENTSO-E Task Force with the clear mission to deliver these facts to national and European authorities and ENTSO-E members, as well as to any interested party, in a transparent and complete manner.

The Task Force, composed of the European TSOs, has been coordinating all relevant ENTSO-E bodies in analysing the event and is responsible for the development of the Technical Report and for overseeing the communication of facts to external stakeholders. This Final Report presents the results of the investigation carried out by the Task Force.

The investigation has classified the event according to the Incident Classification Scale (ICS)[1] Methodology as a Scale 2 event, being the most critical met criterion L2 – Incidents on Loads (see **Section 12**) and, therefore, a relevant investigation Expert Panel was set up, starting its work on 22 October 2021. The Task Force assisted with the development of the work within this Expert Panel and delivered a factual report on 12 November 2021 and the present final report published on 25 March 2022.

1 ENTSOE-E Incident Classification Scale (ICS) methodology of 4 December 2019

Structure of the final report

This final report is structured as follows:

- **Section 2** describes the environmental conditions before the incident, with a focus on the fire in the South of France.
- **Section 3** gives details on the CE power system conditions before the system separation, with a focus on South West Europe and the three mainly affected TSOs: RTE, REE and REN.
- **Section 4** analyses the dynamic behaviour of the system during the event, supported by preliminary dynamic simulation results.
- **Section 5** describes the performance of the protection system during the incident.
- **Section 6** addresses the frequency support activated during the event.
- **Section 7** provides an overview of the resynchronisation process.
- **Section 8** evaluates the N-1 security calculations performed by RTE.
- **Section 9** describes the communication of coordination centres/Synchronous Area Monitor (SAM) and between TSOs.
- **Section 10** analyses the coordination activities that were performed by Coreso, the Regional Security Coordinator (RSC).
- **Section 11** describes the TSO–DSO coordination and the frequency plan and load shedding.
- **Section 12** describes classification of the incident based on the ICS methodology.
- **Section 13** gives a detailed technical analysis of the incident, including dynamic simulation results.
- **Section 14** concludes the report by providing the derived recommendations.

Sources of data and information

The analysis presented in this final report is based on information sent by all CE TSOs and more detailed information from the most affected TSOs. An important source of information comprised recordings from Wide Area Monitoring Systems (WAMS), which have delivered, with their accurate and precise time stamping, valuable measurements for aligning all the events in the correct order. Another important source of information involved measurements from transient recorders and digital protection devices with precise GNSS time stamps.

2 ENVIRONMENTAL CONDITIONS BEFORE THE INCIDENT

This section analyses the environmental conditions in the South of France shortly before and at the time of the incident. The focus is on the fire that occurred on that day in the vicinity of the Spanish–French border.

2.1 Wildfire in the area of Moux

On 24 July 2021, at approximately 13:30, a severe fire broke out in the vicinity of the city of Moux, in the South of France. A massive mobilisation of firefighting services was activated, with more than 850 firefighters, one helicopter and nine firefighting planes. In total, 850 hectares of vegetation were consumed by flames during this two-day event; see Figure 1 through Figure 3.

At first, RTE was not informed about the fire. Based on bilateral exchanges between RTE and the fire department (SDIS: Service Départemental d'Incendie et de Secours) carried out after the event, the situation can be summarised as follows.

During the organisation of the firefighting efforts, the fire department became aware that two 400 kV Baixas–Gaudière lines were located in the fire area, as shown in Figure 4 and Figure 5. In such situations, a request to switch off these transmission lines to ease the intervention of planes and firefighters should have been submitted to RTE. However, in the present case, due to the intense situation, this communication did not occur. Lacking confirmation of the line outages, the fire services organised themselves to deal with the fire by keeping a safe distance from the lines (respecting their own safety rules for high voltage lines).

Requesting the outage of lines to allow an intervention is covered by an agreement between RTE and the French Fire Department. But on July 24, this information was not passed on. Investigations are ongoing between RTE and the French national fire department on how to improve these communications.

Further details are provided in **Section 14.2.2**, Recommendation 2: "Improving the assessment and handling of weather related risks".

Figure 1: Location of the fire on a large-scale map.

Figure 2 & 3: Picture taken during firefighting activities.

Information about the fire

Thus, as explained above, from the start of the fire to the first line trip, at 16:33, RTE was not aware of the fire. During this phase, the rules for the normal system state were applied.

At 16:57, ENEDIS, the Distribution System Operator (DSO) of the area informed RTE that one of its employees had *seen* a fire, with *huge quantities of smoke*, close to transmission system installations. Through complementary exchanges, the DSO specified at 17:06 that one cable of the line *could* have fallen to the ground. At 17:10, RTE called the Fire Department (SDIS 11), to collect all information regarding the fire and its exact location. This exchange of information allowed for the confirmation of the event as well as a better understanding of the situation. This information was provided after the grid separation, but it was used to analyse the grid conditions in the area, and to prepare restorative actions on the lines.

Environmental conditions and operating rules

As detailed in **Section 8**, "N-1 Security Evaluation", one criterion used in security assessment involves the environmental conditions in the vicinity of grid devices. On 24 July, the specific risk was not known and thus not considered.

As dictated by bilateral agreements between RTE and the French Fire Department, information on dangerous environmental conditions related to fires or natural hazards in the vicinity of electrical components shall be promptly communicated to RTE. For instance, on 11 August 2021, a fire was detected by the fire department (SDIS 11) in the area of Sallèles Cabardes and Villegly villages. The fire services realised the fire was in the vicinity of RTE's lines and, thus, at 14:16 they called RTE to inform them about the situation and the fire's particular location. This allowed RTE to prepare for the potential consequences, performing a new contingency analysis that considered the outage of any lines in the vicinity of the fire, and therefore assessed the best operating practice in the event of any loss of electrical components in the region. Therefore, at 14:38, when the fire department requested that RTE switch off the 400 kV Gaudière-Issel lines 1 and 2, RTE was able to react promptly. The fire was extinguished, and at 17:38, the 400 kV lines returned in operation. This illustrates the added value of providing proactive information on environmental conditions, to anticipate system operation conditions.

Following the 24 July event, RTE met with Fire Department SDIS 11 to discuss these elements, and to find a way to improve the communication chain to ensure that relevant information reaches the concerned entities, as recommended in **Section 14.2.2**, Recommendation 2: "Improving the assessment and handling of weather related risks".

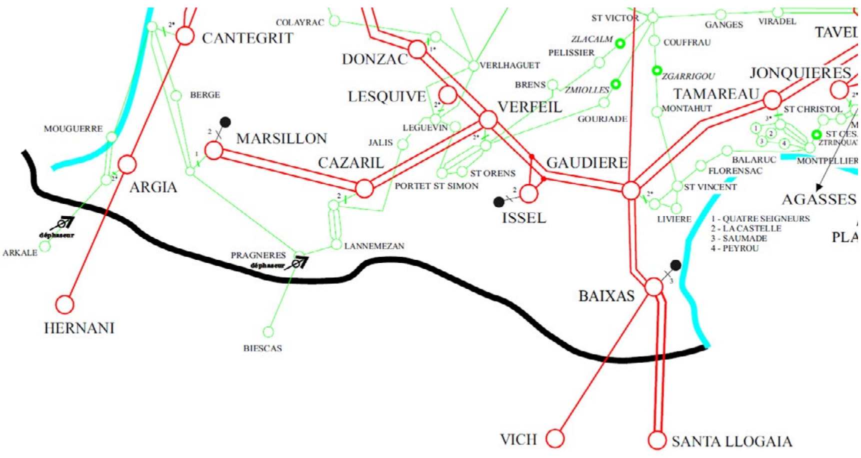


Figure 4: Grid map of the South of France (400 kV in Red; 225 kV in Green).

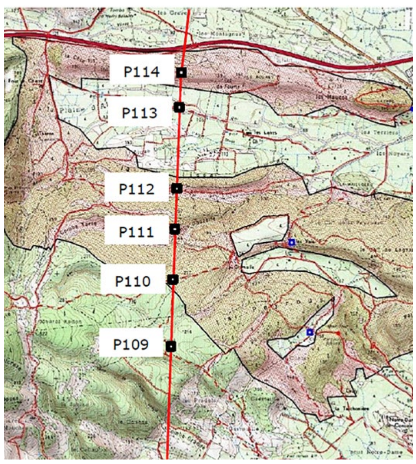


Figure 5: Fire area in Moux on 24 July and 400 kV Baixas-Gaudière line location (in red).

2.2 Statistics of wildfires in the area of Moux

From a global perspective, to assess the risk of wildfires, several elements have to be considered: the location, the size (expressed in surface burned in hectares (ha)), the time period, the origin (voluntary or involuntary) and the evolution over the years. For instance, the Emergency Response Coordination Centre gives European statistics, based on Copernicus data. Figure 6 shows an extract of Wildfires in Europe from January to August 2021.

The starting event of 24 July was a wildfire in Moux, in Aude department of France. This department is located in the South of France, and the following elements give a detailed description of wildfires in this area, allowing the associated risk to be assessed.

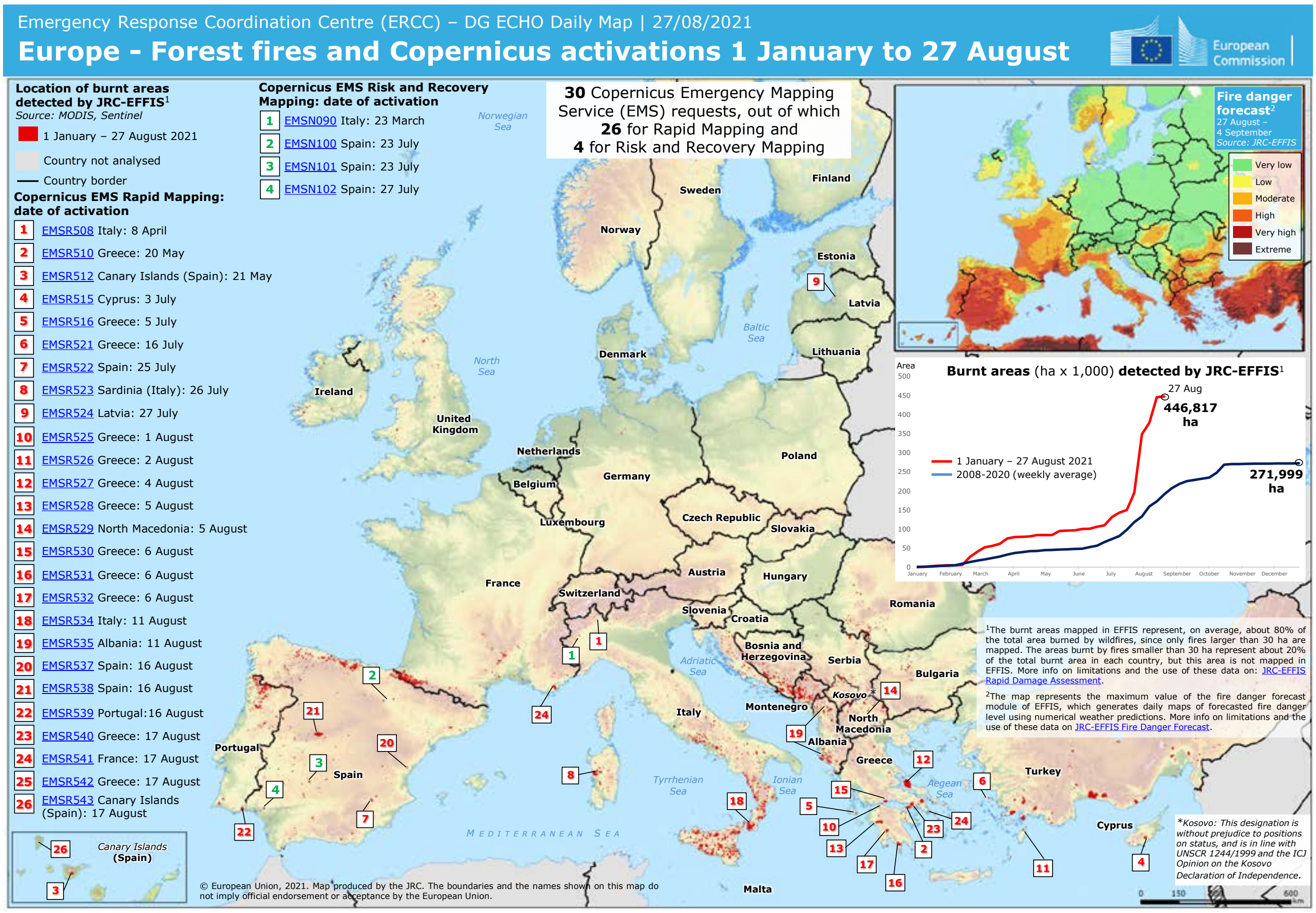


Figure 6: Wildfires in Europe from January to August 2021.

Wildfires of all sizes in Aude department

According to the PROMETHEE online system (official forest fires database for the Mediterranean area in France), around 140 wildfires of all size occurred each year (statistics from 2002 to 2021) in Aude department (where Moux is located). Figure 7 gives the annual occurrence of wildfires in Aude department since 2002, and Figure 8 gives the impact on the environment, through the total burned surface due to wildfires every year.

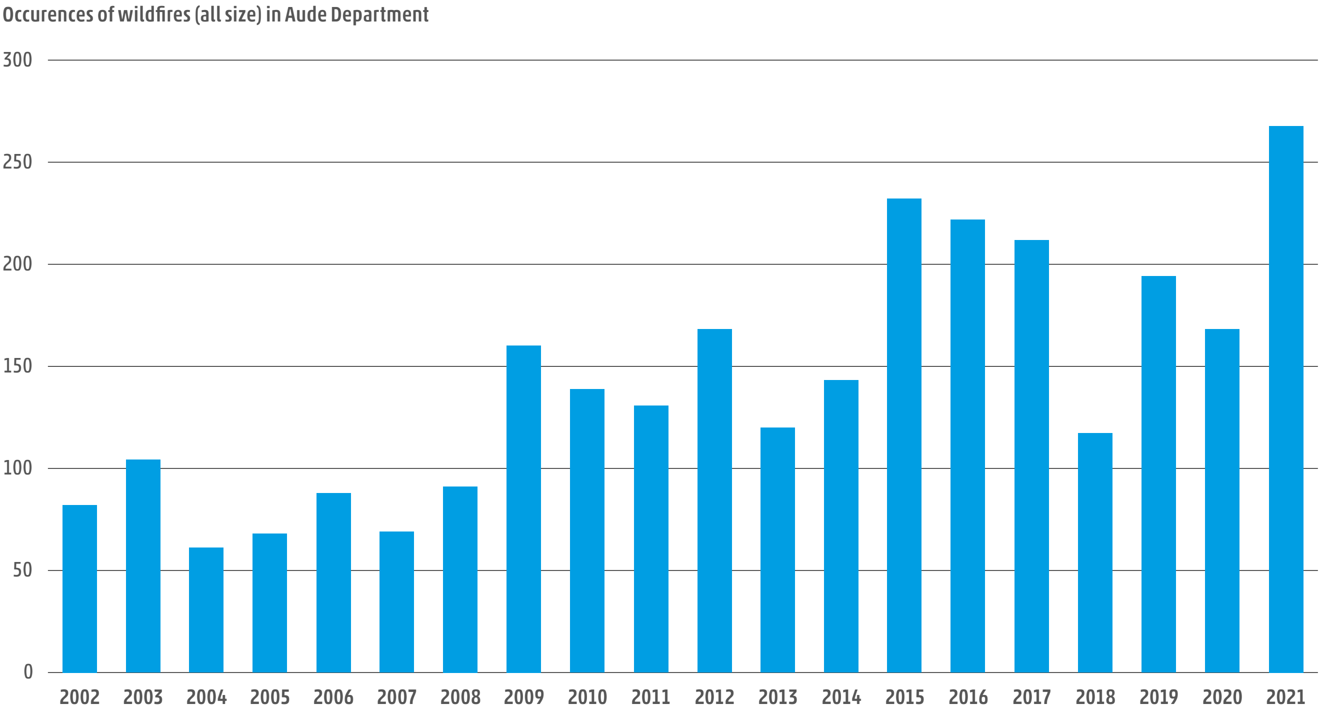


Figure 7: Occurrences of wildfires (all sizes) in Aude department since 2002.

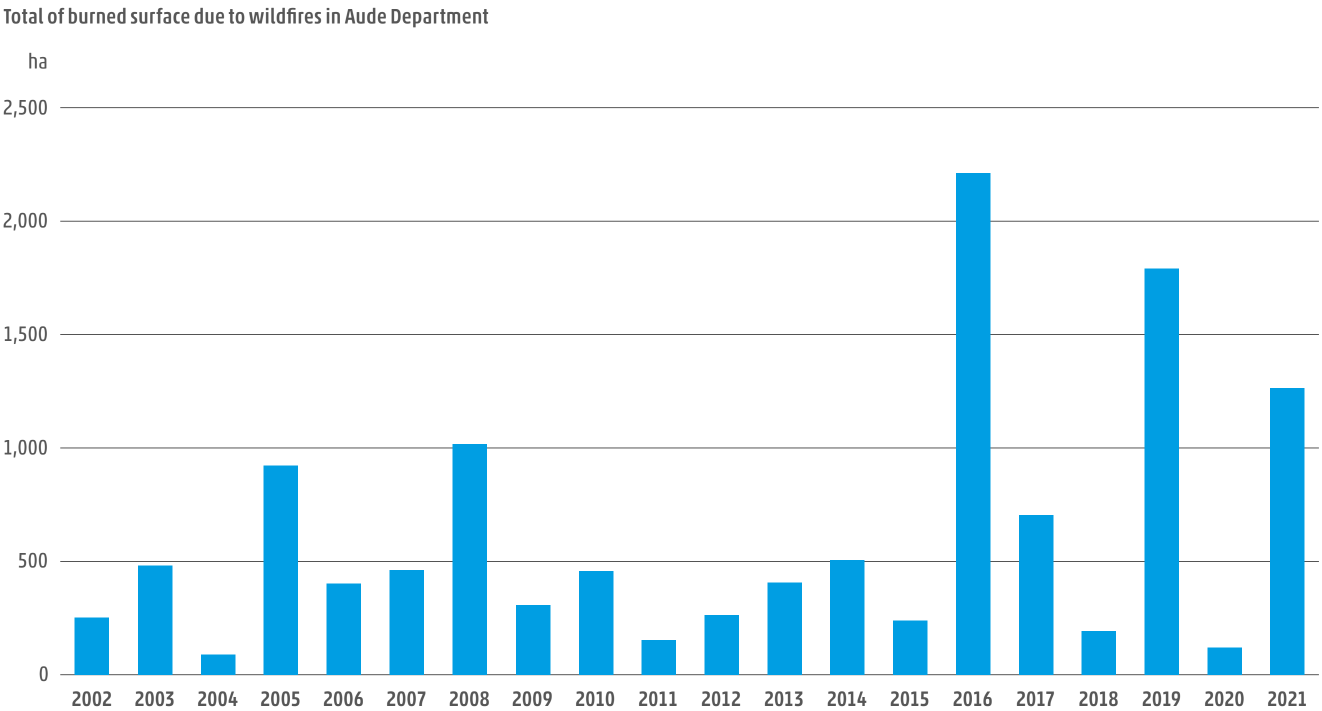


Figure 8: Total of burned surface due to wildfires in Aude department since 2002.

Important and huge wildfires in Aude department

These wildfires vary from a few square meters up to 1,100 ha.

For instance, over the past 20 years, 6 wildfires burned more than 500 ha of landscape, as detailed in Table 1.

Location	Day	Month	Year	Burned surface (ha)
Roquefort-des-Corbières	22	July	2005	670
Saint-André-de-Roquelongue	28	August	2008	812
Bizanet	14	July	2016	716
Padern	5	September	2016	789
Montirat	14	August	2019	1,103
Moux	24	July	2021	849

Table 1: Largest wildfires (>500 ha) in Aude department since 2002.

In 2019, a wildfire in Montirat burned 1,100 ha. In 2016, two wildfires in Padern and Bizanet burned 790 ha and 716 ha. These wildfires were far away from RTE's lines. On 24 July, the wildfire burned 850 ha.

To assess the risk on system operation, one should focus on wildfires with a given size. Thus, the rest of this investigation assesses wildfires with a size sufficient to burn more than 10 ha. On average, 5 to 6 wildfires of this size occurred annually over the twenty past years, as detailed in Figure 9.

Based on records of wildfires in the concerned area, we now focus on those in the close vicinity of grid elements, i.e. transmission corridors. The map in Figure 10 gives an overview of all wildfires (>10 ha) over the twenty past years, and the location of 400 kV lines (Issel–Gaudiere, Gaudiere–Baixas).

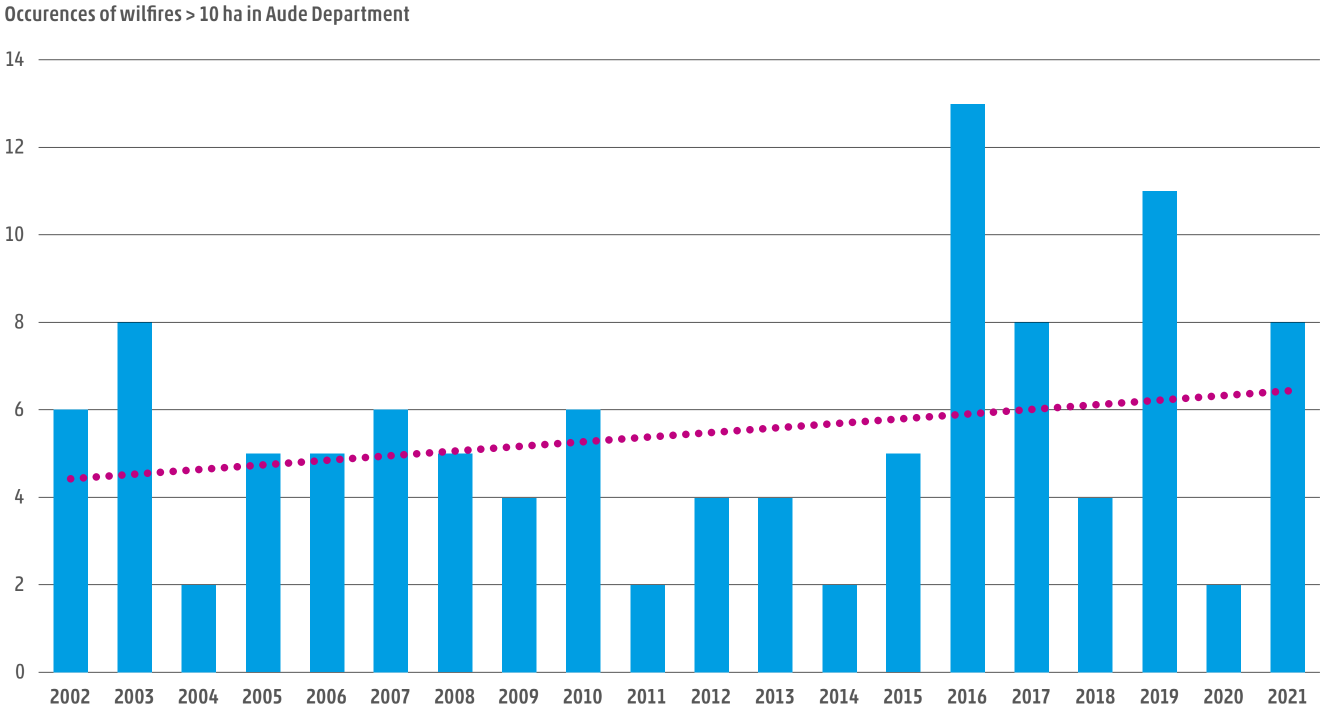


Figure 9: Occurrences of Wildfires > 10 ha in Aude Department since 2002.

Focusing on wildfires in the vicinity of the French–Spanish eastern corridor (Gaudiere–Baixas and Baixas–Vich), the events have been recorded as per Table 2 and Figure 11 and Figure 12

In conclusion, over the past twenty years, only four wildfires occurred in the vicinity of the France–Spain corridor.

Ref	Date	Location	Size (ha)
2014-5366	17/09/2014	Millas (66)	20
2008-4221	28/08/2008	Moux (11)	77,9
2019-6010	06/09/2019	Moux (11)	10,3
2021-4894	24/07/2021	Moux (11)	849

Table 2: Wildfires in the vicinity of RTE's line in the FR-ES corridor over the 20 past years.

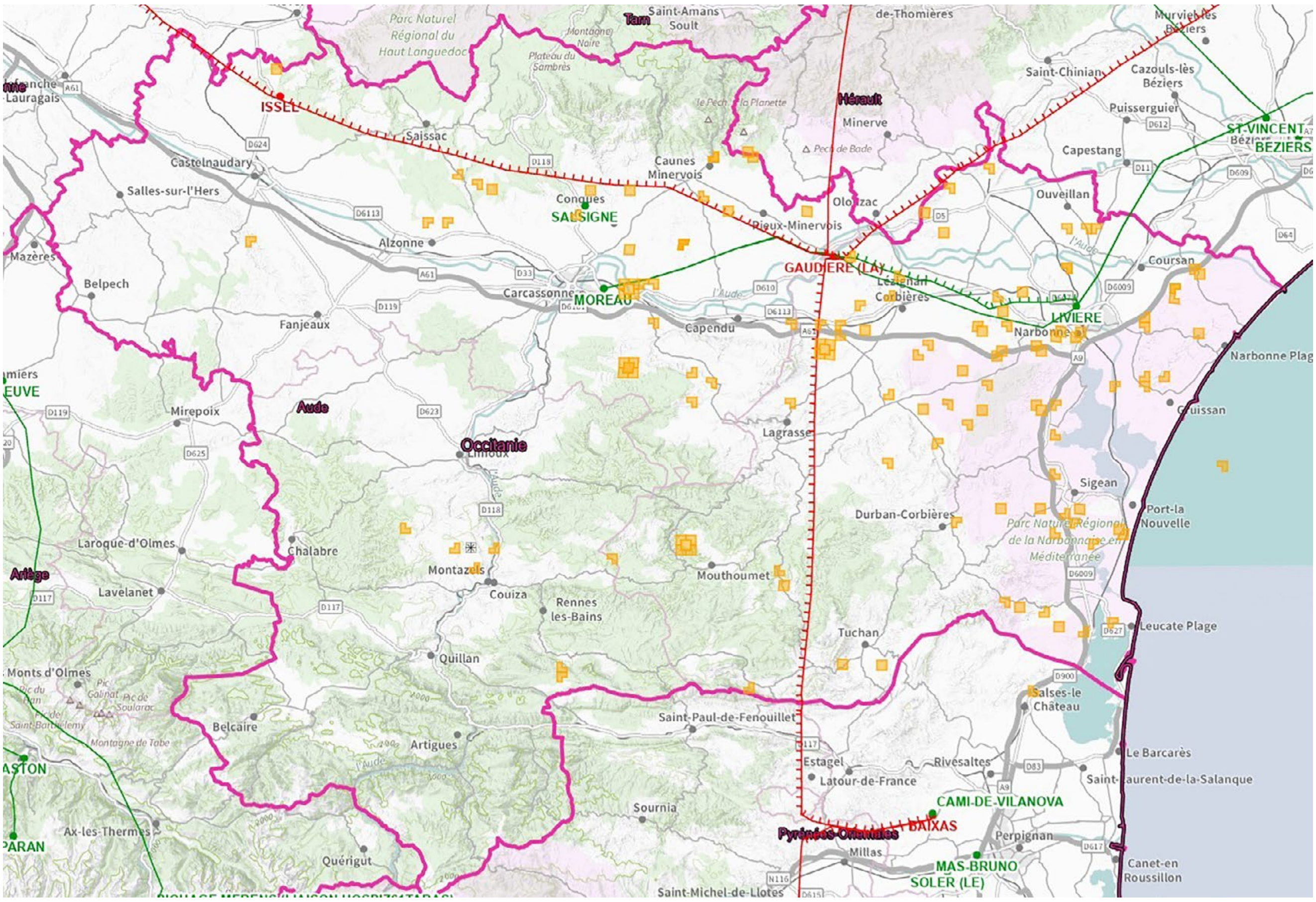


Figure 10: Overview of Wildfires > 10 ha in Aude Department over the past 20 years and 400 kV lines (in red).

Figure 11: Wildfire on 17 September 2014, close to the Gaudiere Baixas line, in Millas (Baixas area).

Figure 12: Wildfires on 06 September 2019 and 24 July 2021, close to the Gaudiere Baixas line, in Moux (Gaudière area).

3 SYSTEM CONDITIONS BEFORE THE INCIDENT

3.1 Forecast coordination activities by the regional security coordinator

The system split concerns a border of the South-West European (SWE) Capacity Calculation Region, where Coreso, located in Brussels, acts in the roles of the appointed Coordinated Capacity Calculator and RSC.

Both roles are executed based on the assumption that a system security threat can be predicted at an earlier stage based on internal grid models (IGMs) provided by the TSOs.

Independent of the RSC activity, TSOs are executing their own forecasts, which might slightly deviate from the forecast of the RSC due to the amount of information available and the refresh periods.

The following activities were executed by Coreso on the date of the incident with increasing timeliness of data (ascending order):

1. Outage planning coordination
2. Short-term adequacy assessment
3. Day-ahead capacity calculation
4. Day-ahead congestion forecast and intraday congestion forecast
5. Real-time snapshot calculations

Here it should be noted that the concepts of the above activities do not consider specific effects resulting from the dynamic behaviour of the electricity transmission system. Real-time snapshot calculation has been performed post event, whereas RSC tasks are performed only in the planning phase. Coreso did not and was not asked by the TSOs to intervene during the incident in real time.

Outage Planning Coordination (OPC)

For OPC, all continental TSOs provide their outage planning information for transmission assets, which is translated into a load flow model of the complete power European system. For this, weekly reference grid models are established by Coreso with the exchange levels of the representative day of the previous week. The grid situation based on the reference grid model is superimposed with the provided outage planning information.

Specifically, with a focus on the SWE capacity calculation region, a security analysis has been performed by Coreso, building on the following assumptions:

- export scenario FR → ES of 2,700 MW and PT → ES of 1,300 MW,
- contingency lists as provided by the TSOs.

If costly remedial actions were required to solve constraints, a coordination would be triggered between Coreso and TSOs to determine whether a cancellation of an outage would be necessary.

The OPC calculation for 24 July 2021 did not reveal any evidence of an outage planning security constraint resulting from an outage planning incompatibility that could not be relieved through the adjusted tap positions of phase shifter transformers.

Short-term Adequacy Assessment (STA)

The STA is executed on a daily cycle based on the generation availability data and transfer capacities available on the continental European level. The calculation for 24 July 2021 was executed on 23 July 2021.

Results of the adequacy calculations were obtained for 24 July 2021 via the STA tool and methodologies used for the STA process. No adequacy issue was detected.

3.2 System conditions in South West Europe

This section analyses the system conditions in South West Europe shortly before and at the time of the incident. The focus is on the market scheduled flows and on the measured cross-border (CB) physical flows between Portugal (PT), Spain (ES) and France (FR).

Calculated NTC values

The net transfer capacities (NTCs) on the borders result from capacity calculations performed on D-2 (two days ahead) by the RSC (CORESO for these countries); see Table 3 and **Section 10.1**. These calculations aim to cover different potential operating situations while ensuring compatibility with real-time operation of the grid. To determine commercial capacities that respect the system constraints, the capacity calculation process is based on the principles, rules and elements considered in the 'N-1 security evaluation', detailed in **Section 8** of this document. The commercial capacities are then offered to market parties, who use them to exchange energy between different areas. The market schedules resulting from these exchanges are thus compliant with operational security limits, whereas the emerging load flow values in real time might slightly differ (see next paragraph on physical cross-border flows). Table 3 shows the NTC for 24 July on the France–Spain border. Market scheduled exchanges (Table 6) were well within this range of values. NTC calculations are based on steady-state load flow calculations, which include known stability limits for specific cases.

Table 5 shows the NTC for 24 July on the Spain–Portugal border. Market scheduled exchanges (Table 4) were well within this range of values.

	16:00-17:00	17:00-18:00	18:00-19:00	19:00-20:00
FR → ES [MW]	2,682	2,682	2,682	2,775
ES → FR [MW]	2,590	2,590	2,590	3,098

Table 3: NTC on France-Spain Border on 24 July.

	16:00-17:00	17:00-18:00	18:00-19:00	19:00-20:00
PT → ES [MW]	3,150	3,150	3,150	3,600
PT → ES [MW]	4,905	4,905	4,905	4,590

Table 4: NTC on Spain-Portugal border on 24 July.

Market scheduled flows versus cross-border physical flows

The market schedules (see Table 5 and Table 6) reflect exchanges of energy between CE and the Iberian Peninsula, with important flows on the France → Spain Border. This reflects cheaper electricity in the Continental European area used to feed into the Iberian Area.

	16:00-17:00	17:00-18:00	18:00-19:00	19:00-20:00
FR → ES [MW]	2,682	1,200	631	1,345
ES → PT [MW]	1,713	1,448	1,236	1,157

Table 5: Day-Ahead Market Scheduled Exchanges for 24 July.

	16:00-17:00	17:00-18:00	18:00-19:00	19:00-20:00
FR → ES [MW]	2,537	1,778	209	1,745
ES → PT [MW]	1,468	928	748	783

Table 6: Intra-Day Market Scheduled Exchanges for 24 July.

Table 7 provides information to compare the market scheduled exchanges between Spain and France on the afternoon of 24 July with those on similar days. This shows that on 24 July, market scheduled exchanges between Spain and France were of the usual values.

	16:00-17:00	17:00-18:00	18:00-19:00	19:00-20:00
Saturday 17 July [MW]	3,000	3,237	2,547	2,490
Thursday 22 July [MW]	3,052	3,052	1,127	-530
Friday 23 July [MW]	2,914	713	-135	810
Saturday 24 July [MW]	2,537	1,778	209	1,745

Table 7: Comparison of Market Scheduled Exchanges on FR-ES Border during various days in July 2021.

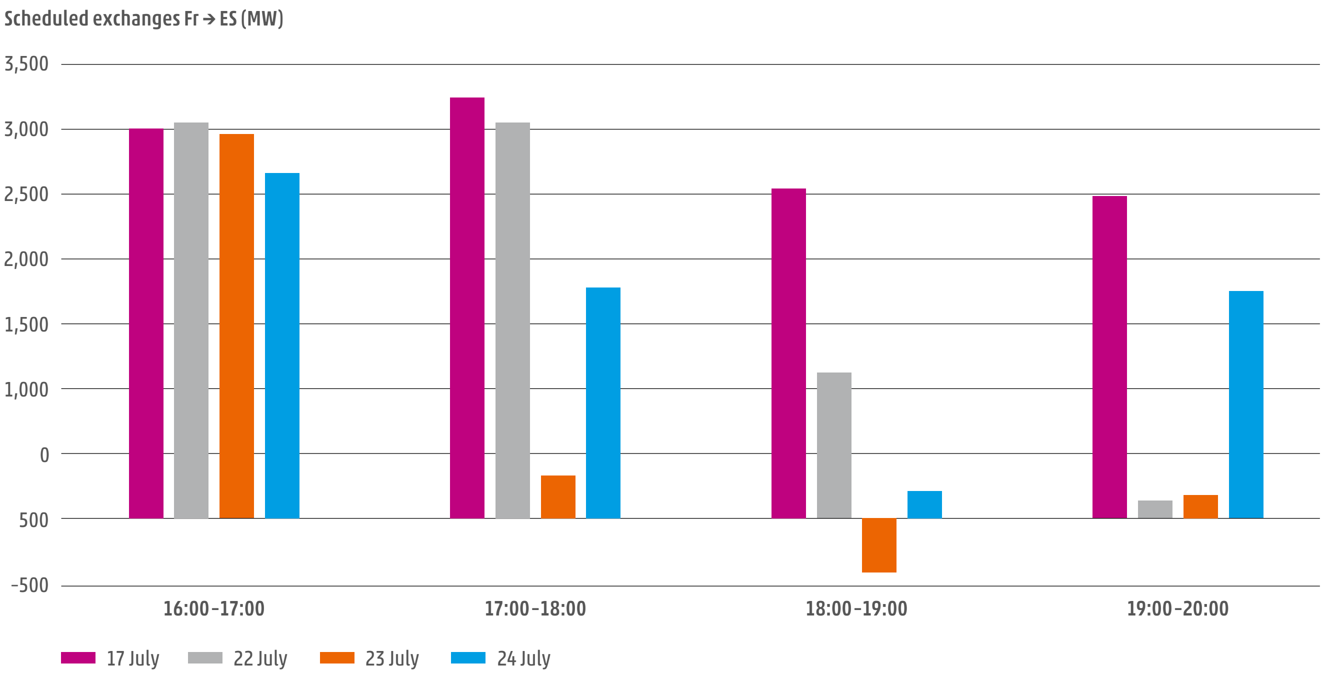


Figure 13: Comparison of Market Schedules on FR-ES Border on different days.

Physical CB flows at 16:30 on the FR–ES border

Physical flows are the result of real-time operations, without the IGCC (International Grid Control Cooperation, implementation project for imbalance netting process as defined by the guideline on electricity balancing (EB GL Article 22)) correction. At 16:30, physical CB exchanges between France and Spain reached 2,451 MW from France to Spain, carried on the different interconnection lines. This value is below the calculated NTC for the border (see Table 3) and fits the intra-day market scheduled exchange (Table 6). Figure 14 gives the details by lines.

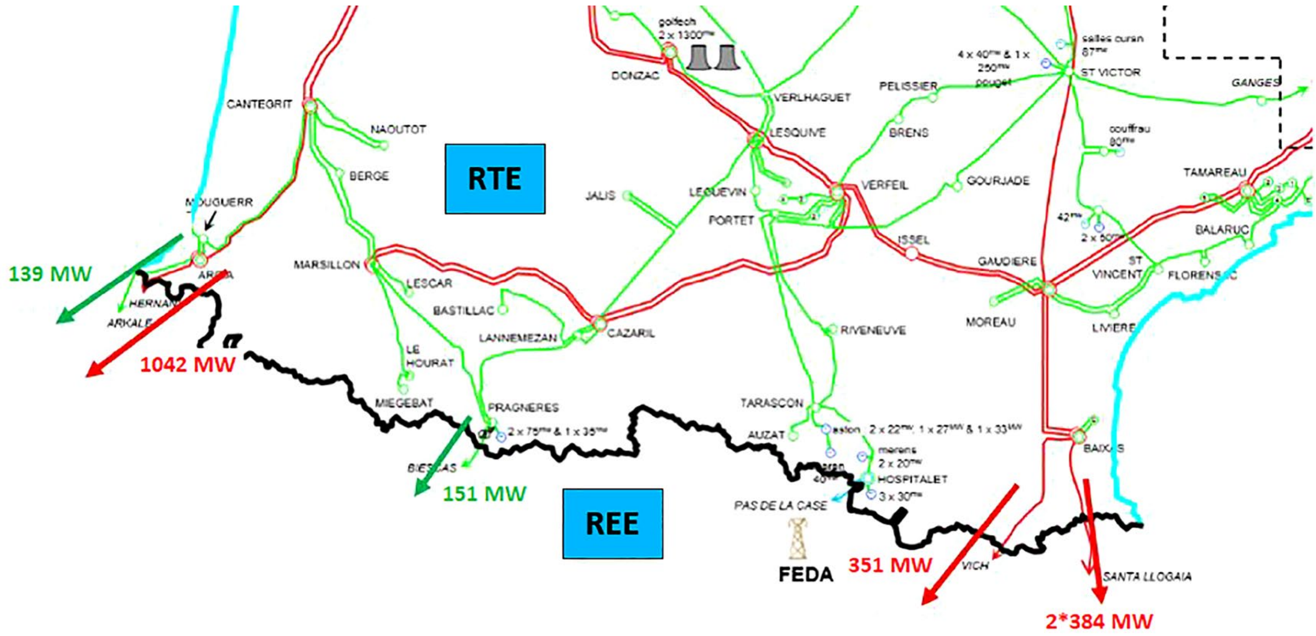


Figure 14: Simplified view (225 kV in green, 400 kV in red) of the southwest French transmission system and the exchanges with Spain before the event.

Physical CB flows at 16:30 on the ES–PT border

Physical CB flows are the result of real-time operations, without the IGCC correction. At 16:30, physical exchanges between Spain and Portugal reached 1,417 MW, carried on the different interconnection lines.

Overall system conditions in South West Europe

Table 8 presents the overall power exchanges in South West Europe.

	NTC	Day-Ahead Forecast	Intra-Day Forecast	Real-Time Snapshot
FR → ES [MW]	2,682	2,682	2,537	2,451
ES → PT [MW]	4,905	1,713	1,468	1,417

Table 8: Cross-border power flows in different in different timeframes (NTC, Day-Ahead, Intra-Day, Real-Time) on 24 July.

3.3 System conditions in France

Production of power plants and renewables

The realised production of power plants corresponds to the scheduled production in France. The scheduled and realised productions in the hour from 16:00–17:00, before the system separation, are shown in Table 9.

Type of Power Plant	Scheduled [MW]	Realised [MW]
Nuclear power plants (NPPs)	38,420	38,046
Other thermal power plants (TPPs)	1,360	1,600
Hydro power plants (HPPs)	5,740	6,396
Solar power plants (SPPs)	5,070	4,665
Wind power plants (WPPs)	1,890	3,306
SUM [MW]	52,480	54,013

Table 9: Scheduled and realised generation in France at 16:00–17:00 summarised by powerplant or fuel type.

Consumption

On the afternoon of 24 July, the forecasted load in France was the usual value for a summer Saturday afternoon. Before the event, the realised load was close to the forecasted one, as seen in Figure 15. At 16:35, the French load was 42,086 MW.

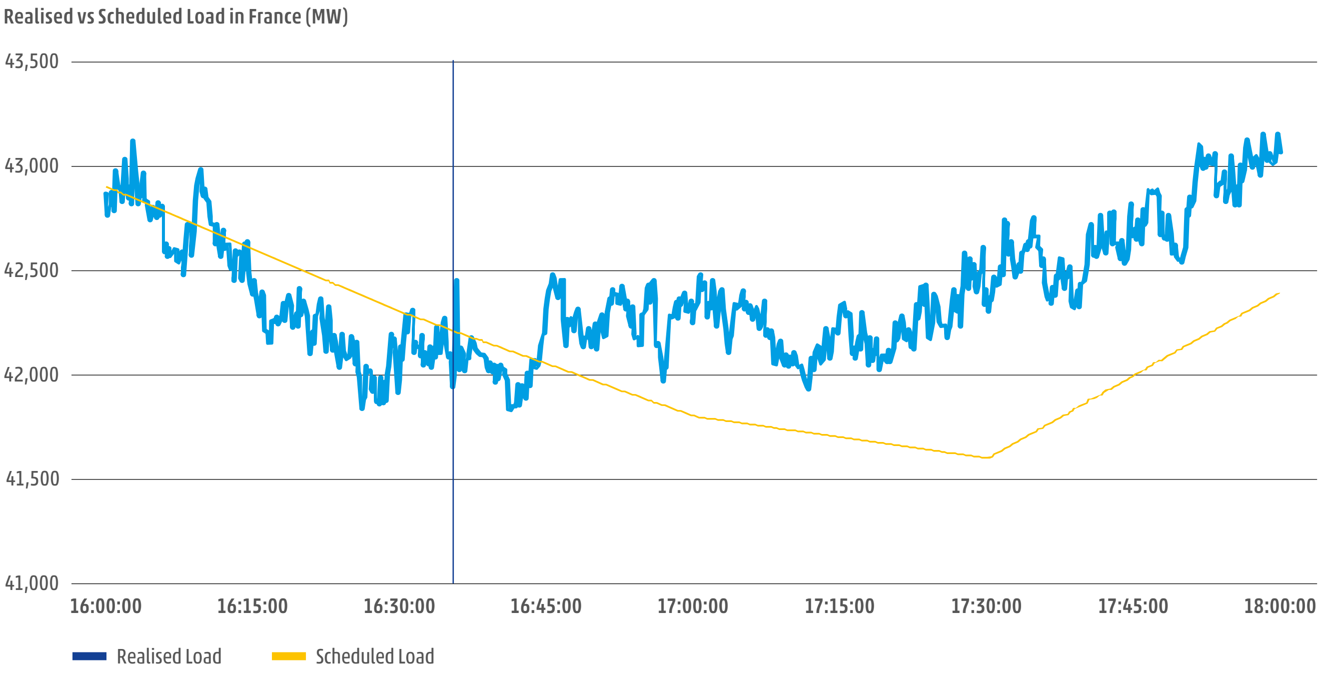


Figure 15: Comparison between realised and forecasted load in France.

Scheduled/planned outages of grid elements

All planned outages of transmission lines were considered during the planning phase for the day-ahead forecast. The following French transmission lines in the vicinity of the Spanish French border were in planned outage:

» Cazaril–Marsillon 400 kV n°2 and Cazaril–Verfeil 400 kV n°1 (France): this grid action was set up to mitigate high voltage phenomena. These topologies are typical and do not create any constraints.

Power flows on surrounding grid elements in different timeframes (day-ahead, intra-day, real-time)

Transmission line		DACF		IDCF		Realised real-time flow 16:30	
	PATL [A]	flow [A]	PATL [%]	flow [A]	PATL [%]	flow [A]	PATL [%]
Argia–Hernani 400 kV	2,050	1,482	72	1,633	80	1,424	69
Argia–Arkale 225 kV	1,076	400	37	472	44	308	29
Argia–Mouguerre 225 kV n°1	1,172	60	5	60	5	131	11
Argia–Mouguerre 225 kV n°2	1,172	55	5	67	6	145	12
Argia–Cantegrit 400 kV	2,050	1,732	84	1,326	65	1,534	75
Biescas–Pragnères 225 kV	786	452	57	452	57	336	43
Marsillon–Pragnères 225 kV	565	192	34	205	36	188	33
Lannemezan–Pragnères 225 kV	737	252	34	242	33	143	19
Baixas–Vich 400 kV	2,179	440	20	421	19	362	17
Baixas–Gaudière 400 kV n°1	4,380	1,060	24	949	22	793	18
Baixas–Gaudière 400 kV n°2	4,380	1,060	24	949	22	793	18

Table 10: Flow on French transmission lines in the vicinity of the Spanish–French border at 16:30.

Focus on the HVDC lines

Due to their conception, it is technically not possible to overload these lines. However, Table 11 provides flows for both Baixas–Santa Llogaia High Voltage Direct Current (HVDC) lines.

Transmission line	DACF [MW]	Realised real-time flow [MW] - 16:30	Maximum transmission [MW]
Baixas-Sant Llogaia 400 kV n°1 - HVDC	527	385	1,000
Baixas-Sant Llogaia 400 kV n°2 - HVDC	527	385	1,000

Table 11: Active power flow on HVDC lines on the Spanish-French border.

Focus on security analyses on the 400 kV Baixas–Gaudière line

As detailed in **Section 8** "N-1 security evaluation", continuous security analyses are performed on grid elements to ensure the respect of the N-1 principle. This computation is performed at different timeframes, from month-ahead up to real-time, whereby it is assessed every 15 minutes. Table 12 shows the results of this security analysis relative to the tripping of the 400 kV Baixas–Gaudière line, and the resulting flows in the remaining lines in respect of their permanent admissible transmission loading (PATL).

The simulation of a trip of one of the two 400 kV Baixas–Gaudière lines does not show any violations on the other lines.

Transmission line		DACF		IDCF		Snapshot 16:30	
	PATL [A]	flow [A]	PATL [%]	flow [A]	PATL [%]	flow [A]	PATL [%]
Argia-Hernani 400 kV	2,050	1,583	77	1,415	69	1,492	73
Argia-Arkale 225 kV	1,076	441	41	506	47	332	31
Argia-Mouguerre 225 kV n°1	1,172	75	6	67	6	142	11
Argia-Mouguerre 225 kV n°2	1,172	80	7	74	6	156	13
Argia-Cantegrit 400 kV	2,050	1,834	89	1,723	84	1,602	78
Biescas-Pragnères 225 kV	786	540	69	531	68	395	50
Marsillon-Pragnères 225 kV	565	221	39	231	41	208	37
Lannemezan-Pragnères 225 kV	737	310	42	294	40	182	25
Baixas-Vich 400 kV	2,179	396	18	384	18	326	15
Baixas-Gaudière 400 kV n°1	4,380	1,982	45	1,771	40	1,463	33
Baixas-Gaudière 400 kV n°2	4,380	fault	NA	fault	NA	fault	NA

Table 12: Results of the simulation of a trip of one of the two 400 kV Baixas-Gaudière lines.

Transmission line	Flow [MW]	Maximum transmission [MW]
Baixas-Sant Llogaia 400 kV n°1 - HVDC	365	1,000
Baixas-Sant Llogaia 400 kV n°2 - HVDC	365	1,000

Table 13: Impact of the trip of one of the two 400 kV Baixas-Gaudière lines on the HVDC lines.

3.4 System conditions in Spain

Production of power plants and renewables

The realised production of power plants corresponds to the scheduled production in Spain. The scheduled and realised productions in the hour from 16:00–17:00, before the system separation, are shown in Table 14.

Type of power plant	Scheduled [MWh]	Realised real-time flow [MW]
Hydro	1,683	1,638
Solar (FV)	10,138	10,356
Nuclear	6,919	6,957
Combined cycles	1,658	1,462
Wind	6,437	6,543
Coal	320	310
Thermal renewable	475	475
Distributed thermal non renewable	3,342	3,136
SUM	30,972	30,877

Table 14: Scheduled and realised generation in Spain at 16:00 – 17:00 and real-time flow at 16:33.

Consumption

On the afternoon of 24 July, the forecasted load in Spain was in the usual range of values for a summer Saturday afternoon. Before the event, the realised load was close to the forecasted value. At 16:33, the Spanish Load was 30,033 MW.

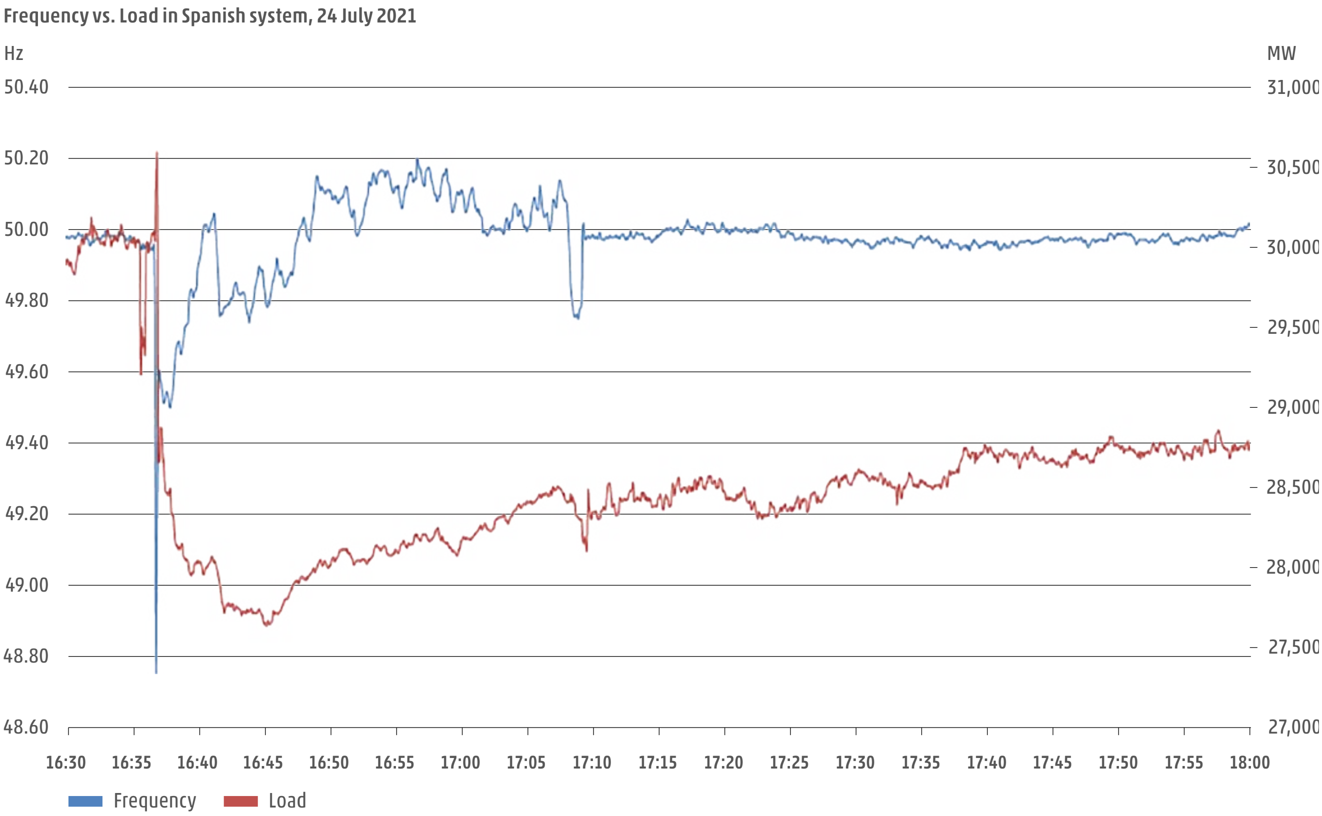


Figure 16: Comparison between realised load and frequency in Spain.

Scheduled/planned outages of grid elements

All outages of transmission lines were considered during the planning phase during day-ahead forecasting. There were no planned outages on Spanish transmission lines in the vicinity of the Spanish French border.

Power flows on grid elements in different timeframes (day-ahead, intraday, real-time)

Transmission line		DACF	DACF	Snapshot 16:25	Snapshot 16:25
	PATL [MVA]	flow [MVA]	PATL [%]	flow [MVA]	PATL [%]
AT9 VIC 400/220 kV	300	89.6	29	80.5	27
VIC-BESCANÓ 400 kV	2,030	99.1	5	61.0	3
VIC-PIEROLA	1,510	212.9	14	114.8	8
VIC-BAIXAS	1,510	410.3	26	316.3	21
AT10 VIC 400/220 kV	600	143.5	23	***	***
AT4 VIC 400/220 kV	600	94.1	15	133.4	22
AT1 VIC 400/220 kV	200	87.4	43	88.2	44
AT1 LLOGAIA 400/132 kV	315	146.0	46	134.3	42
LLOGAIA-BESCANÓ 400 kV	2,030	375.7	18	290.0	14
LLOGAIA-LA FARGA 400 kV	2,030	516.5	25	416.8	20
HVDC LLOGAIA-ECLLOGAIA 1	1,140	512.3	44	418.3	36
HVDC LLOGAIA-ECLLOGAIA 2	1,140	512.3	44	13.9	33
BIESCAS-SABIÑÁNIGO 220 kV	270	197.9	66	165.4	57
BIESCAS-PRAGNERES 220 kV	300	182.5	55	151.6	47
HERNANI-AZPEITIA 400 kV	1,030	406.8	36	403.5	39
HERNANI-ICHASO 400 kV	1,590	420.5	24	411.5	26
HERNANI-ARGIA 400 kV	1,420	1,071.6	75	1,063.8	74
AT5 HERNANI 400/220 kV	600	84.1	13	102.6	17
PST ARKALE 220 kV	550	175.9	28	140.6	24
ARKALE-ARGIA 220 kV	410	175.9	38	140.6	32

Table 15: Flow on Spanish transmission lines in the vicinity of the Spanish-French border at 16:30.

Transformer AT10 VIC 400/220 kV was disconnected in real time to reduce the power flow on the line L-220 kV VIC-SAN CELONI according to operational security limits.

In real time, a security analysis was done every five minutes, and no risk was detected in the contingency list defined by the Spanish security procedures.

From 16:00–17:00, the value of the scheduled interchange between France, Spain and Portugal was very similar to the value in the previous hour.

3.5 System conditions in Portugal

Production of power plants and renewables

The realised production of power plants corresponds to the scheduled production in Portugal. The scheduled and realised productions during the hour from 16:00–17:00, before the system separation, are shown in Table 16.

Type of Power Plant	Scheduled [MW]	Realised real-time flow [MW]
Hydro power plants (HPPs)	372	334
Thermal power plants (TPPs)	1,012	1,011
Wind power plants (WPPs)	1,384	1,588
Solar power plants (SPPs)	668	804
All other power plants	395	393
SUM	3,831	4,130

Table 16: Scheduled and realised generation in Portugal from 16:00-17:00 and real time flow at 16:33.

Consumption

The quarter-hourly forecast and realised consumption levels in Portugal, from 16:00 to 18:00, are shown in Table 17.

Consumption	Forecast [MW]	Actual [MW]
16:00-16:15	5,230	5,175
16:15-16:30	5,230	5,145
16:30-16:45	5,154	4,511
16:45-17:00	5,154	4,088
17:00-17:15	5,122	4,233
17:15-17:30	5,122	4,331
17:30-17:45	5,166	4,522
17:45-18:00	5,166	4,654

Table 17: Comparison between forecasted and realised consumption in Portugal.

Power flows on grid elements in different timeframes (day-ahead, intraday, real-time)

Transmission line		DACF		IDCF		Snapshot 16:30	
	PATL [A]	flow [A]	PATL [%]	flow [A]	PATL [%]	flow [A]	PATL [%]
Alto Lindoso-Cartelle 1,400 kV	2,132	210	10	223	10	179	8
Alto Lindoso-Cartelle 2,400 kV	2,132	211	10	224	10	179	8
Lagoaça-Aldeadavila 400 kV	2,120	465	22	485	23	311	15
Pocinho-Aldeadavila 1,220 kV	981	177	18	183	19	118	12
Pocinho-Aldeadavila 2,220 kV	981	180	18	185	19	119	12
Pocinho-Saucelle 220 kV	945	163	17	168	18	112	12
Falagueira-Cedillo 400 kV	2,000	352	18	389	19	454	23
Alqueva-Brovales 400 kV	1,848	346	19	359	19	535	29
Tavira-Puebla de Guzmán 400 kV	2,000	302	15	311	16	410	21

Table 18: Flow on Portuguese transmission lines in the vicinity of the Spanish-Portuguese border at 16:30.

4 DYNAMIC BEHAVIOUR OF THE SYSTEM DURING THE INCIDENT

This section gives an overview of the dynamic behaviour of the system during the event, by referring to the timeline of the various events, analysing the main dynamic stability criteria, and providing some details on the activated defence equipment.

The section is structured as follows:

- **Section 4.1** gives the timeline of the sequence of the events that led to the system split.
- **Section 4.2** analyses the dynamic stability margin of the system during the event.
- **Section 4.3** analyses the system from the voltage stability perspective, focusing on the risk of facing a voltage collapse.
- **Section 4.4** focuses on the HVDC link at the border between Spain and France, which led to keeping a small part of France connected to Spain during the event.

Finally, to give an exhaustive Figure on the overall energy balance, **Section 4.5** and **Section 4.6** provide an overview of the intentional and unintentional disconnections across the system. In particular, **Section 4.5** deals with the activated automatic defence plans, in terms of frequency support and low frequency demand disconnections (which are thoroughly discussed in **Section 6**). In addition, **Section 4.6** deals with the unintentional loss of generation units and loads (which is thoroughly discussed in **Section 11**).

4.1 Sequence of events

The sequence of events was reconstructed thanks to WAMS[1] that gather data from Phasor Measurement Units (PMUs)[2], measurement devices equipped with precise time information and based on protection device recordings that usually provide GNSS synchronisation (when available). The sequence of events is described in Table 19 and Figure 17.

No	TSO	Delta [s]	Trip time	Substation 1	Substation 2	Voltage [kV]	Comments
1	RTE	0	16:33:12.0	Baixas (FR)	Gaudière (FR)	400	Two phase fault. Circuit 2. Differential protection
2	RTE	131.8	16:35:23.8	Baixas (FR)	Gaudière (FR)	400	Two phase fault. Circuit 1. Differential protection
3	RTE	205.0	16:36:37.0	Argia (FR)	Cantegrit (FR)	400	Overload protection 60 s
4	REE	206.9	16:36:38.9	Biescas (ES)	Pragneres (FR)	220	Distance protection zone 2 out-of-step condition
5	REE	207.2	16:36:39.2	Puerto de la Cruz (ES)	Beni Harchen (MA)	400	Underfrequency protection on Moroccan end that sent a direct transfer trip to Spanish end
6	REE	207.5	16:36:39.5	Puerto de la Cruz (ES)	Melloussa (MA)	400	Underfrequency protection on Moroccan end that sent a direct transfer trip to Spanish end
7	RTE/REE	208.4	16:36:40.4	Argia (FR)	Arkale (ES)	220	Out-of-step protection (simultaneous on both sides)
8	RTE	209.3	16:36:41.3	Argia (FR)	Hernani (ES)	400	Out-of-step protection

Table 19: Sequence of events.

1 Wide Area Monitoring Systems: a system that acquires real-time data from PMUs with wide location displacement and high level of time resolution.

2 Phasor Measurement Unit (PMU): a measurement device that estimates and phase aligns phasors located in different locations of an electrical grid thanks to precise time synchronization (usually based on the GNSS) and reports these measurements at high rates (usually reporting time between 20 and 100 ms depending on TSO settings).

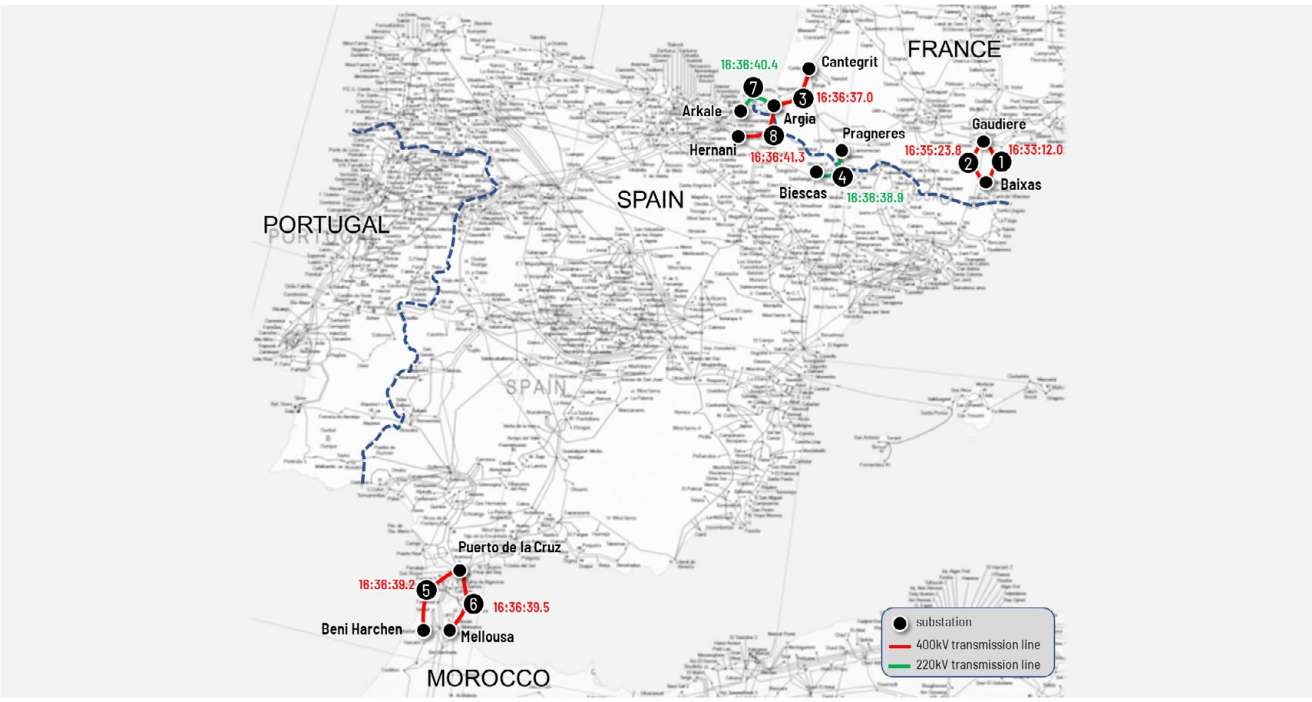


Figure 17: Geographical location of main tripped transmission system elements.

The first trip occurred at 16:33:12, when a two-phase fault happened on circuit 2 of the 400 kV line Baixas-Gaudière and the dedicated distance protection was activated. This trip is hereafter called Event #1, as also detailed in Table 19 and Figure 17.

The second trip occurred a few minutes after, at 16:35:23.8, due to a two-phase fault on circuit 1 of the 400 kV line Baixas-Gaudière that was cleared by the dedicated distance protection system (Event #2).

Before the tripping, the two circuits were transporting 612 MW each from France to Spain. Due to the separation of substation Baixas from the rest of the French grid, these two trips resulted in the loss of the eastern corridor between Spain and France. The Baixas substation remained supplied from Spain.

The loss of the eastern corridor caused the western and central corridors to become overloaded. As a consequence, 73 seconds after the second circuit tripping, also the line the 400 kV Argia–Cantegrit was overloaded and tripped due to overload protection activation at 16:36:37 (Event #3). This third tripping caused the loss of synchronism between the French and Spanish grids, which subsequently led to the separation into two systems.

The tripping of the 220 kV Biescas–Pragneres line (Event #4) was caused by the distance protection (zone 2) under out-of-step conditions. The tripping of the Morocco–Spain tie-lines was caused by the automatic action of an underfrequency protection on the Moroccan side (events #5 and #6). The Spanish side was also disconnected due to the reception of a transfer tripping from the Moroccan side. The remaining tie-lines between France and Spain tripped shortly afterwards due to their out-of-step protection systems (events #7 and #8).

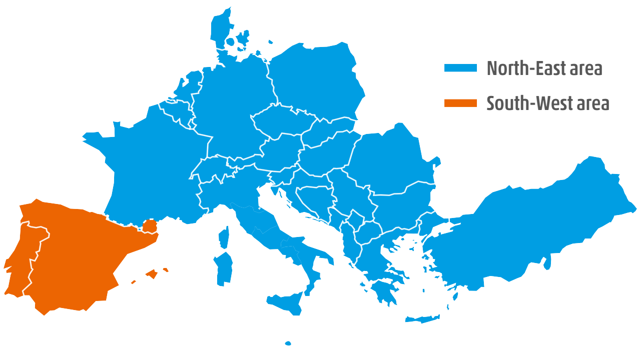


Figure 18: Resulting two synchronous areas after the system split.

It should be noted that this sequence of events reflects only the tripping of transmission lines in the high and extra high voltage transmission system. In addition, on the French side, ten 63 kV lines tripped during the event, due to distance and loss of synchronism protections. Some of these trips indicate that a few RTE substations were connected to the Spanish system. The resulting two synchronous areas are shown in Figure 18.

It should be further noted that after the first line tripped, at 16:34 RTE and REE jointly decided to reduce by 1.3 GW the power flows from France to Spain (further details in **Section 9.1**).

4.2 Dynamic stability margin

The PMU recordings included in Figure 19 show how the separation occurred.

- After the tripping of the 400 kV Baixas–Gaudière 2 line (Event #1) at 16:33:12.0, the frequency, voltage and load of the transmission elements remained within normal values, as is expected after an N-1. However, after this event the N-1 criterion was no longer fulfilled, which is why REE and RTE agreed to reduce the exchange between France and Spain from 2,500 MW to 1,200 MW at 16:34. However, the next two trips (events #2 and #3) occurred before this reduction became effective.

- After the tripping of the 400 kV Baixas–Gaudière 1 line (Event #2) at 16:35:23.8, the remaining interconnection corridors between France and Spain became overloaded and the voltage phase angle between France and Spain increased to values close to the stability margin of 90 degrees. Low voltages were observed in the substations close to the border. To mitigate these low voltages, 12 coils reactors were disconnected in Spain, two of them automatically. In France, six capacitors were connected, five of them automatically, and two coil reactors were disconnected manually. The system was in a critical state, with high angle differences between the peninsular busbars and the rest of Europe and also with low voltages in the area close to the interconnection between Spain and France. Despite this critical situation, the system remained sTable for over one minute until the following event occurred.

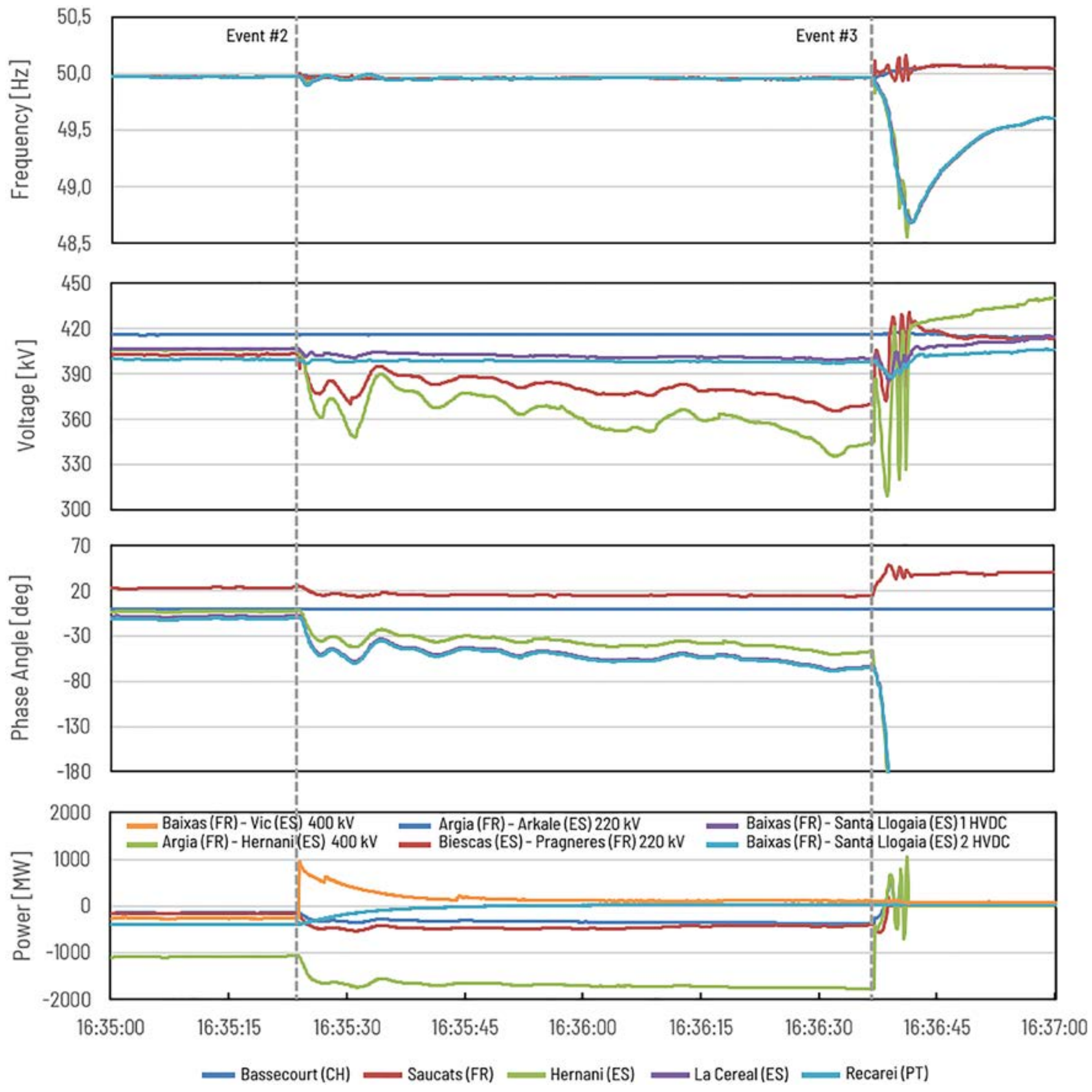


Figure 19: Frequencies, voltages, voltage phase angle difference and active power of France-Spain tie lines as measured by PMUs (reference for voltage phase angle difference is Bassecourt (CH) substations.

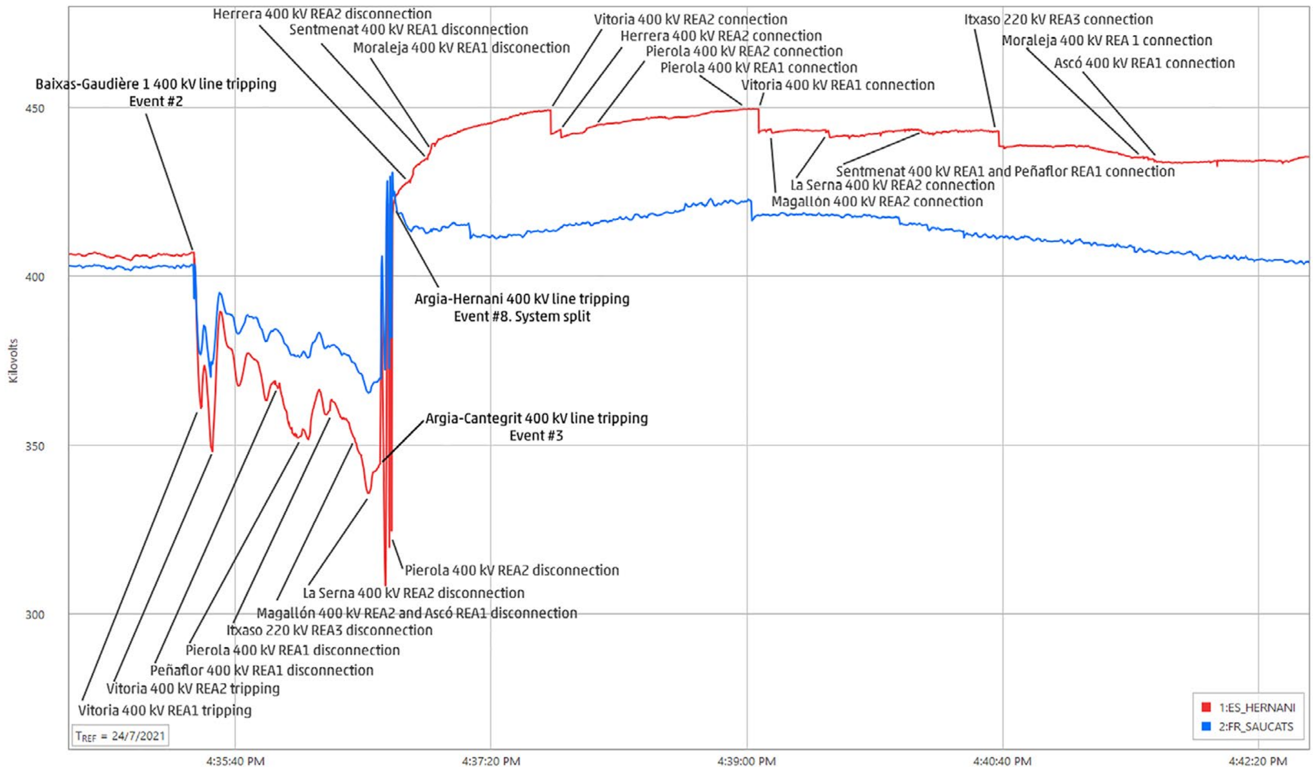


Figure 20: Voltages and coil reactors connected and disconnected in Spain.

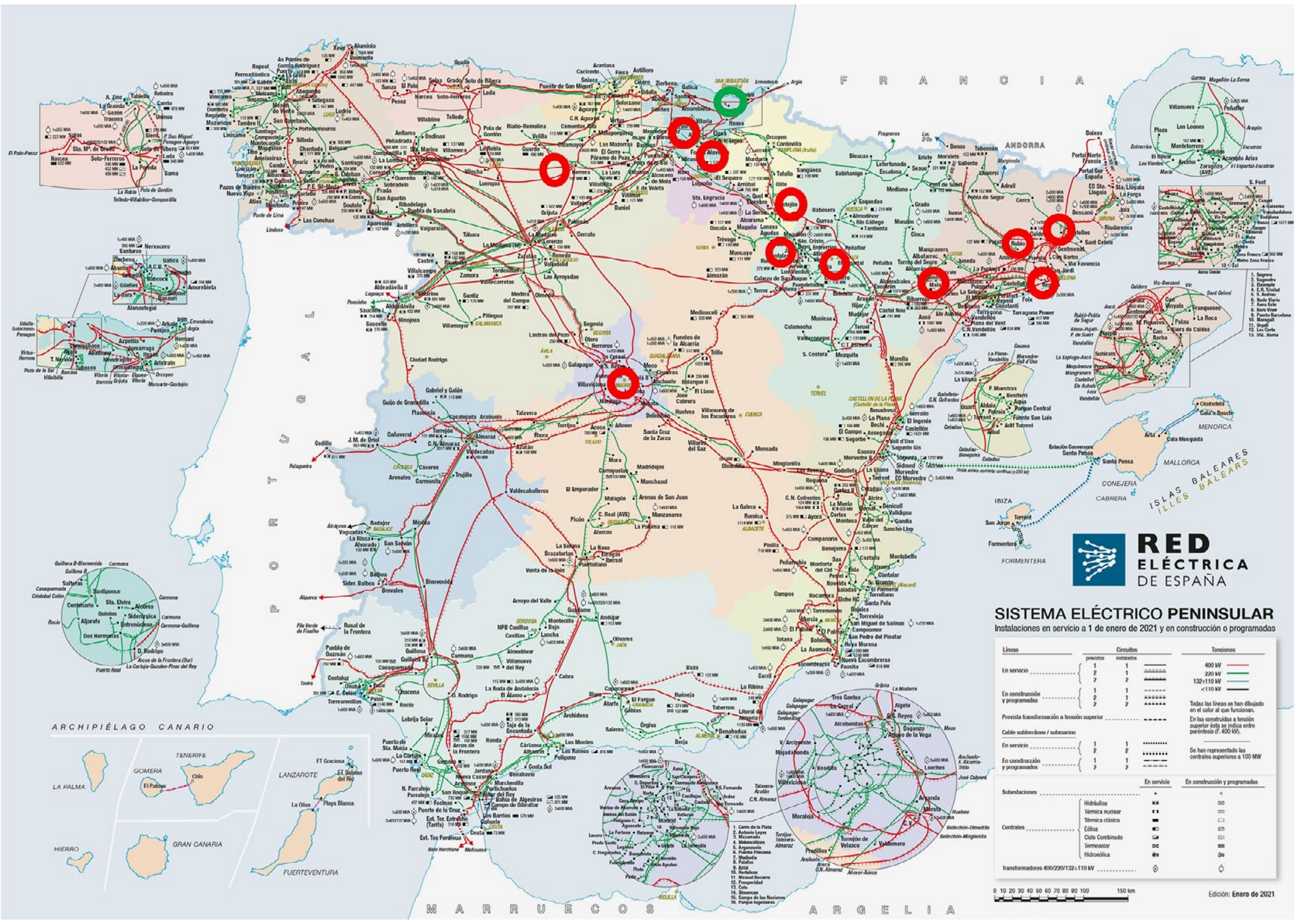


Figure 21: Geographic location of the coil reactors connected and disconnected in Spain.

» Before the exchange reduction previously agreed to by Spain and France became effective, the 400 kV Argia-Cantegrit line tripped (Event #3) at 16:36:37.0 due to the automatic action of the overload protection implemented for this line. This tripping caused the loss of synchronism between France and the Iberian Peninsula. After the loss of synchronism, the only possible defence action was to split the system at the locations where it had been planned. Indeed, RTE and REE have installed loss of synchronism protections at both ends of each interconnection line between the countries as system defence protections.

In Figure 22, the voltage magnitude as recorded by a PMU in Hernani with respect to the angle difference of Spain against the centre of Europe is displayed. It can be assumed that the angle difference δ is proportional to the active power flow P between Spain and France, with the approximated relationship $P = (V^2 \div X) \times \sin(\delta)$, where V is the voltage phasor magnitude and X is the impedance of the corridor. Between Event #2 and #3 we, the classical "nose curve" can be clearly recognizeseen in the dotted red line (interpolant) the classical 'nose curve'), indicating a voltage collapse phenomenon caused by the high power flow increase on the physical section.

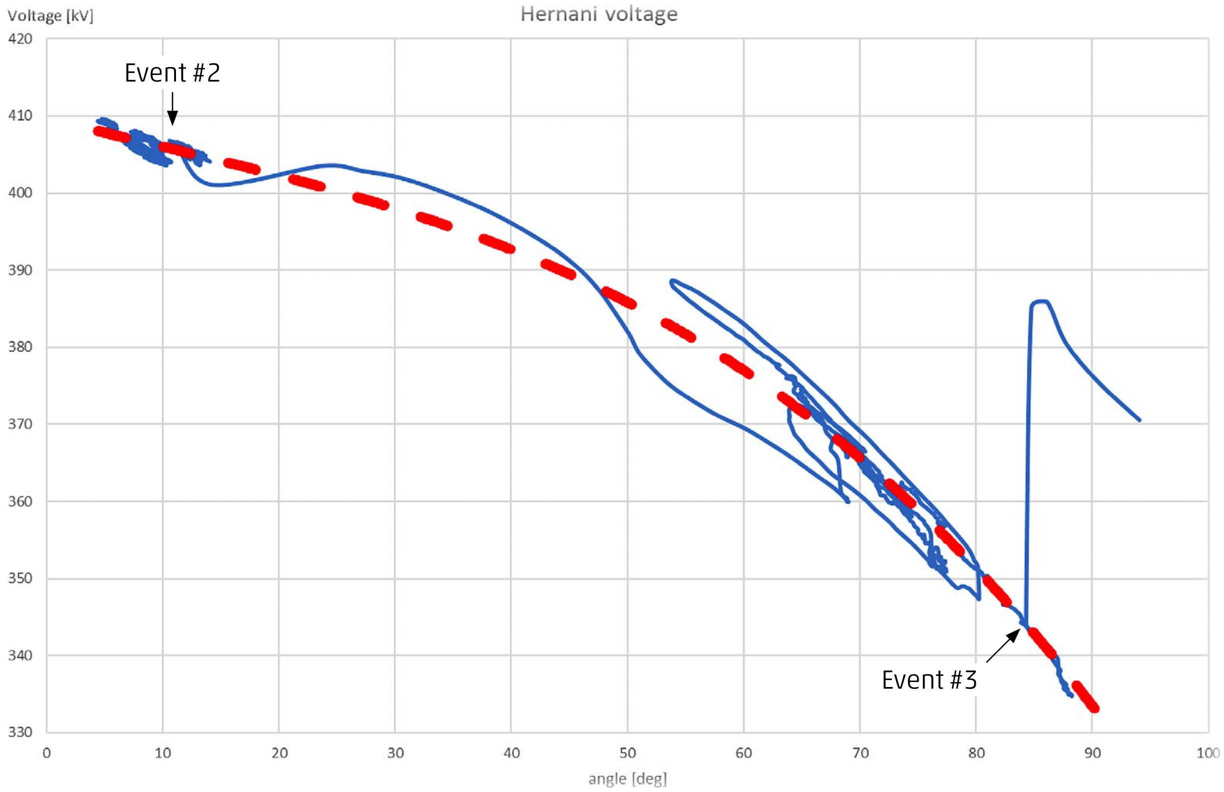


Figure 22: Voltage magnitude versus phase angle difference in Hernani substation – PMU recording (phase angle referred to Bassecourt (CH)).

Due to the loss of synchronism, which occurred after the trip of the 400 kV Argia–Cantegrit line (Event #3), the frequency in the Iberian Peninsula started to drop, even before the three remaining interconnection lines between Spain and France had tripped. The frequency in the rest of the Continental European power system increased slightly. The frequency values measured by PMUs in the middle of the Iberian Peninsula (La Cereal) and in the west of France (Saucats) are shown in Figure 23.

This frequency difference between the Iberian Peninsula and the rest of the Continental European power system caused a voltage angle difference shift that increased in speed as the frequency difference increased. The voltage angle difference shift induced an active and reactive power and voltage oscillation between the two zones until the system split at 16:36:41.3 (Event #8). The active power oscillations are shown in Figure 24.

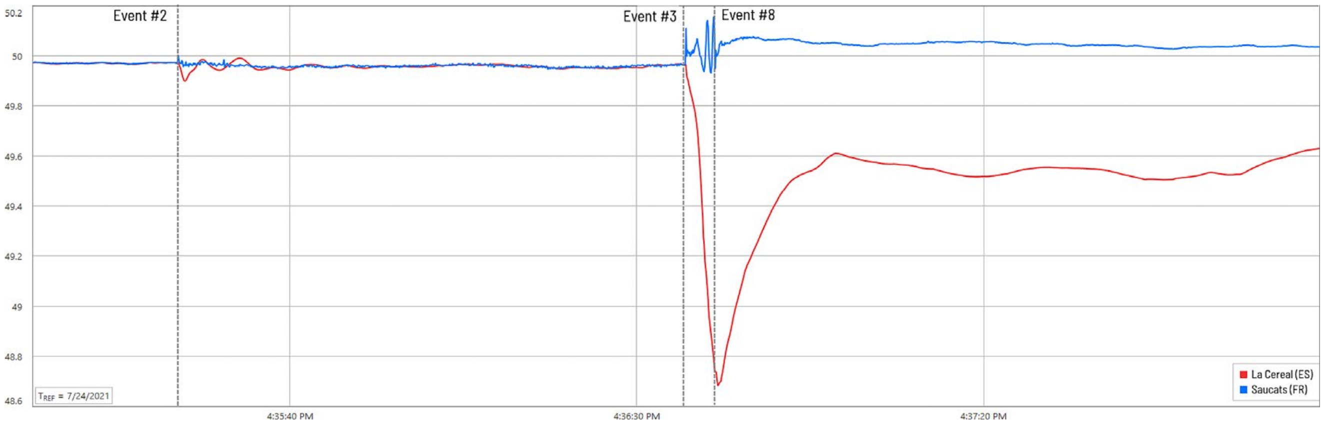


Figure 23: Frequency in Spain (La Cereal) and France (Saucats) as measured by PMUs.

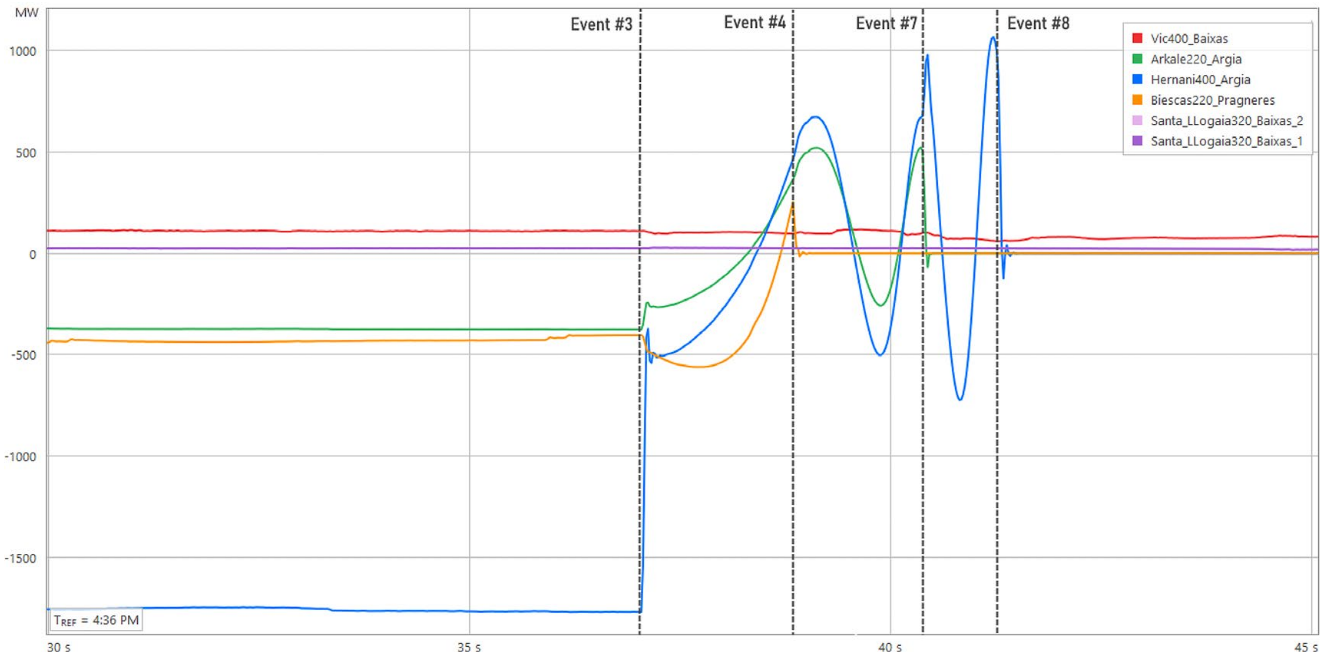


Figure 24: Active power of France–Spain tie lines as measured by PMUs (positive indicates power transfer from Spain to France).

The nadir frequency measured in the middle of the Iberian Peninsula was 48.681 Hz, the nadir being the lowest value of the frequency after a disturbance.

Figure 25 shows the rate of change of frequency (ROCOF) measured in several substations on the Iberian Peninsula. The ROCOF value has been calculated as the incremental ratio between two frequency measurements every 500 ms, divided by 500 ms: f(t) – f(t-500 ms) / 500 ms. This calculation was performed every 100 ms. It should be noted that the recommended standard ROCOF estimation is based on the determination of frequency gradient by applying a sliding window of 500 ms over a set of several consecutive measurement points.

As per SPD recommendations (ENTSO-E System Protection and Dynamics subgroup), the ROCOF was calculated in several locations sufficiently far from the affected lines in order to avoid phase jump distortions. Furthermore, ROCOF was also calculated in Hernani, which is close to the tripped lines. The higher ROCOF was measured close to the France–Spain border due to the oscillations created locally by transients. In the Hernani substation, the local maximum ROCOF measured was −1.03 Hz/s. In the southwestern part of the Iberian Peninsula (Carmona (ES), Sines (PT) and Alqueva (PT)) the local ROCOF was around −0.7 Hz/s and in the middle (La Cereal), which is the approximate centre of inertia, the global ROCOF was around −0.5 and −0.6 Hz/s.

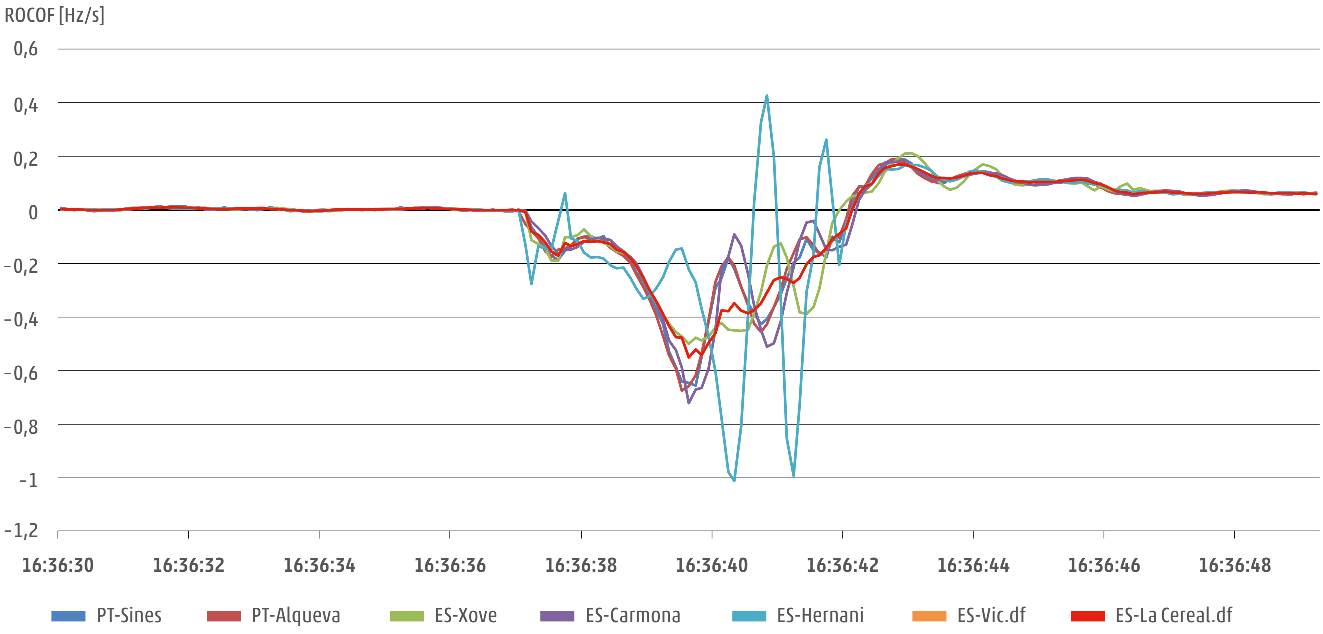


Figure 25: ROCOF measured in several substations on the Iberian Peninsula.

Figure 26 shows in the phase plan (phasor angle difference versus frequency) the overpassing of the so-called "no return border" (disconnection of the Argia–Cantegrit line) that precedes the complete separation between the Iberian and French grids. The green arrow represents the direction and the "no return border" coincides with Event #3. Here, the phase angle difference was chosen between two substations from each area corresponding to their centre of inertia and, consequently, the illustrated voltage phase angle difference is representative for the transients before, during and after the system split.

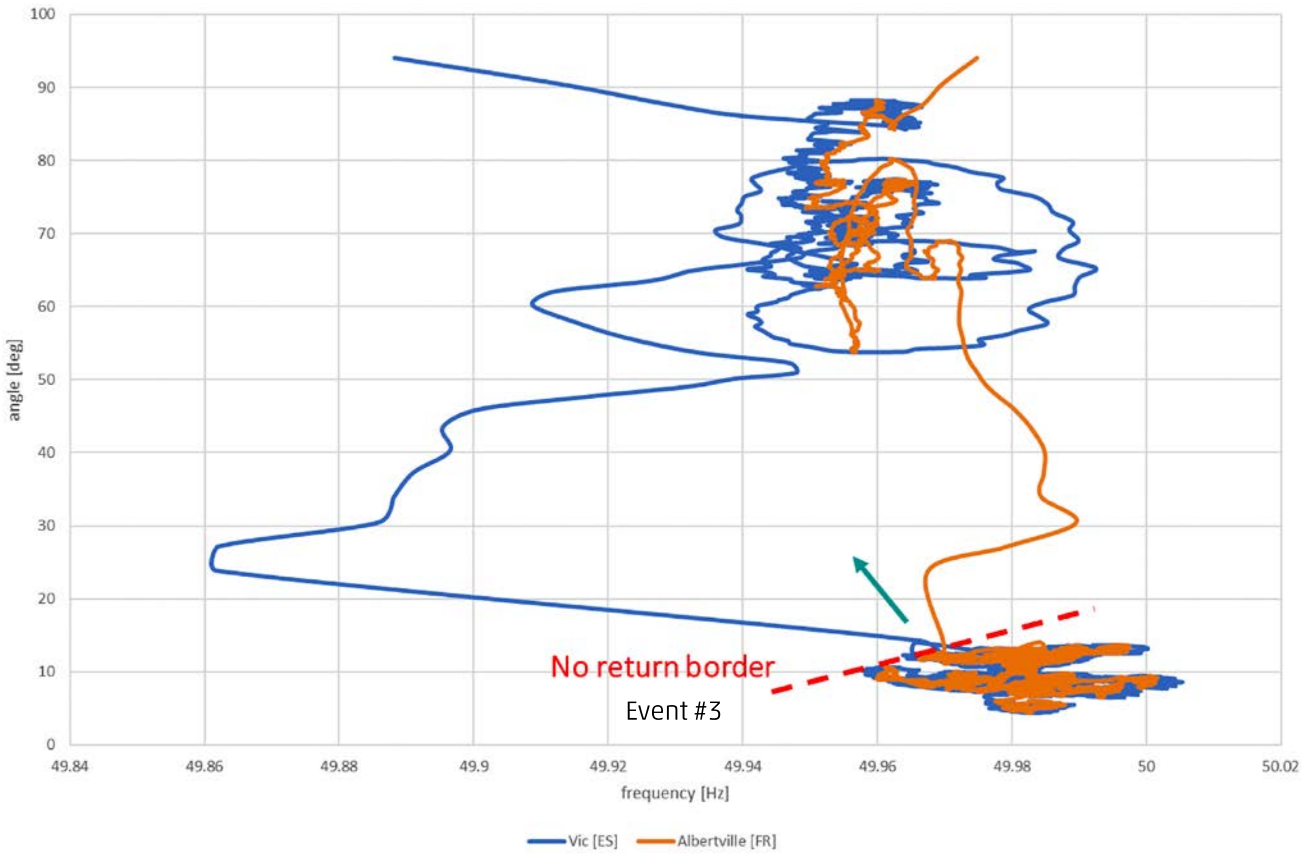
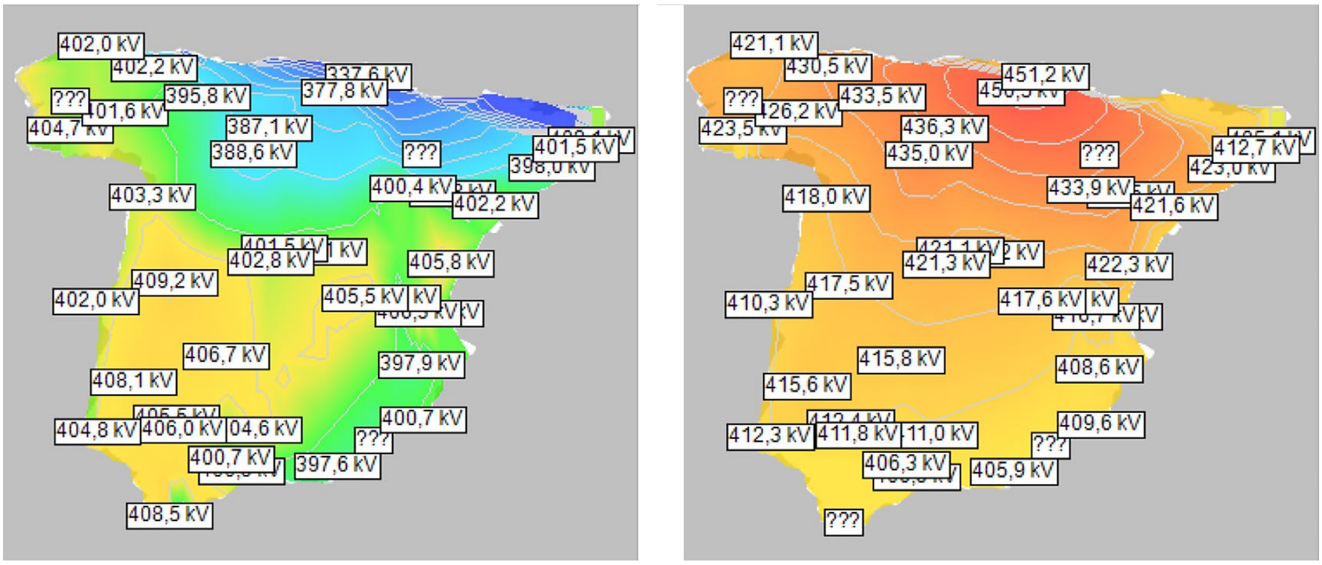


Figure 26: Phase plan (angle difference, frequencies) measured in France and Spain.

4.3 Voltage stability

After the split, high voltages emerged in the Iberian system, especially in the north of Spain. These over-voltages were caused by load shedding, the loss of the interconnection lines and the disconnection of coil reactors, which had been disconnected when the voltages were low (before the system separation). Figure 27 shows the voltages measured by the PMUs installed in the 400 kV transmission network at two different times. Figure (a) represents the voltages five seconds before the trip of the 400 kV Argia–Cantegrit line (Event #3) and Figure (b) represents the voltages approximately one minute after the split, which is when the highest voltages were recorded at the Hernani substation (451.2 kV), close to the Spain–France border.

Figure 28 shows the voltages measured with PMUs in some 400 kV and 220 kV substations in the centre and (mainly) in the north of Spain.



(a) 16:36:32 between Event #2 and #3

(b) 16:37:40 after Event #3

Figure 27: Voltages in Spanish 400 kV network.

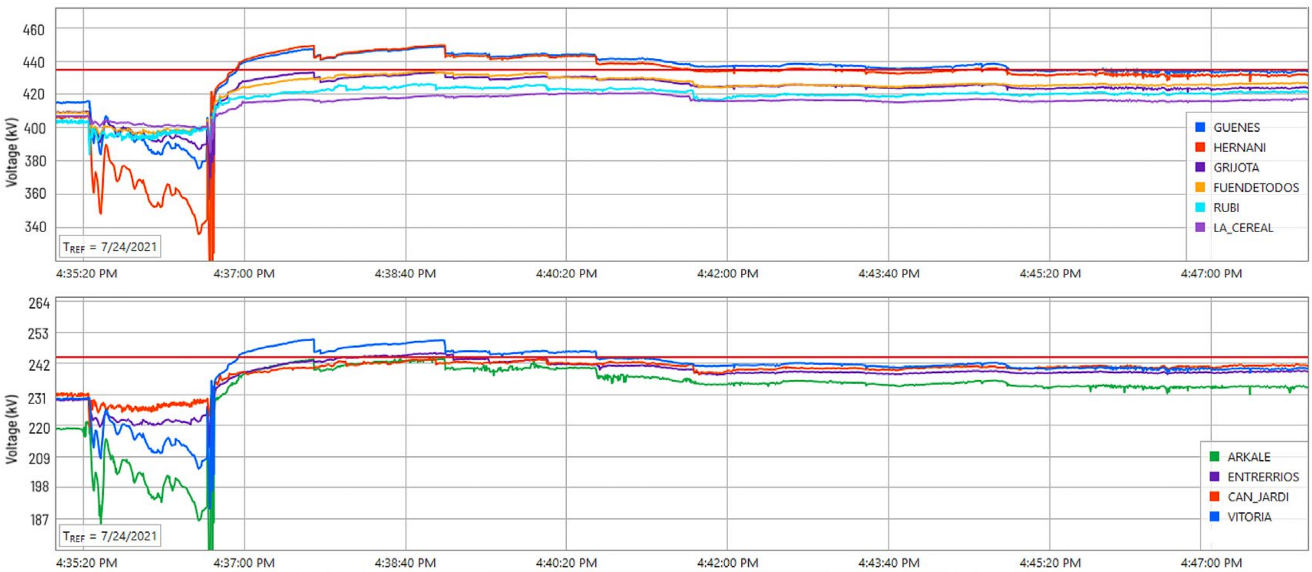


Figure 28: Voltages measured by PMUs at 400 kV and 220 kV transmission networks.

4.4 Behaviour of the Spain–France HVDC

One of the interconnectors between Spain and France consists of a VSC HVDC of 2 × 1,000 MW of nominal power (INELFE HVDC), as seen in Figure 29 and Figure 30.

This HVDC connects the substations of Santa Llogaia 400 kV (in Spain) and Baixas 380 kV (in France). It runs almost in parallel with the AC interconnection line Vic–Baixas 400 kV, forming an AC–DC corridor.

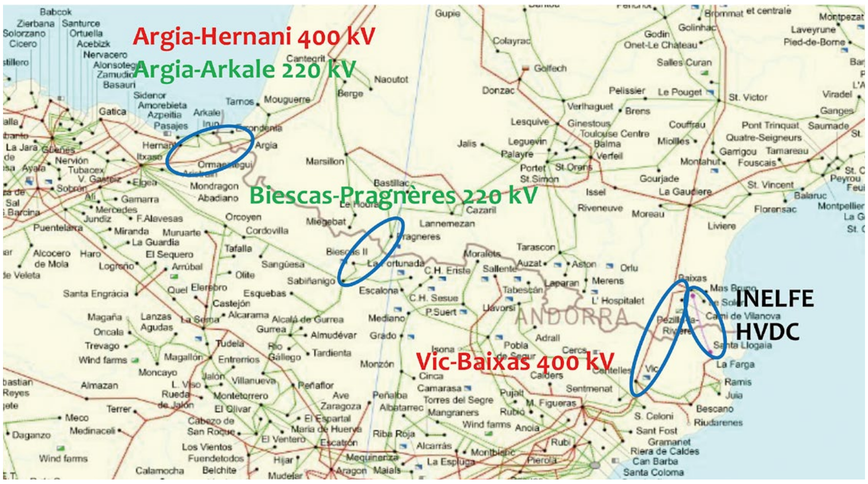


Figure 29: Transmission network in the French-Spanish border.

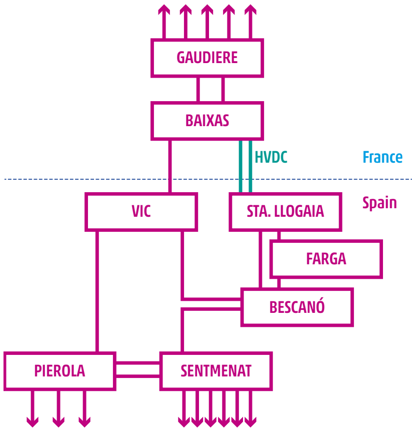


Figure 30: AC–DC corridor formed by the HVDC link and the Vic-Baixas line.

During the event, the HVDC and the AC line Vic–Baixas remained connected, supplying energy to the Eastern Pyrenees of France. In the following graph (Figure 31), the power flow during the system separation event at the AC–DC eastern corridor between Spain and France can be observed. The HVDC active power control mode is an angle difference control, which emulates the behaviour of the active power transfer of an AC line and adapts smoothly to the new topology and system conditions, as can be seen in Figure 31. In addition, each converter station kept performing a correct voltage control in its terminal substations, ensuring voltage stability in the French area that remained fed through the AC–DC eastern corridor and also in the Spanish side of the HVDC.

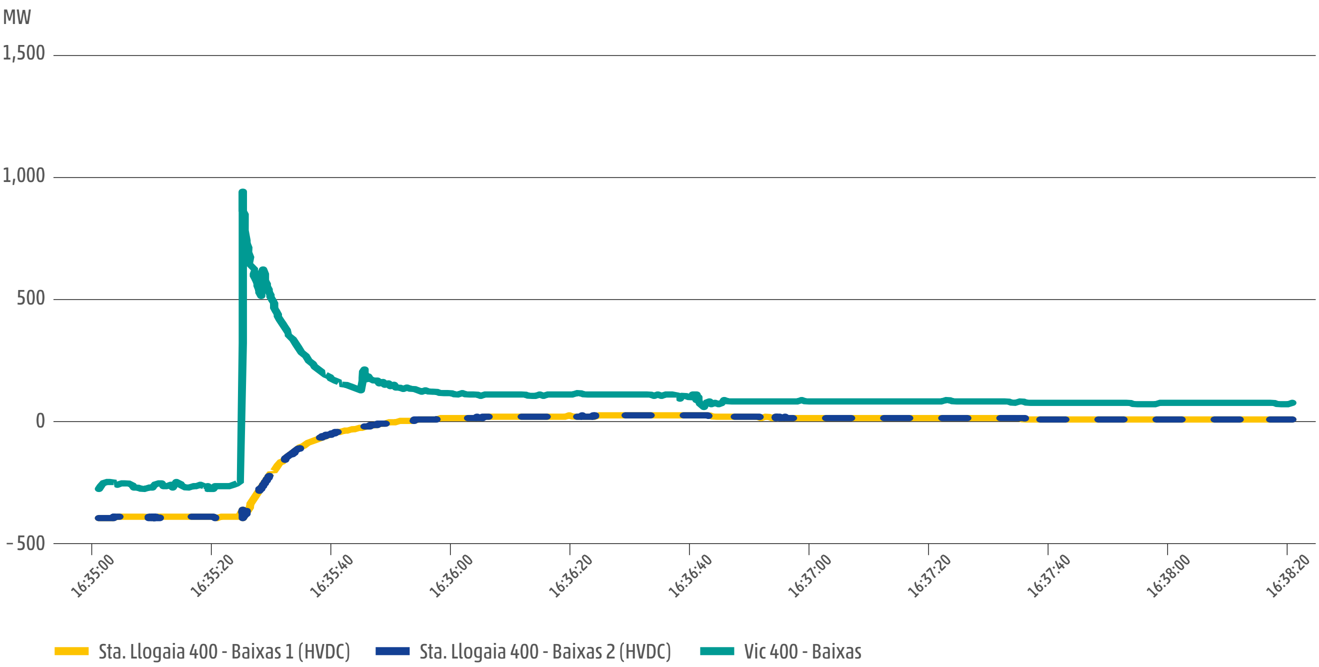


Figure 31: Active power of eastern France-Spain tie lines (positive means power transfer from Spain to France).

4.5 Automatic defence actions activated

Frequency Support Overview

The frequency deviation in the Iberian Peninsula was higher than 200 mHz, and, therefore, the frequency containment reserve (FCR) was fully activated. In Spain, the total amount of FCR estimated in the 30-second period after the incident was 376 MW, in line with the total amount of FCR for the Spanish Control Block (380 MW). In Portugal, the peak FCR reached 58.5 MW, which is above the requested value (50 MW). Further details about the frequency support are provided in **Section 6**.

Low-Frequency Demand Disconnection Overview

The frequency deviation in the Iberian Peninsula also activated automatic low-frequency demand disconnections. In particular, the total amount of pumped storage disconnection was 2,302 MW (1,995 in Spain and 307 in Portugal). The total amount of load shedding was 4,306 MW (3,561 in Spain, 680 in Portugal and 65 MW in France). Further details about the frequency plan and the load shedding are provided in **Section 11**.

4.6 Loss of generation units

4.6.1 Loss of generation units in Spain

In Spain the type of generation, which tripped, except the CCGT of Sabon, was distributed generation, as shown in Table 20. To determine the distributed generation disconnected due to the incident, those facilities with a nominal capacity above 1 MW that were producing at 16:33 and in which production was zero or close to zero (below 5 % of the nominal capacity) at 16:40 have been considered. This criterion has been used because, first, the main reason for the tripping of generation is voltage (under-over voltage), and hence it happened gradually in a several minute window, and, second, to consider only the generation tripped and not the production variation. From the information received from generation control centres, the disconnection criteria for almost 60 % of the installations have been derived. It is estimated that the cases reported as Over-Frequency happened due to the loss of means to evacuate the generation, because of the tripping of its own facilities or because of the tripping of generator facilities being used as grid connection by the other generators as no over-frequency was recorded during the incident.

Cause	Wind [MW]	Solar FV [MW]	Hydroelectric [MW]	Cogeneration, Thermal RE and waste [MW]	Solar Thermal [MW]	Combined Cycle [MW]	Total [MW]
Loss of other agent facilities	43	105.5	6.9	44.1			199.5
Voltage Out of Step (78)			10.4	24			34.4
Over-Frequency	39.2	3.6	8.3	23.8			74.9
Over-Voltage	254.4	358.5	14.9	218.4		227.7	1,073.9
Ground Over-Voltage	2.8						2.8
Under-Frequency	95	13.9	15.7	55.1			179.7
Under-Voltage	50.7	33.9		25.5	22.3		132.4
No detailed information available	226.9	172.1	19.9	463.1	94.2		976.2
Total [MW]	712	687.5	76	854.1	116.4		2,673.8

Table 20: Disconnection of generation units in Spain.

In Figure 32, the volume of generation tripped in Spain by cause and by area is presented. The generation with unknown cause has been assigned to other causes according to the causes reported in its vicinity and assigning to the area a volume proportional to each known cause.

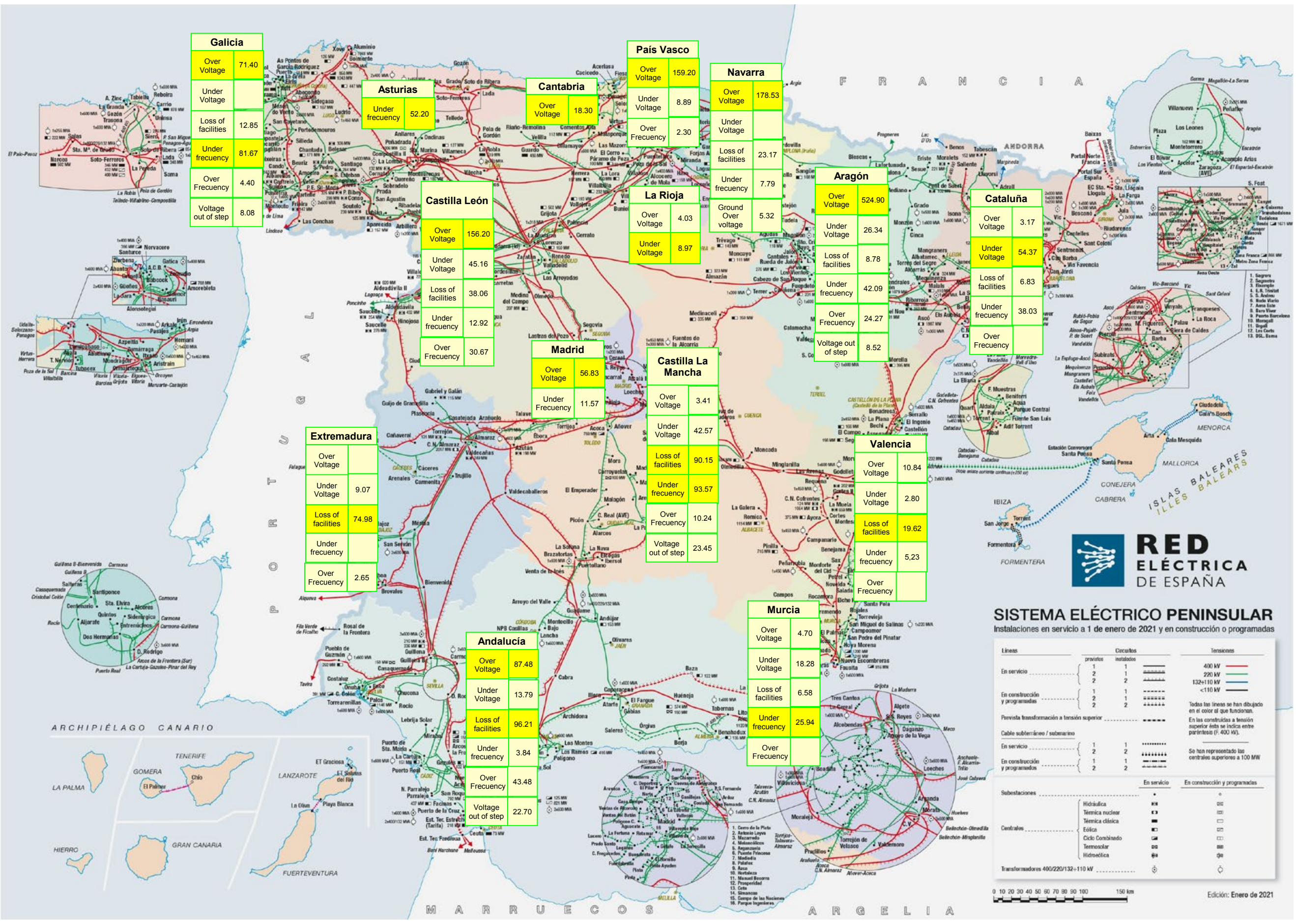


Figure 32: Geographical location of the disconnected generation units in Spain including estimation of generation with unknown cause.

4.6.2 Loss of generation units in Portugal

In Portugal, records indicate that on 24 July at 16:36, a high loss of generation occurred, at high voltage and medium voltage levels. This generation loss resulted from the operation of several frequency relays, reaching a total power of 1,015 MW. From this amount, about 712 MW were due to the protection settings by the DSO, 117 MW were due to the producers' own protections and another 110 MW were due to the branches disconnected as part of the load shedding.

Table 21 characterises this loss, by type of generator.

Type	P [MW]
Wind	404
Solar	235
NG Cogen	249
Biomass Cogen	23
Biomass Other	81
Small Hydro	23
SUM	1,015

Table 21: Loss of generation, by type.

Table 22 describes, in a simplified manner, the lost generation blocks and the corresponding frequency and time delay values.

F [Hz], time delay [s]	P [MW]
49.8	199
49.5	544
49.5 @ 1.5	89
49.5 @ 2.4	122
48.7	61
SUM	1,015

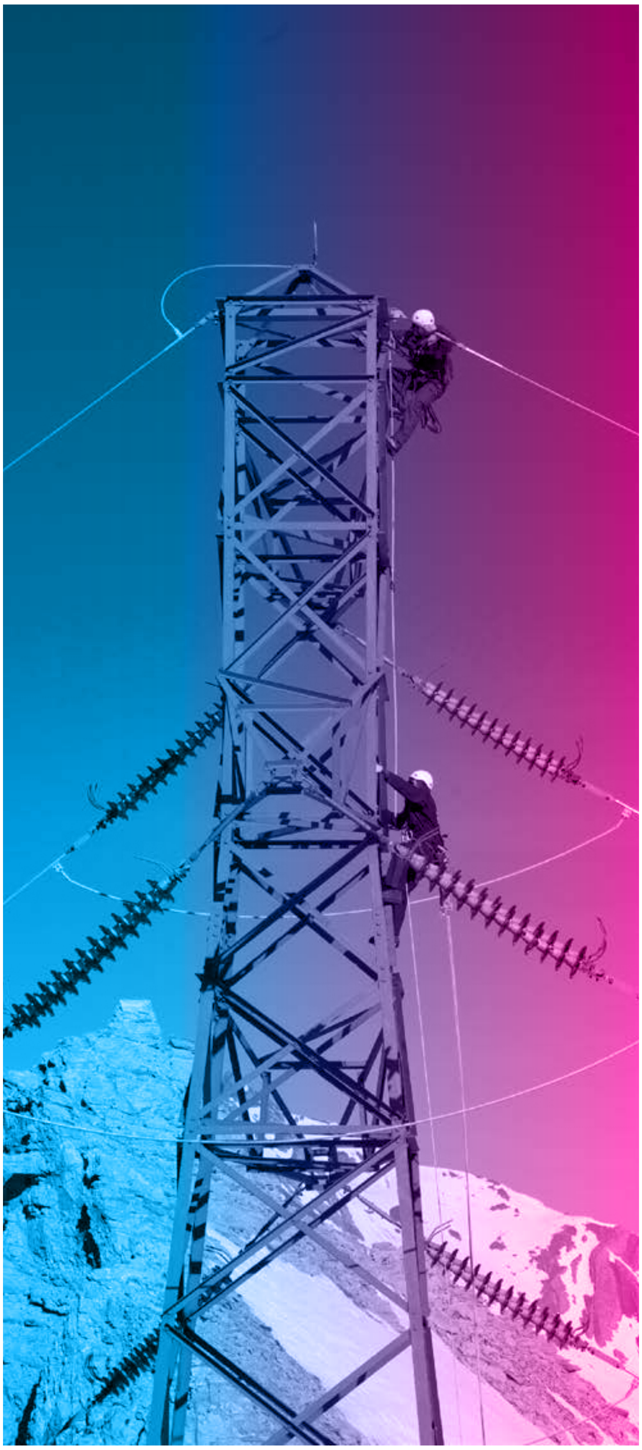
Table 22: Loss of generation by frequency threshold.

Finally, it should be noted that in some of the COGEN-type producers considered in the two previous tables, the operation of the frequency relays, in addition to generation, also tripped the associated consumption, causing the formation of islands (with generation and consumption). The reduction in consumption connected to the system, with this origin, reached **172 MW**.

Table 23 characterises this reduction.

F [Hz]	Generation [MW]	Consumption [MW]
49.8	57	40
49.5	81	58
48.7	61	73
SUM	199	172

Table 23: Loss of load of COGEN, with corresponding generation.



4.6.3 Undesirable generation disconnection

During the incident, a substantial amount of generation units were disconnected from the system due to the activation of their protection relays.

For the Portuguese system, 1,015 MW of the generation was disconnected, due to the frequency drop that occurred in the Iberian Peninsula. Most of these disconnections occurred in an undesirable manner, mainly because of the related under-frequency protection settings by the DSO. These under-frequency protection settings are intended to prevent islanding in the distribution systems, but their negative impact on transmission system stability has not sufficiently considered. The installation of the frequency sensitive relays in the connection points of the generators to the distribution grid is prescribed in the Portuguese Distribution Grid Regulation ("Regulamento da Rede de Distribuição") published in 2010. The DSO decides the settings.

For the Spanish system, most of the generation disconnected due to under- or overvoltage. However, due to the fact that voltage measurements are available only at the high voltage level, it was not possible for this investigation to assess if the generation disconnections occurred in a conform or non-conform manner. In the case of Spain, generators are obliged to fulfil operational procedure 1.4 "Conditions of energy delivery in connection points" (1998) for voltage conditions and operational procedure 1.6 "Implementation of defence plans for System Operation" (2009) for frequency conditions.

According to the Network Code on Requirements for grid connection of Generators (NC RfG)[3], the automatic tripping of generating units should not occur in the frequency range between 47.5 Hz and 51.5 Hz in less than 30 minutes, in order to avoid further power system degradation.

Furthermore, according to the NC RfG, independently of the voltage level of the bus of connection of the generator, the automatic tripping of generating units should not occur in specific voltage ranges (±15 % of the nominal voltage value) and time windows.

The requirements are only mandatory for generators put into service after the date of the definition at the national level of the NC RfG. The regulation does not apply to generating modules which before that date were already installed or their installation was already at an advanced planning stage, unless assessed by a dedicated cost–benefit analysis. Prior to the entry in force of NC RfG, similar requirements for frequency limits were regulated by the ENTSO-E Operational Handbook and national grid codes.

Recommendation 1 – "Reduce the volume of generation tripping" – provides the recommendations derived to avoid/reduce generation disconnection.

3 Commission Regulation (EU) 2016/631, establishing a Network Code on Requirements for grid connection of Generators (NC RfG)

5 PERFORMANCE OF THE PROTECTION SYSTEM DURING THE INCIDENT

The protection system constitutes a key element in the operation of the electrical system, so that its design, coordination and performance in response to disturbances occurring in the grid determine the quality of the supply and the stability of the electrical system. The ultimate objective of the protection system is to minimise the impact of disturbances.

This section analyses the performance of the protection system during the incident. As detailed in Recommendation 3 – "Investigate the opportunity to supplement important transit corridors with Special Protection Scheme (SPS) functionality in combination with automatic overload protection" – the Expert Panel recommends coordinating automatic overload protections with SPS functionalities and to coordinate DRS (*"Débouclage sur Rupture de Synchronisme"* – Protection against Loss of Synchronism) schemes with the protection systems of the neighbouring TSOs.

5.1 400 kV Baixas–Gaudière 2 line protection

At 16:33:11, a phase-to-phase fault on the 400 kV Baixas–Gaudière 2 line was detected and correctly cleared by line differential protections, acting in 49.4 ms (circuit breaker opening time included). At Baixas substation, the fault had also been detected by differential protections and eliminated in 53 ms (circuit breaker opening time included).

A phase-to-phase fault between phase 0 and phase 8 occurred on this transmission line, and the transient recording gives us the information reported below in Table 24. Figure 37 provides a graphical interpretation of the phase naming.

Gaudière Bay					Baixas Bay			
Phase 0	Phase 4	Phase 8	Residual current	Residual voltage	Phase 0	Phase 4	Phase 8	Residual current
12,400 A	980 A	13,300 A	90-100 A	5,000 V	3,400 A	870 A	2,500 A	250 A
179° phase shift between 0 and 8					179° phase shift between 0 and 8			

Table 24: Transient recording analysis.

Table 24 confirms that currents and voltage phase shifts were close to 180° (see also Figure 33 and Figure 34); this behaviour is typical for an isolated phase-to-phase fault. In fact, an angle equal to 180° means that the two currents in Phase "0" and Phase "8" have reverse signs, which means that the fault current flows from one phase ("0") to the other phase ("8"). The fact that the current amplitudes differ and the residual current (the current that flows to ground due to the fault) is not equal to zero might point towards a very resistive double phase-to-ground fault. It has to be a highly resistive fault as the residual current to ground is relatively small. This high resistivity of the fault confirms the typical "fire effect" behaviour that causes a high ionisation of air near the conductors and non-linear high resistance (15 … 20 Ohms).

A dedicated locator device estimates the fault location at 7.8 km from Gaudière substation. Offline calculations of the fault position locate the fault at 8.9 km from Gaudière substation, which confirms the value from the locator device.

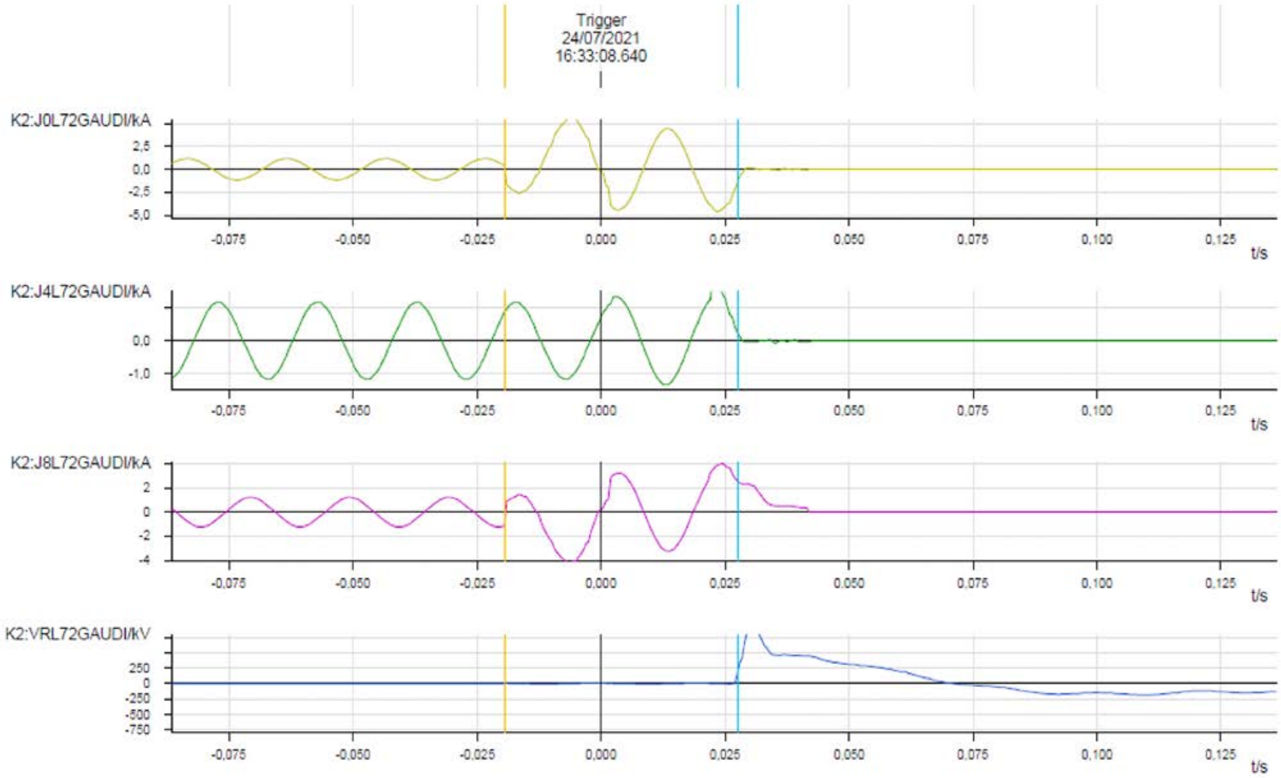


Figure 33: Oscillography recording of currents of Gaudière bay.

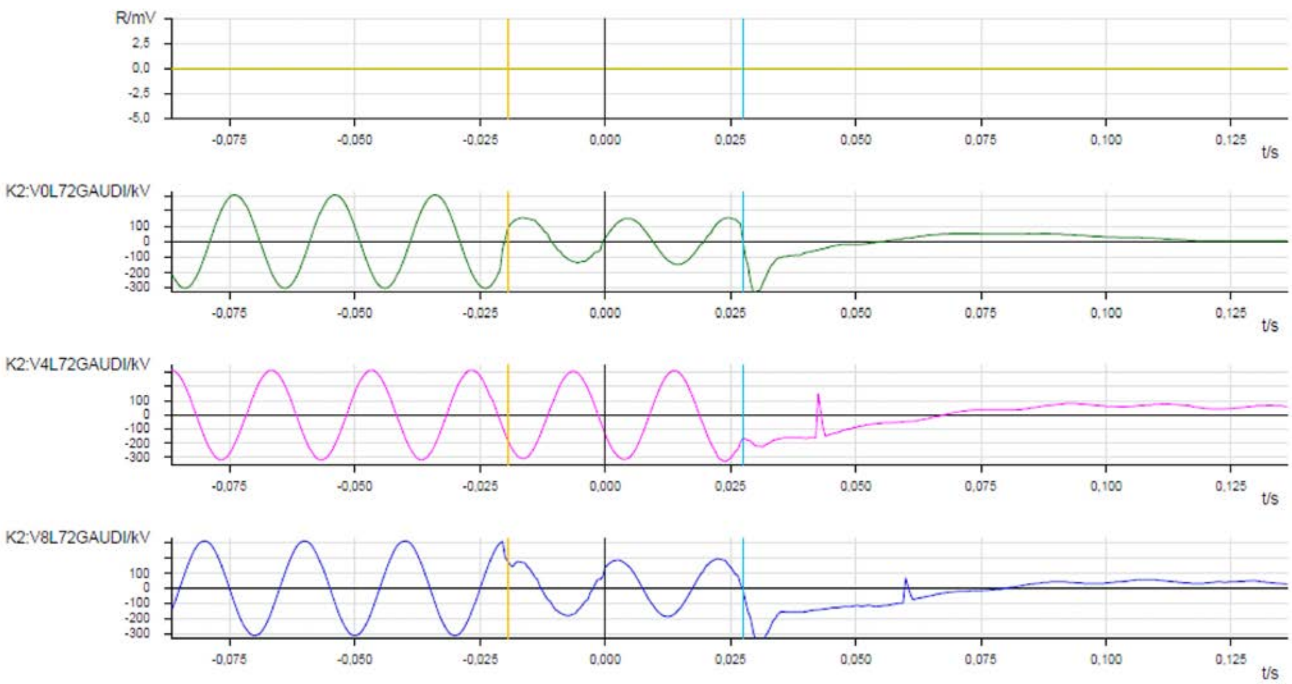


Figure 34: Oscillography recording of voltages of Gaudière bay.

Five seconds after this first trip, an automatic reclosing occurred from Gaudière substation. The reclosure attempt was unsuccessful. Consequently, no automatic reclosing occurred from Baixas substation.

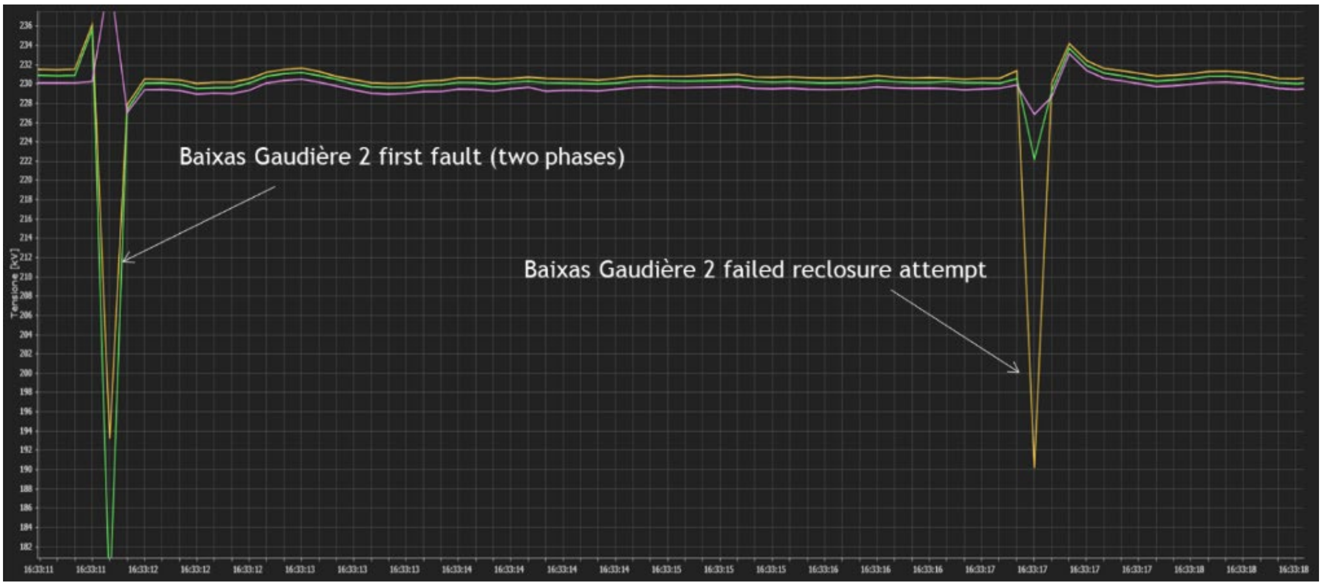


Figure 35: PMU recording of voltages in Baixas (20 ms sampling rate).

The complete sequence of events is clearly evident in Figure 35. The protections on this line demonstrated correct behaviour during the event and worked according to their settings.

5.2 400 kV Baixas–Gaudière 1 line protection

At 16:35:23 the system was in N-1 condition; simultaneously, a two phase fault on the 400 kV Baixas– Gaudière 1 line was detected and correctly cleared by line differential protections, acting in 50.6 ms (circuit breaker opening time included). At Baixas substation, the fault was detected by differential protections, and eliminated in 62 ms (circuit breaker opening time included).

Gaudière Bay					Baixas Bay
Phase 0	Phase 4	Phase 8	Residual current	Residual voltage	unavailable
10,800 A	1,800 A	12,400 A	140-160 A	5-8.5 kV	
177° phase shift between 0 and 8					

Table 25: Transient recording analysis.

Similar to the first fault, an analysis of the recordings in Table 25 indicates an isolated phase-to-phase fault or a very resistive double phase-to-ground fault.

The calculated fault location estimated the fault at 7.2 km from Gaudière substation. SIGRA software located the fault at 7.8 km from Gaudière substation.

Five seconds after this first tripping, an automatic reclosing occurred from Gaudière substation. No automatic reclosing occurred at Baixas substation, probably due to an exceeded transmission angle (66° was estimated, whereas 60° is the maximum allowed by the protection system).

This was confirmed by the PMUs' phase recording, as shown in Figure 36.

The protections on this line demonstrated correct behaviour during the event and worked according to their settings.

The fault locations of both 400 kV Baixas–Gaudière lines are consistent with the wildfire area in the Aude region on 24 July (see the map in **Section 2**).

Regarding the typology of the line, the phases that tripped are located on the bottom part of the pylons (see Figure 37).

The fault location, temporality and fault types confirm the causal links between the wildfire and the tripping of both Gaudière–Baixas lines. The impact of smoke for phase-to-phase short circuits in the vicinity of vegetation fires is well described in the CIGRE TB 767 "Vegetation fire characteristics and potential impacts on overhead line performance" from June 2019.

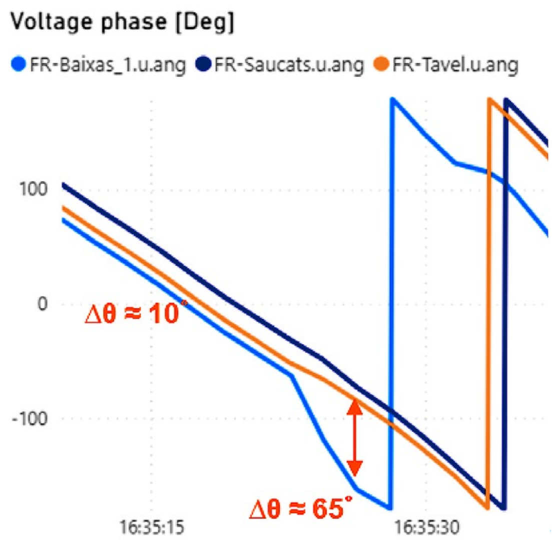


Figure 36: PMUs phase angles.

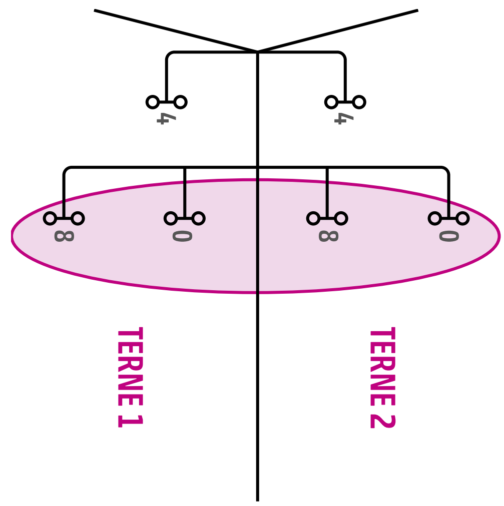


Figure 37: Phase identification on the wildfire area.

5.3 400 kV Argia–Cantegrit line protection

At 16:36:37.0, after the successive trips of the Baixas–Gaudière lines, all transit was redirected to the other interconnection lines, mainly located on the Atlantic coast side.

The current intensity on interconnection lines increased between 16:35 and 16:36, as presented in Table 26:

Argia 400 kV substation, outgoing Cantegrit		
16:35	Estimated current [A]	1,742
16:36	Estimated current [A]	**3,028**
PATL [A]		2,050
TATL 20'[A]		2,400
TATL 10' [A]		2,800

Table 26: 400 kV Substation ARGIA, outgoing CANTEGRIT.

It is worth noting that on this transmission line the following scheme applies, depending on the current (I) value (intensity of the current), being PATL the Permanently Admissible Transmission Loading and TATL the Temporarily Admissible Transmission Loading:

- If PATL < I < TATL 20', the overload protection will switch off the line after 20 minutes
- If TATL 20' < I < TATL 10', the overload protection will switch off the line after 10 minutes
- If TATL 10' < I, the overload protection will switch off the line after one minute (to avoid tripping due to transient phenomena)

These limits are set to respect the physical operation limits of the transmission line and also to avoid endangering the surrounding people, goods and installations close to the line.

The estimated current at 16:36 was higher than the PATL and even higher than the TATL 10'. As expected, overload protection started operating at Argia 400 kV substation, on the Cantegrit outgoing line. The line tripped due to the confirmed overload.

The protections on this line showed correct behaviour during the event and worked according to their settings.

5.4 220 kV Biescas–Pragneres line protection

At 16:36:38.40, after the trip of the 400 kV Argia–Cantegrit line, the impedance measured by the relay installed at Biescas substation (parameter shown in Table 27) entered zone 2, 400 ms later the distance protection tripped, and the breaker opened at 16:36:38.873. Only the main 1 protection tripped.

Main 1			Main 2		
Prot. functions	Set value [Ω]	Time	Prot. functions	Set value [Ω]	Time
21 (Z1) – phase mho	17.4	0 ms	21 (Z1) – phase mho	17.55	0 ms
21 (Z2) – phase mho	38.5	400 ms	21 (Z2) – phase mho	38.55	400 ms
21 (Z3) – phase mho	63.0	800 ms	21 (Z3) – phase mho	62.80	800 ms

Table 27: Biescas 220 kV bay Pragneres protection settings.

Figure 38 shows the protection recording, which confirms that zone 2 of the distance protection (M2P) caused the trip. The power oscillation block function was active, and the relay detected a power oscillation (OSB), but the inverse sequence current exceeded the threshold that enables zone 2 distance tripping (50Q2). In any case, the loss of the synchronism condition had been reached before this tripping, so the line disconnection was inevitable. The figure presents the measurements from a digital relay that consist of current waveforms (top), voltage waveforms (centre) digital signals, including the time at which the relay was triggered (bottom).

Figure 39 is an R / X graph representing the impedance, resistance and reactance evolution in Pragneres bay at Biescas 220 kV substation during the incident. It was calculated using PMU data because the protection recording is too short to represent the whole incident. The situation before and after the trip of Baixas–Gaudière circuit 2 (Event #1) is represented in blue, the impedance after the trip of Baixas–Gaudière circuit 1 (event #2) in orange, and after the Argia–Cantegrit 400 kV trip (Event #3) in red. The graph shows a classical protection representation of reactance versus resistance and the point where the protection thresholds (Z1, Z2, Z3) are crossed. The sequence of events goes from the left hand side to the right hand side.

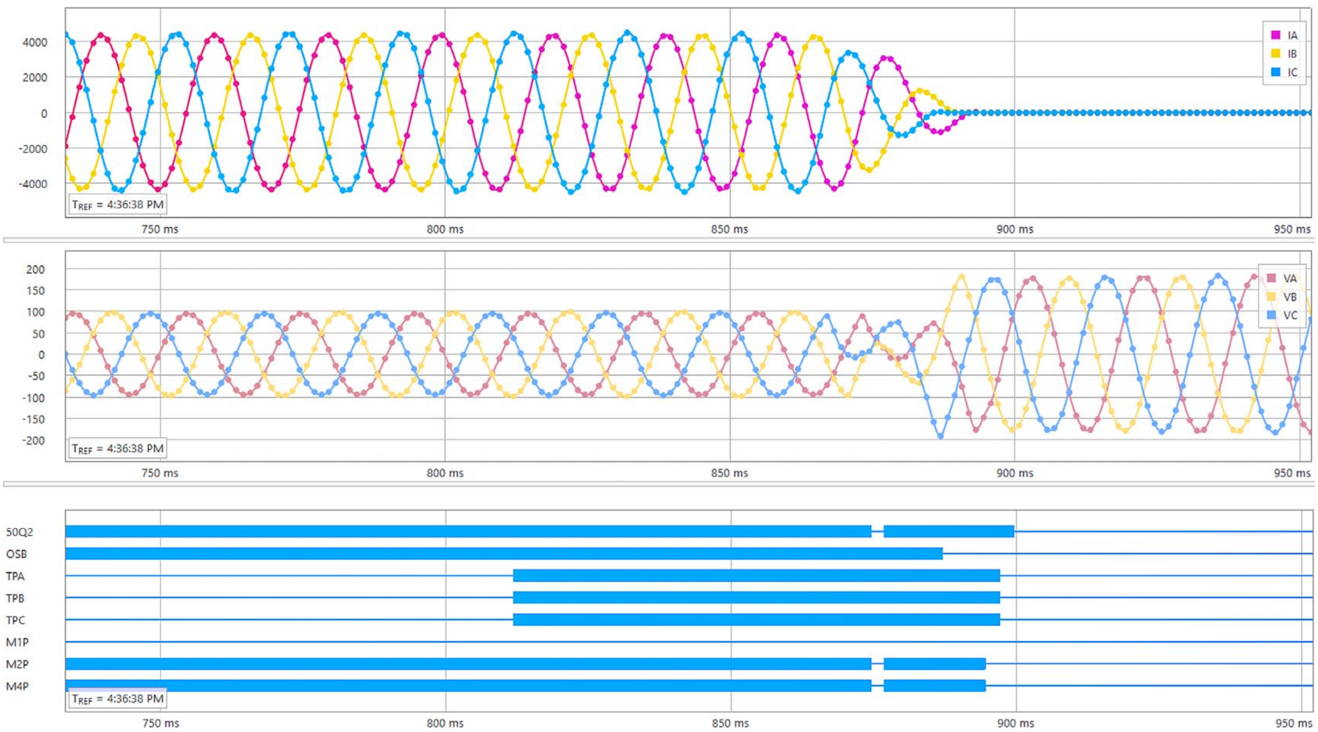


Figure 38: Pragneres bay at Biescas 220 kV substation relay recording.

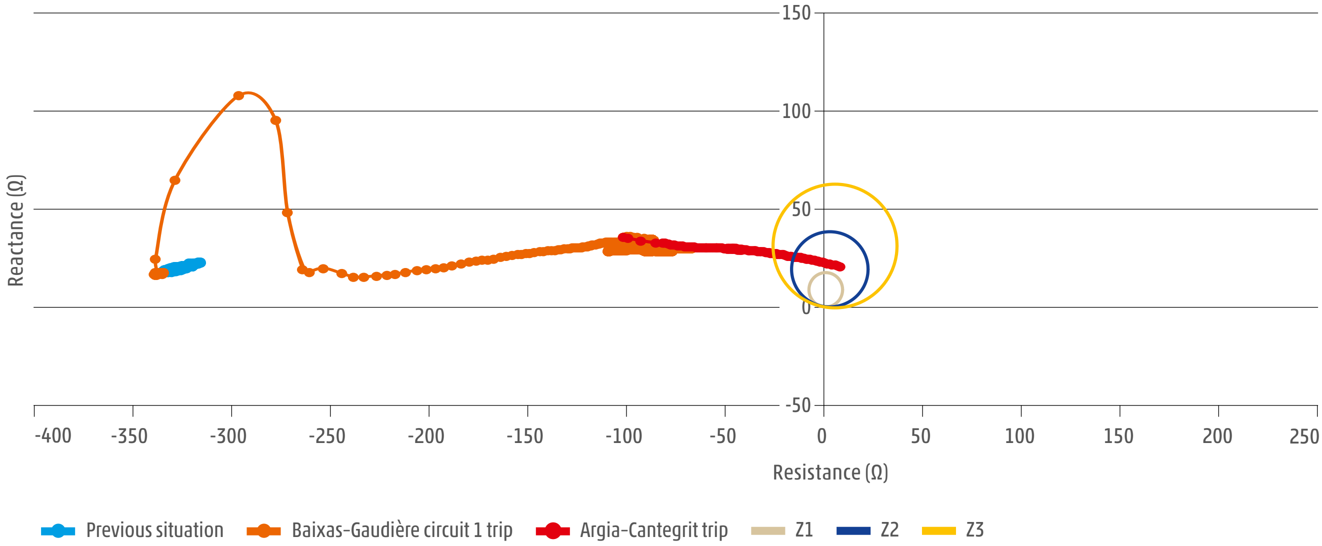


Figure 39: Pragneres bay at Biescas 220 kV substation: Impedance evolution using PMU data.

The protections on this line showed correct behaviour during the event and worked according to their settings.

5.5 400 kV Puerto de la Cruz–Melloussa and Puerto de la Cruz–Beni Harchen

At 16:36:39.18, the Puerto de la Cruz–Beni Harchen 400 kV line opened in Beni Harchen due to an underfrequency protection and also sent a direct transfer trip to the Spanish side (Puerto de la Cruz) that opened a few milliseconds later.

Figure 40 shows the current, voltage, active and reactive power measured by the PMU installed in the line. After the line trip, there was still current and voltage due to the discharge of the submarine cable on the reactor.

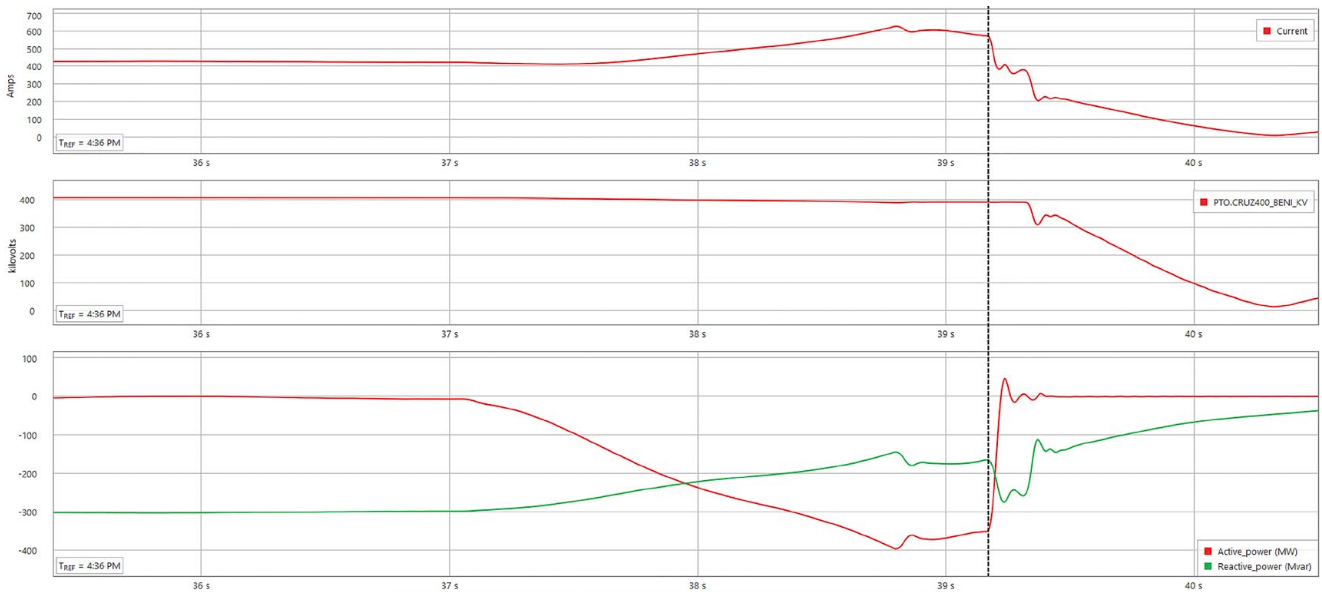


Figure 40: Beni Harchen bay at Puerto de la Cruz 400 kV substation PMU recordings.

At 16:36:39.458, the Puerto de la Cruz–Beni Harchen 400 kV line opened in Melloussa due to an underfrequency protection and also sent a direct transfer trip to the Spanish side (Puerto de la Cruz), which opened 103 milliseconds later.

Figure 41 shows the recording of the protection installed in the Melloussa bay at the Puerto de la Cruz 400 kV substation. The recording shows how the Moroccan end of the line tripped and indicates that it sent a direct transfer trip to the Spanish end. In addition, Figure 41 shows a trip signal, but this operation occurred when the breaker was already opened. This relay operation was caused by the discharge of the submarine cable on the reactor as there was current with a low voltage.

The protections of both interconnectors displayed the correct behaviour during the event and worked according to their settings.

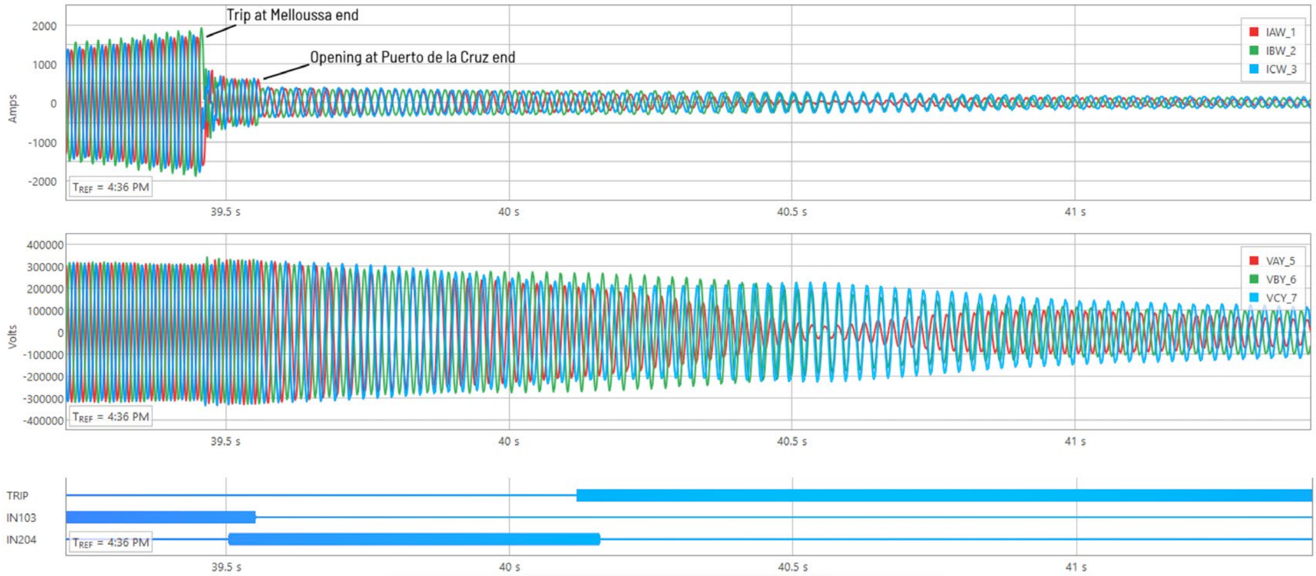


Figure 41: Melloussa bay at Puerto de la Cruz 400 kV substation relay recording (IN103: breaker position, IN204: direct transfer trip reception).

5.6 220 kV Arkale–Argia line protection

At 16:36:40.451, the Argia-Arkale 220 kV line opened in Arkale due to the tripping of the out-of-step DRS protection.

The DRS protection permanently measures the voltage peak values. When the relay measures at least 10 consecutive decreasing peaks followed by four consecutive increasing peaks, it detects one beat if the minimum voltage reached is below a configured voltage threshold. After detecting the configured number of peaks, the relay is ready to trip, and it will trip after a time delay that starts when the average RMS voltage during the oscillation is exceeded, as seen in Figure 42. The DRS settings at the 220 kV substation Arkale are shown in Table 28.

DRS protection	
Setting	**Set value**
Beat numbers	2
Voltage	65 %
Switch time	30 ms

Table 28: DRS settings at Arkale 220 kV substation.

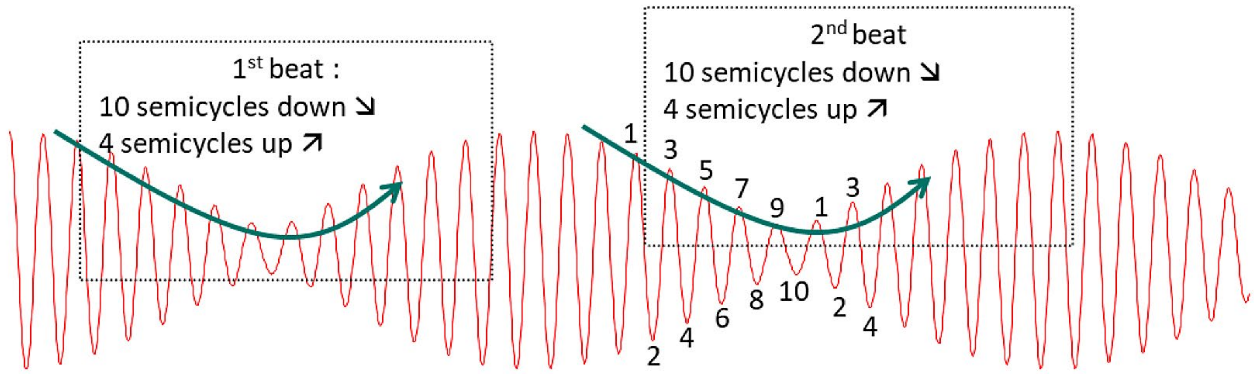


Figure 42: DRS operating principle.

Figure 43 shows the digital fault recorder (DFR) oscillography that confirms the operation of the out-of-step protection.

Figure 44 shows the voltage PMU recordings in Arkale 220 kV. In this record it can be seen how the relay tripped after the second beat.

The protections worked according to their settings during this event. The current assessment is based only on the Spanish side protection system operation.

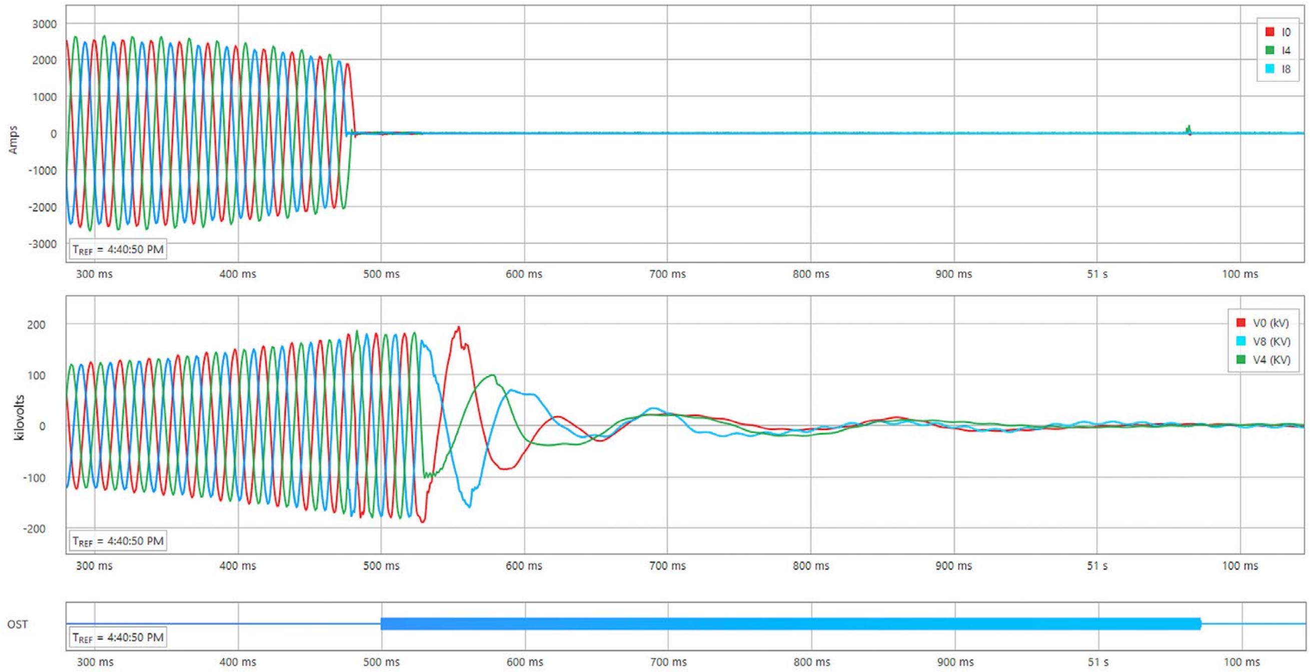


Figure 43: Arkale 220 kV bay Argia DFR recording (device not time synchronised).

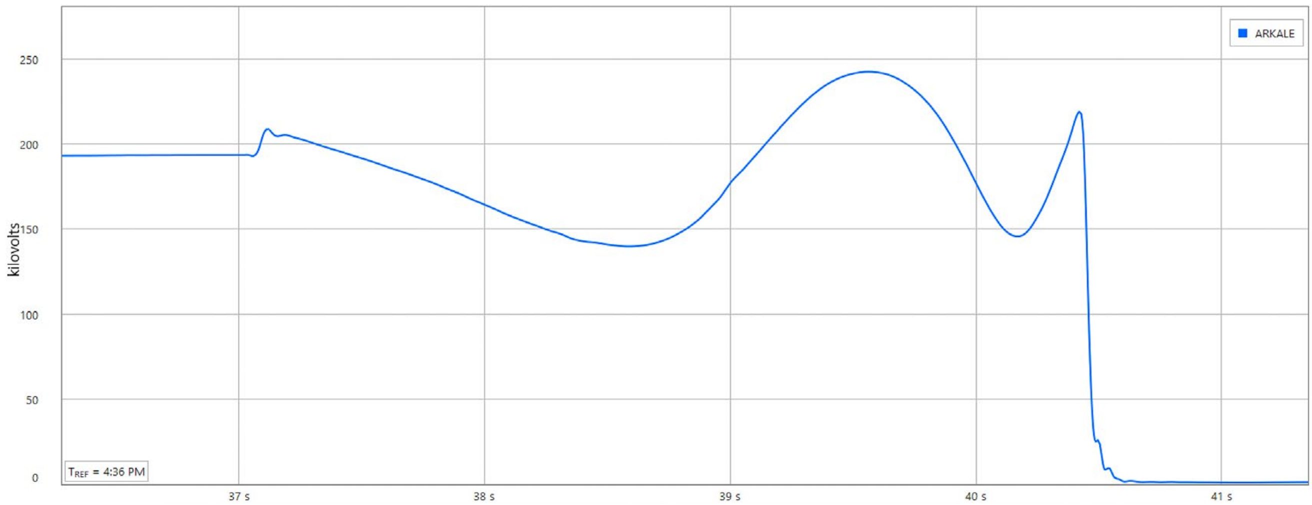


Figure 44: Arkale 220 kV voltage.

5.7 400 kV Argia–Hernani line protection

At 16:36:41.3, the Argia–Hernani 400 kV line opened in Argia due to the tripping of the out-of-step protection DRS.

Focus on Protections against Loss of Synchronism ("DRS")

After the Argia–Cantegrit 400 kV tripping, the only synchronising links between France and Spain remaining were Biescas–Pragneres 220 kV, Argia–Arkale 225 kV and Argia–Hernani 400 kV. These three lines were connected to the French network via three links:

» Cantegrit–Mouguerre 225 kV (only UHV link remaining on the Atlantic coast) ensuring the Cantegrit → Mouguerre → Argia → Spain link.
» Marsillon–Pragneres 225 kV, Cazarilz–Lannemezan 225 kV and Lannemezan–Pragneres 225 kV.
» 63 kV axis between Marsillon and Mouguerre.

Those links were not sufficiently strong (the impedance was too high) to maintain frequency synchronisation between France and Spain, leading to a loss of synchronism.

Protection against loss of synchronism is part of the defence protection scheme implemented by RTE. It monitors voltage on the line where protections are installed in order to detect voltage beats. It triggers the opening of the line according to defined settings (voltage thresholds and number of voltage beats).

The overall scheme for the protection against loss of synchronism in France is designed with 19 consistent zones (oscillations of rotating machines, similar frequency beats). In the case of a loss of synchronism leading to voltage beats, loss of synchronism protections will support the preservation of "healthy" zones. At the 400 kV and 225 kV levels, loss of synchronism protections are located at both ends of a line. At lower voltage levels, loss of synchronism protections are only located at one end of a line.

The Basque Country region is located in the "E" DRS area (see Figure 45), defined by:

» South: Argia–Arkale 225 kV and Argia–Hernani 400 kV interconnection lines.
» South-East: Link to the "F" DRS area is ensured by the following lines: 225 kV Cantegrit–Marsillon and Berge–Marsillon; 63 kV Guiche–Mouguerre, Dax-Arriosse–Orthez, Dax–Rouye–Lacq–Marsillon, Midour-Naoutot–Lussagnet, Hagetmau–St Sever, Aire s/ Adour-Naoutot–Borderes et Lamensan and Mezin–Montreal. On 24 July, these 63 kV tripped at around 16:36:40.

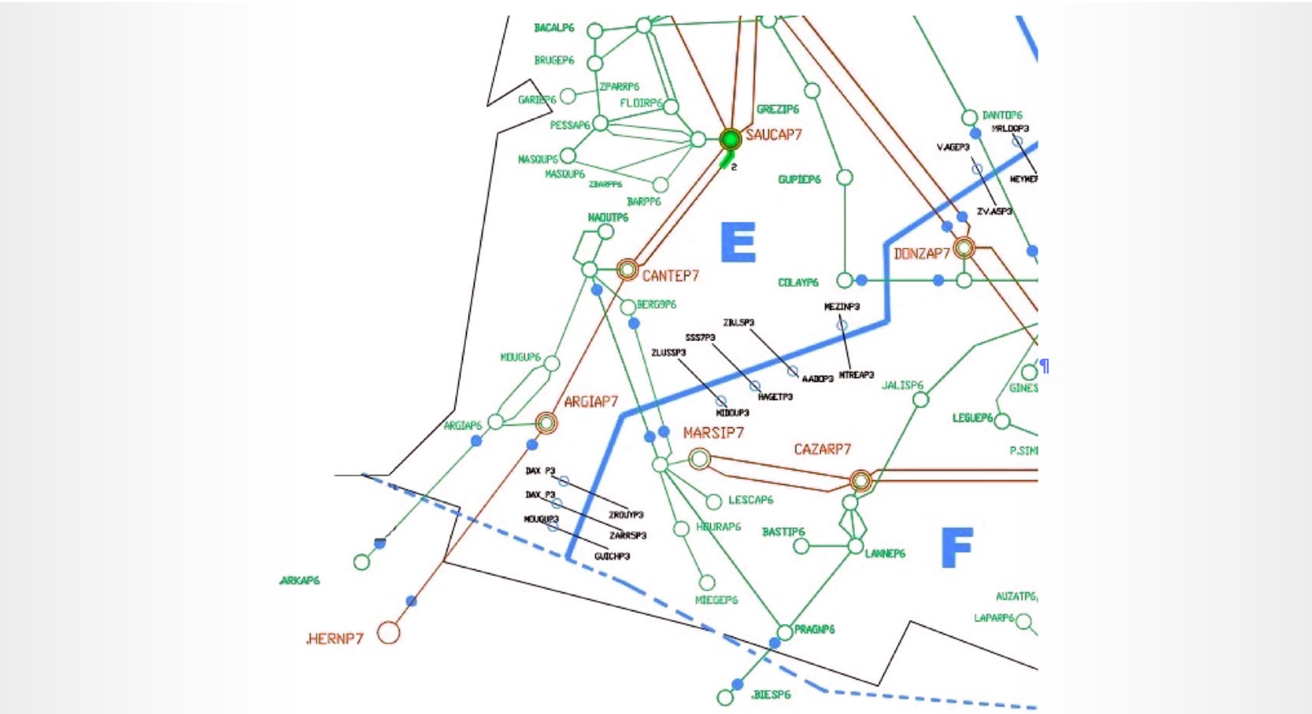


Figure 45: "E" DRS area, with connection lines to "F" area. Red lines: 400 kV, Green lines: 225 kV, Black lines: 63 kV.

Each of the protections against loss of synchronism mentioned above are expected to show the same behaviour (see Table 29).

Transmission line	Nr. Voltage beats	Voltage thresholds [%]
63 kV lines	1	80
225 kV lines	2	65
Argia–Hernani 400 kV	2	65

Table 29: DRS settings for the "E area".

NB: It is expected that to be considered by the protection, actual voltage thresholds must be lower than the value given in Table 29.

During this event, the voltage beats occurred, in about four seconds.

» The first voltage beat caused the 63 kV transmission lines to trip;

» The third voltage beat caused the 400 kV Argia–Hernani transmission line to trip.

Figure 46 shows the voltage beats measured at ARGIA 400 kV substation, on HERNANI outgoing:

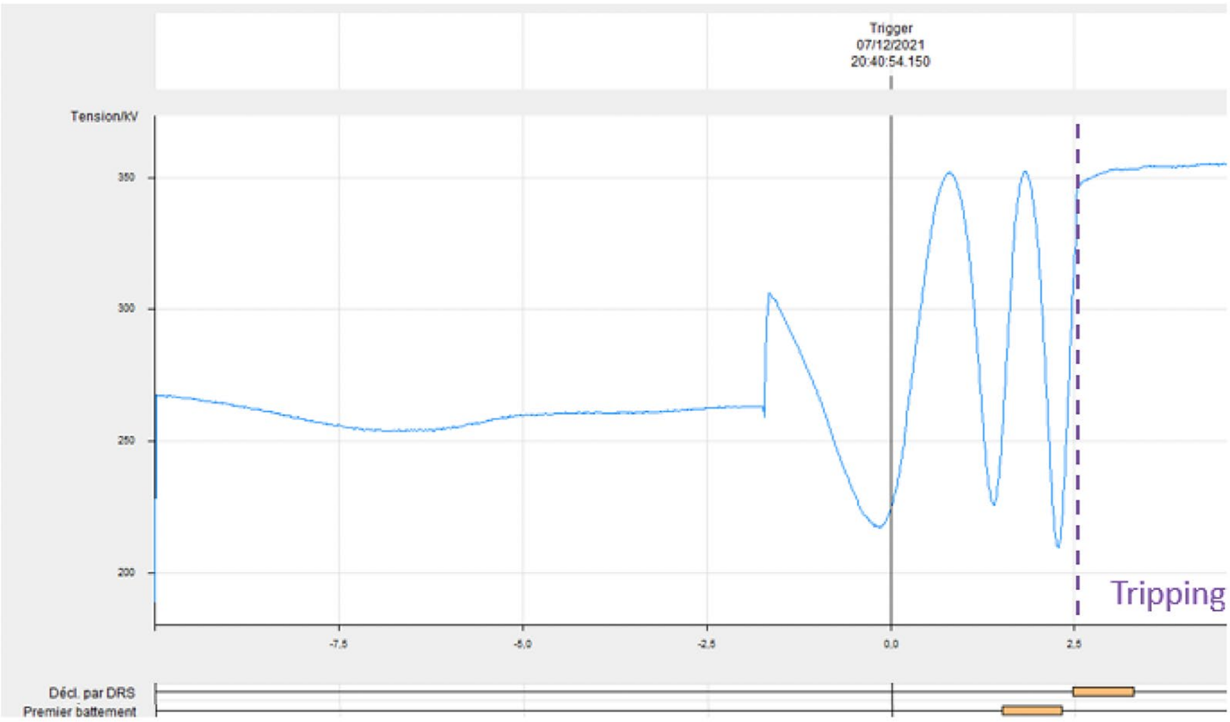


Figure 46: Voltage beats at Argia 400 kV substation (device not time synchronised).

This Figure gives the depth[4] of each one of these beats. Table 30 further clarifies the settings of the protection system: voltage threshold represents the ratio between the minimum and maximum voltage and after 1 or 2 beats meeting the criterion on the voltage threshold, the line is disconnected by the protection system.

Voltage beats	Voltage thresholds [%]
First voltage beat	71
Second voltage beat	64
Third voltage beat	60

Table 30: Beats at the 400 kV Argia substation.

The first voltage beat was not sufficiently deep to be considered by the protection, which explains why the line tripped only after the "third" voltage beat. Thus, the protection operated as expected. Figure 47 shows the impedance by the protection, projected on the two axis with reference to the imaginary component (ordinate) and real component (abscissa). When zooming in as indicated in the figure, the trajectory of impedance can be seen. This provides additional interesting information: the typical "geometric" behaviour of asynchronism between two grids and the rate of change of the impedance seen by the protection device. The high value of this rate of change (500 Ω/s) confirms the very strong effect of separation.

4 Beating depth corresponds to the ratio between the lowest value of voltage of the beat and the "peak" value of voltage just before the beat.

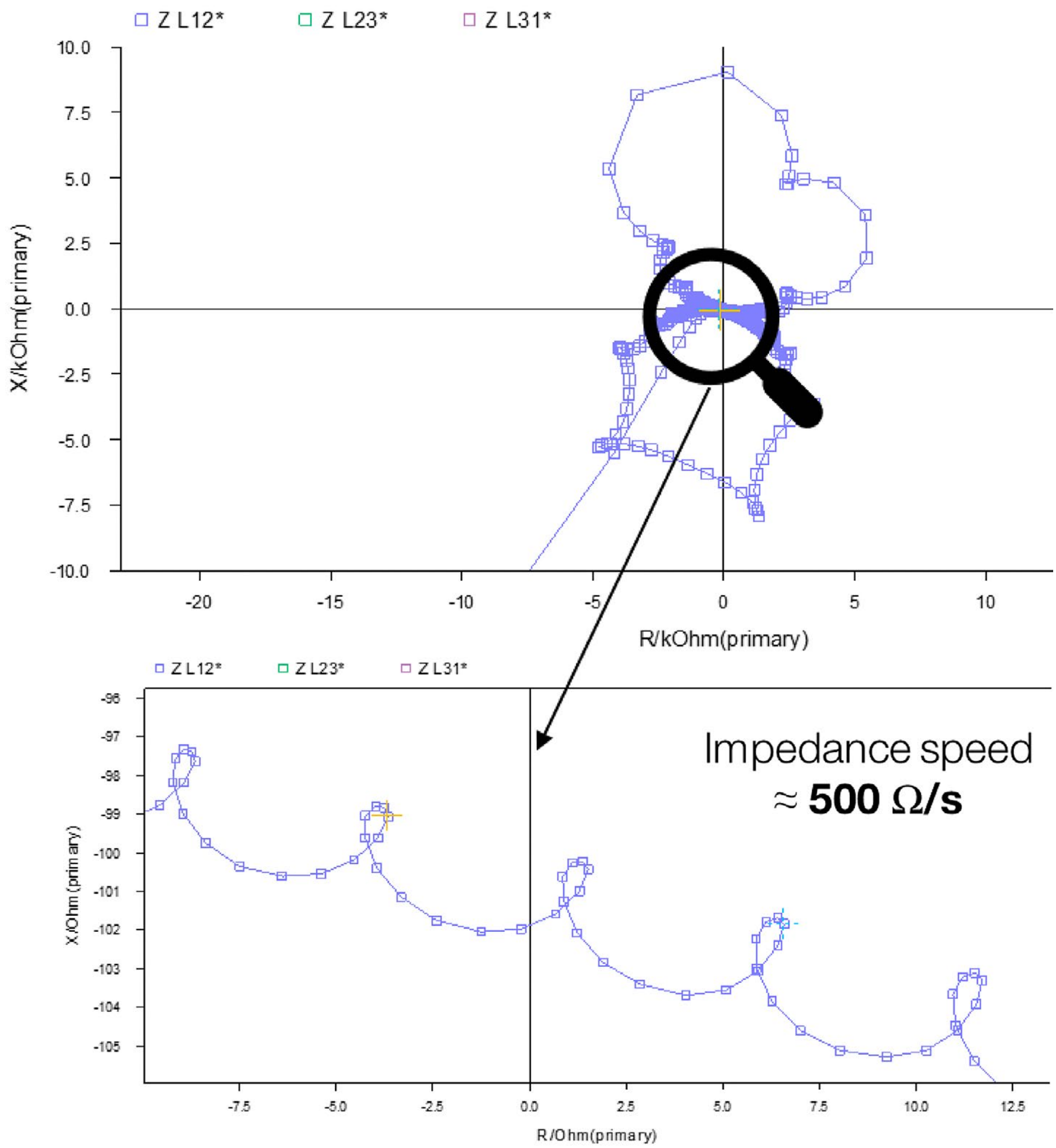


Figure 47: impedance trajectory seen by protection.

6 FREQUENCY SUPPORT AND ANALYSIS

6.1 Activation of Frequency Containment Reserves (Primary Control)

The frequency deviation on the Iberian Peninsula was very high in the first minutes after the separation, requesting the activation of the full amount of FCR in Spain and Portugal. According to ENTSO-E requirements for 2021, the FCR in Spain has to be 380 MW and 50 MW in Portugal.

As the frequency deviation was much higher than the predefined 200 mHz, REE and REN were required to activate the full amount of FCR within 30 seconds. According to the real-time unit's active power SCADA measurements, REE practically fulfilled this requirement with the activation of 376 MW. In Portugal, the FCR response was satisfactory as well. In the peak, it reached 58.5 MW, which is above the required value.

	FCR activated (MW)	FCR control block (MW)
Spain	376.0	380.0
Portugal	58.5	50.0

Table 31: FCR activated in Iberian Peninsula in the 30 second period after the incident.

To conclude, on the Iberian Peninsula the FCR responses were sufficiently fast and the requested quantities were delivered. The frequency change in the main part of the CE synchronous area network was much smaller and did not allow TSOs to check the response of the units participating in the FCR. Indeed, 30 seconds after the system split, so when the CE system reached a new stead-state, the frequency deviation in CE was lower than 40 mHz.

The FCR from units (or aggregations of units) which provided FCR after the incident was measured by considering the variation of the power output of the units from 16:36:36. The total amount of FCR estimated in the 30 second period after the incident is similar to the total amount of FCR for the Spanish Control Block (380 MW), as shown in Figure 48.

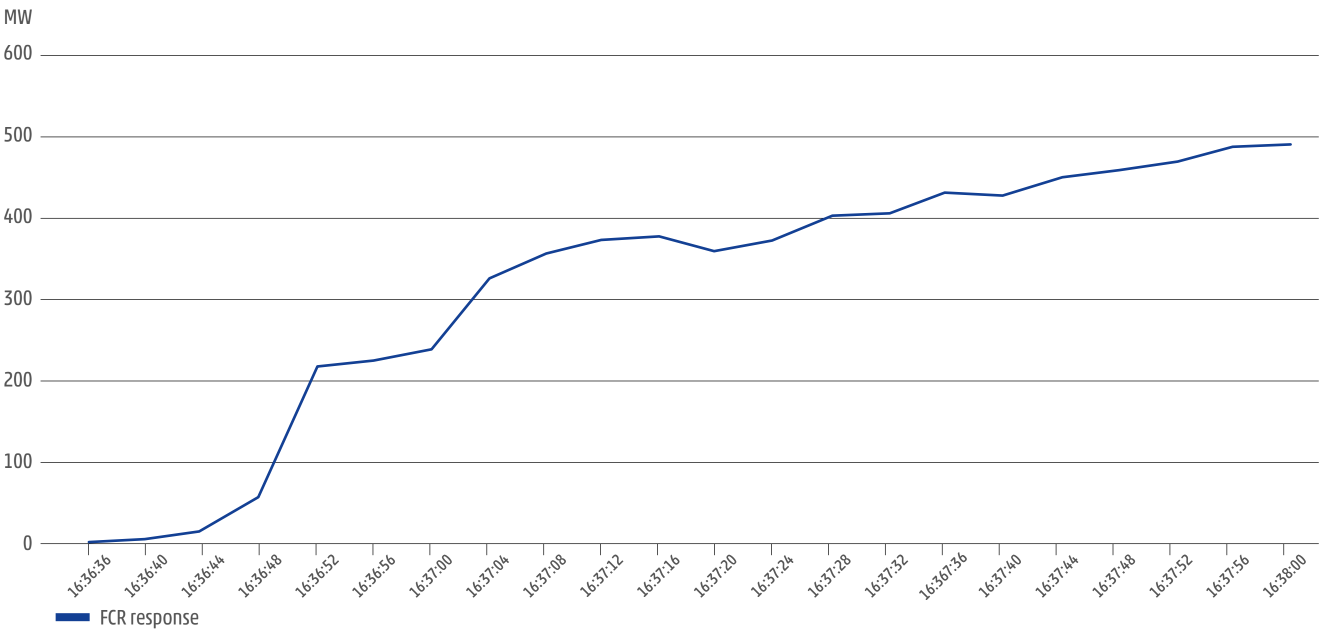


Figure 48: FCR activation in CB Spain.

6.2 Activation of automatic Frequency Restoration Reserves (Secondary Control)

The top part of Figure 49 presents the evolution of aFRR activation in Spain. Immediately after the incident, the activation of aFRR sharply increased as the frequency mode was automatically activated in the Spanish Control Block at 16:36:44, after the Iberian Peninsula disconnected from CE and the frequency drop went below 49.7 Hz, as seen in the bottom figure.

At 16:39:09, the absolute value of frequency deviation dipped lower than 250 mHz, and the frequency mode was automatically switched off because the Load Frequency Controller (LFC) did not detect that the Iberian Peninsula was still disconnected from CE. The reason for this was that the tie line Vic–Baixas remained connected, feeding the load in the Baixas node. Due to this, the Spanish LFC output gave a downward signal from 16:39:09 until 16:42:08, when the exchange schedule was manually set to 0. The subsequent variations of aFRR activation occurred due to the frequency deviation evolution. In addition, starting at 16:55, a downward signal was generated in the system due to the ramping of the exchange scheduled for 17:00, which was later manually corrected and set to 0.

REE was the frequency leader and the resynchronisation leader, according to the predicted scenario in the REE–REN agreement.

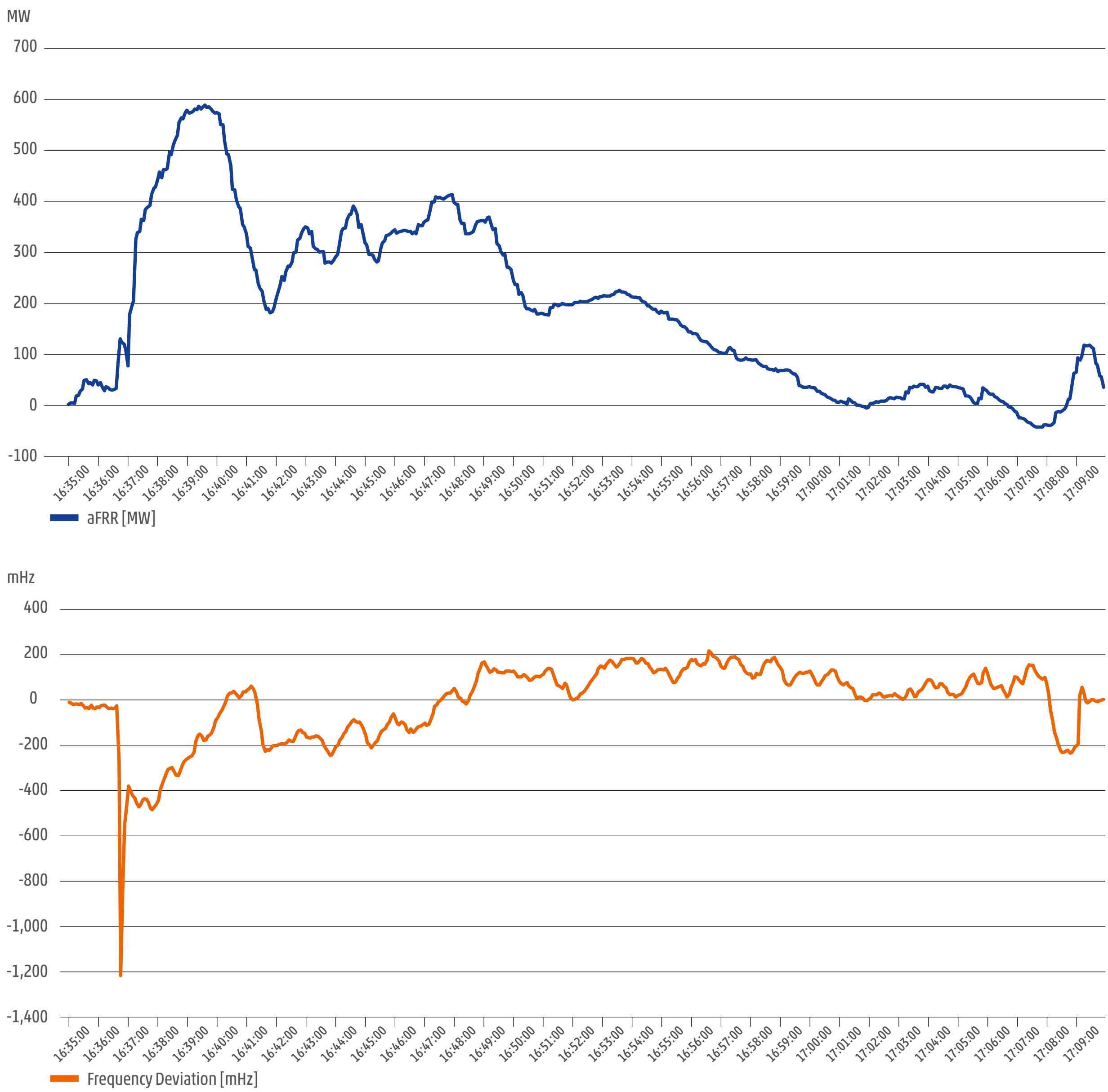


Figure 49: aFRR activation in CB Spain and frequency deviation in the Iberian Peninsula.

6.3 Manual countermeasures and system stabilisation in individual areas

In Spain, several manual frequency restoration reserve (mFRR) activations were requested by REE using the tertiary reserve mechanism as described in operational procedure 7.3 "Tertiary reserve" (2020), and provided by the most efficient service providers:

- At 16:29 (before the incident), downward mFRRs of 477 MW were requested. The activation was effective at 16:40.
- At 16:38 upward 1,008 MW were requested. The activation was effective at 16:45.
- At 16:45 upward 567 MW were requested. The activation was effective at 16:50.
- At 16:58 downward 1,125 MW were requested. The activation was effective at 17:00.
- At 17:21 upward 680 MW were requested. The activation was effective at 17:30.
- At 17:30 upward 907 MW were requested. The activation was effective at 17:35.

In Portugal, after the incident, there were no manual actions in the period just after the separation.

France remained connected to the main part of the interconnection. The frequency changed just slightly, and there was no need for mFRR activation.

6.4 Impact of coordination between affected TSOs during the incident

After the first line tripped (Event #1), REE and RTE jointly decided to reduce the power flow from France to Spain by 1.3 GW. IGCC ran without any problem during the whole incident period. Only correction for REE and REN (blue curves in following Figure 50 and Figure 51) stopped at the time of incident.

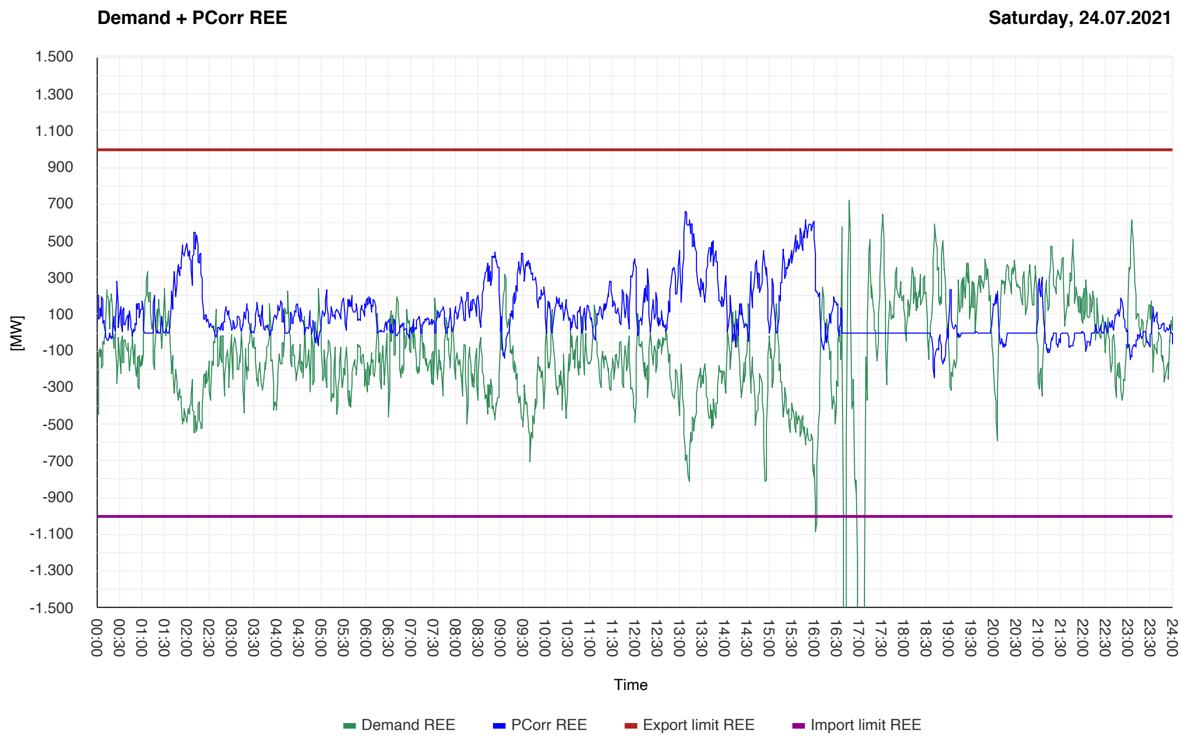


Figure 50: Control Block Spain participation in IGCC.

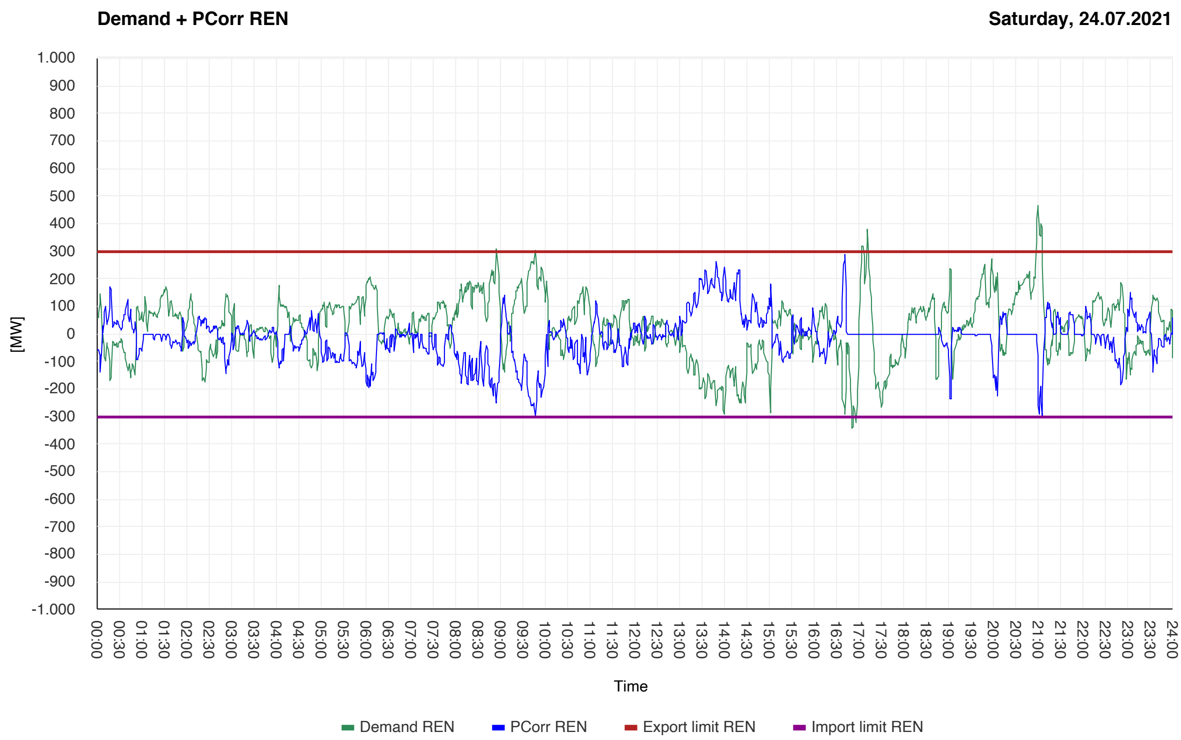


Figure 51: Control Block Portugal participation in IGCC.

7 RESYNCHRONISATION

Article 32 of the Network Code on electricity Emergency and Restoration (NC ER)[5] stipulates the following (Resynchronisation procedure):

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.

7.1 Preconditions for system resynchronisation

Once the incident occurred, the highest priority was to stabilise the Iberian Peninsula System in terms of voltage and frequency and to prepare the resynchronisation with the European Continental System. During the first few minutes, the resupply of load previously disconnected was not allowed due to the frequency relays activation. Once the frequency value reached 50 Hz, the progressive resupply of load was authorised stepwise (not higher than 50 MW), aimed at bringing the Iberian Peninsula frequency close to the CE System. REE performed the role of frequency leader following the bilateral agreement established between REN and REE, in which it is agreed that REE will be the frequency leader in case of separation of the Portuguese and Spanish system from the rest of CE.

7.2 Preparatory actions

REE performed the role of resynchronisation leader following the bilateral agreement established between RTE and REE. The strategy and the measures to synchronise both regions were jointly defined between RTE and REE by phone in real time. It was agreed to perform the reconnection by energising the L-400 kV line Hernani–Argia from Argia 400 kV and synchronising from Hernani 400 kV using the dedicated resynchronisation devices once the frequency was stable and the frequency difference between areas was low.

7.3 Resynchronisation sequences

The lines which tripped during the incident were reconnected according to the following sequence:

- The resynchronisation with the Continental European System was performed at 17:09 by energising the 400 kV Hernani–Argia line from Argia 400 kV and synchronising at Hernani 400 kV.
- At 17:17, RTE reconnected the 400 kV Baixas–La Gaudière 1 line.
- At 17:28, the 220 kV Biescas–Pragneres line was reconnected.
- At 17:33, the 220 kV Arkale–Argia line was reconnected.
- The 400 kV Baixas–La Gaudière 2 line remained unavailable. RTE reconnected it on 25 July at 13:46.

5 Commission Regulation (EU) 2017/2196, establishing a Network Code on Electricity Emergency and Restoration (NC ER)

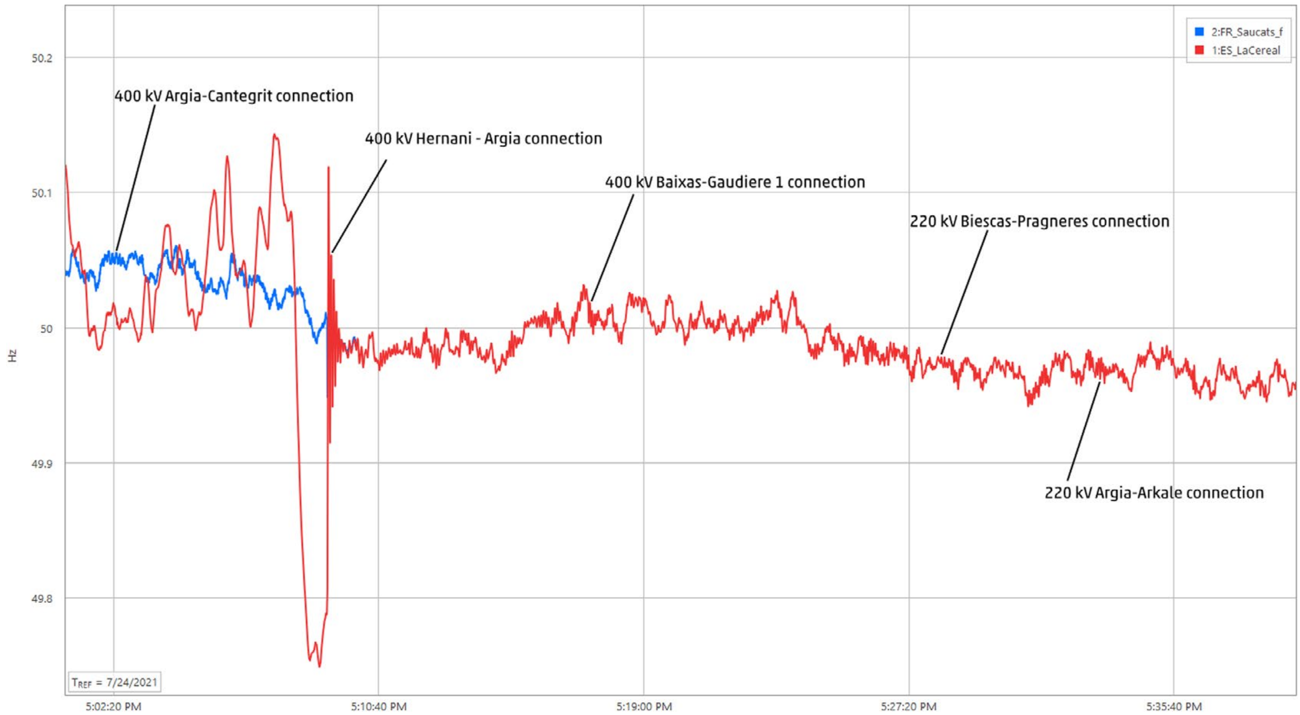


Figure 52: Frequencies and resynchronisation sequence.

It is worth noting that due to an increase in the frequency difference between systems during the process of reconnecting, the frequency difference was 218 mHz. The dedicated resynchronisation device setting for the maximum allowed system frequency difference was set to 300 mHz.

After the resynchronisation, a power oscillation was observed on the 400 kV Hernani–Argia line active power and on the frequency. The power oscillation had a frequency of 0.20 Hz and an amplitude of 1,840 MW peak–peak, which disappeared in approximately 30 s, leaving a load in a steady state of 500 MW through the 400 kV Hernani–Argia line. This is illustrated in Figure 53.

Recommendation 5 on "Review the dedicated resynchronisation devices settings for tie-lines" recommends reviewing the settings of the resynchronisation devices to avoid the synchronisations while large frequency deviations are still registered.

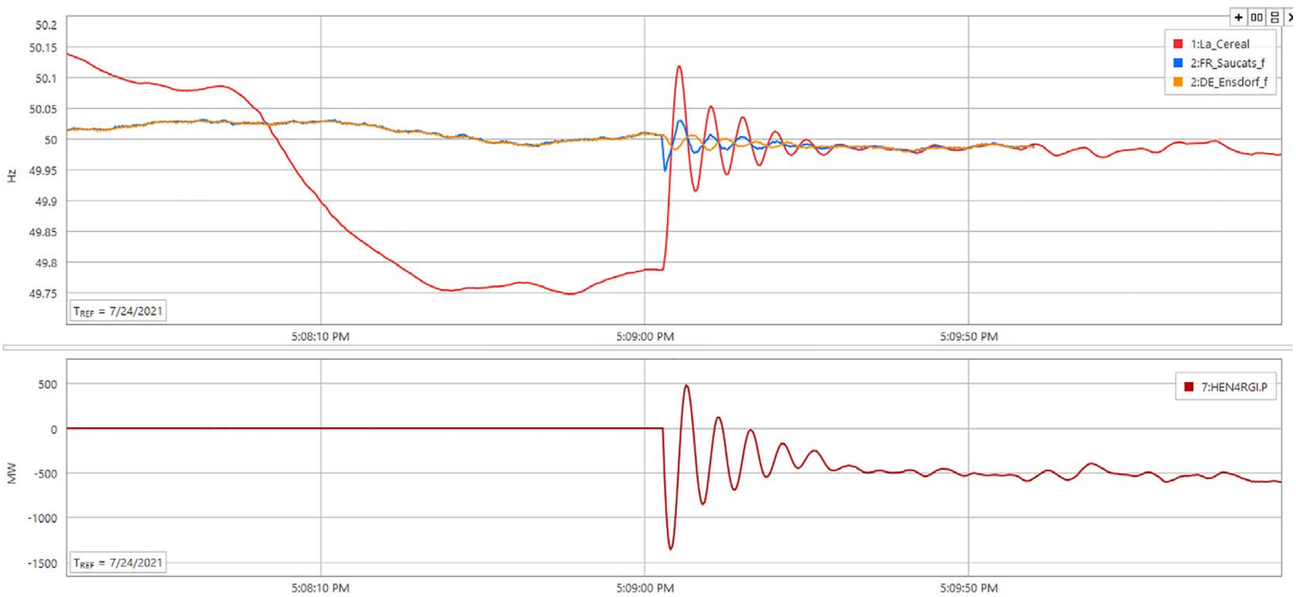


Figure 53: Flow through 400 kV Hernani–Argia line during the resynchronisation.

8 N-1 SECURITY EVALUATION

8.1 Contingency analyses

The operational security of any power system relies on respecting the operational security limits and on the application of the System Operation Guidelines (SO GL)[6], which state that any single contingency should not endanger the system.

Contingency analyses are performed by RTE pursuant to SO GL Article 34.

Article 34 of the SO GL stipulates in particular that:

1. *Each TSO shall perform contingency analysis in its observability area in order to identify the contingencies which endanger or may endanger the operational security of its control area and to identify the remedial actions that may be necessary to address the contingencies, including mitigation of the impact of exceptional contingencies.*

2. *Each TSO shall ensure that potential violations of the operational security limits in its control area which are identified by the contingency analysis do not endanger the operational security of its transmission system or of interconnected transmission systems.*

3. *Each TSO shall perform contingency analysis based on the forecast of operational data and on real-time operational data from its observability area. The starting point for the contingency analysis in the N-Situation shall be the relevant topology of the transmission system which shall include planned outages in the operational planning phases.*

RTE continuously checks the contingency analysis and applies – or plans to apply – available remedial actions if necessary to mitigate the consequences. To do so, RTE is using an up-to-date real-time and forecasted network model of its control area merged with the ones provided by neighbouring TSOs. These models include planned and forced outages on the grid, topological options, local generation and demand forecast.

This set of data is merged and computed in operational planning (from monthly, weekly, and day-ahead up to intra-day). In addition, contingency analyses are updated by RTE every 15 minutes in real time.

6 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a Guideline On electricity transmission System Operation (SO GL)

RTE's contingency list is established pursuant to SO GL Article 33.

Regarding the contingencies to be monitored by TSOs, Article 33 of the SO GL "Contingency lists" specifies that:

> 1. *Each TSO shall establish a contingency list, including the internal and external contingencies of its observability area, by assessing whether any of those contingencies endangers the operational security of the TSO's control area. The contingency list shall include both ordinary contingencies and exceptional contingencies identified by application of the methodology developed pursuant to Article 75.*
>
> 2. *To establish a contingency list, each TSO shall classify each contingency on the basis of whether it is ordinary, exceptional or out-of-range, taking into account the probability of occurrence and the following principles:*
>
>   *[A] each TSO shall classify contingencies for its own control area;*
>
>   *(b) when operational or weather conditions significantly increase the probability of an exceptional contingency, each TSO shall include that exceptional contingency in its contingency list; and*
>
>   *(c) in order to account for exceptional contingencies with high impact on its own or neighbouring transmission systems, each TSO shall include such exceptional contingencies in its contingency list.*

RTE is considering ordinary and exceptional contingencies, depending on operational conditions, in its contingency list where "exceptional contingency" refers to SO GL Article 3 Definitions, which specifies:

> *(39) "exceptional contingency" means the simultaneous occurrence of multiple contingencies with a common cause;*

Multiple contingencies could be relevant regarding the sequence of events on 24 July: the initial trip of the 400 kV Baixas–Gaudière 2 line was followed, a few minutes later, by a trip on the 400 kV Baixas–Gaudière 1 line. These two lines are part of a double-circuit line and share the same towers. As such, the simultaneous occurrence of the contingency of both lines cannot be excluded.

RTE includes the double-circuit contingency in its contingency list under exceptional environmental conditions only.

Article 8 of ACER's decision on a methodology for coordinating operational security analysis provides that:

> 1. *Each TSO shall determine for each exceptional contingency the relevance and criteria of application of the following occurrence increasing factors: [...]*
>
>   *(b) temporary occurrence increasing factors: [...]*
>
>   *(ii) weather or environmental conditions;*

The **weather conditions** mentioned in Article 33(2)b of the SO GL are duly considered by RTE: strong wind, lightning storms and sticky snow episodes are factors deemed likely to increase the probability of occurrence of the loss of a double-circuit line.

Regarding **environmental conditions**, RTE considers **wildfires** close to double-circuit lines.

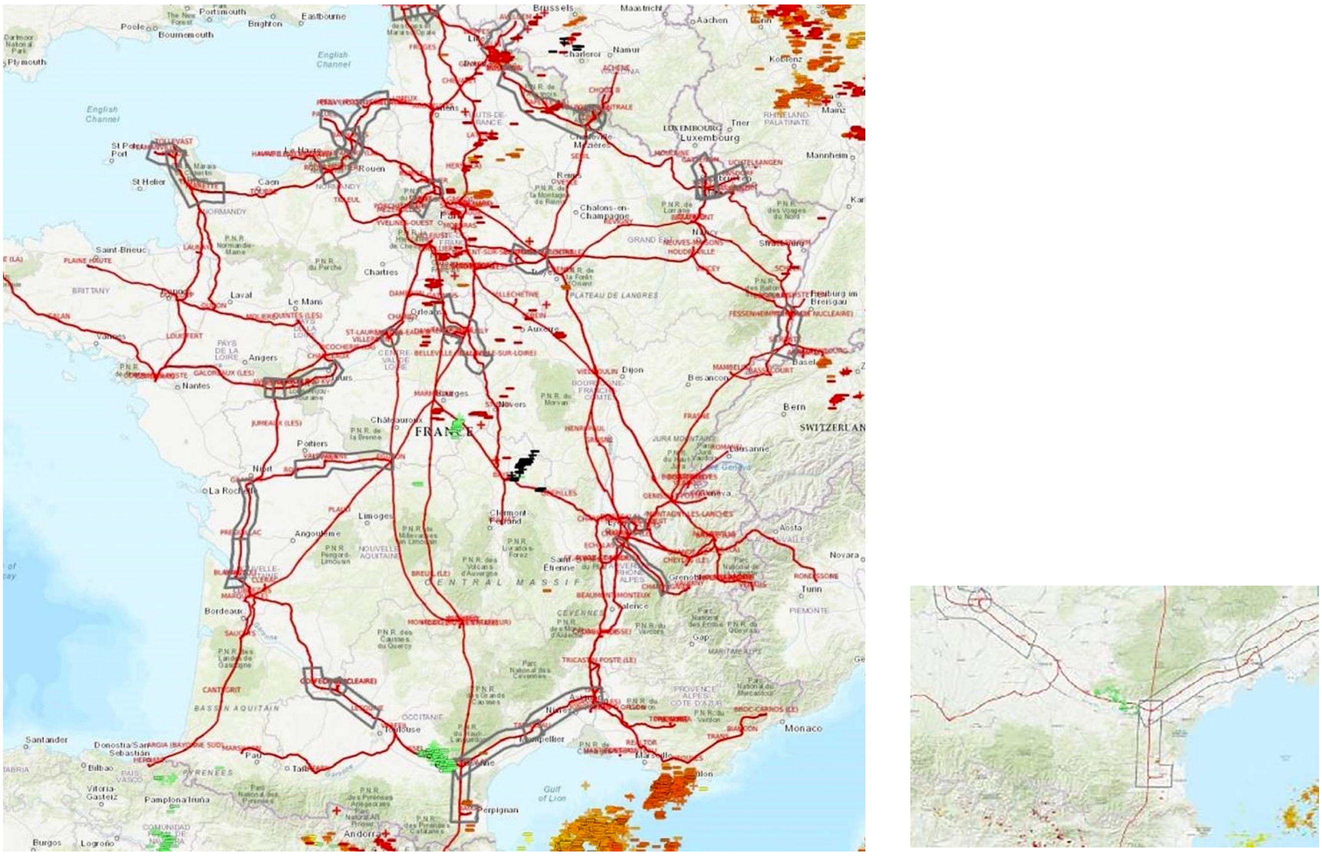


Figure 54: Real-time monitoring of lightning events close to the 400 kV French Grid.

RTE is informed by national agencies by means of dedicated information and alarm processes, as dictated by bilateral agreements. In particular, in the event of weather conditions that may pose a risk to electrical components, the French Weather Agency Meteo-France promptly informs RTE by means of automatic alarms. For example, Figure 54 shows the visualisation platform for lightning monitoring, and Figure 55 shows the visualisation platform for generic dangerous environmental conditions such as risk of high winds, thunderstorms, sticky snow, etc. In the event of wildfires close to double-circuit lines, the French Fire Department informs RTE.

As soon as RTE is informed about weather or environmental severe conditions developments, RTE assess if these changes are increasing the probability of the occurrence of a double fault in double-circuit transmission lines. In the event the risk exists, a new contingency analysis is executed, and the double-circuit contingency is added to the contingency list used to perform security analysis. This process is activated promptly as soon as RTE assess an increased risk for double-circuit faults, and the contingency list is update in all the upcoming security calculations. That is to say, if the information is available in Day-Ahead, the contingency list is enlarged accordingly in the Day-Ahead studies. However, in Intra-day, RTE updates the contingency list in the daily periodic security analysis using the latest information available.

Moreover, RTE considers the probability of occurrence mentioned in SO GL Article 33(2) to establish its contingency list. Long-term statistics in France reveal that double-circuit contingencies have mostly occurred under exceptional **weather** conditions. As an example, the previous proximate tripping of the 400 kV Baixas–Gaudière lines were recorded on 28 January 2017 at 01:15 and 04:12. These occurred under lightning storm conditions. Considering that there were several hours between the two lines tripping, this event cannot be considered as an exceptional contingency, and it occurred under exceptional weather conditions.

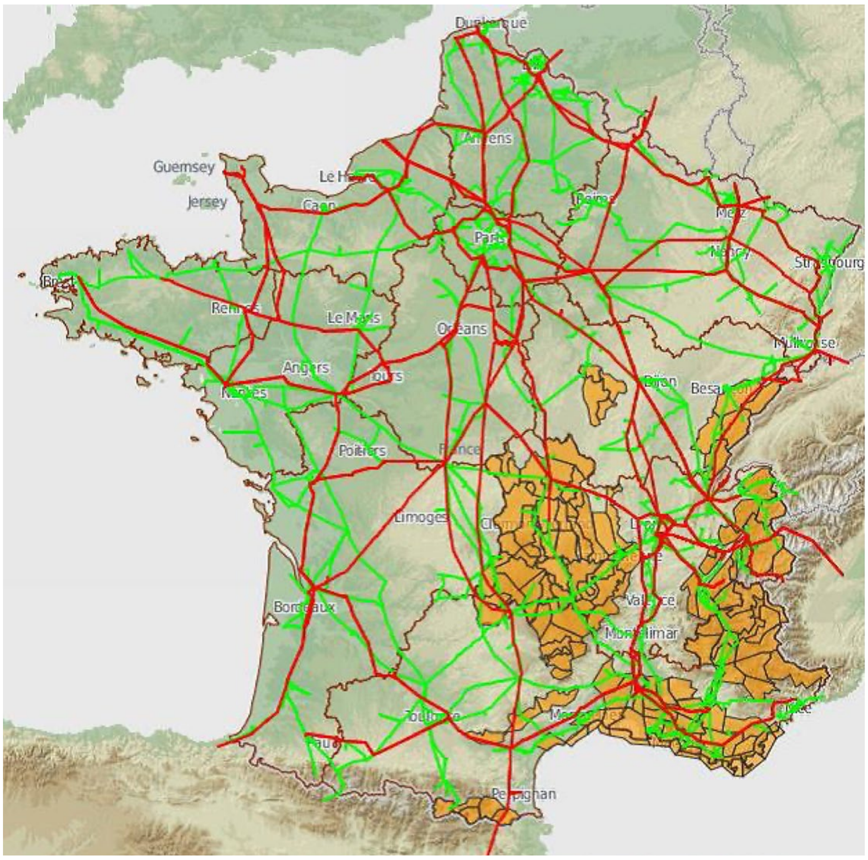


Figure 55: Day-ahead monitoring of special weather conditions (orange area: risk of high winds, thunderstorms, sticky snow…).

To establish its contingency list, RTE considers the potential impact of remedial action compared to the very low probability mentioned in Article 33 §2(c). In particular, if the remedial action is very costly compared to a very low probability, these contingencies are only covered during exceptional weather conditions or natural hazards (risk of high winds, thunderstorms, sticky snow…). As RTE determines, the Baixas–Gaudière double-circuit contingency requires the exchanges between France and Spain to be limited by more than 1,000 MW, depending mostly on the market coupling and on the network outages to a much lower level. should be stressed that a 1,000 MW reduction represents between 25 % and 30 % of the exchange capacity between the Iberian Peninsula and Continental Europe. The double-circuit fault on Baixas–Gaudière is a low probability event (over the 20 past years, the only double-circuit fault was in 2009, during the Klaus Storm special event), whereas such permanent and massive reductions would have a significant impact on social welfare, energy exchanges and system adequacy.

Over the last 20 years, 26 unplanned outages of Baixas–Gaudière occurred, as detailed in Table 32.

Line	Type of trip	Nb Trip
Baixas Gaudière 1 400 kV	fugitive	13
	permanent	2
Baixas Gaudière 2 400 kV	fugitive	8
	permanent	3

Table 32: Unplanned outages on Baixas Gaudière since 2002.

The causes of the unplanned outages on Baixas Gaudière since 2002 are mainly Lightning and Wind&Storm, as detailed in Figure 56. Lightning and Wind&Storm are events for which MeteoFrance is providing information to RTE, in Day-Ahead, allowing the contingency list to be adjusted for the security analyses.

Considering the 400 kV lines between France and Spain (Baixas Gaudiere 1&2, Argia Hernani, Argia Cantegrit, Baixas Vic and Baixas Santa Llogaia 1&2), wildfires are the cause of trip in 1 % of the unplanned outages. The main causes are Wind/Storm and Lightning, as detailed in Figure 57.

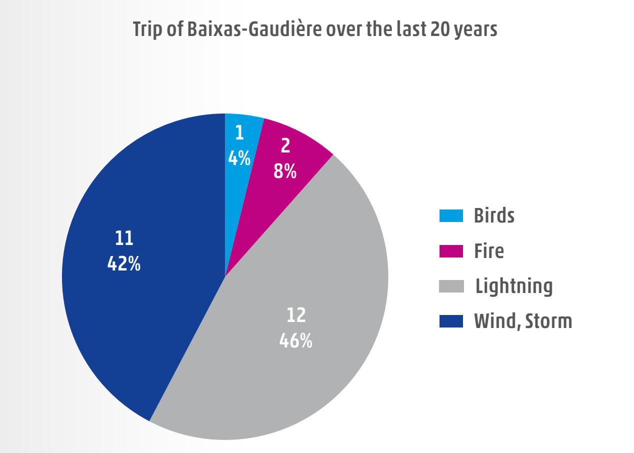


Figure 56: Causes of unplanned outages on Baixas-Gaudière since 2002.

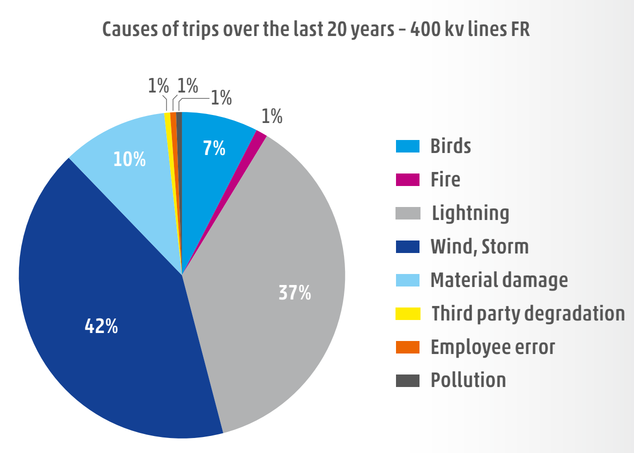


Figure 57: Causes of unplanned outages on 400 kV lines between France and Spain since 2002.

On 24 July, in the event that RTE had been informed about the risk that a wildfire could be approaching close to the 400 kV Baixas–Gaudière double-circuit line, RTE would have assessed the related double contingency. The outcome of the contingency analysis would have been the preventive activation of the 1,500 MW counter-trading that was identified as necessary after the initial trip of the 400 kV Baixas–Gaudière 2 line on 24 July. For the sake of clarity, during contingency analysis, a first volume of countertrading is estimated. When activating it in real-time, the TSOs have to update the volume to feet with the exact need and possibility. In the present case, a volume of 1,300 MW has been agreed.

8.2 Robustness to sequences of N-1s

The robustness to consecutive N-1s is described in SO GL article 35, Contingency handling:

> *4. A TSO shall not be required to comply with the (N-1) criterion in the following situations:*
>
> *[A] during switching sequences;*
>
> *(b) during the time period required to prepare and activate remedial actions.*

Thus, TSOs do not have to cover all sequences of successive contingencies, whereas their main objective is to anticipate remedial actions, in order to react rapidly in case of contingency.

Having received no information on exceptional environmental conditions for 24 July, prior to the intraday operational planning, RTE was operating the grid without the exceptional contingency N-2 Baixas–Gaudière 1 and 2 in its contingency list. Hence, operators in RTE's national control room had to ensure that an N-1 situation on Baixas–Gaudière would not endanger the system and that all operational limits were respected. Baixas–Gaudière circuit 2 tripped at 16:33:12. Within a few minutes, at 16:34 and using pre-defined remedial actions, RTE's operators coordinated with their colleagues in REE's national control room on how to restore the ability of the interconnected system to face another N-1. A reduction of the physical exchanges on the border was agreed to. Downward orders were sent to reduce the French net position. Upward orders were sent to increase the Spanish one. The fastest offers were selected on both sides, but the orders could not be met instantaneously due to ramping constraints on generation units as well as AGC (Automatic Generation Control) parameters (for stability purposes). For a period of time, the French system was not robust to another N-1 close to the border, and the tripping of the second Baixas–Gaudière 1 in particular. The modification of flows is usually achieved in about 10 minutes.

8.3 Conclusion

In accordance with SO GL, the contingency analyses process is based on the statistics that the loss of a double-circuit has a very low probability of occurrence and only occurs under exceptional weather or environmental conditions. The loss of a double circuit may occur as a single event, with both circuits tripping simultaneously, as in the case of the collapse of a pylon carrying the double circuit line or, as in the incident of July 24, as two separate events within a few minutes. It is only when real-time conditions increase the probability of the loss of a double-circuit that exceptional contingencies must be considered. The TSOs are then required to manage the system operation risks and implement remedial actions timely.

The communication chain between RTE and Fire Services usually works reliably (see wildfires on 11 August 2021 close to the 400 kV double-circuit Gaudière–Issel 1 and 2), but the consequences of a failure as on 24 July indicate the need for substantial actions from RTE to secure the process and to ensure such an event will not happen again. The process review has already started, with concerned services (fire departments) and other provisions being investigated (such as using real-time satellite pictures, acquiring new informing systems, etc.) to ensure the awareness of exceptional conditions close to the transmission lines. Further details are given in **Section 14.2.2**, Recommendation 2: "Improving the assessment and handling of weather related risks".

9 COMMUNICATION OF COORDINATION CENTRES/SAM AND BETWEEN TSOs

Communication among TSOs as well as with SAMs is the basis for the operation of a wide, interconnected system. It ensures a common view of the situation, shared analyses, and coordinated actions on the grid.

This communication is essential for day-to-day business, and of utmost importance in the event of an incident. TSOs' operators usually communicate by phone and, when necessary, by e-mail to confirm the information previously exchanged. They also share a common tool: EAS (ENTSO-E Awareness System), which allows for the sharing of the system states and other important information in all countries among all European TSOs.

This communication took place on 24 July and is further detailed in the present chapter. This communication is, of course, performed in addition to usual TSO business in each national control room. In particular, just before the separation and up until the reconnection of the grid, close coordination took place between RTE and REE.

Within the Synchronous Area Continental Europe (SA CE) two Coordination Centres (CC) are defined on a geographical basis. This responsibility is fulfilled by Amprion (Germany) for the Northern part of Europe and Swissgrid (Switzerland) for the Southern part on behalf of the Regional Group Continental Europe (RG CE) TSOs. The two CCs are, in addition to the coordination and verification of scheduling, responsible for the coordination of accounting and unintended energy exchange within and between both blocks of the SA CE. Furthermore, the CCs carry out the role as the SAM of the SA CE.

As part of the responsibility as SAM, the CCs fulfil various tasks in real-time operation e.g. monitoring of system frequency, determination of the system state with regard to the system frequency, monitoring of grid time and coordination of correcting any grid time deviations. Furthermore, they are responsible for the procedures and coordinated countermeasures. During emergency situations, the SAM carry out additional activities, among others: carrying out frequency procedures, being the contact point for affected and non-directly affected TSOs and documenting agreed additional measures to solve the emergency situation.

The SO GL Article 133 defines the SAM of the RG CE, meaning the TSO responsible for collecting the frequency quality evaluation criteria data and applying the frequency quality evaluation criteria for the synchronous area. According to Article 153(5) of the SO GL, the SAM shall ensure that all TSOs of all synchronous areas are informed in the event the system frequency deviation fulfils one of the criteria for the alert state referred to in Article 18.

The responsible CC was in contact with the affected TSOs (RTE and REE) immediately after the separation and regularly throughout the whole event. The CCs informed all other TSOs about the ongoing situation, as explained in the next section. They contacted all RG CE TSOs via phone (Amprion for CC North, Swissgrid for CC South), via the EAS system and via email. Amprion further coordinated measures concerning IGCC. After resynchronisation, Amprion informed all TSOs about the end of the situation via EAS platform and via email.

The NC ER Article 29 further defines that during system restoration, when a synchronous area is split in several synchronised regions, the TSOs of each synchronised region shall appoint a frequency leader, meaning the TSO appointed and responsible for managing the system frequency within a synchronised region or a synchronous area to restore system frequency back to the nominal frequency.

Amprion as SAM took over the role as frequency leader for the bigger island of RG CE in analogy to Article 29 NC ER, even if NC ER was not explicitly applicable as emergency status in the bigger island of RG CE was not declared in accordance with SO GL. Furthermore, REE was appointed as frequency leader for the smaller island with REN and REE, according to a bilateral agreement between REN and REE. Both TSOs were thus responsible for managing the system frequency in order to restore system frequency back to the nominal frequency in their respective island.

9.1 Timeline of communication among SAM and TSOs

Details of all communications between TSO, SAMs and Regional Coordination Centres are shown below:

- **16:34:** Immediately after the first tripping of the 400 kV Baixas-Gaudière 2 line, phone discussions began between the national control centres of RTE and REE to analyse the situation and jointly decide to decrease cross-border exchanges from 2.5 to 1.2 GW (reduction of 1.3 GW).
- **16:38:** Two minutes after the tripping of the 400 kV Baixas-Gaudière 1 line and the disconnection of the Iberian Peninsula, RTE set "Emergency State due to critical event" on the EAS Platform (see Table 33).
- **16:38:** Additional contact was made between RTE and REE, resulting in the following joint decision: exchanges to be reduced to 0 MW.
- **16:40:** The first coordination call occurred between Swissgrid and Amprion (decision: Swissgrid will call RTE and REE as they are geographically located within CC South).
- **16:44:** Call between TNG as IGCC Host and Amprion (CC) (involving information about the separation of REE from IGCC and the decision that REN should be separated by TNG as well).
- **16:45:** Discussions between CORESO and RTE to inform CORESO about the two trips.
- **16:48:** Additional communication between REE and RTE to exchange information about the reconnection strategy and frequency stabilisation on the Iberian side.
- **16:50:** Second coordination call between Swissgrid and Amprion (update of information; decision that AMPRION will take the lead as CC for this system split, in its role as SAM).
- **16:52:** AMPRION (SAM) called RTE to ask for information about the event and reconnection strategy.
- **16:52:** REN's control room operator contacted REE's control room operator and confirmed that the existing protocol was applicable in this specific situation. It was also determined that the scheduled exchange program should be maintained.
- **16:53:** AMPRION starts to inform all TSOs (North) via phone.
- **16:55:** Another call between RTE and REE. Discussions focused on frequency reconnection and the decision of which substation to be used for the re-closing device: the reconnection should be done at Hernani Station.
- **16:57:** Third coordination call between Swissgrid and Amprion (decision: Swissgrid will inform TSOs (South) as well.
- **16:57:** EAS Freetext Message was sent by Amprion (see Figure 58).
- **16:57:** Information about the system split was sent to all TSOs via mail by Amprion.
- **17:05:** Call between REE and Amprion to discuss further steps.
- **17:09:** Reconnection between areas. RTE and REE coordinated by phone during this reconnection.
- **17:12:** Call between RTE and Amprion (information that both islands are reconnected again).
- **17:14:** Fourth coordination call between Swissgrid and Amprion (information that islands are reconnected again).
- **17:19:** EAS free-text-message that islands are reconnected again by Amprion (see Figure 58).
- **17:27:** Mail was sent by Amprion to RG CE TSOs with the information that the islands are reconnected again.
- **17:31:** End of RTE Emergency State on EAS Platform (see Table 33).
- **17:41:** Discussions between RTE and AMPRION to explain the reconnection conditions and update the state of grids. RTE announced that the presumed cause of the trips is a fire.
- **17:43:** Call between RTE and Amprion (status update).
- **17:53:** RTE and REE calculated new NTC values (1,000 MW).
- **18:49:** Email from RG CE Convenor to RG CE members.
- **20:52:** Publication on REMIT Platform: Outage of 400 kV Baixas–Gaudière 2 line.

In addition to this operational information, the management of the TSOs had several exchanges to provide updates about the situation, its evolution and actions undertaken.

As detailed in this call-log, the communication among TSOs and SAM was very intensive and efficient during this event, allowing for a fast resolution of the incident. Use of the EAS, as the awareness tool for all EU TSOs, also facilitated this communication, avoiding multiple phone calls to share information about the situation.

In the Portuguese control area, REN followed the bilateral agreement established between REN and REE in 2012, where such a system split scenario was foreseen. In that agreement, it was determined that in the event of a separation of the Portuguese and Spanish system from the rest of RG CE, REE is the frequency and resynchronisation leader.

Table 33 reports the main messages generated by the EAS system. Nevertheless, CC Nord and CC South did not change the CCN and CCS system state, because of the limited capabilities of the EAS system to detect a system separation where part of the separation line is within one TSO area and not completely at the border between two TSOs.

Time	TSO	System State	Main Message
24.07 16:38:44	RTE	Emergency state	Critical event
24.07 17:31:19	RTE	Normal state	
24.07 18:09:52	REE	Emergency state	Loss of tools and facilities
24.07 18:33:08	REE	Normal state	

Table 33: EAS states and main messages reported by the EAS system.

The EAS platform was also used for several text messages in order to inform all TSOs and improve the overall situational awareness, as shown in Figure 58, which reports the EAS free text messages.

A	Date/Time	B1	B2	B3	Elem	Status
******* Saturday 24.07.2021 *******						
	24.07 16:57:27	Message from:	DE_AMPRN	to ALL		
	FTM	System Split in RGCE Split under investigation Amprion is in lead as CC				
	24.07 17:19:25	Message from:	DE_AMPRN	to ALL		
	FTM	The two islands are back together Further information will follow via email				
	24.07 18:32:53	**Message from:**	**FR_RTE to**	**ALL**		
	FTM	Separation SpainPortugal from Europe after trips in RTE reconnection at 17h09				
******* Monday 26.07.2021 *******						

Figure 58: EAS free text messages manually sent by operators.

9.2 Communication between RSCs and TSOs

In addition to the timely communication and coordination between the affected TSOs and the CC / SAM, the following communication occurred for informative purposes between Coreso, the RSC covering the geographical area of France, Spain and Portugal, TSOs and other RSCs:

» **Approximately 16:40:** Elia calls Coreso for information regarding an observed frequency deviation and a detected exchange imbalance. Coreso observed unusual flow deviations on the FR/ES border using the Coreso data acquisition system.

» **16:45:** Discussion between Coreso and RTE takes place, confirming a decoupling between FR and ES due to lines tripping. The information is provided to Elia.

» **After the event,** restoration updates are provided to Coreso by RTE. Coreso provides an update to TSCNET, who requests Coreso to share this information at the Daily Operation Planning Teleconference (DOPT conference).

» **21:00:** Coreso provides an update on the situation to TSCNET and TSOs during the DOPT conference call.

There is currently no task assigned to RSCs that stipulates the inclusion of the RSCs as an additional coordinating party in the resynchronisation process. Article 37.1.h. of (EU) 943/2019 foresees such a task for the Regional Coordination Centers (successors to the RSCs): supporting the coordination and optimisation of regional restoration as requested by transmission system operators. Due to the geographical situation of the Iberian Peninsula REE and the fact that operational procedures between REE and REN are well established and very efficient in terms of the resynchronisation process, it is not expected that such support will be required in the near future for incidents limited to the Spanish and Portuguese transmission systems.

10 MARKET ASPECTS

10.1 Day-ahead Capacity Calculation

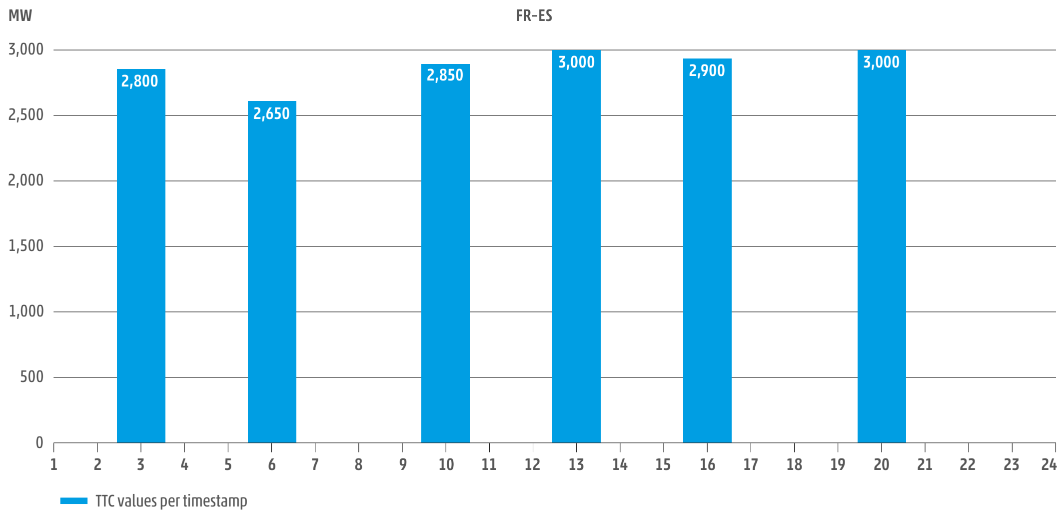
The day-ahead capacity calculation is based on the Capacity Allocation and Congestion Management (CACM)[7] Guideline.

The capacity calculation is executed by Coreso based on the coordinated capacity calculation methodology developed by REN, REE and RTE and approved by the respective National Regulatory Authorities (NRAs).

The calculation of Total Transfer Capacities (TTCs) for six timestamps is completed by Coreso and a proposal is sent to TSOs. A validation process is then completed by TSOs; subsequently, a spanning to allocate the 24 hours based on the 6 calculated timestamps is done by the TSOs. Their answers are sent and processed by Coreso to set the final TTC of each border in each direction. To then calculate the NTC, the following parameters are used:

NTC = TTC – TRM

The Transmission Reliability Margin (TRM) is 7.5 % of TTC for the ES–FR border with a minimum of 200 MW. The TRM is 10 % of TTC for the PT–ES border with a minimum of 100 MW.



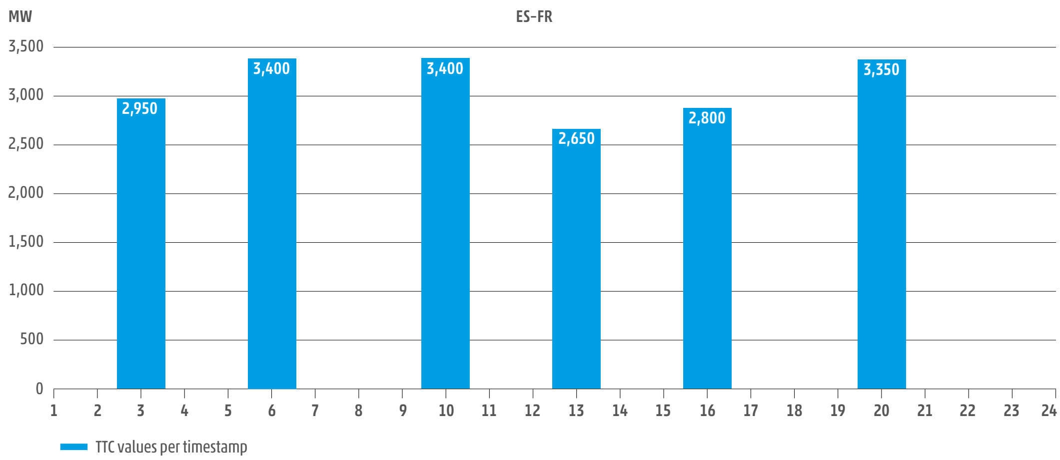


Figure 59: TTC calculation results for the FR/ES border.

7 Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM)

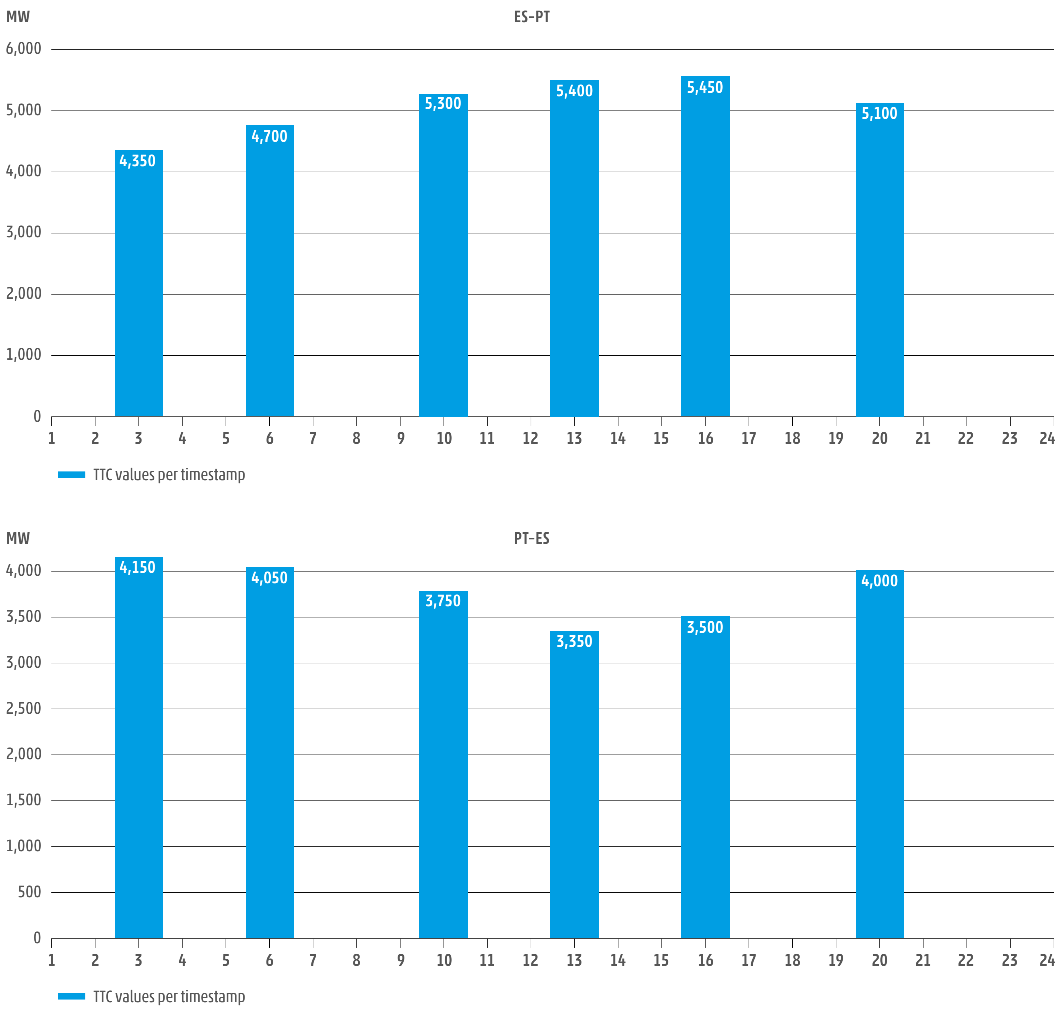


Figure 60: TTC calculation results for the PT/ES border.

10.2 Day-ahead, Intraday Congestion forecast and real-time snapshot calculations

The security analysis for SWE is performed by Coreso on day ahead and intraday, using information from Day-Ahead Congestion Forecast (DACF) and IntraDay Congestion Forecast (IDCF) files.

On request of TSOs, in addition to the regular intraday cycle, additional Intraday Coordinated Regional Operational Security Assessments can be executed.

The Intraday snapshot for the timestamp 24 July 2021 – 16:30 was based on the last grid model created before the incident around 16:00.

As there were no extraordinary intraday requests, no further intraday calculations were performed around the time of the system split.

For some TSOs and regions, other than for SWE CCR, Coreso regularly performs a security calculation based on merged real-time snapshots provided by the TSOs. This activity runs offline and cannot be used as a basis for real-time system operation evaluations.

An active security coordination between the RSC and the TSOs during the system split period did not occur.

TSO	Lines	Flows in MW		
		DACF	IDCF	Snapshot
REE	Azpeitia - Gatica 400 kV	298	249	317
	Bescano - Sentmenat 400 kV	290	196	260
	Azpeitia - Hernani 400 kV	–379	–342	–379
	Hernani - Ichaso 400 kV	417	333	400
	Bescano - Vic 400 kV	112	117	100
	Pierola - Vic 400 kV	–112	–102	–100
REE → REN	Aldeadavila - Lagoaca 400 kV	–442	–365	–199
	Aldeadavila - Pocinho 1 220 kV	–72	–58	–27
	Aldeadavila - Pocinho 2 220 kV	–71	–58	–27
	Brovale - Alqueva 400 kV	–303	–302	–362
	Cartelle - Alto Lindoso 1 400 kV	–131	–75	–110
	Cartelle - Alto Lindoso 2 400 kV	–131	–75	–110
	Cedillo - Falagueira 400 kV	–247	–234	–302
	Pueguzma - Tavira 400 kV	–252	–260	–268
	Sub TOTAL	–1,649	–1,427	–1,405
RTE	Argia - Cantegrit 400 kV	–1,192	–1,139	–1,131
	Cantegrit - Mouguere 225 kV	337	301	276
RTE ← REE	Arkale - Argia 220 kV	–165	–190	–130
	Hernani - Argia 400 kV	–988	–900	–1,029
	Santa Llogaia - Baixas 1 400 kV	–525	–496	–444
	Santa Llogaia - Baixas 2 400 kV	–525	–496	–444
	Biescas - Pragneres 220 kV	–179	–179	–150
	Vic - Baixas 400 kV	–300	–277	–255
	Sub TOTAL	–2,682	–2,538	–2,452

Table 34: Summary of RSC calculation results for 24 July 2021, 16:30.

10.3 Day-ahead and Intraday prices

An overview of the hourly price [EUR/MWh] per day from 23–25 July is presented for the day-ahead market to determine whether market prices were significantly impacted by the incident.

Figure 61 below illustrates the Day-Ahead average daily hourly prices in SWE countries, France, Spain and Portugal and shows that on average the prices in Portugal and Spain are relatively sTable when prices in France trend to decrease.

An overview of the volume weighted average hourly price [EUR/MWh] per day on the continuous intraday trading from 23 – 25 July is presented for the intraday market to determine whether market prices were significantly impacted by the incident.

Figure 62 below illustrates the daily hourly prices [EUR/MWh] for France, Spain and Portugal, thus providing an insight into how price trends changed throughout the day of the incident.

Numbers show that Intraday prices are similar to Day-Ahead forecasts.

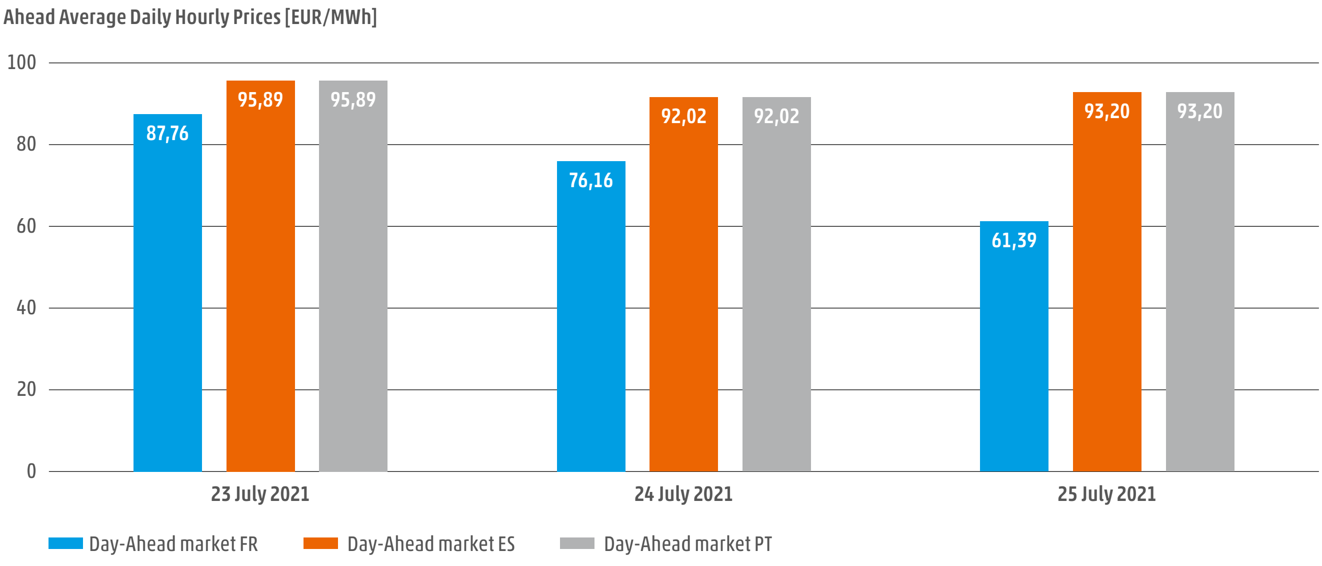


Figure 61: Day-Ahead average daily hourly prices [EUR/MWh].

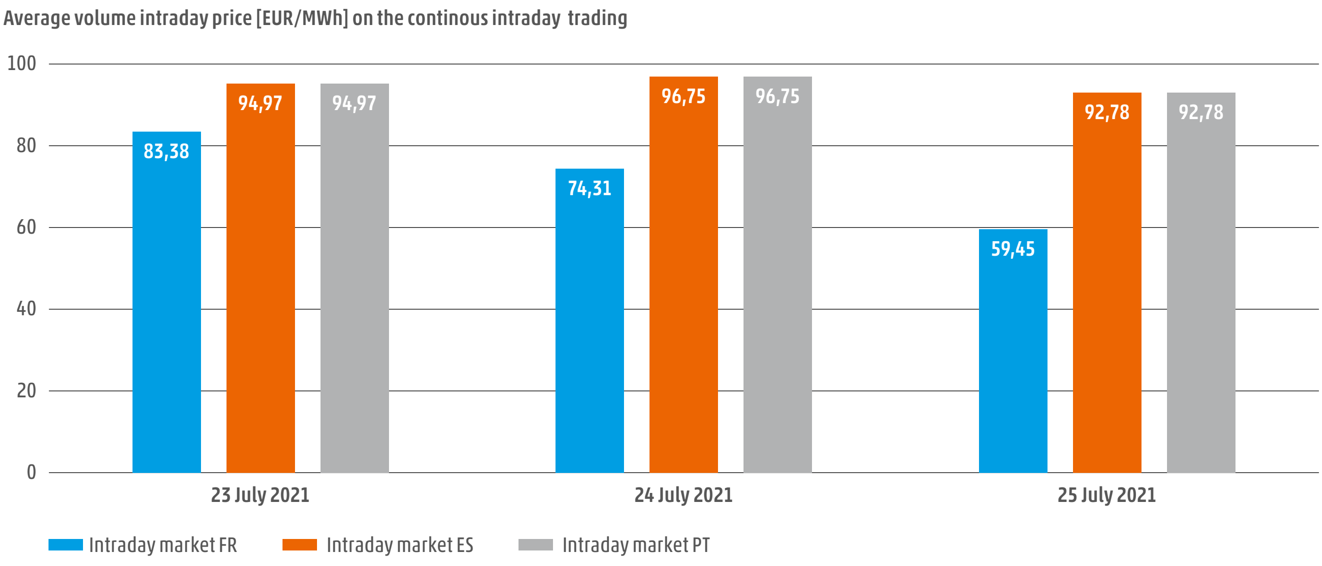


Figure 62: Intraday average daily hourly prices [EUR/MWh].

10.4 Market impact of the incident in selected areas

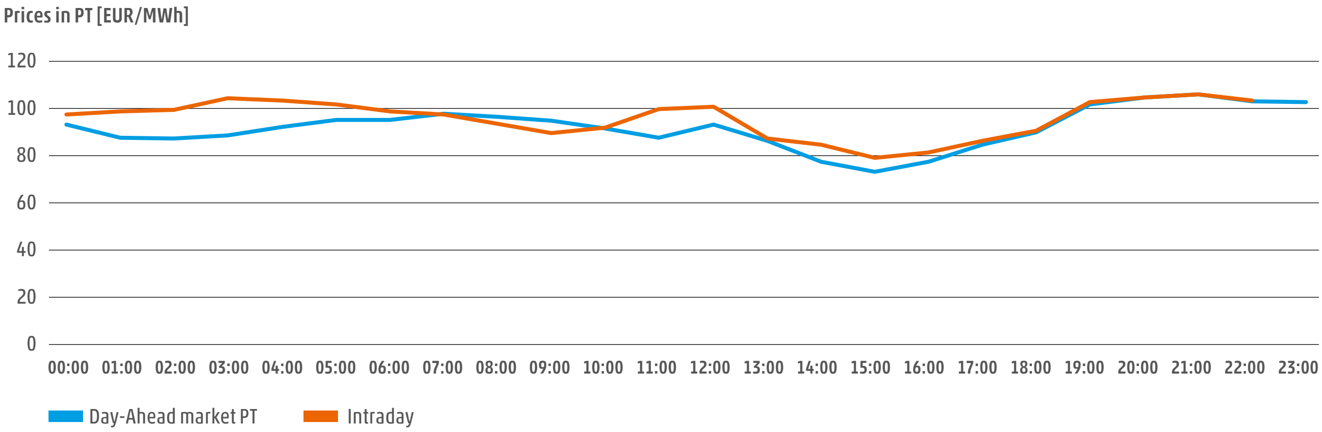


Figure 63: Prices in Portugal (x-axis WET time, y-axis €/MWh).

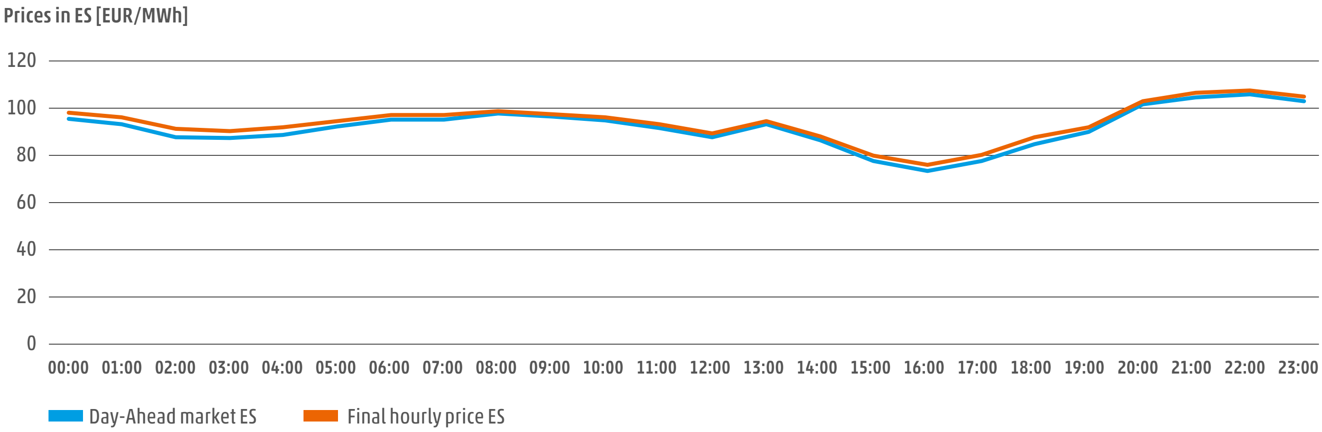


Figure 64: Prices in Spain (x-axis CET time, y-axis €/MWh).

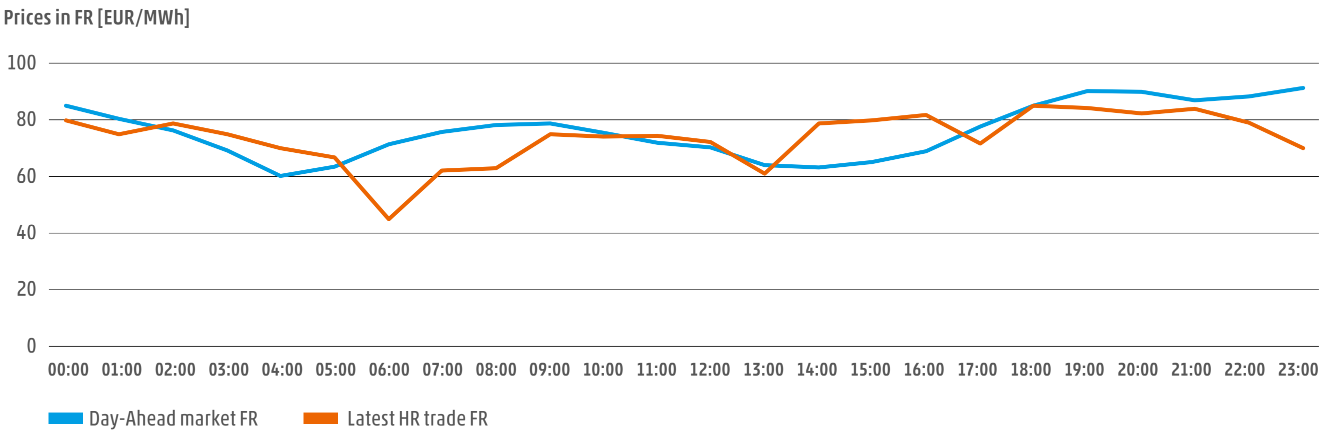


Figure 65: Prices in France (x-axis CET time, y-axis €/MWh).

Figure 63, Figure 64 and Figure 65 above indicate that price trends are continuous without any abnormal fluctuations. The price trends behave in the same manner for France, Spain and Portugal.

The general observation of both day-ahead and intraday price analysis is that the comparison between different time frame average prices does not show any link with the incident.

10.5 Communication to the Market

At 16:34 and 16:37, the reduction of exchanges between France and Spain had been performed using counter trading, an agreement allowing the physical flows to be reduced without modifying the commercial flows:

- After the first line trip (Event #1), RTE and REE agreed to reduce the cross-border exchanges from 2.5 to 1.2 GW (reduction of 1.3 GW)
- This reduction was performed using a "Counter Trading agreement" between the TSOs
  - Each TSO activates downward and upward orders in its area and modifies the exchange program in its SCADA accordingly
  - The physical flows are modified, but the commercial flows remain unchanged (no reduction for market parties)
  - The usual method for dealing with network constraints without impacting the market
  - Used to master contingencies not covered by Capacity Calculation process
- After the second trip (Event #2), an additional countertrading activation has been set-up

It is worth noting that although the power reduction were promptly coordinated by RTE and REE, the system split occurred before the agreed reduction became effective.

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 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.

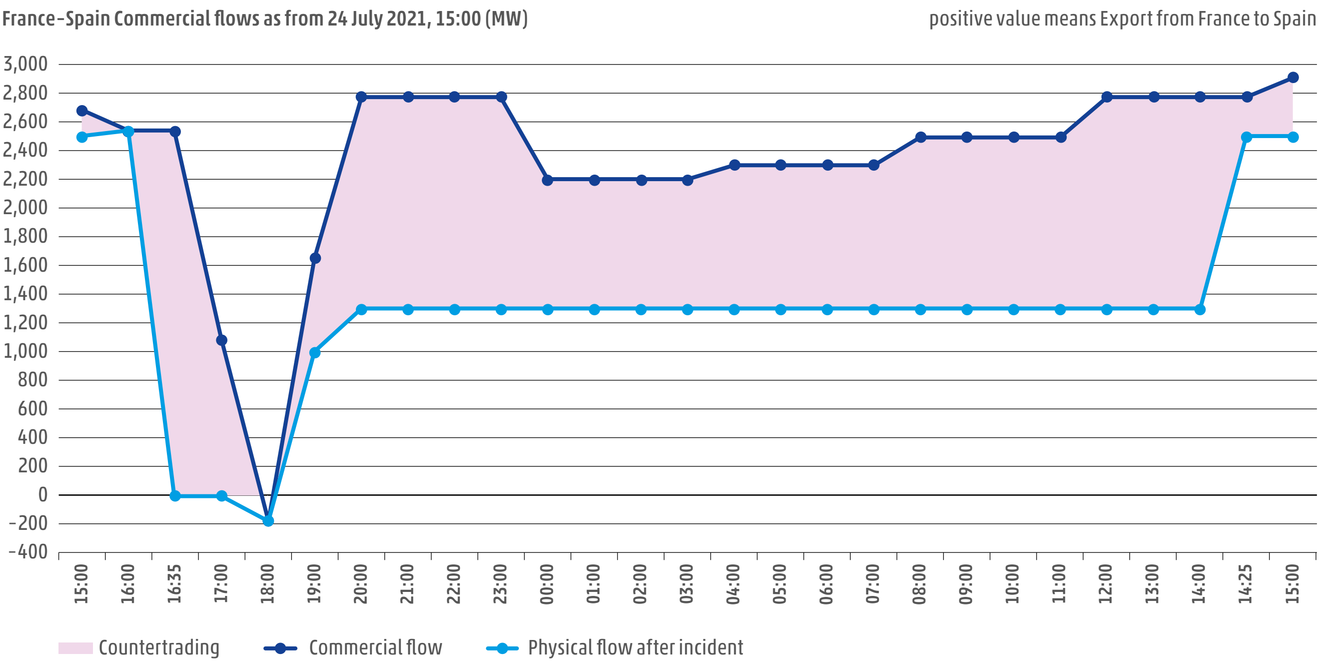


Figure 66: France-Spain commercial flows as from 24 July at 16:00.

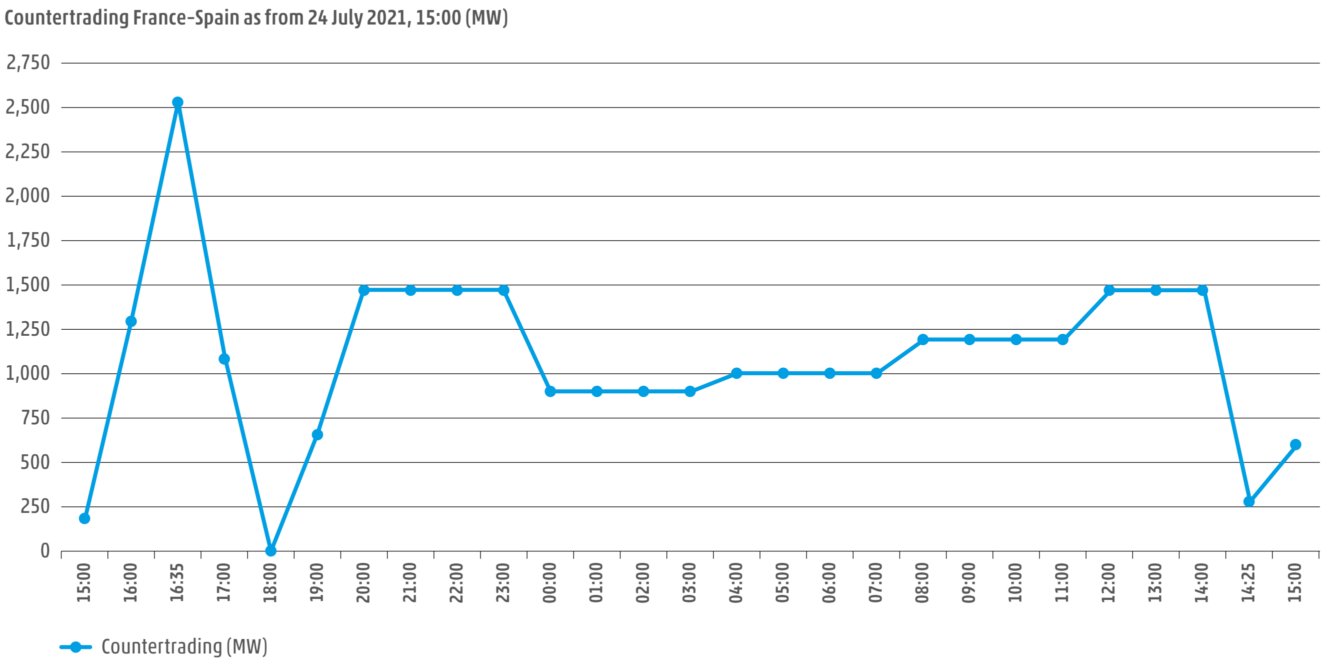


Figure 67: Countertrading France-Spain as from 24 July at 16:00.

At 16:46, due to the situation, XBID (Cross-Border Intraday) market on France-Spain was closed. It was re-opened at 18:22.

Baixas-Gaudière 2 automatic reclosure was not possible on the 24th, thus the line remained unavailable. RTE reconnected it on 25 July at 13:46 CET. This forced outage was published on the transparency platform, with new NTC values.

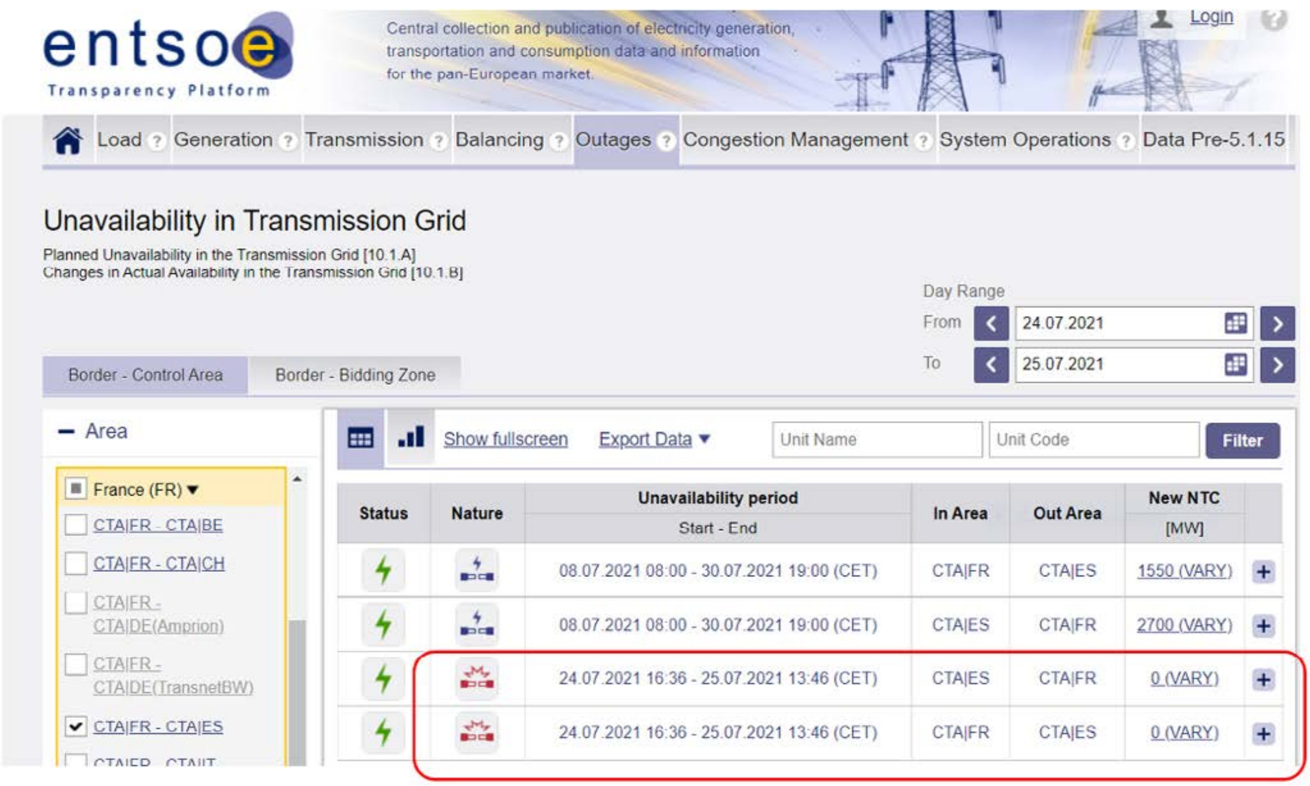


Figure 68: Extract from the ENTSO-E transparency platform.

11 TSO–DSO COORDINATION – FREQUENCY PLAN AND LOAD SHEDDING

TSO and DSO coordination is of utmost importance regarding system operation. This coordination occurs in real time, but is also performed in advance, to be prepared for possible events. This is particularly the case for frequency events, where time to exchange and coordinate is not appropriate. This is the reason why, following EU legislation, a strong coordination between TSOs and DSOs has been setup, to design and implement the Low Frequency Demand Disconnection (LFDD) scheme.

Given the importance of the measurements of LFDD recordings, Recommendation 4 – "Enhance the monitoring and setting of LFDD operation (Low Frequency Demand Disconnection)" – recommends improving the overall process of LFDD data collection and sharing between TSOs and DSOs.

11.1 Low-Frequency Demand Disconnection scheme preparation

Articles 11, 12 and 15 of the regulation EU 2017/2196 establishing a *network code on electricity emergency and restoration* state that:

Article 11 – Design of the system defence plan

1. *By 18 December 2018, each TSO shall design a system defence plan in consultation with relevant DSOs, SGUs, national regulatory authorities, or entities referred to in Article 4(3), neighbouring TSOs and the other TSOs in its synchronous area.*

Article 12 – Implementation of the system defence plan

1. *By 18 December 2019 each TSO shall implement those measures of its system defence plan that are to be implemented on the transmission system. It shall maintain the implemented measures henceforth.*
2. *By 18 December 2018 each TSO shall notify the transmission connected DSOs of the measures, including the deadlines for implementation, which are to be implemented*

SECTION 2 – Measures of the System Defence Plan

Article 15 – Automatic under-frequency control scheme

1. *The scheme for the automatic control of under-frequency of the system defence plan shall include a scheme for the automatic low frequency demand disconnection and the settings of the limited frequency sensitive mode-underfrequency in the TSO load frequency control (LFC) area.*

According to these requirements, a strong coordination among TSOs and DSOs is established to design, prepare, implement and regularly update a low-frequency demand disconnection plan. This coordination includes the definition of frequency thresholds to be implemented in the relays, as well as the amount of load to be disconnected for each threshold.

The coordination in the design phase is needed and performed in advance, to allow a fast and adapted reaction when the frequency deviation occurs.

The system defence plan measures activated during the event are summarised in Section 4.5.

11.2 TSO–DSO coordination after low-frequency demand disconnection scheme activation

After the activation of the measures of the system defence plan, and especially in the case of the activation of the low-frequency demand disconnection scheme, a strong coordination was set up between TSO and DSO. The aim was to ensure that the reconnection of the shed load was scheduled according to system behaviour. For instance, in France, Toulouse Regional Centre coordinated with the "ACR Aquitaine Sud" (regional control room of ENEDIS, the French DSO), to agree on load reconnection by 17:06, and with "ACR Nimes" (DSO control room for area of Baixas) to reconnect the load between 17:30 and 17:36.

In the case of Spain, communication between the TSO and the DSO was continuous during the whole period, and the reconnection of the shed load was allowed and coordinated, once both frequency and voltage were stabilised, starting at 16:55.

11.3 Overview of pump-storage shedding

Prior to the incident, 1,995 MW of pump-storage were connected in Spain and 422 MW in Portugal. Due to the underfrequency condition, all of them (except one, in Portugal, with 115 MW) tripped during the frequency drop to support the restoration of the generation-demand balance.

Table 35 shows the frequency thresholds and the load assigned for every step. It should be noted that the load shedding relays of some units have a delay for its proper operation.

TSO	Frequency threshold [Hz]	Disconnected load [MW]
REE	49.5	1,004
REE	49.3	991
REN	49.3	122
REN	49.8	185

Table 35: Pump-storage shedding.

11.4 Overview on load shedding

The underfrequency condition on the Iberian Peninsula caused the activation of the first two load shedding steps in Spain and Portugal and the first load shedding step in the southeast of France (see Table 36) to restore the generation–demand balance. In Spain, 3,561 MW were disconnected, 680 MW in Portugal and 65 MW in France, to restore the generation–demand balance.

TSO	Frequency threshold [Hz]	Disconnected load [MW]
REE	49.0	1,574
REE	48.7	1,987
RTE	49.0	65
REN	49.0	424
REN	48.8	256

Table 36: Load shedding.

In addition, in the Portuguese system, a group of industrial consumers were shed at 49.2 Hz. The effective power reduction of these consumers reached a total value of 394 MW.

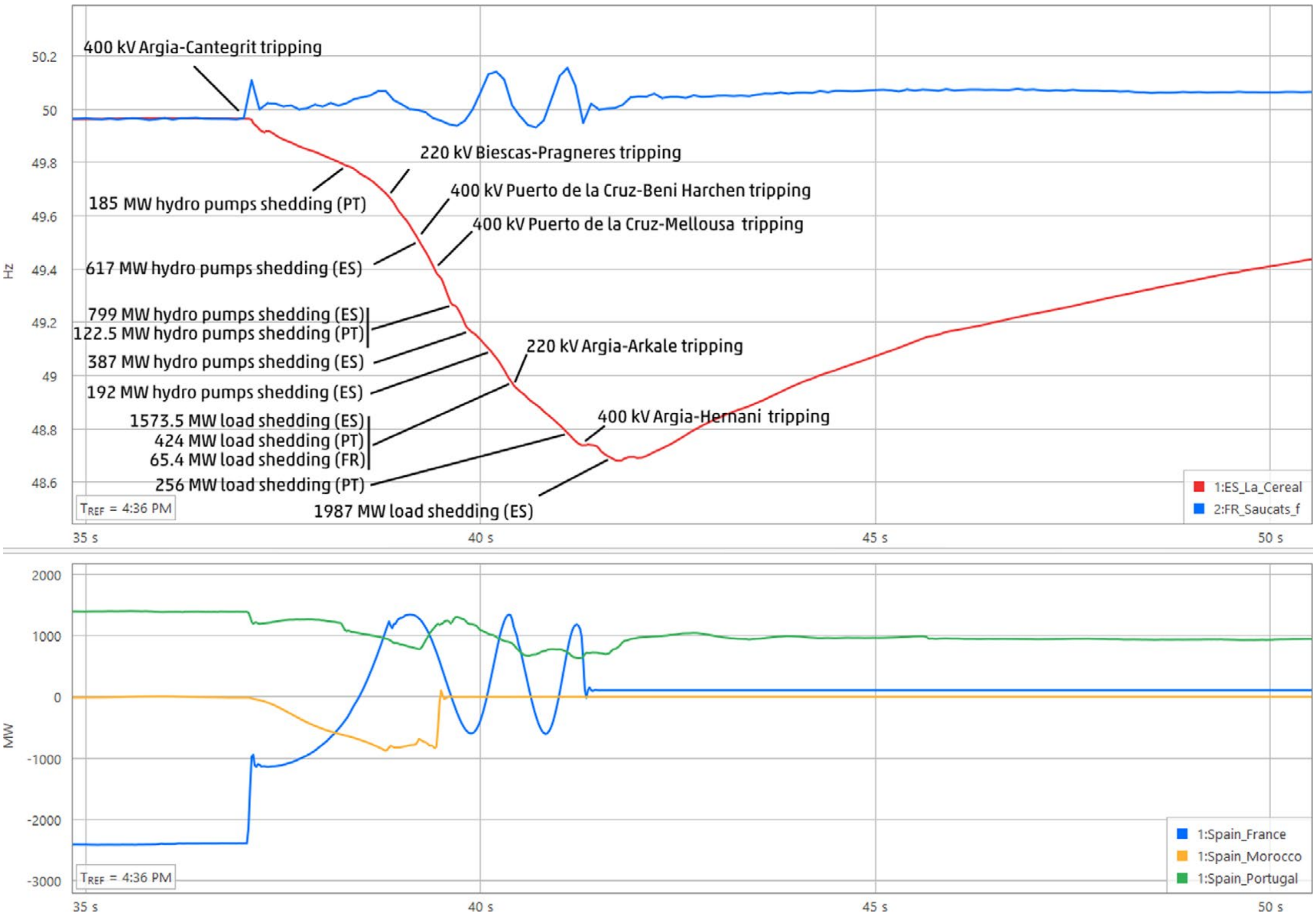


Figure 69: Grid tripping, load and pump-storage shedding.

11.5 Portuguese system defence plan

The Portuguese defence plan for a situation of a sudden drop in system frequency, originating from an imbalance between production and consumption, includes the following components:

- **A.** Automatic disconnection of hydro-pumps,
- **B.** Automatic power reduction in industrial interruptible consumers,
- **C.** Low frequency demand disconnection plan.

In the 24 July incident, where the frequency dropped to 48.65 Hz, these three components were activated as described below.

A. Automatic disconnection of pump-storage

The disconnection plan for the pump-storage, established in accordance with Article 15(4) of the Network Code on Electricity Emergency and Restoration (NC ER)[8], has six frequency steps (49.8; 49.7; 49.6; 49.5; 49.4; 49.3 Hz), with zero delay and with similar power values (total installed capacity of pump-storage is 2,698 MW).

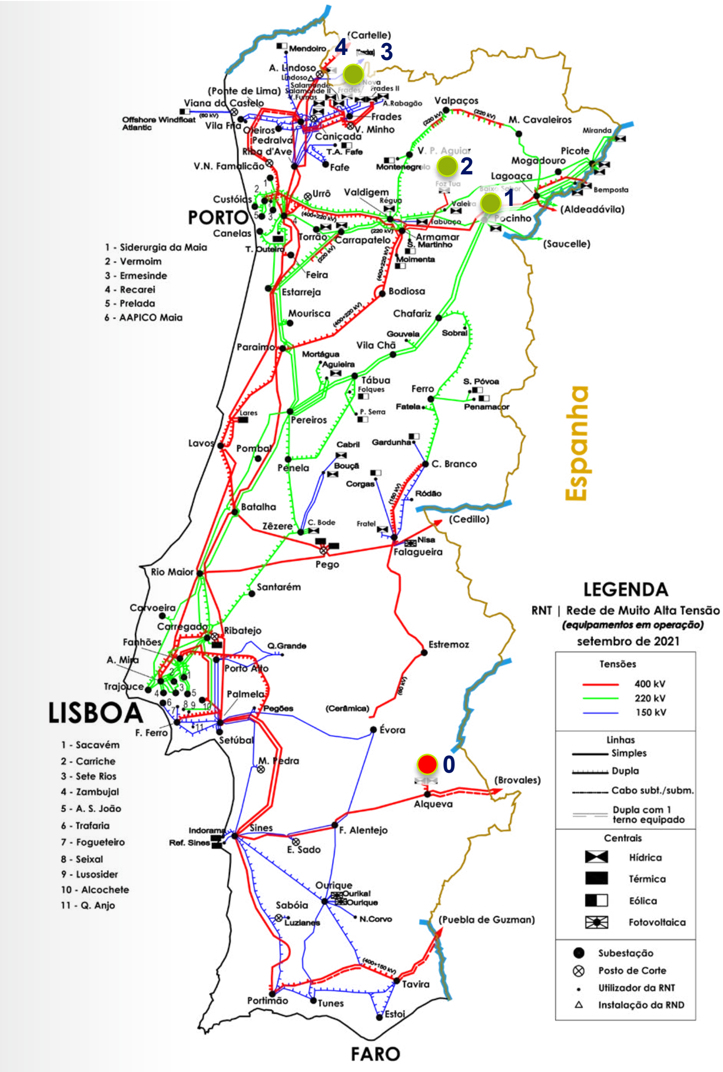
In the 24 July incident, five pump-storage generators were connected, with a total load of 422.3 MW. One failed to trip and four tripped, resulting in 307.5 MW disconnected load.

Table 37 characterises the plan and the effective tripping.

Plan				24 July – 16:36	
Hydro pump	Code	P Max [MW]	Planned tripping value [Hz]	P realised [MW]	P tripped [MW]
Central do Alqueva – Grupo 2	ALQUEB2	120	49.6	114.8	[failed]
Central de Baixo Sabor Jusante – Grupo 1	BASBJB1	18	49.8	17.77	17.8
Central de Foz Tua – Grupo 2	FOZTB2	130.5	49.3	122.5	122.5
Central de Frades – Grupo 1	FRADEB1	95.5	49.8	85.0	85.0
Central de Frades – Grupo 2	FRADEB2	95.5	49.8	82.2	82.2
SUM		2,698		422.2	307.4

Table 37: Disconnection of hydro pumps, plan and realised. Note that 2,698 MW represents the maximum power of all Portuguese hydro-pumps, whereas the Table only includes those five connected at the time of the event.

8 Commission Regulation (EU) 2017/2196, establishing a Network Code on Electricity Emergency and Restoration (NC ER)



		Pump	Code
● (red)	0	Alqueva – Grupo 2	ALQUEB2
● (green)	1	Baixo Sabor Jusante – Grupo 1	BASBJB1
● (green)	2	Foz Tua – Grupo 2	FOZTB2
● (green)	3	Frades – Grupo 1	FRADEB1
● (green)	4	Frades – Grupo 2	FRADEB2

Figure 70: Geographical location of the pumps that were in operation in Portugal during the incident.

B. Automatic power reduction in industrial interruptible consumers

In the Portuguese system, there is a group of industrial consumers who provide a paid service, which includes the obligation to reduce their consumption to a certain power value instantly if the frequency value drops below 49.2 Hz. This power reduction is set up in accordance with Article 15(11) of the NC ER.

On 24 July, the total consumption of this group of consumers was 655.5 MW, with a residual value of 28 MW, which corresponded to a maximum power reduction value of 627.5 MW. This power reduction value could be reached if all consumers were connected, with the average power considered in the contract, and fulfilled the contractual obligation.

Current data reveal that on 24 July, at 15:36, the total power in these consumers was 628 MW, with a residual power of 23 MW.

The effective power reduction of these consumers, at 49.2 Hz, reached a total value of 394 MW.

C. Low frequency demand disconnection plan

The Portuguese low frequency demand disconnection plan complies with Article 15(5) of the NC ER and the provisions of Annex 5 of the Synchronous Area Framework (SAFA) for the ENTSO-E RG CE, with the following characteristics:

- Provides a power reduction in the range of 45 ± 7 % of the total consumption if the frequency drops from 49.0 to 48.0 Hz.
- It has 6 steps, with the following frequency values: 49.0; 48.8; 48.6; 48.4; 48.2; 48.0 Hz.
- In the 49.0 Hz step, the reduction is greater than or equal to 5 % of the total consumption.
- In each step, the reduction does not exceed 10 % of the total consumption.
- No intentional time delay was set in relays.
- These characteristics were agreed upon between the TSO and the DSO.

On 24 July at 15:36, the total consumption was 5,145 MW. At the time of the incident, the frequency dropped to 48.65 Hz, whereby the 49.0 and 48.8 Hz steps were activated. The tripped consumption at these steps, exclusively at the DSO level, was 424 MW and 256 MW, respectively, thus reaching a total value of 680 MW. This value corresponds to 13.3 % of the total 5,145 MW consumption, in line with the expected value of 13.2 %.

Table 38 characterises the plan and the effective tripping.

	Plan	24 July - 16:36	
Step [Hz]	P [%]	P [%]	P [MW]
49.0	6.7	8.2	424
48.8	6.6	5.0	256
48.6	6.9	0.0	0
48.4	6.6	0.0	0
48.2	6.4	0.0	0
48.0	9.7	0.0	0
SUM	43.0	13.2	680

Table 38: Disconnection of demand, plan and realised.

11.6 Spanish system defence plan

The Spanish defence plan for a situation of a sudden drop in system frequency, originating from an imbalance between production and consumption, includes the following measures:

A. Low frequency automatic disconnection of pump-storage:

At 16:36:39.240, the frequency dipped below 49.5 Hz, and at 16:39.600, the frequency descended below 49.3 Hz, hence both frequency disconnection steps as designed, in accordance with Article 15(4) of the NC ER, were activated. Consequently, all connected pump-storage tripped, as shown in Table 39.

Name	Busbar	Step [Hz]	MW
La Muela G4	La Muela 400	49.5	210.0
Aguayo G2	Aguayo 220	49.5	89.0
Aguayo G3	Aguayo 220	49.5	89.0
Moralets G2	Moralets 220	49.5	74.0
Bolarque G1	Bolarque 220	49.5	52.0
Bolarque G2	Bolarque 220	49.5	51.0
Bolarque G3	Bolarque 220	49.5	52.0
La Muela G1	La Muela 400	49.5	194.0
La Muela G2	La Muela 400	49.5	193.0
Total at 49.5 Hz step			1,004.0
La Muela G5	La Muela 400	49.3	207.0
La Muela G6	La Muela 400	49.3	206.0
La Muela G7	La Muela 400	49.3	207.0
Aguayo G1	Aguayo 220	49.3	90.0
Aguayo G4	Aguayo 220	49.3	89.0
La Muela G3	La Muela 400	49.3	192.0
Total at 49.3 Hz step			991.0
Total (both steps)			1,995.0

Table 39: Hydro-pumps disconnected in each frequency step.

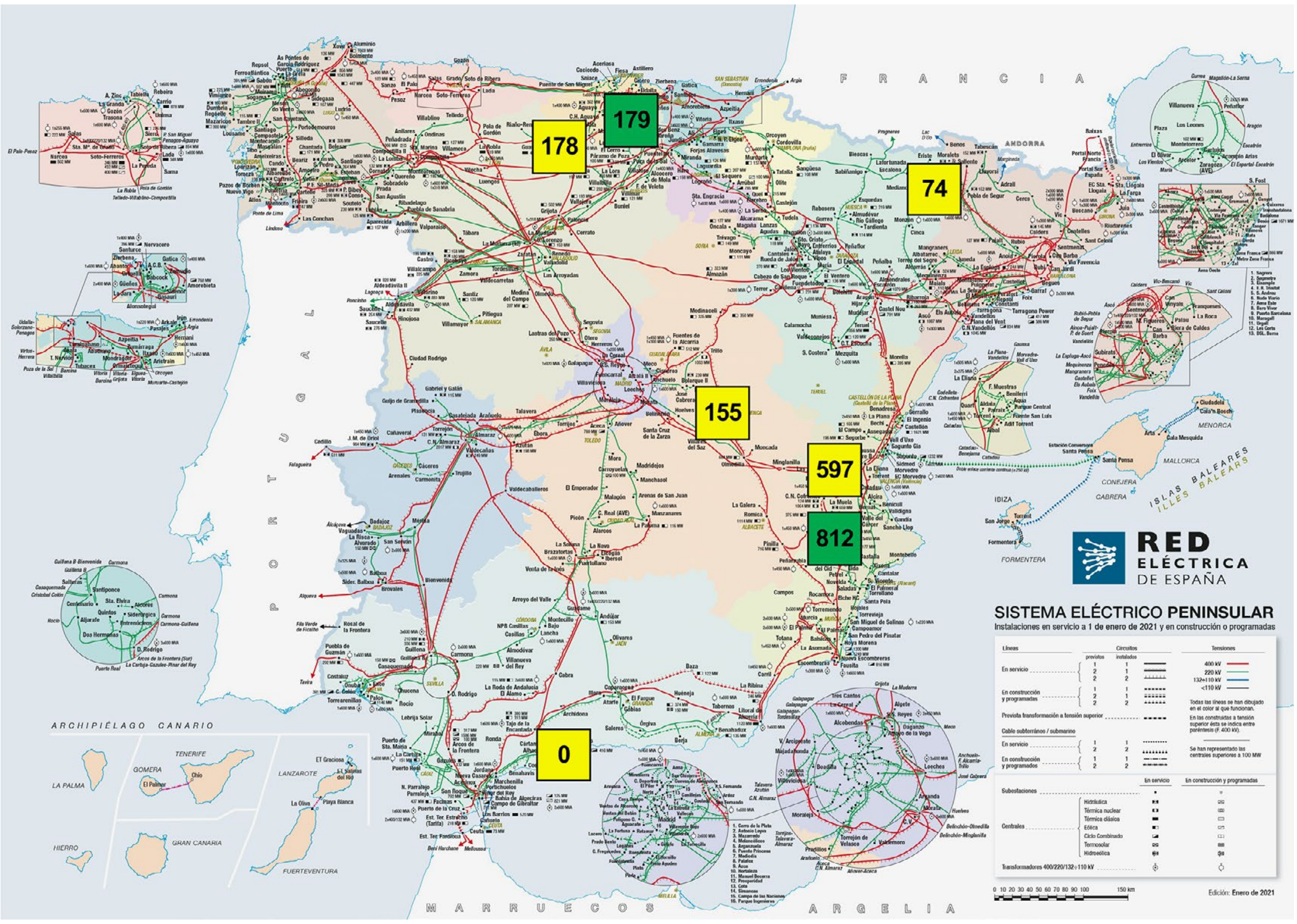


Figure 71: Geographical location of the MW of pump consumption that were disconnected in Spain during the incident.

B. Low frequency automatic demand disconnection:

The Spanish automatic low frequency demand disconnection scheme, previous to the implementation of the requirements established in the NC ER, is shown in Table 40.

Plan		24 Jul, 16:36	
Step [Hz]	P [%]	P [%]	P [MW]
49.0	10	5.2	1,573.5
48.7	10	6.6	1,987.0
48.4	15	0.0	0
48.0	15	0.0	0
	50	11.8	3,560.5

Table 40: Demand disconnection plan prior to implementation of the NC ER and demand disconnected in each frequency step.

Presently, the Spanish low frequency demand disconnection plan does not comply with Article 15(5) of the NC ER (which is not mandatory until 18 December 2022). Nevertheless, REE, in coordination with DSOs, is currently in the process of adapting the scheme for the automatic low frequency demand disconnection to fulfil the requirements established in the NC ER, evolving the previous scheme of 4 to 6 steps and, therefore, reducing the size of the futures steps. The new scheme is expected to be fully implemented within the deadline established in the Regulation, 18 December 2022.

In the 24 July incident, the lowest frequency recorded at La Cereal 400 kV Substation was 48.681 Hz, whereby the 49.0 and 48.7 Hz steps were activated. The tripped consumption at these steps was 1,573 MW and 1,987 MW, respectively, thus reaching a total value of 3,560 MW consumption.

11.7 French system defence plan

The French defence plan for a situation of a sudden drop in system frequency, originating from an imbalance between production and consumption, includes the following components:

- **A.** Automatic disconnection of hydro-pumps,
- **B.** Automatic power reduction in industrial interruptible consumers,
- **C.** Low frequency demand disconnection plan.

A. Automatic disconnection of pump-storage

The pump-storage disconnection plan designed in accordance with Article 15(4) of the NC ER is based on the automatic disconnection of a maximum power of 4,100 MW (depending on generators schedules), when frequency reaches the range [49.6 to 49.2 Hz].

B. Automatic power reduction in industrial interruptible consumers

In the French system, a group of network users is selected to provide a service consisting of reducing their consumption to a certain power in an emergency situation. The service is automatically activated if the frequency drops below 49.8 Hz in accordance with Article 18(5) of the NC ER or manually to manage power flow outside the operational security limits in accordance with article 20 of the NC ER. The maximum interruptible volume is 1,200 MW with an activation in 5s. The requirements have changed from the year 2022.

On 24 July, this mechanism had not been activated as the frequency measurement for its activation is located in the part of France that remains connected to the rest of Europe.

C. Low frequency demand disconnection plan

The French low frequency demand disconnection plan, previous to the implementation of the requirements established in the NC ER, is shown in Table 41.

Plan	
Step [Hz]	**P [% of DSO load]**
49.0	20
48.5	20
48.0	20
47.5	20
	80

Table 41: French Demand disconnection plan prior to implementation of the NC ER.

RTE, in coordination with DSOs, is currently in the process of adapting the scheme for the automatic low frequency demand disconnection to fulfil the requirements established in the NC ER, evolving the previous scheme of 4 to 6 steps and, therefore, reducing the size of the futures steps. The scheme is expected to be fully implemented within the deadline established in the Regulation, 18 December 2022.

On 24 July, the first threshold has been reached in the areas of Biarritz (before the separation with Spain, leading to shed 10 MW of load) and of Baixas (in the area remaining connected to Spain after the trips, leading to shed 55 MW of load).

12 CLASSIFICATION OF THE INCIDENT BASED ON THE ICS METHODOLOGY

The ICS methodology was developed according to Article 15 of SO GL to provide a common incident classification scale to ensure the coordination of system operation in emergency conditions. Based on definitions from EU network codes and IEC standards, the methodology classifies events or observable situations that may arise after power system incidents. Depending on the severity of the incident, and therefore depending on the identified ICS criteria, the affected TSOs are requested to provide further clarifications on the event.

This Section analyses the incident from the perspective of the ICS methodology and clarifies the reason why it was classified as a scale 2 event.

12.1 Analysis of the incident

The event began due to a fire in the area of Moux (south of France). RTE's control room could not be informed about the fire close to the Baixas–Gaudière 400 kV corridor, and thus the risk of having an N-2 was not considered. The grid was N-1 compliant. The fire caused the subsequent tripping of the two circuits of the double circuit line Baixas–Gaudière 2 and Baixas–Gaudière 1 within a few minutes. This led to an overload on the remaining lines between France and the Iberian Peninsula. This is not an ON2 according to the ICS classification, because covering the N-2 Baixas–Gaudière 2 and Baixas–Gaudière 1 is not included in the contingency list under normal conditions.

The tripping of the Argia–Cantegrit line resulted in the cascading tripping of the remaining lines on that corridor between RTE and REE. The result was a loss of interconnection between Spain and France. This is a T2 according to the ICS classification. This criterion was reached 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 trips of several lines led to the system split. This is an RS2 according to the ICS classification. This criterion was reached because the separation of the grids involved more than one TSO and because at least one of the synchronised regions affected by the split 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 over frequency, the deviation of more than 200 mHz lasted less than 30 seconds. In the under-frequency region, the deviation of more than 200 mHz lasted more than 30 seconds. This is an F2 according to the ICS classification. The criterion for an F2 was reached because there was an incident leading to frequency degradation (200 mHz for more than 30 seconds).

There was also a loss of load of 3,560 MW of a total load of 30,033 MW for more than three minutes for REE. Regarding REN, there was a loss of load of 1,494 MW of a total load of 5,145 MW. For both TSOs, the L2 criteria according to the ICS classification was met. This criterion was reached because the loss of load was higher than 10 percent of the load in both TSOs.

12.2 Classification of the incident

The priority of each criterion is shown in Table 42 with 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 is also collected.

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 42: Classification of incidents according to ICS methodology.

The highest criterion from ICS for this incident is an L2, and thus an Expert Panel for a scale 2 incident investigation is required.

For incidents of scales 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 the incidents of scale 2 and scale 3 based on the investigation of the incidents according to article 15(5) of the 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 the SO GL. ENTSO-E must also inform ACER about the upcoming investigation in due time, before it is launched and not later than one week in advance of the first meeting of the Expert Panel.

Each TSO must report the incidents on 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 24 July 2021, the affected TSOs have to classify the events during this incident according to the ICS Methodology before 31 August. An expert investigation panel with TSOs, NRAs and ACER was established on 22 October 2021 and has published a factual report on 12 November 2021 and the present document (final report) on 25 March 2022.

13 TECHNICAL ANALYSIS OF THE INCIDENT

This Section presents the results of the detailed technical analysis carried out to confirm all the collected facts and to validate the correct behaviour of all the elements that played a role during the overall event.

13.1 Dynamic behaviour of the system during the incident

13.1.1 Simplified dynamic analysis

This section describes the results of a preliminary dynamic analysis, which serves as an important basis to confirm the main figures concerning the balance and dynamic behaviour of the system at the moment of the incident. This is elaborated on in detail in the next **paragraph 13.1.2**.

A first approach for the dynamic analyses has been made by means of the single busbar model used in ENTSO-E for all kinds of frequency stability studies (defence plans, load frequency disconnection schemes, ROCOF and inertia, etc.). This is a balanced model that, tuned appropriately with information taken from the ENTSO-E Transparency Platform, is able to reproduce the main system frequency dynamics and, therefore, confirm the major hypothesis and facts of the event such as system inertia, activation of primary regulation, generation and pump-storage disconnection pattern, and load shedding performance.

The single busbar model takes as an input the imbalance between the Iberian Peninsula and the rest of the Continental European system and the disconnection series for generation, pump-storage and loads in Spain and Portugal. Subsequently, the results of the simulations are compared to the real measurements and, if necessary, the input values are readjusted by means of an iterative process. As these simulations try to reproduce the effect over the frequency of the evolution of the system balance during a fast transient, the resulting adjusted value for the balance refers to the total variation of generation, and not only the reported disconnected generation appearing in this document (**Section 4.6** and **Section 11**). In this sense, it was necessary to increase the generation disconnection considered in this study in Spain and Portugal around 800 MW in order to adjust the simulation results with the measured frequency during the event. This was subsequently confirmed by the detailed dynamic analyses simulations.

In the following graphs, the model output for frequency (Figure 72) and ROCOF (Figure 73) in the Iberian Peninsula during the event (starting at Event #3, i.e. the opening of line 400 kV Argia–Cantegrit) is compared to the real PMU measured value in La Cereal 400 kV substation, which is close to the centre of inertia of the peninsula.

The accurate match obtained between model and real behaviour sets the basis for further analyses to be performed with the full dynamic model. The main parameters for the single busbar model are shown in Table 43.

Parameter	Value
System load	35.4 GW
Active power deficit	1,000 MW (at 16:36:37.1)
	1,500 MW (at 16:36:38.7)
System inertia constant (H)	4 s
Self-regulating effect of loads	2 %/Hz

Table 43: Main parameters for the single busbar model.

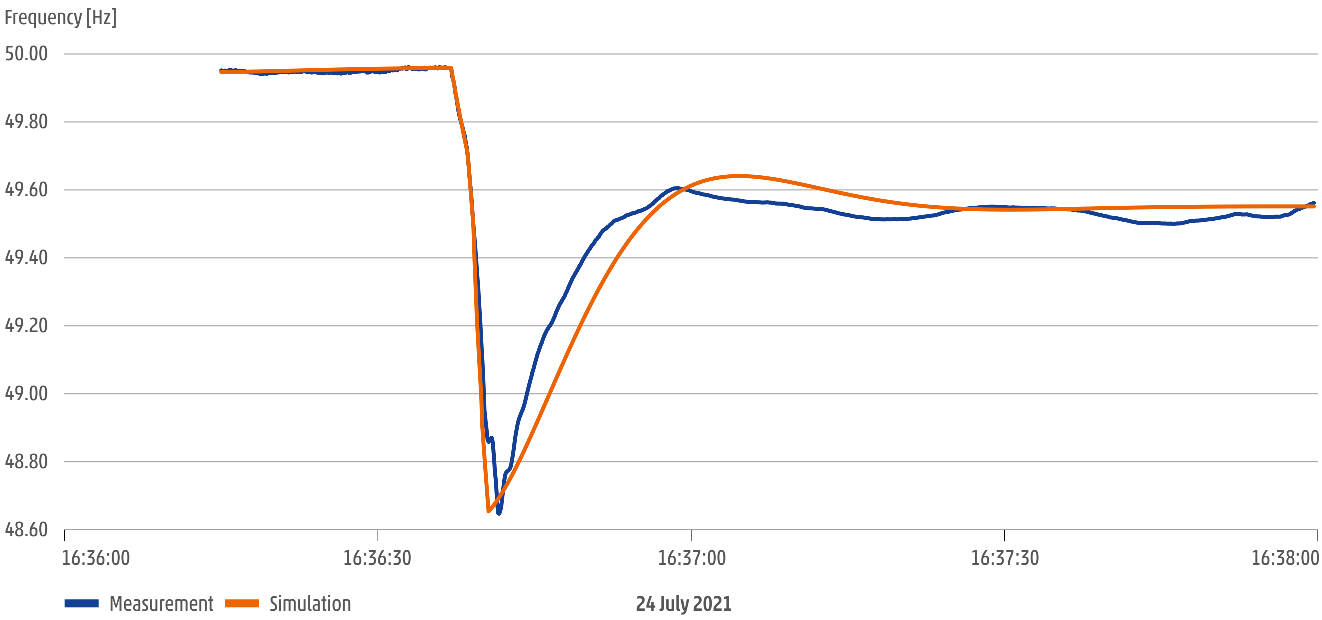


Figure 72: Simulation results (frequency) of the single busbar model and comparison with real PMU measured value (La Cereal).

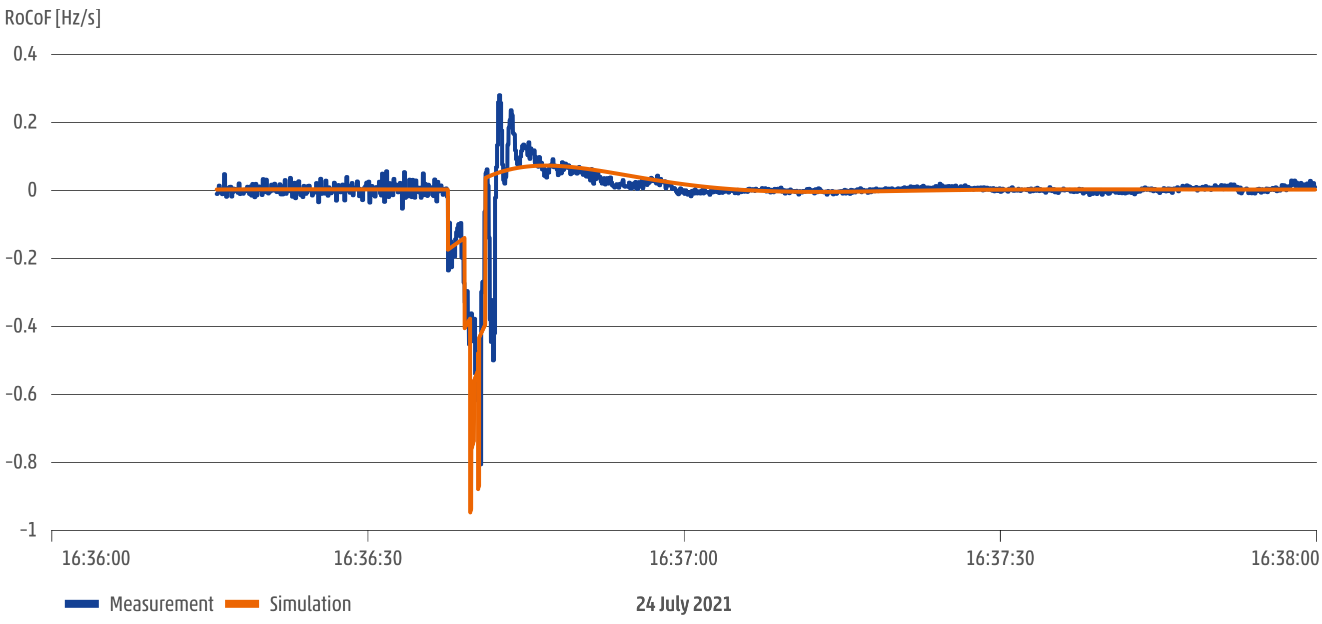


Figure 73: Simulation results (ROCOF) of the single busbar model and comparison with real PMU measured value (La Cereal).

13.1.2 Detailed dynamic analysis

This chapter presents the analyses and conclusions that can be extracted from the electromechanical dynamic simulations performed over a full dynamic model of the system. This model is built up from a static snapshot to which detailed dynamic models are attached for the generators, pumps, phase shifters and HVDC links. Frequency and voltage dependence of the loads is based on the involved TSOs' characterisation of past events and accurate information. Load shedding relays are also modelled in order to represent the industrial load disconnection as well as the load shed. The operation of the coils and capacitors is further considered. Finally, protection relays in the Spain-France interconnection area are considered (out of step relays -DRS- and French overcurrent relays).

The model consists of more than 1.400 generators, out of which around 350 are synchronous machines (modelled with a generator, exciter and governor model – and power system stabilizer in around 50 units) and the rest are renewable power park modules (with ad-hoc performance model depending on their technology).

Iterative process of simulation and tuning has been done in order to endorse the main hypothesis of the event or, if needed, to refine them in light of evidence arising from these simulations.

The following Figure 74 depicts a comparison between the PMU measured frequency in La Cereal 400 kV substation (located close to the centre of the Iberian Peninsula) and the simulation output. The line openings are marked in the graph and the event numbering corresponds to the sequence of events presented in Table 19.

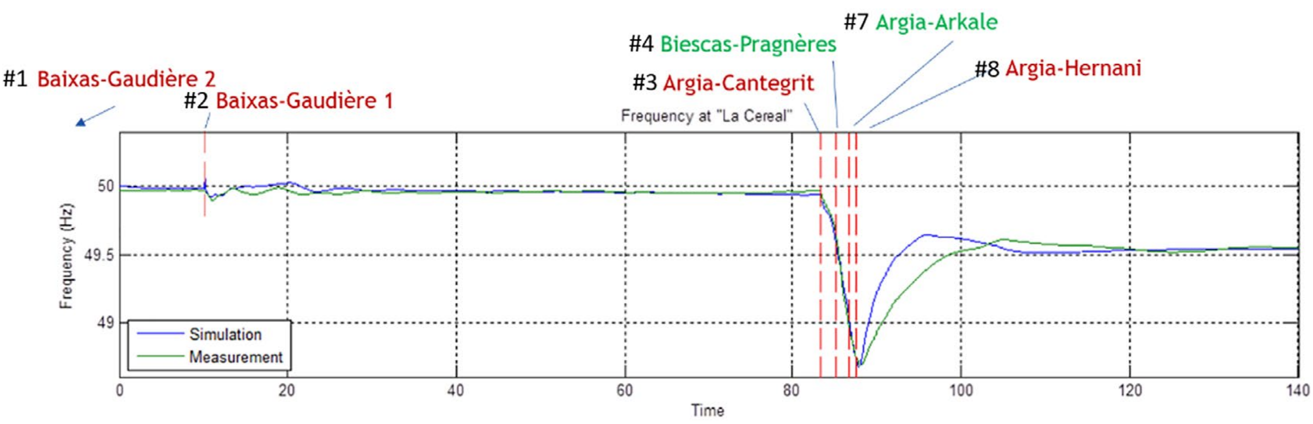


Figure 74: Frequency evolution during the event. Simulation vs. real measurement.

As presented in Figure 75, zooming in shows in detail a good match between the simulation and real measurement of the frequency, both in the centre of the Iberian Peninsula (bottom graph, La Cereal 400 kV) and also in the area close to the Spain-France interconnection (i.e. Hernani 400 kV substation, in Spain, top graph), where the transients were stronger.

As can be observed, an accurate match is achieved for the frequency evolution during the event.

Concerning the voltage magnitude, as presented in Figure 76, the model can reproduce the voltage evolution in the different areas of the system during the event. In the following graph, the evolution of the voltage in different parts of the system can be seen (Hernani 400 kV and Arkale 220 kV, near Spain-France interconnection and La Cereal 400 kV, in the centre of the Iberian Peninsula): from the undervoltage situation, when the eastern corridor is lost, to the overvoltage situation once the system splits. Due to the unavailability of a complete set of data, induction machines are not modelled separately, which could limit the model accuracy in the undervoltage situation.

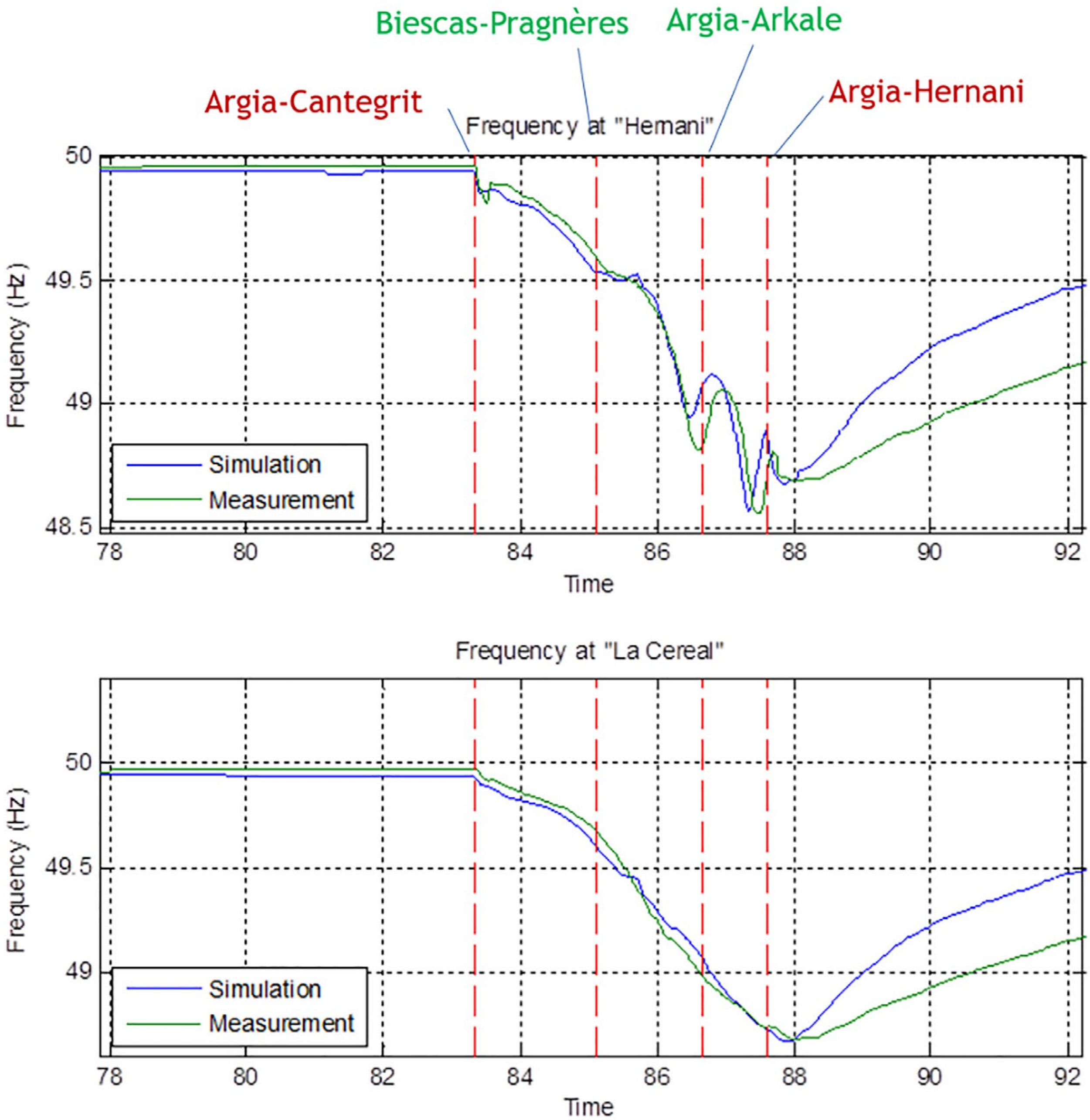


Figure 75: Detail of frequency evolution during the event. Simulation vs. real measurement.

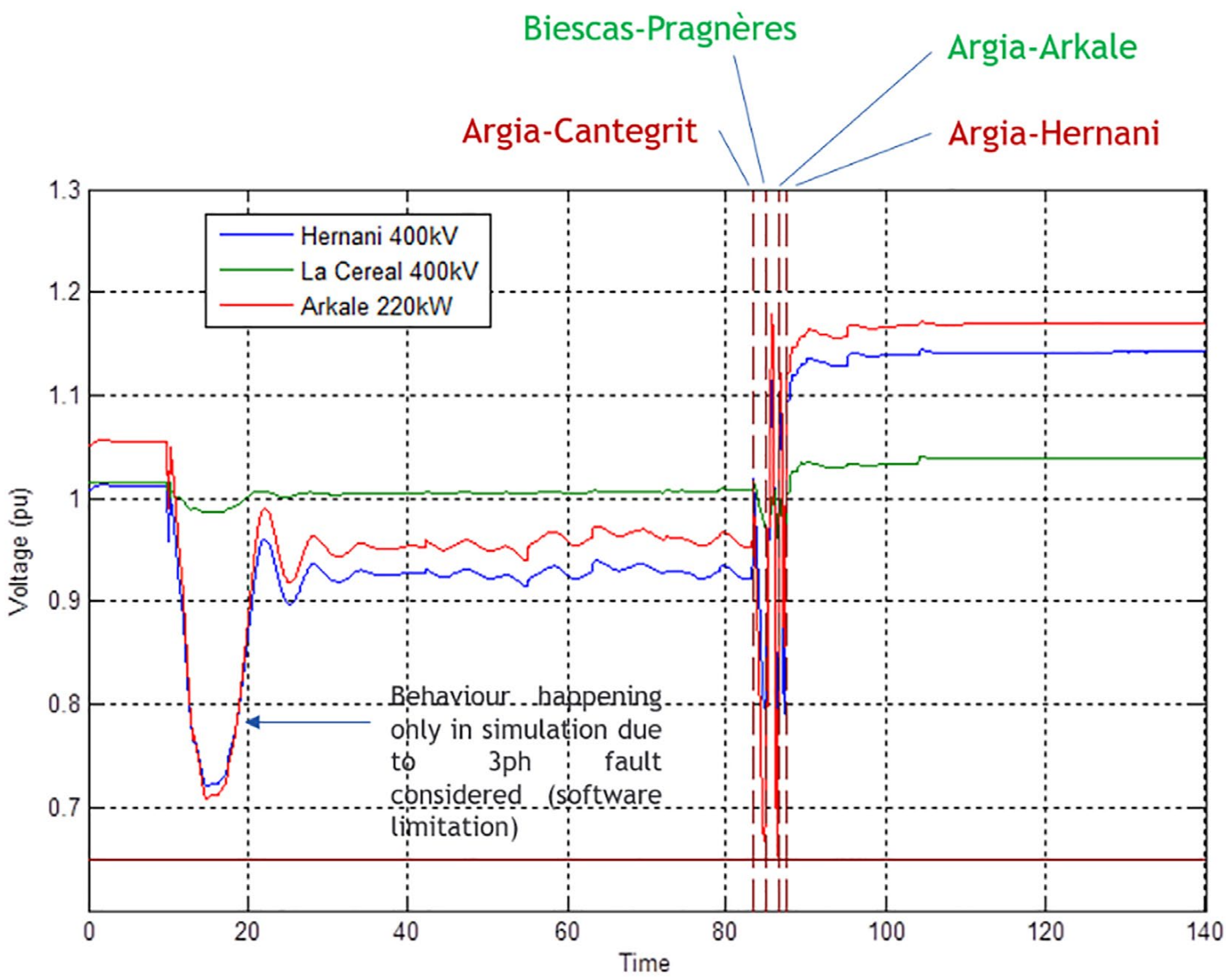


Figure 76: Voltage evolution during the event. Simulation results.

Different causes have been reported for the disconnected generation during the event. A complete representation into a dynamic model is not possible due to the uncertainty of several parameters and mainly due to an enormous increase of complexity that, pragmatically, does not give added value to the study. In addition, the generation tripping affected thousands of units that are at a different voltage level of connection and not always equipped with complete event recording devices, so some estimation hypotheses had to be made.

The simulation confirms that:

» in Portugal, the main cause of the generators' disconnection relates to frequency (i.e. underfrequency

» in Spain, the main cause of the generators' disconnection concerns voltage (most of them, overvoltage).

The simulation helps to understand the voltage dip extension due to the fault on the Baixas–Gaudière line (Figure 77 A depicts a simulated three phase fault, instead of two phase fault, due to software limitations) creating low voltages close to the interconnection due to the diverted flows to the western corridor before the system separation (Figure 77 B). These low voltages could have triggered the disconnection of generation without low voltage ride-through capabilities or seeing this fault near enough to go beyond the voltage disconnection threshold of LFDDs.

In the same manner, as presented in Figure 78, overvoltages appear in the simulation once the system splits, pump-storage units disconnect and load shedding starts to act.

The simulation reproduces the disconnection of a noTable amount of generation due to their overvoltage protection (1.1 pu) and the overvoltage profile across the system (see Figure 79).

These results regarding overvoltages and generation disconnection are coherent with the reported information of generation trip during the incident given by the generation companies.

It should be noted that the model considers connection to the generation to transmission (400 and 220 kV) or distribution network (132/66 kV) by means of equivalent step-up transformer considering a simplified aggregation of all the involved impedances. No tap-changer is monitored or modelled for most of the RES generation. Considering that the overvoltage situation comes after an undervoltage situation (therefore taps might be in a position with negative impact to the voltage surge), the additional disconnection of generation (closer to what occurred in reality) might arise naturally in the simulations for this reason and also because of transient voltages due to load shedding, if a more detailed model could be available.

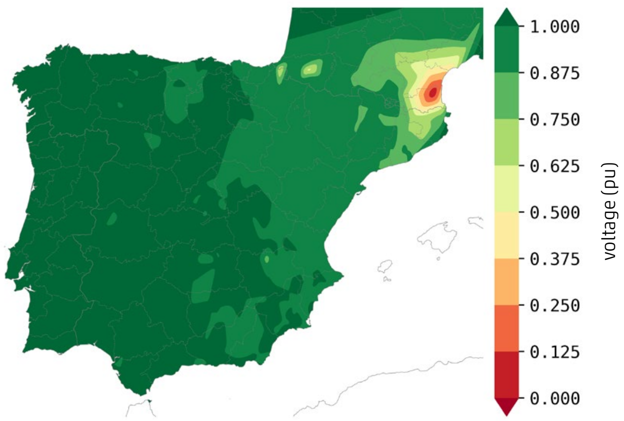


Figure 77 A: Voltage dip expansion due to Baixas-Gaudière 2 phase to phase fault (Event #1) based on simulation. (3ph fault simulated due to software limitation).

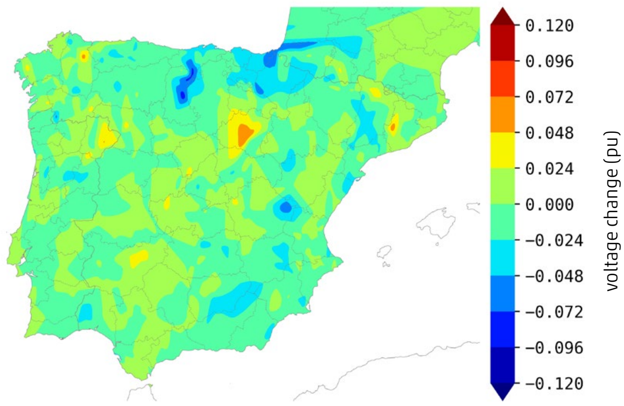


Figure 77 B: Voltage change between initial state and after events #2 based on simulation.

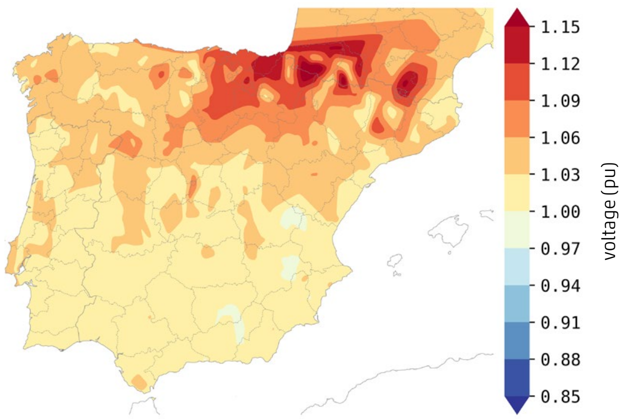


Figure 78: Overvoltage after system separation based on simulation.

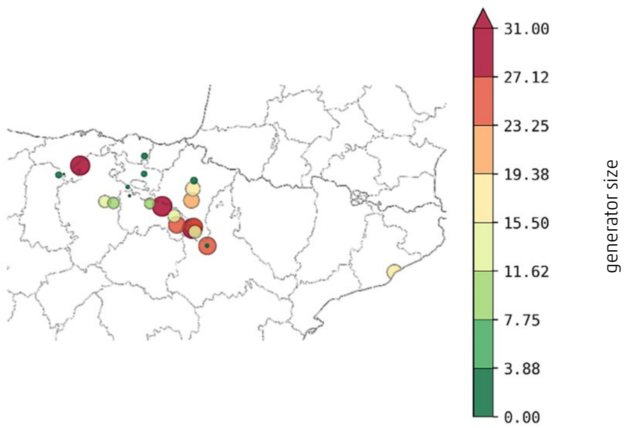


Figure 79: Main location of the disconnected generation due to overvoltage based on simulation.

13.2 Behaviour of protection devices

In previous chapters, the behaviour of protection devices was analysed and explained thanks to the recordings of several sources (PMUs, transient recorders, internal recordings of digital devices). The aim of this chapter is the validation of the analyses with a powerful instrument, which is the electromechanical simulation of the entire grid dynamic behaviour. This activity is based on the complex set up of the complete dynamic model and several fine tunings already explained in the previous chapter in order to provide the greatest possible accuracy in the results.

Analyses conducted with the full dynamic model show that, even if the stability conditions worsen when the Baixas–Gaudière double circuit opens (higher angle difference between the split areas), the system is able to withstand it and it is only after the Argia–Cantegrit trips that the Iberian Peninsula loses synchronism with the rest of CE. When this occurs, no effective power transfer occurs between the two systems and, therefore, frequency begins to decrease due to the imbalance. This effect can be seen in Figure 80, which shows the active power exchange between the western corridor lines of the Spain-France interconnection (Biescas-Pragnères 220 kV, Arkale–Argia 220 kV and Hernani–Argia 400 kV) and the angle difference between the two parts of the split system (La Cereal in Spain and Saucats in France).

This loss of synchronism is detected by the protection relays in the interconnection (DRS) which triggers the line opening. In the next figures, the simulation results for the evolution of the active power of the interconnection lines between Spain and France are depicted (Y-axis) in relation to the angle difference between voltage and current (X-axis).

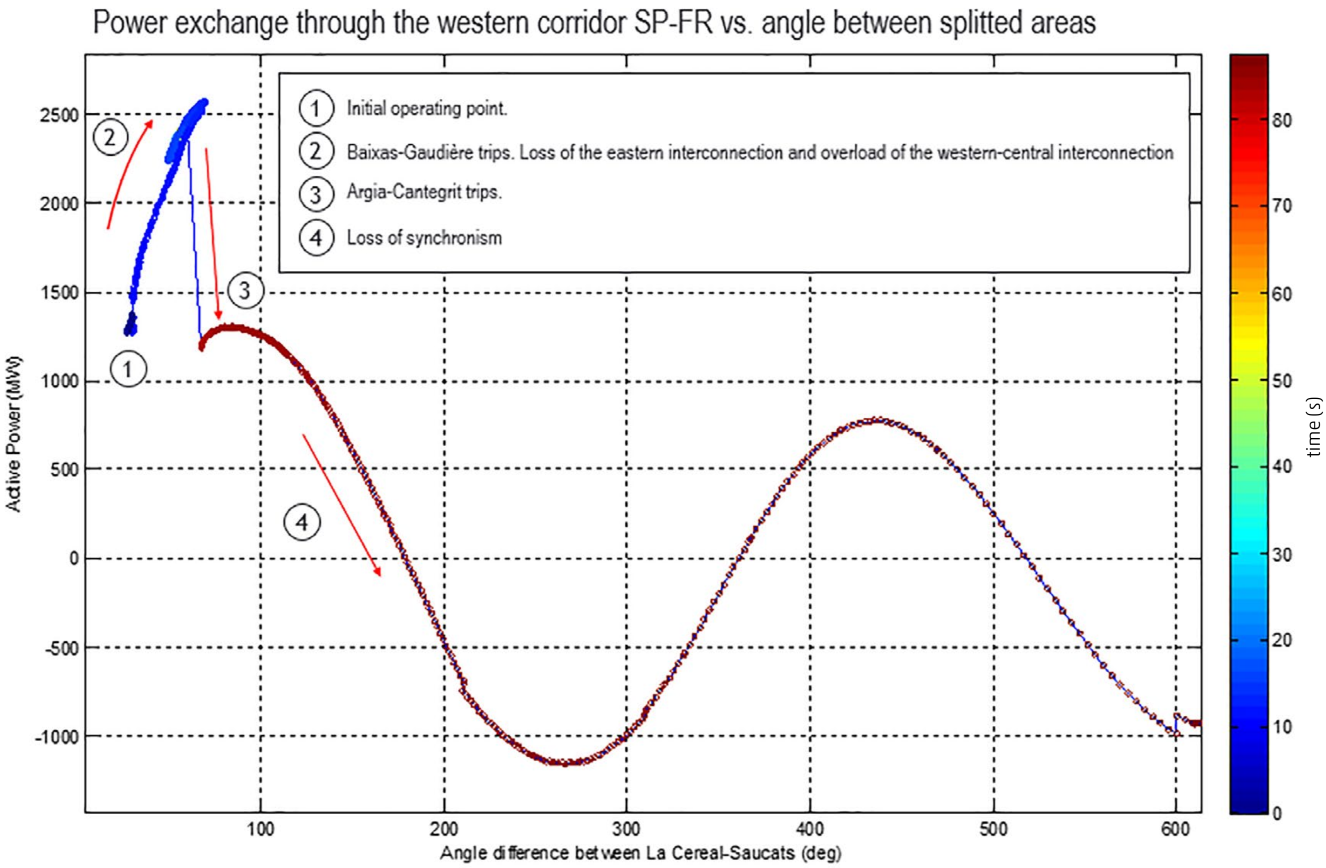
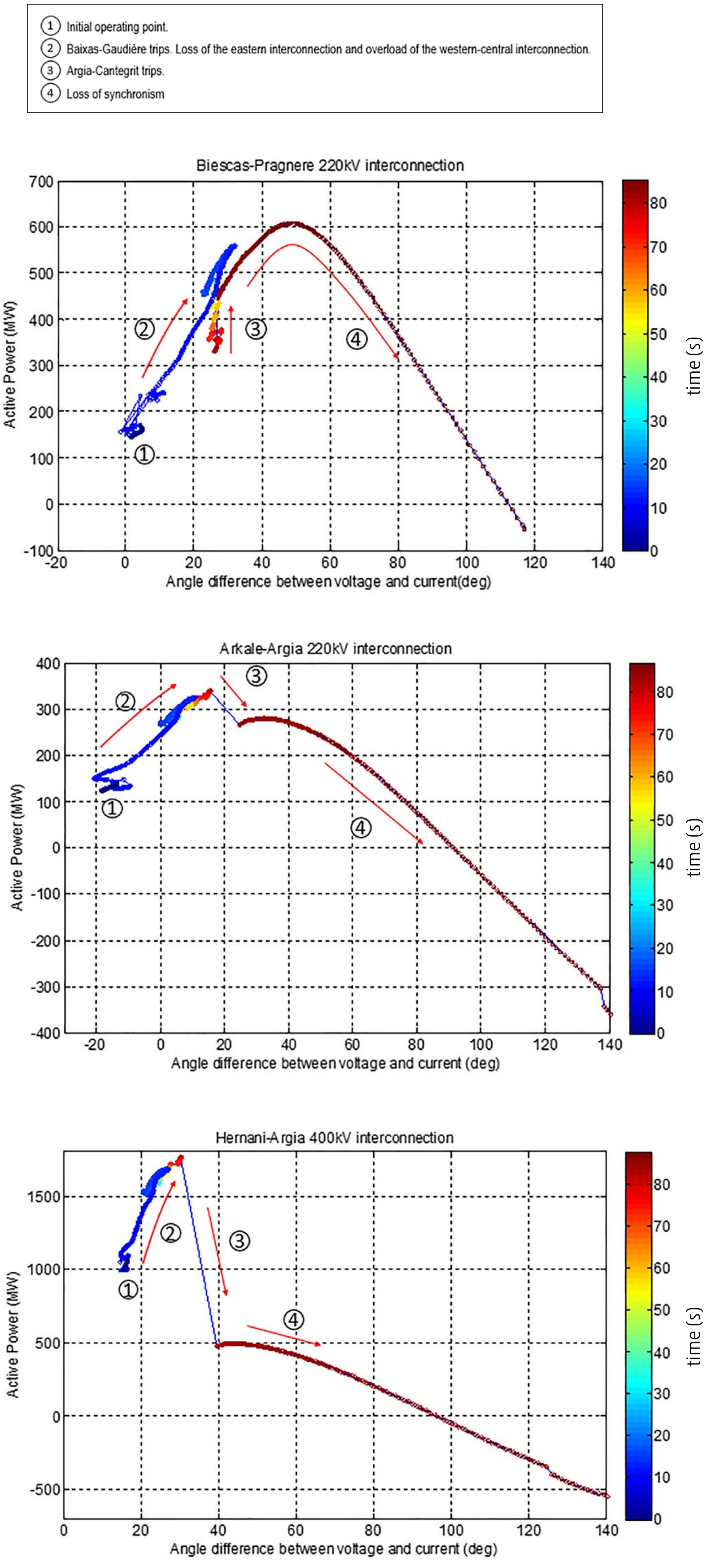


Figure 80: Loss of synchronism based on simulation: active power vs. angle difference.



Start of loss of synchronism in Biescas-Pragnères 220 kV interconnection line after Argia-Cantegrit trips.

Actuation of distance protection

Loss of synchronism in Arkale-Argia 220 kV interconnection line.

Actuation of DRS

Loss of synchronism in Arkale-Argia 220 kV interconnection line.

Actuation of DRS

Figure 81: Actuation of loss of synchronism (DRS) and distance protection relays based on simulation.

The simulation results endorse the correct functioning of the DRS relay in Hernani-Argia 400 kV line as it shows again a loss of synchronism and correct intervention.

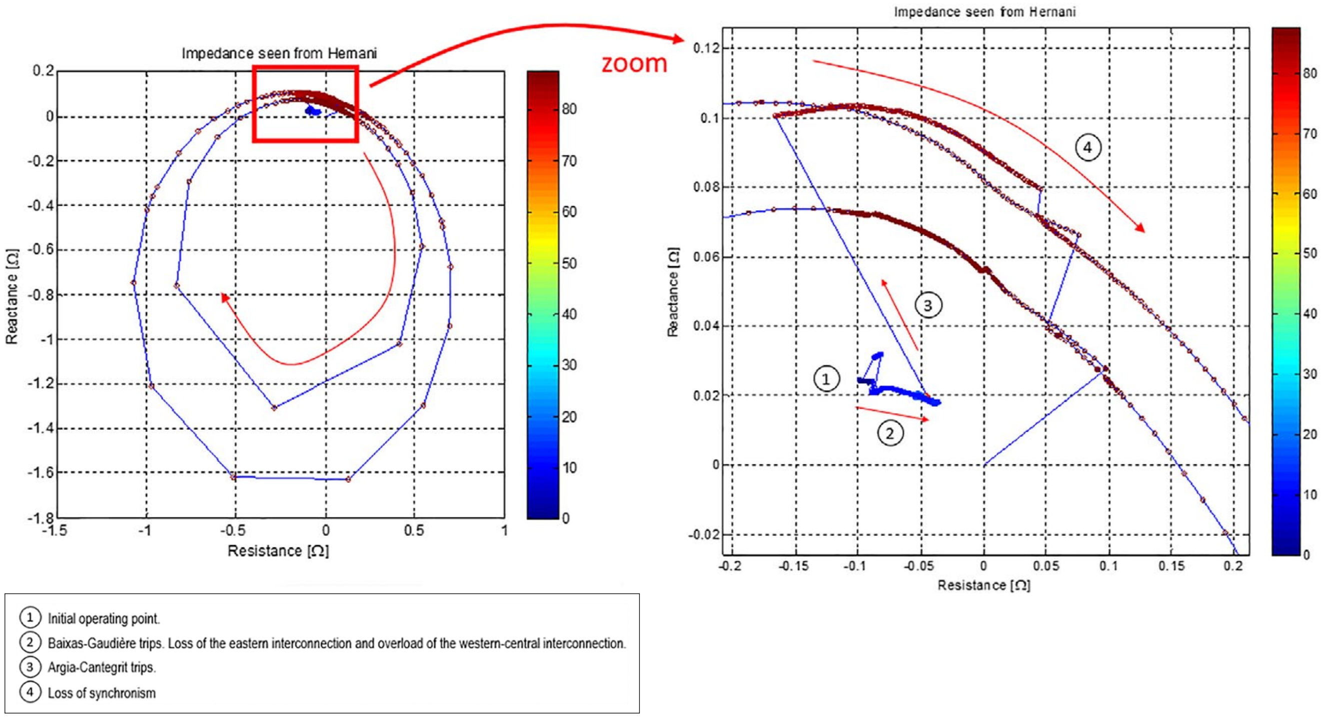


Figure 82: Actuation of loss of synchronism relay in Hernani-Argia 400 kV line based on simulation. R-X diagram.

In conclusion, simulations fully confirm the correctness of protection intervention and settings, giving more details about the "perspective" of devices during the transient. It is important to underline that protection actions preserve the system integrity due to serious damage; in fact, the automatic disconnection during a loss of synchronism avoids damage to synchronous machines / turbine shaft and, in any case, causes a cascading trip of all system devices due to the unsustainable fluctuation of frequency and voltages.

Some additional considerations can be done about protection criteria by overload implemented on HV overhead lines by delayed maximum current relays; this strategy influences the general protections selectivity and coordination criteria while potentially increasing a cascading phenomenon evolution. It is suggested that some alternative protection strategies based on Special Protection Schemes should be further analysed to prevent overloads.

13.3 Frequency support during the system separation

Figure 83 presents the location of 7 PMUs that were selected as the main representatives of the sequence of events. The PMU in Avelin in the northern part of France was selected as the reference for the voltage phase angle. Indeed, the substation remained always connected to the CE system and, therefore, represents a sTable phase angle reference. Three PMUs were selected in the southern part of France, as representative of the system dynamics that occurred close to the separation line on the CE side. These are located in Tavel and Saucats in France and Biescas in Spain. Four PMUs located in different points of the Iberian Peninsula were also selected. One PMU was selected from Recarei in Portugal as representative of the most western part of the system. From Spain, three PMUs were selected: Hernani and Vic, which are very close to the separation line, and Le Cereal, which is close to the centre of inertia of the small island.

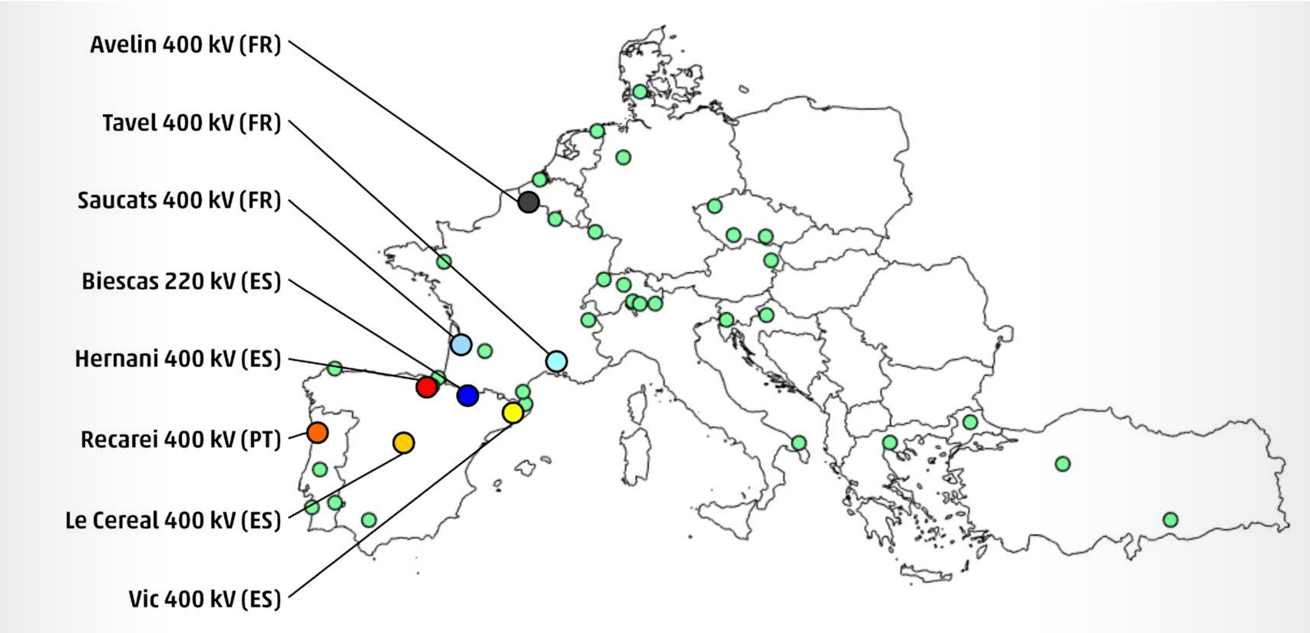


Figure 83: Selected PMUs Location for Detailed Analysis.

The following figures present the details of the sequence of events in terms of PMU recordings of frequency and voltage profiles, PMU recordings of cross-border exchanges and connections and disconnections of elements. Specifically:

a) The top three plots present the PMU estimates from the PMU locations presented in Figure 83. The colouring also coincides with the same figure: in blue are the measurements from the CE system and in red/orange those from the Iberian islanded system. The top plot presents the synchrophasor frequency in Hz.

b) The second plot presents the synchrophasor voltage magnitude in per unit.

c) The third plot presents the synchrophasor voltage phase angle difference with respect to the PMU Avelin (FR) in degrees.

d) The fourth plot presents the power through several tie-lines equipped with PMUs, including the two HVDC links.

e) The bottom plot presents the loss of active power resulting from the disconnection of generators (blue), loads and pumps (cyan), and the changes in reactive power resulting from the connection and disconnection of coils and capacitors (red). The load, pumps and generator reconnections are not reported. It is worth clarifying that the following sign convention was used:

- Positive reactive power means absorbed inductive reactive power: coil reactor CLOSE (connection) and capacitor OPEN (disconnection)
- Negative reactive power means injected inductive reactive power: coil reactor OPEN (disconnection) and capacitor CLOSE (connection)
- Load disconnection: negative active power
- Pump disconnection: negative active power
- Generator disconnection: negative active power

In Figure 84 the complete event overview is represented. The numbering is as follows:

1. 400 kV Baixas–Gaudière 2 line trip (Event #1)
2. 400 kV Baixas–Gaudière 1 line trip (Event #2)
3. 400 kV Argia–Cantegrit line trip (Event #3)

As it can be seen in the bottom graph, first coil reactors disconnect and capacitors connect, therefore Q is injected (Q<0). Then, shortly after the split, coil reactors connect and capacitors disconnect, therefore Q is absorbed (Q>0).

As can be seen in the bottom graph, first coil reactors disconnect and capacitors connect; therefore, Q is injected (Q<0). Then, shortly after the split, coil reactors connect and capacitors disconnect; therefore, Q is absorbed (Q>0).

Figure 85 shows the detailed analysis after the second 400 kV line Baixas–Gaudière tripped (Event #2) and the voltage instability and consequent collapse had already started. The way in which the voltage phase angle differences increased is also visible. Due to this voltage degradation, the first generator was lost and coil reactors started to be disconnected.

Figure 86 shows the details after the third line 400 kV Argia–Cantegrit trip (Event #3) and the system separation started. In this timeframe, the total load shedding was 4,872 MW (REE 3,561 MW, REN 1,246 MW, RTE 65 MW) and the total pump-storage disconnection amounted to 2,302 MW (REE 1,995 MW, REN 307 MW, RTE 0 MW) for an overall loss of load of 7,174 MW.

It is also worth noting that at the very beginning of the event, the frequency measurements from substation Biescas show that the latter remained connected to the CE system, and then after few seconds it joined the Iberian Peninsula system (visible in Figure 86). The reason for is that the bay on which the PMU is installed is the line 220 kV Biescas (ES) – Pragneres (FR). When the line was disconnected (Event #4), the substation topology was such that that bay was also part of the Iberian system.

Figure 87 gives an overview of the disconnections and the voltage management actions after the third event (Event #3). Due to early voltage issues, the coils start to be disconnected and capacitors to be connected in France and Spain already before pump and load shedding. Coil reactors were disconnected and put back in service by REE for a total of ±1,750 MVAr, whereas in RTE -144, +272 MVAr. As regards capacitors, these were connected and disconnected in France for -339, +519 MVAr. Overall, the total loss of reactive power was -2,233 MVAr (coil disconnected and capacitors connected) and the total reactive power injection was +2,541 MVAr (coil connected and capacitors disconnected). In the same timeframe, an additional 3,764 MW of generation was lost (REE 2,674 MW, REN 1,016 MW, RTE 74 MW). It is worth noting that some generation was lost in Spain and France already before the separation (480 MW).

Finally, Figure 88 shows an overview of the resynchronisation process.

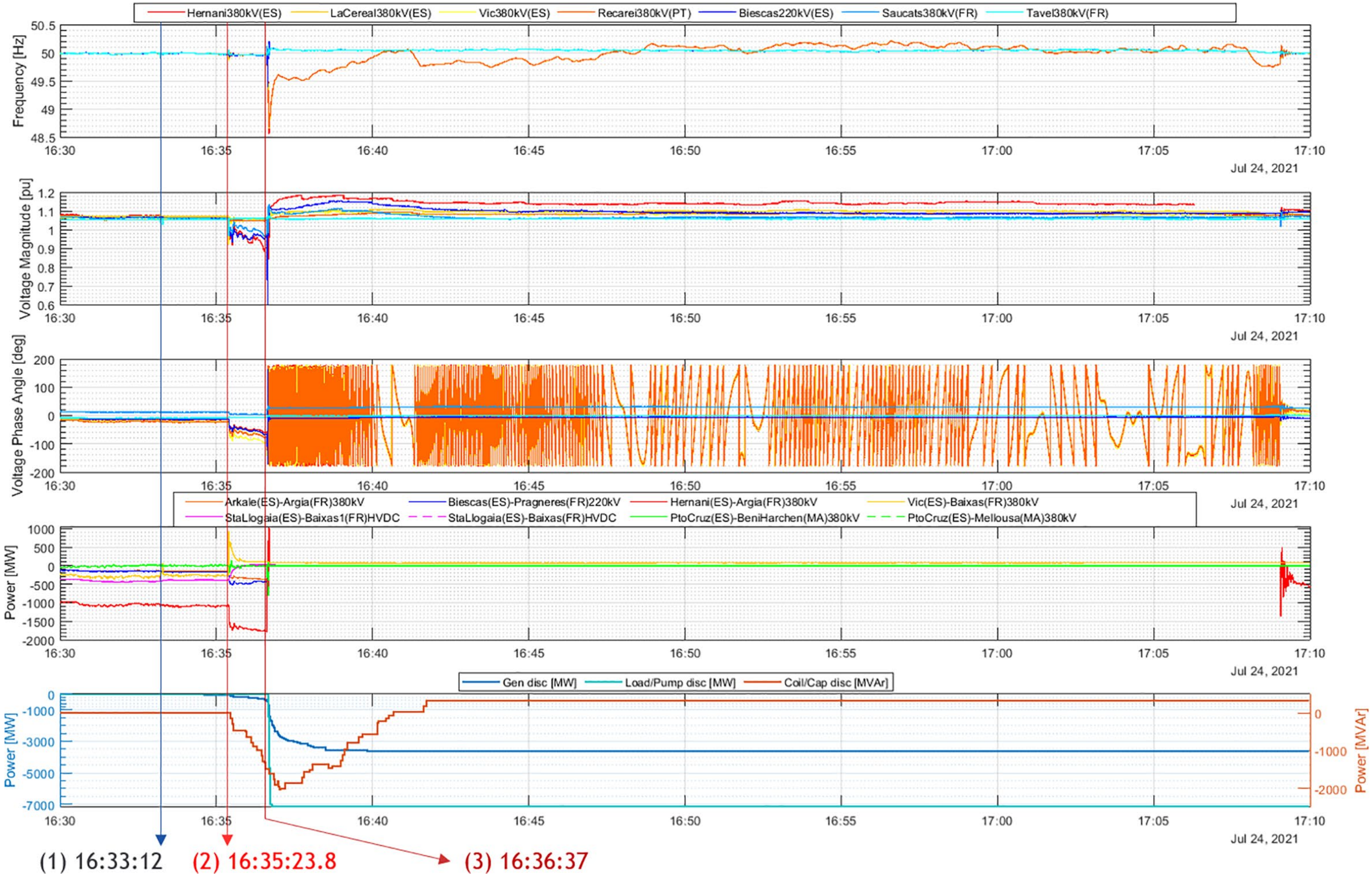


Figure 84: Complete Event Overview.

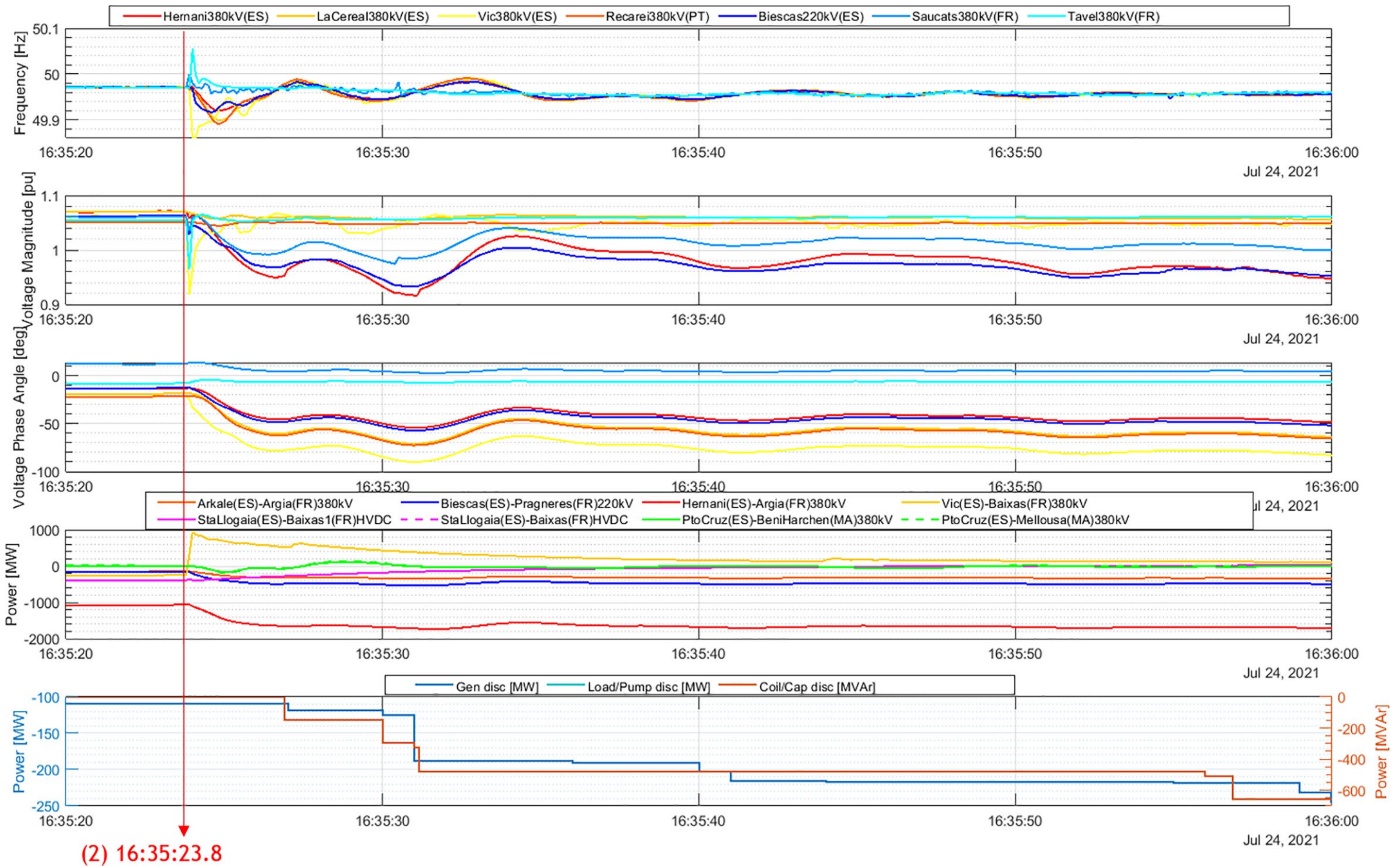


Figure 85: Detailed Analysis – After second line trip (Event #2).

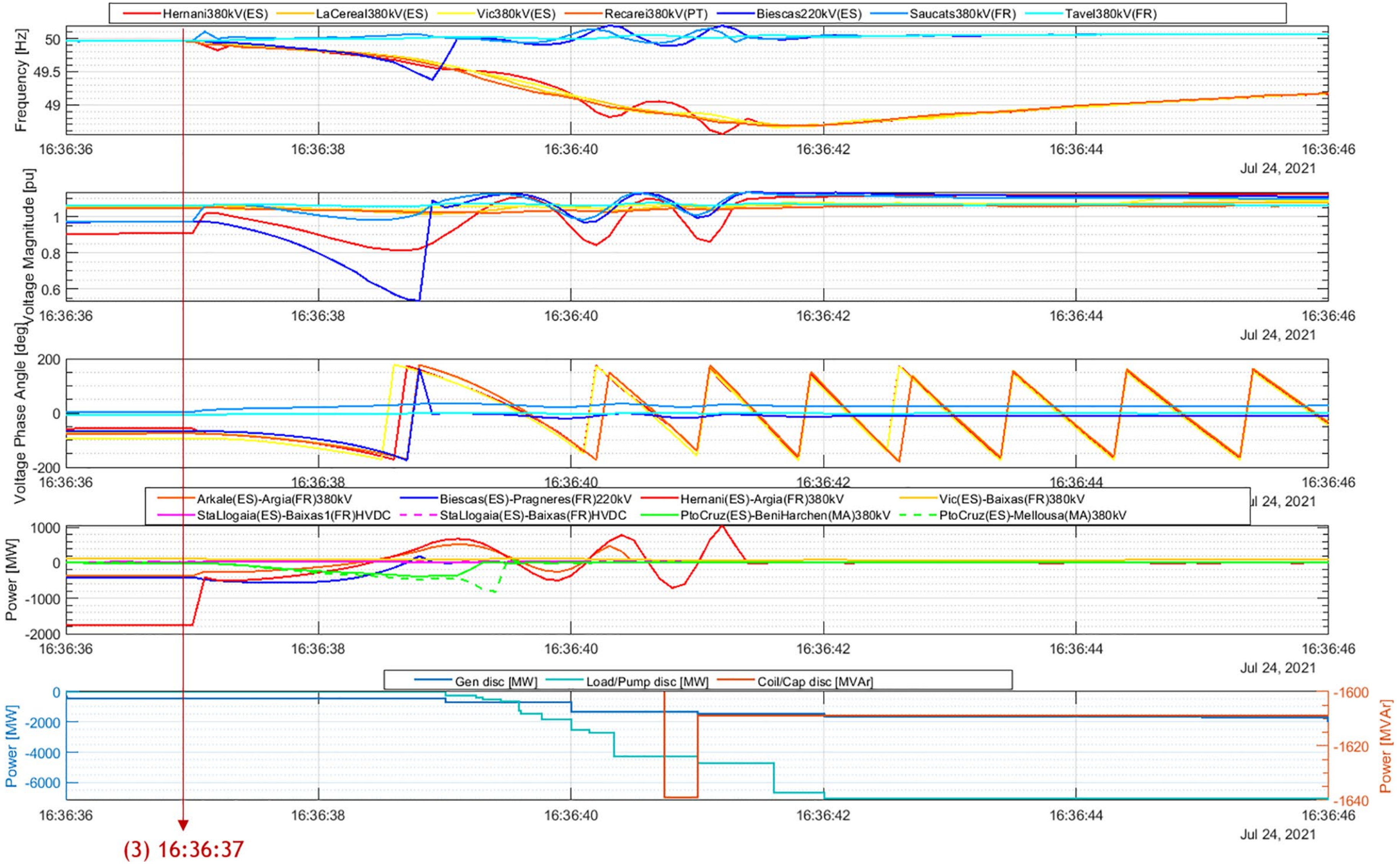


Figure 86: Detailed Analysis – After third line trip (Event #3) – System Separation.

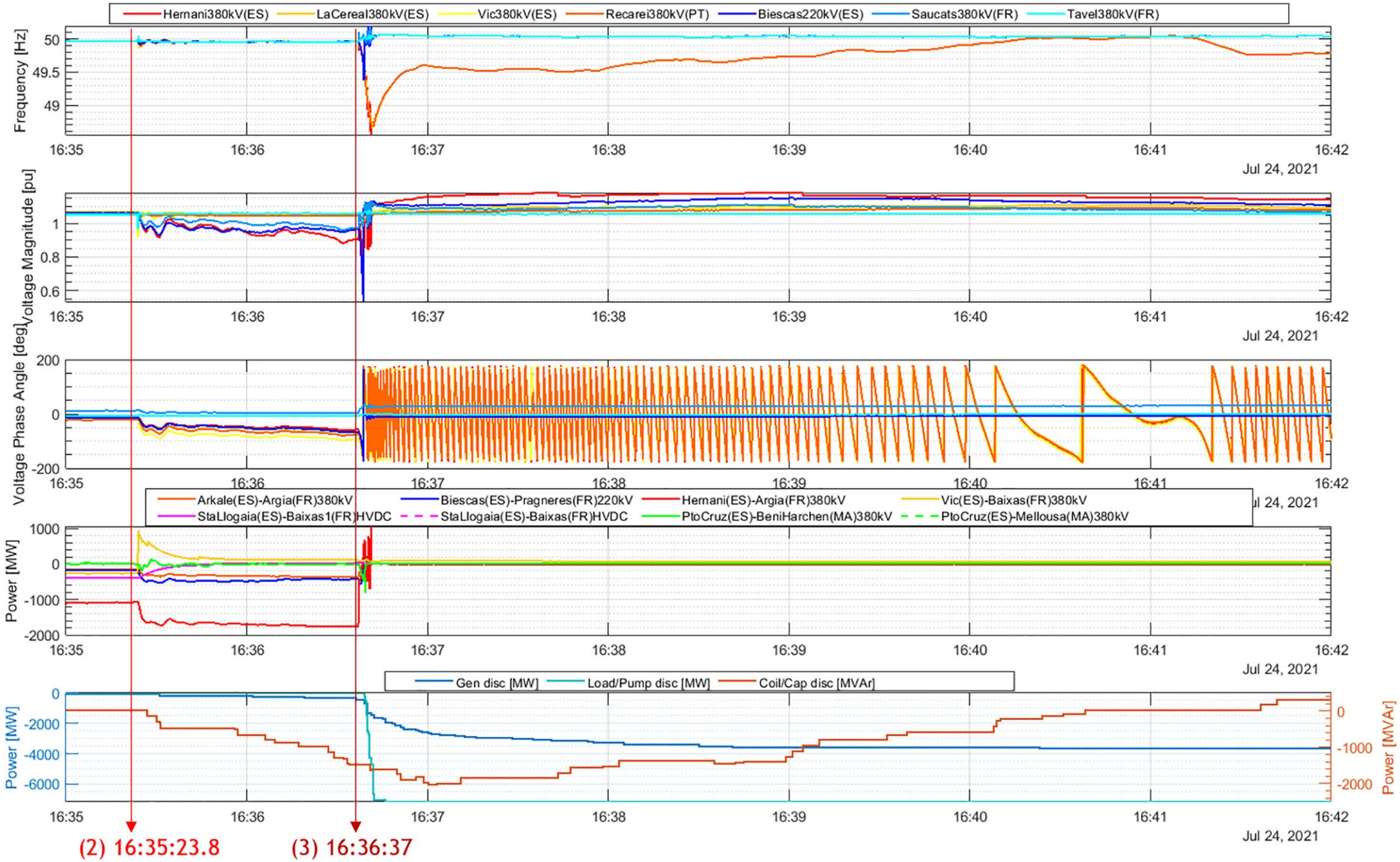


Figure 87: Detailed Analysis – disconnections & voltage management.

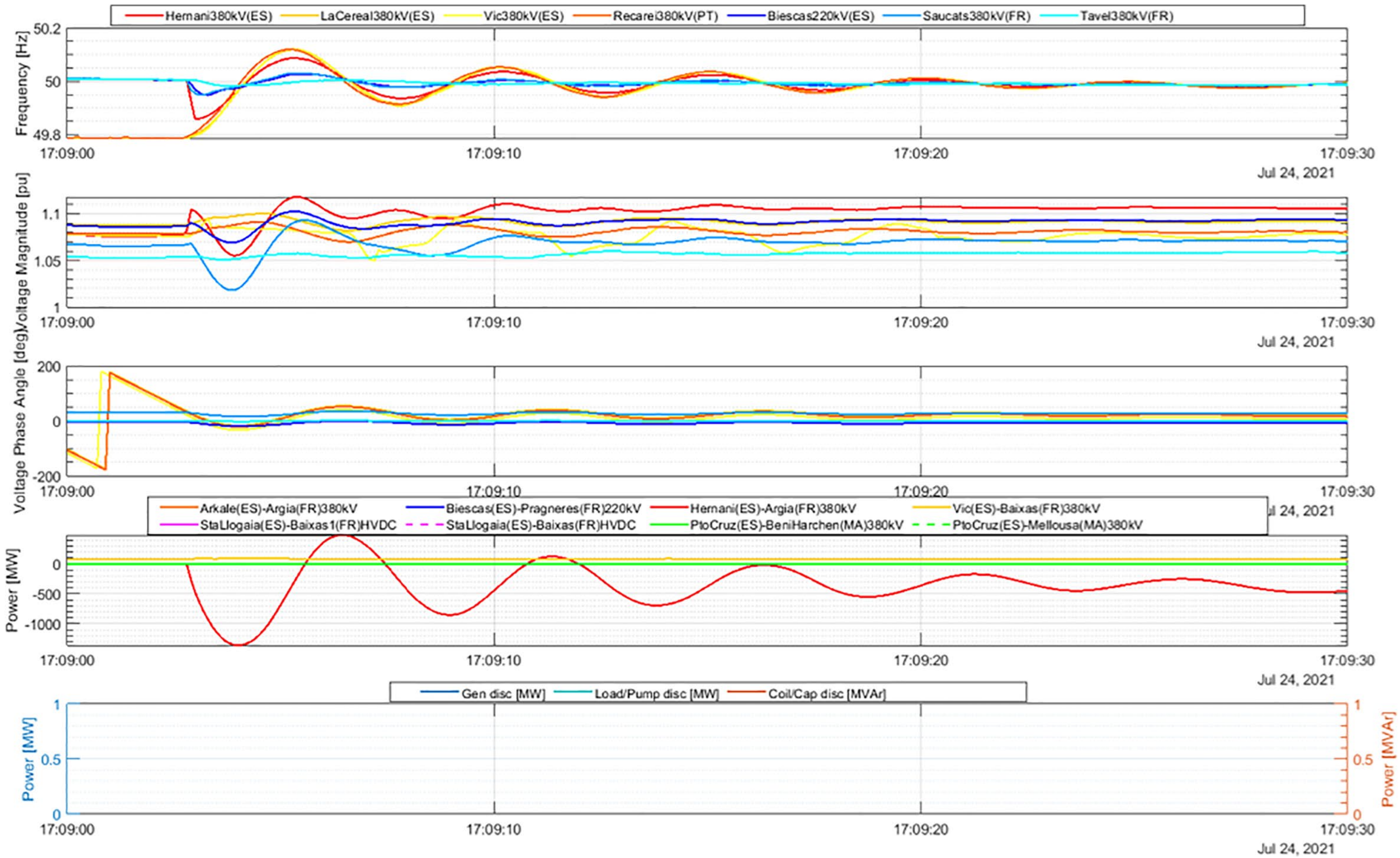


Figure 88: Resynchronisation Process – Overview.

Figure 89, Figure 90 and Table 44 show the power plant and system load disconnections. Note that for this analysis, the total Load Shedding was at 680 MW in Portugal (**Section 11.5-C**), of which the industrial costumers disconnections amounted to 394 MW (**Section 11.5-B**) and the consumption reduction due to COGEN-type generators disconnection amounted to 172 MW (**Section 4.6.2**) These amounts of power were considered up to a total load reduction of 1,246 MW in Portugal.

		tot	REE	REN	RTE	Before split	After split
Gen Disc	MW	3,764	2,674	1,016	74	480	3,284
Load Shed & consumption disconnection	MW	4,872	3,561	1,246	65	10	4,862
Pump-storage	MW	2,302	1,995	307	0	0	2,302
Coil Reactors	-MVAr +MVAr	128	-1,750 +1,750	0 0	-144 +272	-1,150 0	-744 2,022
Capacitor	-MVAr +MVAr	180	0 0	0 0	-339 +519	-290 0	-49 519

Table 44: Power Plant & System Load Disconnections (System Protection Schemes).

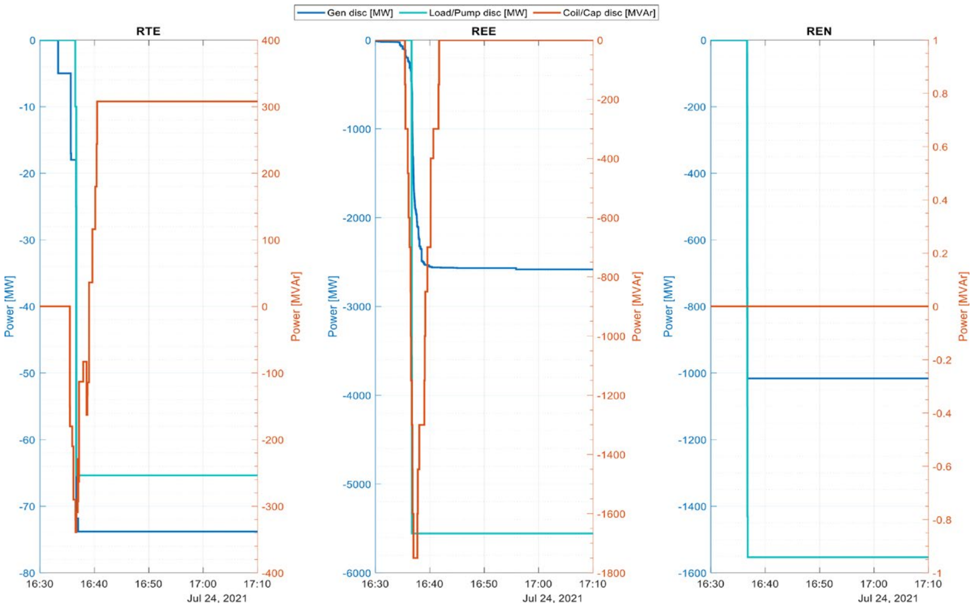


Figure 89: Power Plant & System Load Disconnections (System Protection Schemes).

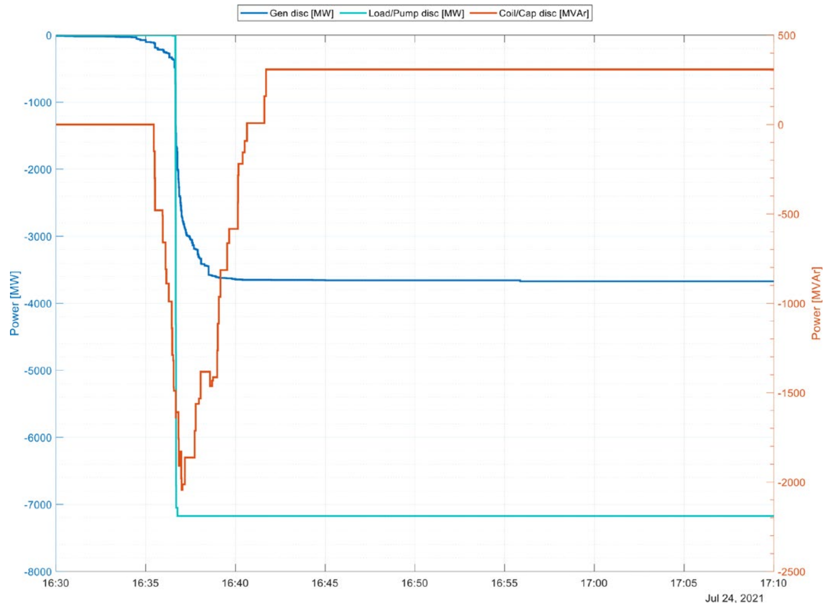


Figure 90: Power Plant & System Load Disconnections (System Protection Schemes).

Figure 91 and Figure 92 present the phase angle heat map as extracted with the WAM Tool. All PMU measurements, indicated with the bullet points, were used and the reference phase angle refers to the PMU in Albertville (big green dot). The two figures show the evolution of the voltage phase angle deviation before (Figure 91) and after (Figure 92) the trip of the second 400 kV Baixas–Gaudiere line (Event #2). As can be seen, after Event #2 the voltage phase angle between France and Spain increased to values close to the stability margin of 90 degrees.

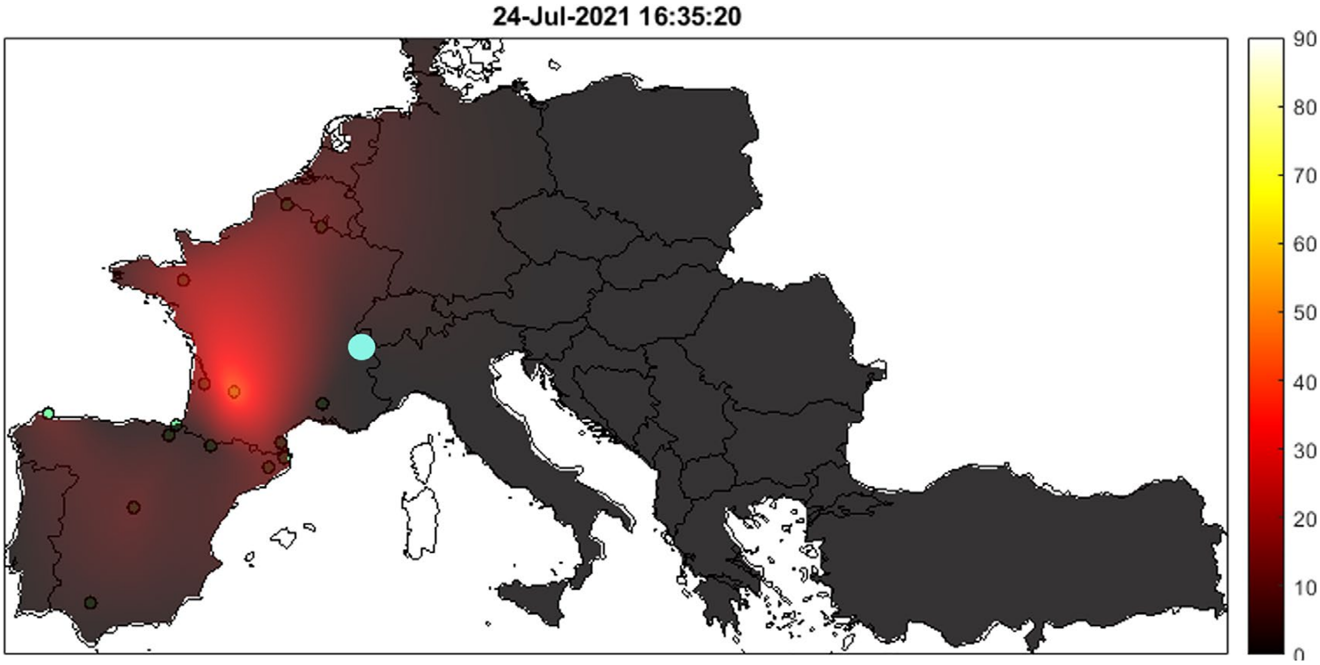


Figure 91: Phase angle heat map between Event #1 and #2.

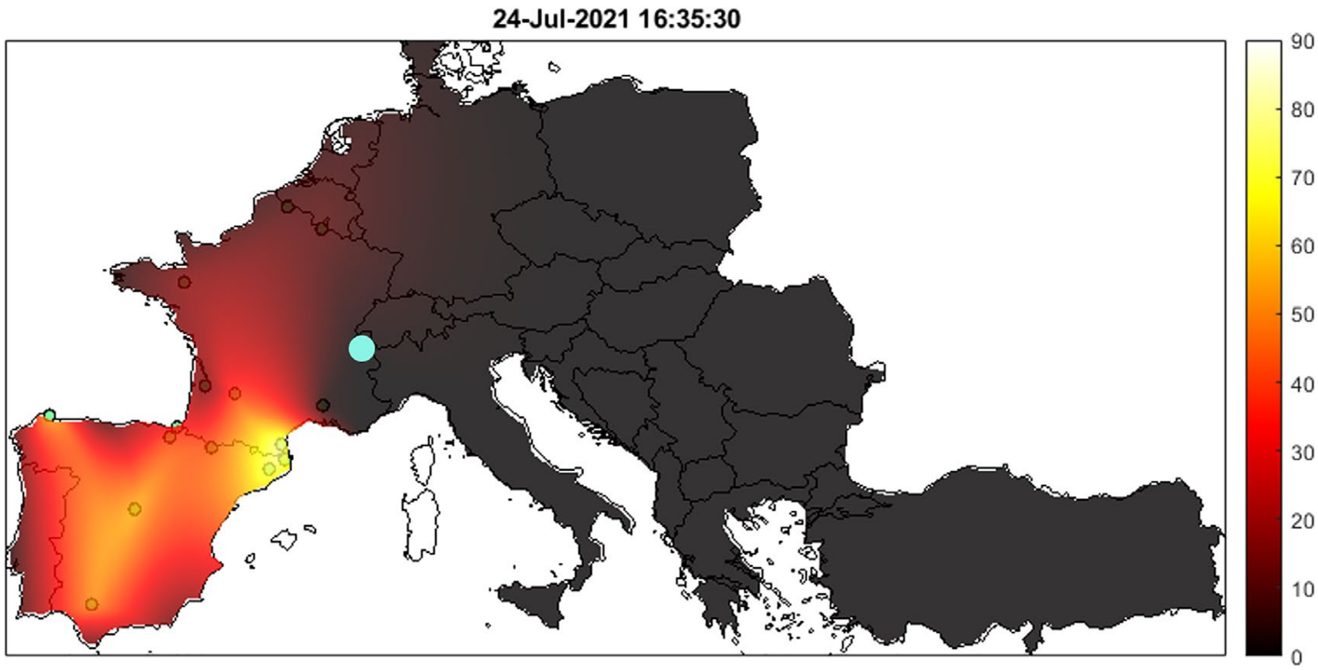


Figure 92: Phase angle heat map between Event #2 and #3.

13.4 Analysis of LFDD activation

A well-functioning and efficient system defence plan is highly dependent on a few key factors, as in the present case, specifically:

1. Precise engineering and parametrisation of the individual LFDD relays, including the corresponding maintenance

2 Good collaboration between all involved parties. For sensitivity and selectivity reasons, the relays are installed in the lower voltage levels under the responsibility of DSOs, and good cooperation with the TSOs is a prerequisite. The exact relay settings and the system-wide coordination of the activation of the different stages are under the responsibility of the TSOs on the level of the entire synchronous area.

Available Measurements

The following analysis is based on GPS time-synchronised measurements from WAMS from France, Spain and Portugal as well as on individual digital protection relays or transient recorders from several triggered devices from the Iberian Peninsula from REN and REE, who were able to get those recordings from their DSOs as COMTRADE files. Most of the recordings are GPS-time stamped.

The locations of all available measurements are depicted in Figure 93.

As can be observed, 21 PMU measurements and 18 relay/transient recorder measurements were available with fairly good geographical coverage

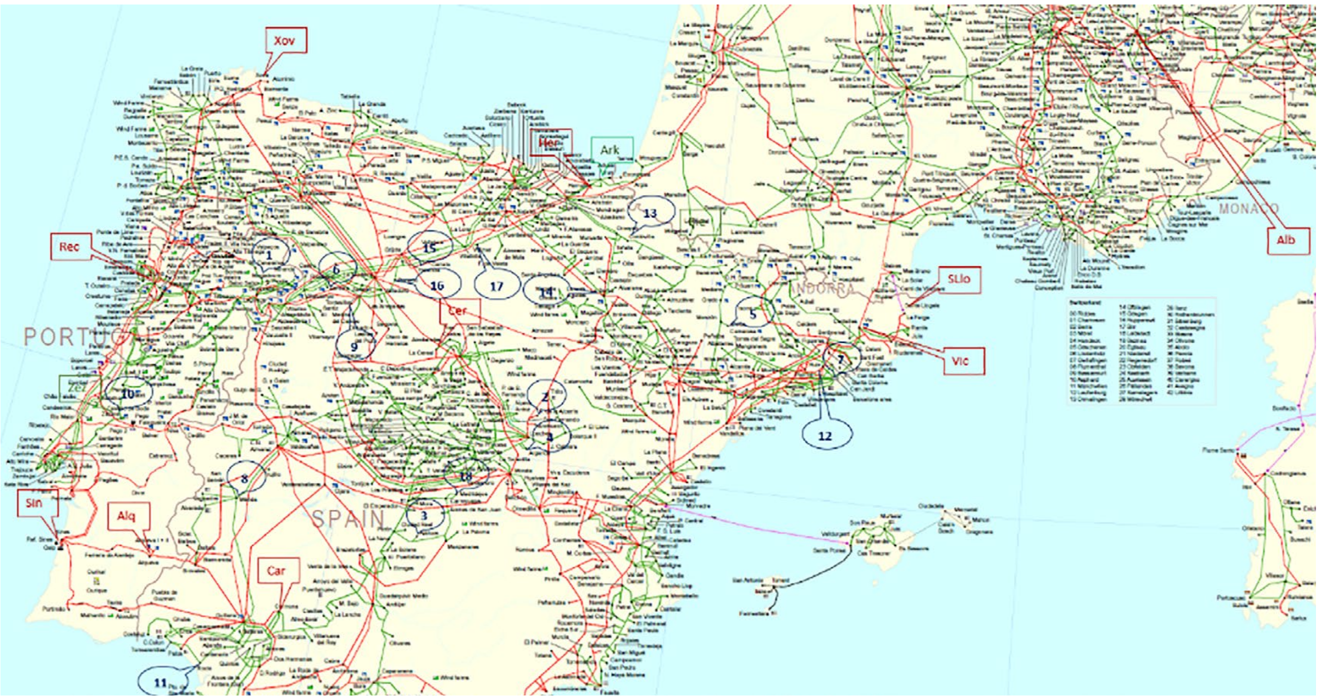


Figure 93: Location of PMU and LFDD measurements.

Comprehensive Overview

The analysis focuses on the most critical time window between 16:36:37 and 16:36:45 where the critical frequency drop suddenly stopped due to the successful triggering and activation of about 1,000 LFDD relays installed on the DSO level in Southern France, Spain and Portugal; see Figure 94 and Figure 95 for the related WAMS and digital protection or transient recorder recordings correspondingly.

The Measurements from WAMS are available for a longer time period, but only with a time resolution of 100 ms between two measurement points.

The voltage measurements reflect how the three measurement devices closest to the separation line, namely [10-12] Biescas, Arkale and Hernani, have suffered the highest transients.

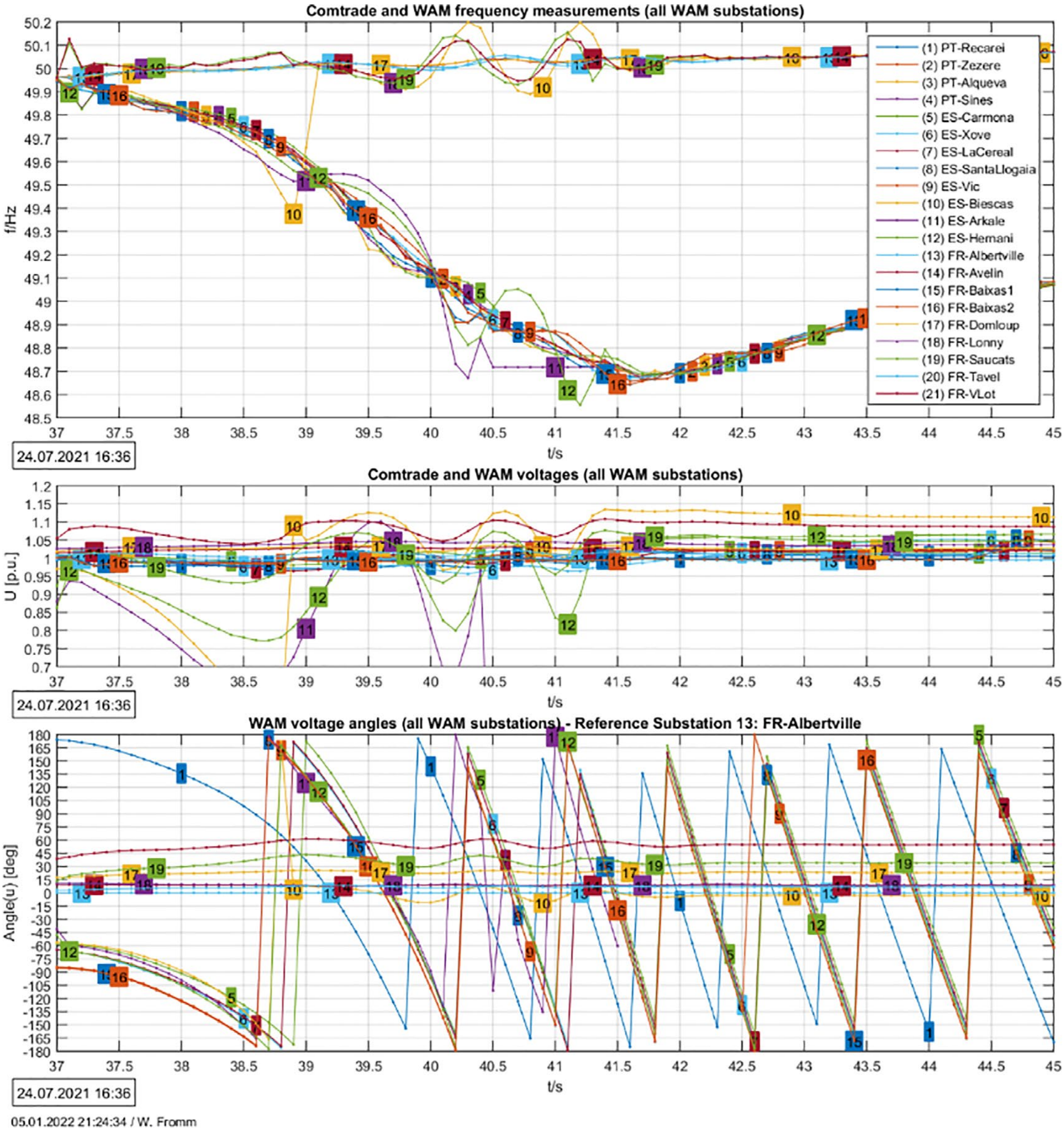


Figure 94: WAMS Frequency, voltage and voltage phase angle measurements.

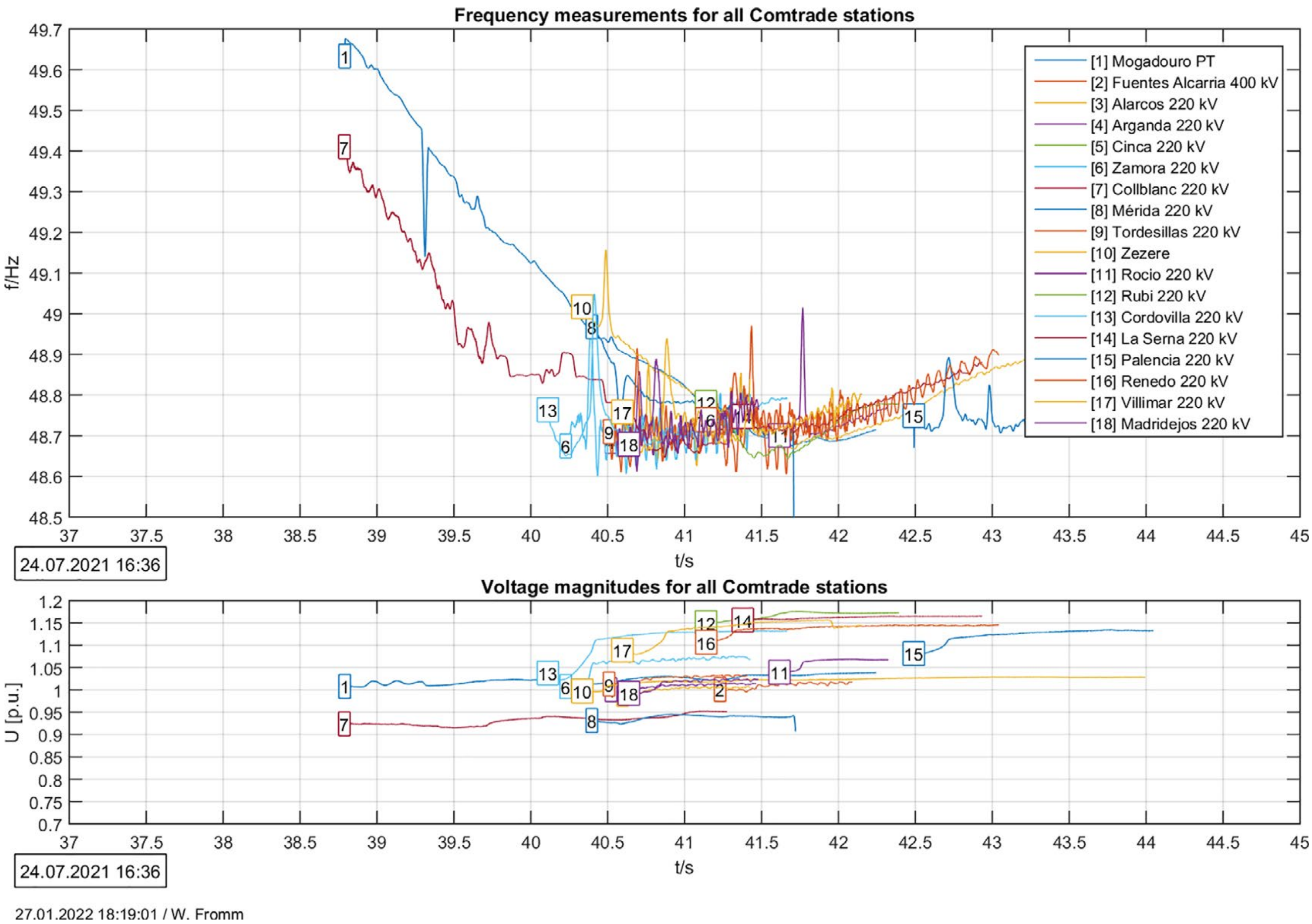


Figure 95: LFDD Frequency and voltage measurements.

It can clearly be seen how well all the relay measurements are aligned together and how the different system-wide disconnections are affecting the individual measurements by the resulting phase jumps etc. At the same time, the very short time window of the relay is also visible.

The voltage recordings document shows that all available relays operated in a fairly large voltage range between 0.9 p.u. and 1.2 p.u.

It is important to understand that the manner in which the frequency is estimated within the individual devices might be quite different. For the Measurements from WAMS, the frequency is already computed within the PMU itself and reported at defined reporting times (for the purpose of this report, every 100 ms). This is not the case for the LFDD and transient recorders that store and report only the "raw" samples as point-on-wave voltages and currents at defined sampling rates (0.5 kHz – 2.5 kHz).

The subsequent frequency estimation was performed based on a typical digital protection relay frequency estimation procedure.

The following Figure 96 – Figure 98 show the zooming-ins for 2 seconds of LFDD and Measurements from WAMS for the following geographical regions in the Iberian Peninsula: South-West, Centre, North-East. The time range 16:36:40 – 16:36:42 was chosen because the estimated frequency nadir was reached there. The geographical distinction was chosen to better highlight the frequency behaviour as getting closer to the separation line.

It should be noted that the relay numbers are marked with [quadratic brackets] and the related numbers have a white background, whereas the WAM/PMU numbers are marked with (rounded brackets) and have a coloured background on the related curve number marks.

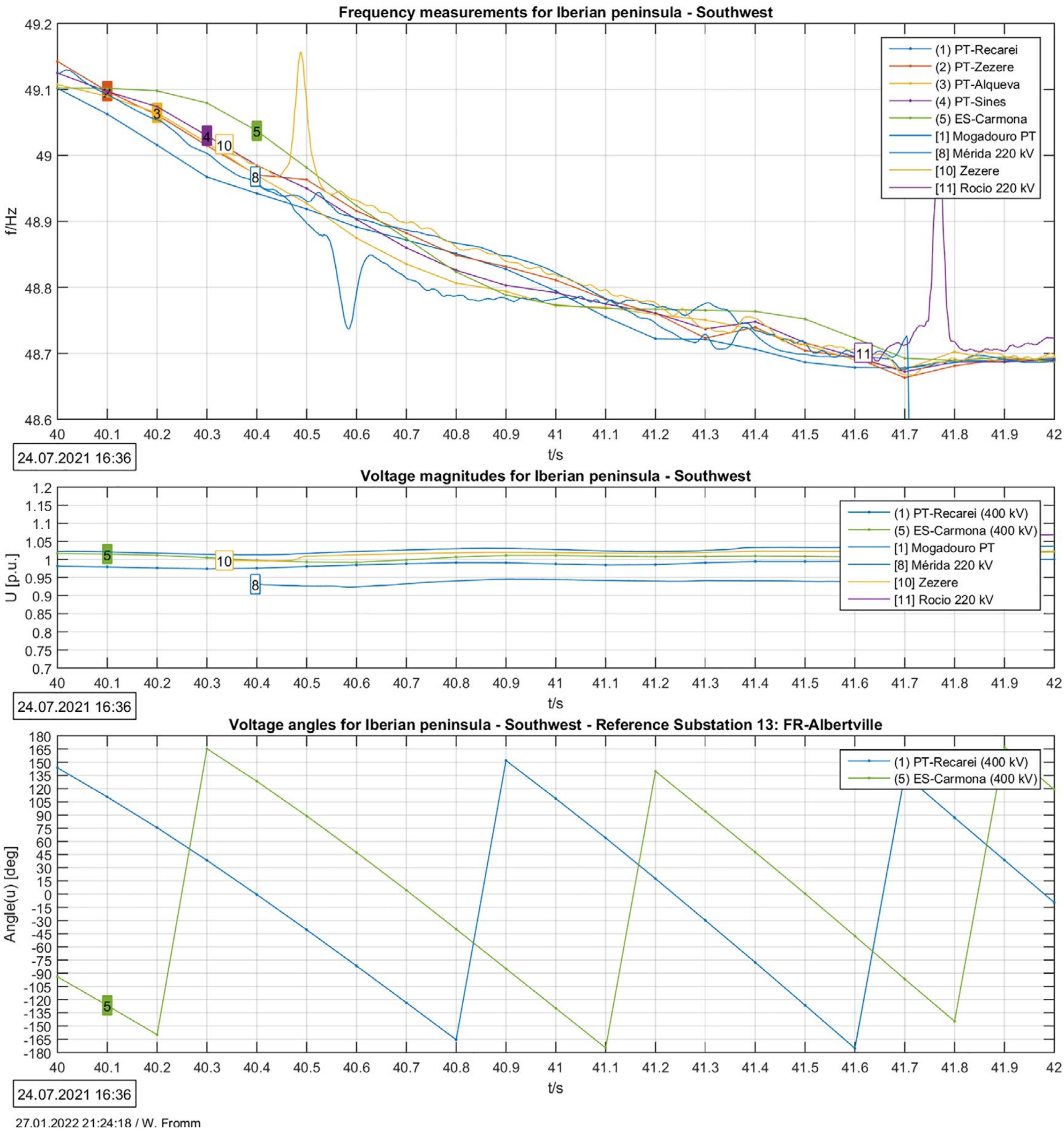


Figure 96: LFDD and Measurements from WAMS Iberian South-West region.

The earlier reach of lower frequency for a few relays is due to the related higher voltage phase displacement during the transient phase based on the additional impedance between the WAMS high voltage measurement location and the medium voltage measurement closer to the system load.

The LFDD measurements are indeed located at the medium voltage level, close to the system load and generation points. Therefore, they sense load or generation disconnections with a very limited delay. Conversely, WAMS measurements are located at the high voltage level. One possibility could be that the electrical distance between load or generation disconnection and WAMS measurements results in a delay in reaching the lower frequency values. Another possibility is that the devices are not properly time-synchronised, and this resulted in poor frequency estimates.

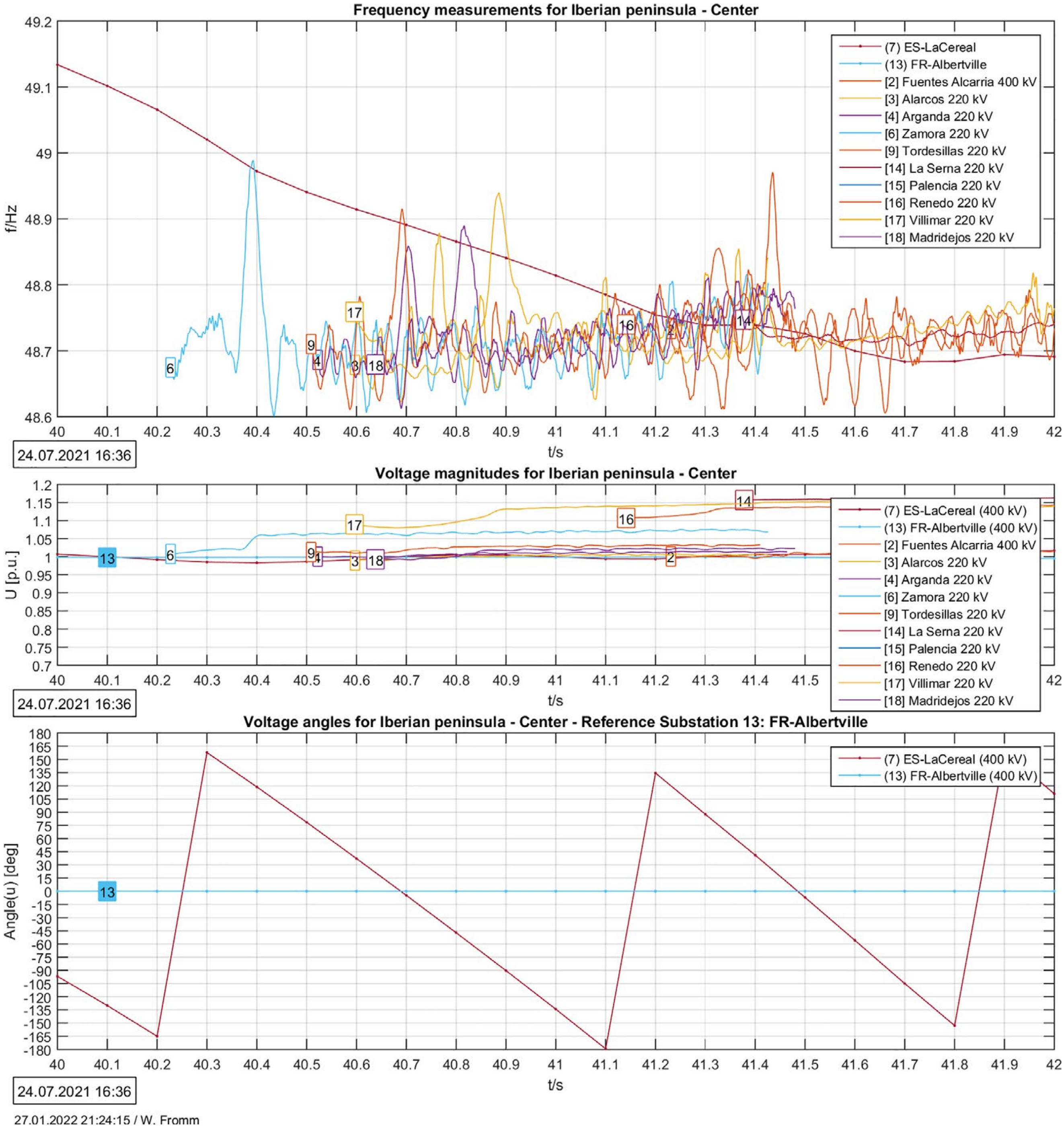


Figure 97: LFDD and Measurements from WAMS Iberian Centre region.

In the centre of the Iberian system, where a significant amount of the load in the urban and suburban area of Madrid was shed in the second load shedding stage at 48.7 Hz, the effect of the close nearby and own phase jump becomes clearly visible by the related excursions of up to ±250 mHz within the computed/estimated frequency measurements.

It is worth noting that these frequency oscillations can be regarded as estimation errors that result from the frequency estimation algorithm when applied to non-sinusoidal waveforms and do not represent a physical frequency behaviour.

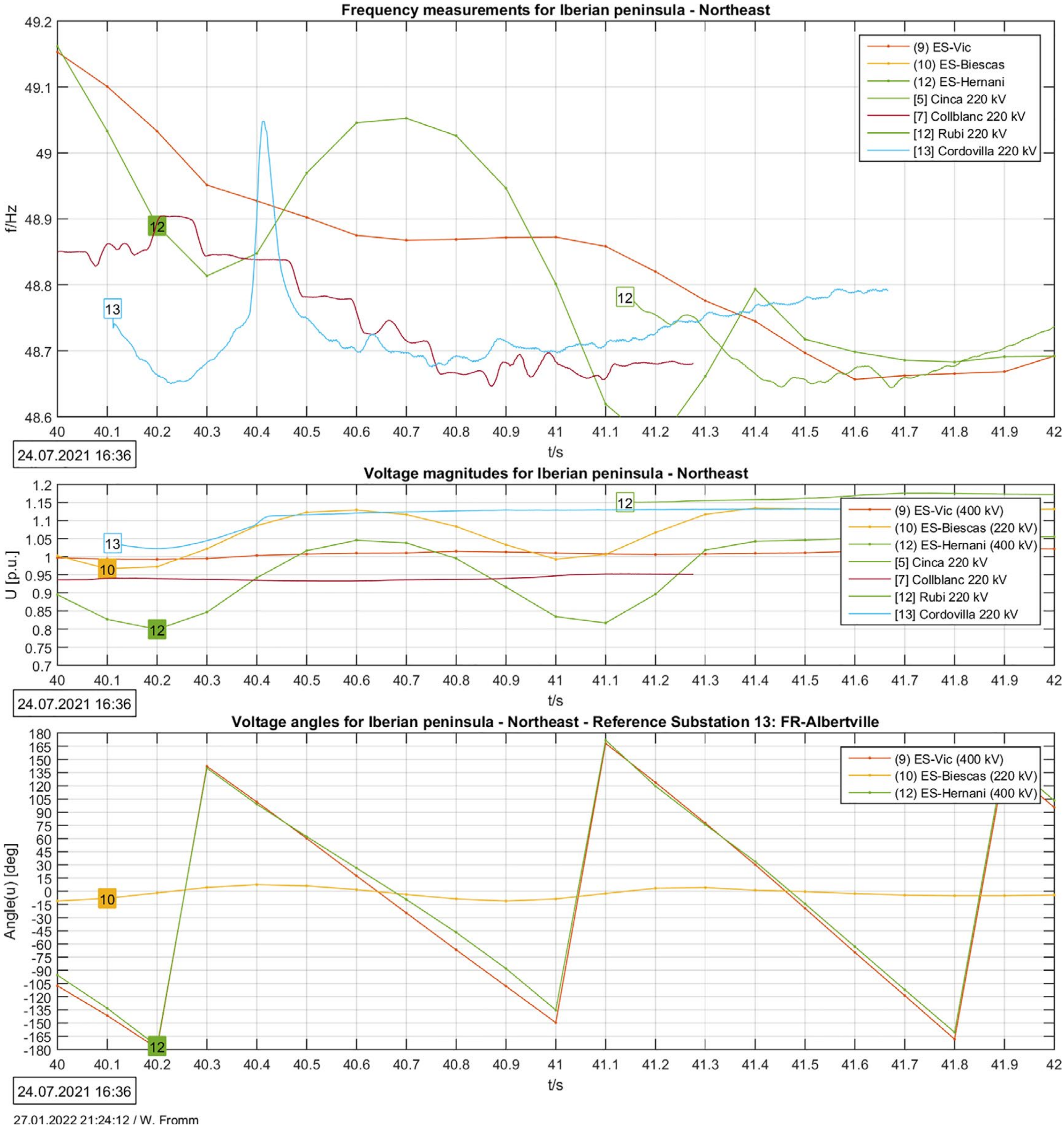


Figure 98: LFDD and Measurements from WAMS Iberian North-East region.

The high transients close to the geographic separation line between the Iberian island and the main CE power system reflected in voltage and frequency measurements clearly highlight the challenge for the LFDD located close by.

The overlapped LFDD and Measurements from WAMS of the lowest frequency range in a time window of 3 seconds (16:36:40–16:36:43) are shown in Figure 99.

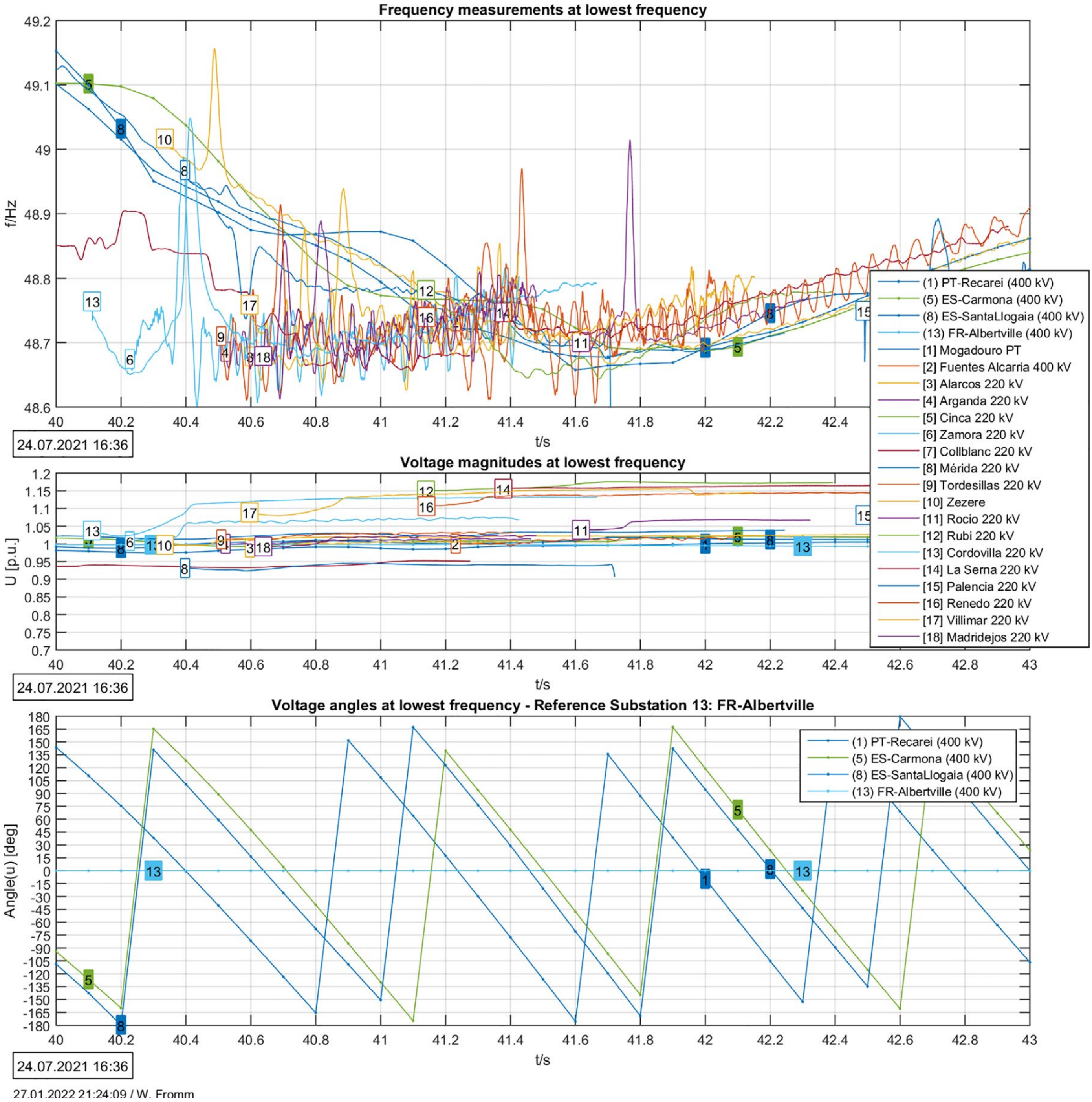


Figure 99: Overlapped measurements at the lowest frequency.

The earliest recordings are those where either a pump was shed at 49.5 Hz or a load at 49 Hz – both in Portugal, see Figure 100.

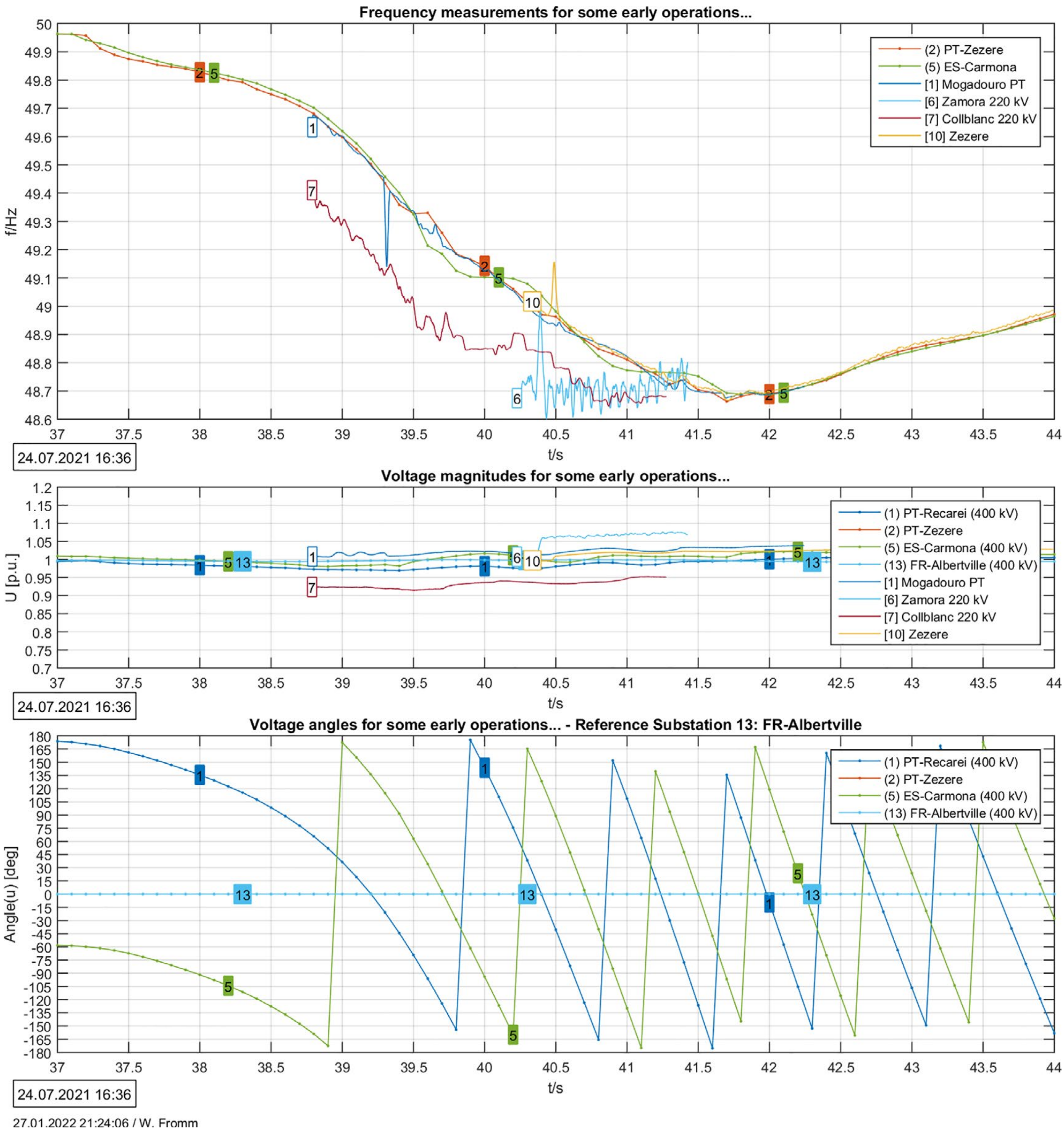


Figure 100: First load shedding.

As in Figure 96, it is clear how close to the load during the transient phase the frequency excursion arrives up to one second earlier as in the high voltage due to the related electrical distance between generation and load area.

Detailed Analysis

Further detailed analysis is based on the comprehensive review of the 18 available COMTRADE recordings. Those recordings with a sampling rate of 0.5 – 2.5 kHz consist of point-on-wave measurements of all three voltage phases and, for most of them, there are also current measurements as well as recordings of several digital channels and additional information about the exact trigger time stamp.

As already mentioned, the frequency measurement was derived from the 3-phase voltage timely high resolution channel samples by using one well-established frequency estimation algorithm of a specific significant vendor for digital relays. All related graphs have the same structure and are available in Annex 15.1 – 15.18.

However, Figure 101, concurrently with Annex 15.18, explains the structure of the individual relays comprehensive reporting as being quite representative for almost all other recordings:

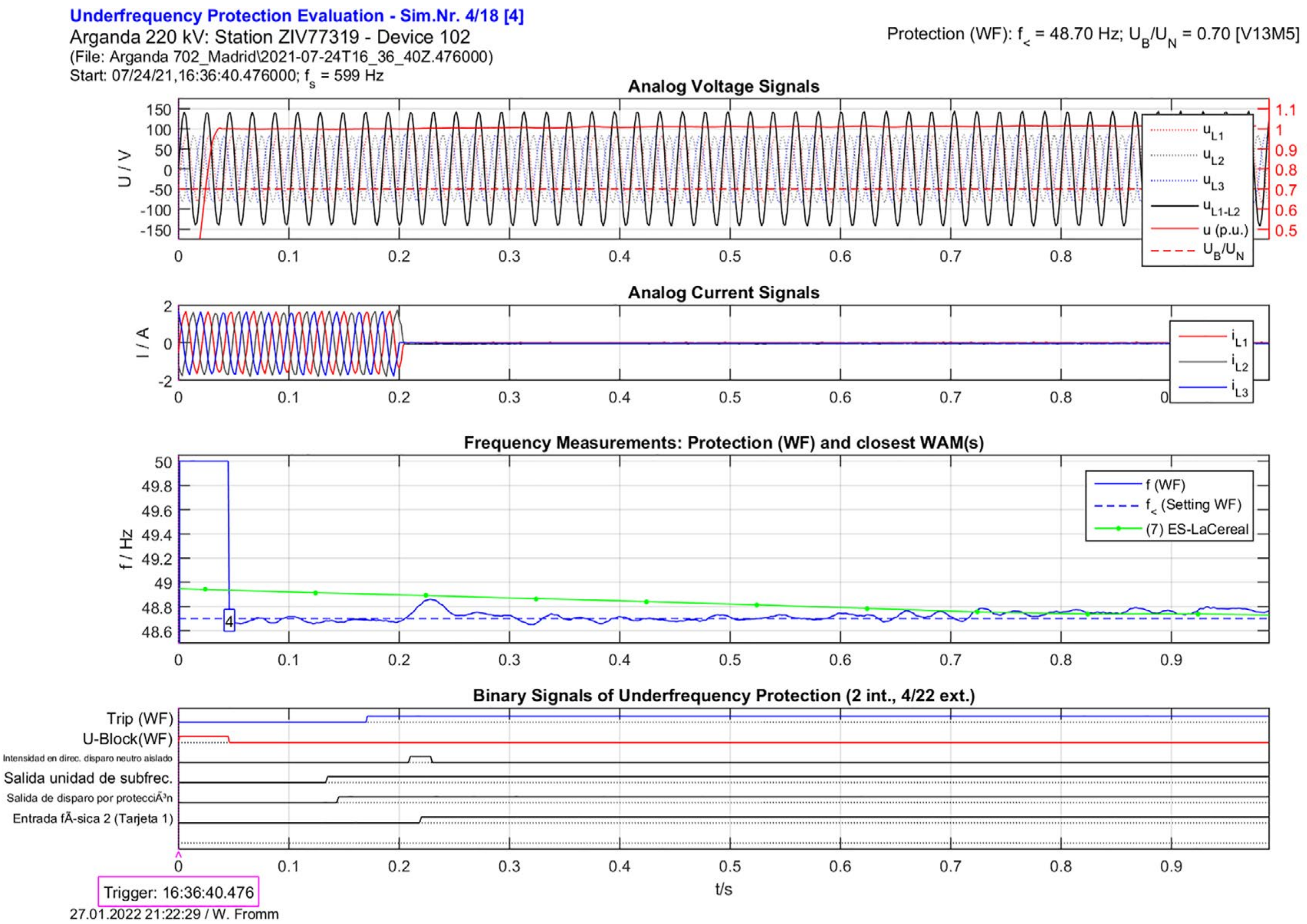


Figure 101: COMTRADE analysis for relay 4 – Arganda recording.

The upper graph contains the three phase-to-ground secondary voltages as well as the line-to-line voltage used as input for the frequency estimation.

In the second graph, the secondary three-phase currents are presented.

The third graph depicts the estimated frequency in blue colour and left-hand side y-axis and the p.u. voltage in red colour and right-hand side y axis. The graph also shows the triggering values for frequency and voltage, respectively (dotted lines).

The last set of curves on the bottom are a mirror of the significant digital COMTRADE channels in black colour, whereas the blue and the red two channels on the top are synthetic signals derived from the proprietary frequency evaluation chosen.

Examining the details of the above recording, we can state:

- **a)** The frequency measurement algorithm requires about 2 – 3 cycles = 60 ms before a valid frequency measurement is available. That means that the first estimations equal to 50 Hz can be neglected and are an artefact of the estimation procedure.
- **b)** Between the relay output contact and the circuit breaker operation – circuit breaker opening time – we measure about 70 ms.
- **c)** The slight increase of the voltage with about 1 % after load shedding is also clearly visible.

By analysing all the other recordings in the same manner, a few additional observations can be derived accordingly:

1. Most of the relays show a reaction time of 100 ms – 130 ms. By adding the also clearly visible circuit breaker time of 60 s – 100 s, this results in a total delay of 170 ms – 220 ms.
2. The time stamp of load disconnection is, in most cases, fairly well visible by a related slightly jump of the related frequency measurement mainly caused by the local voltage phase jump after the load disconnection.
3. It should be noted that all COMTRADE file time stamps seem to be correct and reasonable; only for relay 10 was a manual correction required.

Conclusions

All available LFDD recordings document a conforming and reliable operation of the distributed system defence scheme based on underfrequency.

The early activation of one relay, Nr. 5, at 16:01.10.505 is not clear as also only one voltage is available, and no disconnection could be detected.

The present available recordings illustrate:

- **A.** The LFDD scheme has worked properly and as expected.
- **B.** Even in extreme boundary conditions, e.g. significant phase jumps due to neighbouring relay activation, the relays were able to work properly.
- **C.** However, the weaker the system becomes the higher is the risk that correct LFDD activation can be expected.
- **D.** A typical overall delay between the frequency triggering time stamp and the successful load disconnection of about 100 – 200 ms is clearly visible.
- **E.** The measured time between the relay trip output and the successful circuit breaker disconnection was in the range of 50 – 100 ms.

14 CONCLUSIONS AND RECOMMENDATIONS

Based on the valid legal framework, soon after the system separation in the power system of CE on 24 July 2021, according to the ICS methodology, a scale 2 investigation was launched to describe the course of the incident and its underlying causes. The present final report provides the findings and insights from this investigation. The resulting recommendations are valuable and highly appreciated inputs that will help to prevent similar incidents in future power system operation. The ongoing energy transition requires a resilient and sustainable power system to guarantee a sTable supply of electric power to all European citizens.

14.1 Summary

On Saturday, 24 July 2021 at 16:36 CET, the Continental Europe Synchronous Area was separated into two areas (the north-east area and the south-west area) due to cascaded trips of several transmission network elements. This cascade of trips was caused by a forest fire in the vicinity of the two-circuit 400 kV Baixas– Gaudière transmission line in France. The fire began around 13:30 CET and a request should have been made to RTE to disconnect the two circuits because of their proximity to the fire. In this case, due to the extreme environmental conditions which hampered communications, this request was unfortunately not made and so the two circuits remained in service. At 16.33.11, the fire caused a short circuit between two of the phases of circuit 2 approximately 8 km from the Gaudière substation. The protection system detected the fault and responded correctly by opening the circuit breaker and tripping the line at 16.33.12. Five seconds after this first tripping, an unsuccessful automatic reclosure attempt was made, after which circuit 2 remained out of service. At 16.35.23, circuit 1 experienced a similar fault and tripped. The automatic reclosure was again unsuccessful and from this point on, both circuits of the 400 kV Baixas–Gaudière transmission line were out of service.

Before the tripping, the two 400 kV Baixas–Gaudière circuits were transporting 612 MW each from France to Spain. Due to the separation of the Baixas substation from the rest of the French transmission system, these two trips resulted in the loss of the eastern interconnection between Spain and France. The Baixas substation remained supplied from Spain. The loss of the eastern corridor caused the western and central France–Spain interconnection corridors to become overloaded. These overloads caused the tripping of the Argia-Cantegrit 400 kV line 73.2 seconds after the second tripping. This third tripping caused a loss of synchronism between the French and Spanish systems, which subsequently led to the complete loss of interconnections between the two systems.

It should be noted that this sequence of events reflects only the tripping of transmission lines in the high and extra high voltage transmission system. In addition, on the French side, ten 63 kV lines tripped during the event, due to distance and loss of synchronism protections.

After circuit 2 tripped, RTE and REE immediately decided to reduce by 1.3 GW the power flows from France to Spain. Unfortunately, circuit 1 tripped before this reduction could impact the load flow situation. Automatic frequency restoration reserves were correctly activated in Spain and Portugal, together with manual frequency restoration in Spain. Shortly after the separation, the affected TSOs as well as the CCs Amprion and Swissgrid informed all TSOs via the EAS of the incident. REE as the frequency leader, with support from Amprion, as SAM, then coordinated the return of the frequency to 50 Hz in the Iberian Peninsula. The Continental European Power System was resynchronised at 17.09.

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.

From the perspective of regional security coordination, it can be concluded that the operational situation was consistent with the forecast and within the limits of usually expected deviations.

Given the 3 hour time span between the identification of the fire breakout and the system split, it is obvious that the risk assessment could have been effectively supported by TSOs in the event the information on the fire and updated contingency lists was made available in time. Subsequently, necessary remedial actions could presumably have been aligned between RTE and REE and the system split might have been prevented.

14.2 Derived recommendations

Based on the collected facts, the further analysis and the subsequent derivation of the main causes and critical factors, the Expert Panel has outlined the following recommendations.

In **Section 14.2.1**, recommendations resulting from the incident of 24 July are presented in detail.

This Expert Panel has further studied the recommendations derived after the system split of 8 January 2021 and found that most of them are also relevant for the system split of 24 July. These recommendations are presented in **Section 14.2.2**.

14.2.1 Recommendations derived from the event of 24 July 2021

1. Reduce the volume of generation tripping

The Network Code on Requirements for Generators (NC RfG) establishes that generating units should not automatically trip in the frequency range between 47.5 Hz and 51.5 Hz and in different voltage ranges independently of the voltage of the point of connection. The NC RfG is only mandatory for generators installed after its requirements of general application have been defined at the national level.

As detailed in **Section 4.6**, during the event, in total 3,764 MW of generation was disconnected. Most of the generation units which were disconnected in Spain operated at the medium voltage level and were disconnected due to under- or overvoltage relays on the DSO level. In Portugal, most of the generator disconnections occurred due to underfrequency relays on the DSO level. As precise and reliable voltage measurements are only available at the high voltage transmission level, it is difficult to assess the exact amount of non-conform disconnections.

This recommendation is focused on avoiding as much as possible the generation tripping that is acting against the system stability and has a consequence of imposing more load shedding than the minimum necessary. The recommendation also addresses the need to improve the data collection in the case of generation trips. Specifically, the Expert Panel recommends the following:

a) Improve TSO–DSO coordination for the definition of settings of under frequency protection settings that trip the generation connected to the distribution grids.

b) Improve the monitoring of distributed generation by means of digital relays or dedicated transient recorders in the connection points of the generation.

c) Develop clear specifications in terms of standardised protocols and interfaces on the way to collect and exchange data in case of generation trips.

d) Improve the consistency between the specifications on conform automatic tripping affecting generating units connected on all voltage levels in the NC RfG and the Demand Connection Code (DCC).

e) Investigate and quantify the risk posed by the fact that the NC RfG does not apply to existing generators and quantify, through a cost–benefit analysis, the advantage of making existing generators comply to the NC RfG.

f) Analyse at the ENTSO-E level which TSOs (if any) have difficulties in getting real-time data from generators directly or indirectly as per SO GL Articles 44, 47 and 50 and, where this is the case, identify and implement corrective actions at the national level, in coordination with and to be approved by the national competent authority.

2. Improving the assessment and handling of weather-related risks

Incorporating climate-related risks into transmission network outage planning is addressed by Article 8 of ACER's decision on a methodology for coordinating operational security analysis and in SO GL Article 33(2) on Contingency lists. This implies that TSOs are able to monitor weather and environmental conditions with a potential impact on system operation.

Several communication channels are in place which allow TSOs to be informed in the event that external conditions have to be considered in the security analysis. For example, TSOs monitor weather conditions and the related environmental impact by means of service agreements with the local weather service provider. Furthermore, firefighting organizations and civil protection authorities contact grid operators as soon as environmental hazards occur in the vicinity of electrical components. Conversely, Fire Departments are informed by TSOs in the event of electrical risks. The communication means are dictated by local agreements that are established on a national basis for each TSO.

The problem of wildfire risk is tackled from different standpoints by the power and energy community. For instance, the CIGRE Working Group C2.24 is working on a technical brochure aimed at finding an efficient way to mitigate the risk of fire starts caused by electricity assets and the consequences of fires near overhead lines for system operations. The scope of the Working Group is to describe methods for successful operational decision-making in the event of fire and methods for risk assessment. Furthermore, coordination with external parties such as fire agencies when creating safety conditions and mitigating impact shall be considered.

As detailed in Section 2, in the current event, it appears that a lack of information about ongoing wildfire did not allow its potential impact to be anticipated; furthermore, the risk of the environmental hazard was hedged appropriately but there is room for improvement. Therefore, the following recommendations are proposed by the Expert Panel:

a) Assess weather conditions that are currently considered in the security analyses by TSOs under normal and other conditions (storm, snow, wind, fire…), as per SO GL Article 33.

b) Re-evaluate the existing processes set up by TSOs to monitor environmental hazards, to assess the associated risk for system operation and to mitigate the risks assessed with corresponding operational procedures.

c) Identity best practices and best available technologies for early warnings and online monitoring tools to detect exceptional environmental conditions that significantly increase the probability of an exceptional contingency (icing, wildfires, extreme wind, cold spells, etc.) in the vicinity of transmission corridors.

d) When necessary, identify how to develop complementary processes to ensure the awareness of environmental conditions changes. Regarding wildfires, it is recommended to:

- Exchange information with public authorities (Fire Department, Civil Protection) and Weather Forecast Service Provider to access the necessary information
- Consider using the existing platforms "ERCC – Emergency Response Coordination Centre" and "COPERNICUS" portals to gather information about different events related to Citizens Security.
- Investigate if new technologies could be used (e.g. thermal camera, satellite monitoring, specific sensors, IoT…) to ease the detection of wildfires in the vicinity of transmission corridors. Specific attention should be paid to areas where the risk of wildfire is relevant, and has an significant impact on the power system (due to grid configuration for instance, such as corridors between electric areas). A cost-benefit analysis has to be performed to assess the type and number of devices to be deployed, as well as the location to install them. This study should be based on the current statistics of wildfires, but also integrate possible evolutions of these events as a consequence of on-going climate change. TSOs should contribute to international collaborations (e.g. CIGRE Working Group C2.24) that could lead to implement additional measures if deemed necessary and relevant.
- Investigate if prioritised contacts between TSOs and public authorities should be established, e.g. a dedicated phone number or other communication means for contacting authorities in emergency cases.

e) When necessary, identify how to develop complementary processes to evaluate the risk of environmental hazards occurring.

3. Investigate the opportunity to supplement important transit corridors with Special Protection Scheme (SPS) functionality in combination with automatic overload protection.

SPSs used as a supplement for important transit corridors operation should be designed in such a manner that they immediately stop the cascading effect in a very short time after the trip of one or several elements leading other parallel elements to become overloaded. To achieve this objective, one example is to implement a rapid centralised automatic load shedding system.

In this event, corridor lines automatically tripped due to the activation of their overload protection relays, as detailed in Section 5. To limit this fact in the future, the Expert Panel recommends the following:

a) Investigate the opportunity to complement overload protection with 1 – 5 min threshold with SPS functionality, e.g. based on a centralised industrial load shedding scheme.

b) TSOs operating SPSs such as the DRS (*'Débouclage sur Rupture de Synchronisme'* – Protection against Loss of Synchronism) or similar should coordinate the settings with the protection schemes operated by neighbouring TSOs.

4. Enhance the monitoring and setting of LFDD operation (Low Frequency Demand Disconnection)

As detailed in Section 11, the information derived from LFDD relays was of paramount importance to investigate the causes of this event. To enhance the availability of LFDD recordings in the future, the Expert Panel recommends the following:

a) Improve data recording and collection from LFDD relays

b) Improve TSO–DSO coordination of monitoring and of relay settings and activation

5. Review the dedicated resynchronisation devices settings for tie-lines

As discussed in Section 7, the resynchronisation occurred when the frequency difference between the two areas was still large, therefore resulting in an active power oscillation over the re-connected tie-line. To enhance the resynchronisation in future events, the Expert Panel recommends the following:

a) Avoid synchronisation with inappropriate frequency settings

14.2.2 Recommendations derived from the event of 24 July

Recommendation		Justification	Responsible
R1	Reduce the volume of generation tripping	Generation disconnection may act against system stability	TSOs, DSOs, NRAs, ACER
R2	Improving the assessment and handling of weather related risks	Environmental hazards not correctly included in security calculations may result in system instability	TSOs, ENTSO-E
R3	Investigate the opportunity to supplement important transit corridors with Special Protection Scheme (SPS) functionality in combination with automatic overload protection	Automatic tripping of tie-lines due to line overloading may act against system stability	TSOs
R4	Enhance monitoring and setting of LFDD operation (Low Frequency Demand Disconnection)	LFDD relay recordings provide indispensable information to investigate power system incidents	TSOs, DSOs
R5	Review the dedicated resynchronisation devices settings for tie-lines	Resynchronisation performed with wrong settings may result in active power oscillations over the resynchronisation tie-line	TSOs

14.2.3 Review of the recommendations derived from the event of 8 January 2021

The ICS Expert Panel that analysed the Continental Europe Synchronous Area System Separation on 8 January 2021 derived several recommendations to eliminate the underlying causes of that incident.

These recommendations have been reviewed by the present ICS Expert Panel and, where applicable, additional recommendations have been derived. These are listed in the following table.

	Recommendations event 8 January 2021	Relevant for event 24 July	Comments and recommended additional actions
R1	**Configuration of substation topology** 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.	No	This was not relevant for this incident as there were no issues with substation topology.
R2	**Setting and exchange of the protection parameters** 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.	No	This was not relevant for this incident. The alarms and procedures in the control room were well defined. Because of that, both TSOs have agreed to reduce the exchange within one minute into the first event.
R3	**Alarm handling in control centre** 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.	No	This was not relevant for this incident. The alarms and procedures in the control room were well defined. Because of this, both TSOs have agreed to reduce the exchange within one minute into the first event.
R4	**Capacity calculation: Assess TRM and FRM** It shall be assessed if the TRM and the FRM are sufficient to cope with sudden high overloading.	No	This was not relevant for this incident as there were no issues related to capacity calculation.

Recommendations event 8 January 2021		Relevant for event 24 July	Comments and recommended additional actions
R5	**Capacity calculation: Coordinated NTC calculation** 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.	No	This was not relevant for this incident as there were no issues related to NTC calculation.
R6	**Modelling and execution of (n-1) calculation: Observability Area** Monitor the implementation of the common approach to determine and update the observability area.	No	This was not relevant for this incident as there were no issues related to the observability area.
R7	**Coordinated processes in South-East Europe** 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 TSO cooperation.	No	This was not relevant for this incident as the coordinated processes in South-West Europe are in place.
R8	**Modelling and execution of (N-1) calculation** It should be mandatory to include outages of any transmission elements (including 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.	No	During the incident all the elements that tripped were included in the contingency list, so it was not relevant.

Recommendations event 8 January 2021		Relevant for event 24 July	Comments and recommended additional actions
R9	**Modelling and execution of (N-1) calculation: Data model** 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 the event 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 be modelled on the IGM.	No	During the incident, all the elements that tripped were included in the contingency list, so it was not relevant.
R10	**Recommendation concerning forecast quality** Assess and improve the forecast quality, particularly the IDCF quality, to reduce the difference of results between IDCF and real-time calculations.	No	This was not relevant for this incident as there were no issues related to forecast quality.
R11	**Recommendation for further legal analysis** 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.	Yes	This has been made specific for this incident in Recommendation 1.f.
R12	**Recommendation for dynamic stability margin** 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.	Yes	During the event of 8 January it was mainly angular instability, whereas during the event of 24 July, it was mainly frequency instability and voltage instability. During both events, dynamic stability margins were reached due to high power flows. During the event of 24 July, the dynamic instability started after the second line trip.

Recommendations event 8 January 2021		Relevant for event 24 July	Comments and recommended additional actions
R13	**Frequency support and stability: System Inertia** 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.	No	This was not relevant for this incident as there were no issues related to system inertia.
R14	**Non grid code conform disconnection of generation and loads** 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.	Yes	Recommendations 1 and 4 treat this aspect.
R15	**Recommendation for Frequency Stability Evaluation Criteria for ROCOF** 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.	Yes	The same Recommendation applies to this incident.
R16	**Frequency support and stability: Fast Acting Reserves** 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.	Yes	The same Recommendation applies to this incident.

Recommendations event 8 January 2021		Relevant for event 24 July	Comments and recommended additional actions
R17	**Recommendation for System Defence Plans** 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 LFDD scheme).	Yes	The same Recommendation applies to this incident.
R18	**Recommendation for frequency support from embedded HVDC cables** 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 technically possible.	No	The only affected HVDC link on the border between FR and ES was unable to deliver any substantial contribution as the connection of the FR side was disrupted during the event.
R19	**Operation of IGCC during system separation** Determine procedures for the imbalance netting as well as the exchange of reserve in the event of a system separation for current and future balancing platforms, i.e. IGCC, PICASSO, MARI and TERRE.	Yes	The same Recommendation applies to this incident.
R20	**Data representation in EAS** 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.	Yes	An automatic EAS alarming in the event of system separation could be added to cover these situations better.

Recommendations event 8 January 2021		Relevant for event 24 July	Comments and recommended additional actions
R21	**Recommendation for Region Continental Europe resynchronisation procedure** 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 the event 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.	Yes	An ENTSO-E task force was created to develop a RG CE common procedure for resynchronisation in the event of system separation which uses the experience of previous system splits.
R22	**Recommendation for regional coordination** 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 necessary.	Yes	RCC support to SWE TSOs in system restoration processes associated with events of this kind does not appear to create added value.

14.3 Overall assessment and conclusion

The present final report of the ICS Expert Panel yields a comprehensive analytical overview of the Continental European system separation on 24 July 2021. After the incident, ENTSO-E and the European TSOs as well as ACER and NRAs began an intensive assessment of the incident in close collaboration.

Overall, this incident was atypical in that it resulted from the failure of an efficient and suiTable communication channel between the emergency services and the TSO and did not originate from any faults in transmission system operation or planning. As in the 8 January 2021 incident, the system defence plans functioned properly and coordinated measures were activated quickly, which again allowed for fast resynchronisation. However, the event was ranked level two in ICS because LFDD was widely activated, and consequently many customers were disconnected from their electricity supply. The event is also important for further analysis because it showed that the limits of sTable system operation can be reached, even if all security evaluations are executed correctly and timely. In particular, the undesired tripping of generation connected to the distributions systems is a risk that must be mitigated to assist in preventing the breaching of these limits during future events. This proved to be particularly true for existing generators that are not required to comply with the NC RfG. With the continued increase of the penetration of distributed generation to achieve the de-carbonisation of the energy system, the impact of non-compliance with technical requirements as stipulated in the network codes may generate uncontrollable and unmanageable breaches of the security of the electricity system. It is therefore critically important that NRAs, TSOs and DSOs, and owners of distributed generation units, work together to ensure that the mandatory system security requirements are implemented and monitored for their compliance. One of the two key recommendations from this Expert Panel is to address this issue at the European level. The second key recommendation is for TSOs to continuously develop and improve their environmental risk identification and mitigation processes to be prepared for a potential increase in their occurrence due to the effects of climate change. Additional measures also should be taken to ensure that TSOs have redundant information channels with the relevant emergency services, to be certain that information on critical environmental risks is always available to the control rooms.

Further analysis has shown that there were no structural deficiencies regarding the implementation of TSO responsibilities under the network codes, in particular CACM, SO GL and NC ER. There were also no issues with the regional capacity calculation and operational security coordination processes.

In summary, the incident was well handled, which was largely due to the quality and the correct activation of the protection systems and the system defence plans as well as the close coordination between the affected TSOs.

The results from the in-depth analysis have delivered several recommendations for specific improvements in the following areas, in addition to the recommendations related to non-compliant generator tripping and environmental risk management and communications:

- Investigate the opportunity to supplement important transit corridors with SPS functionality (in combination with automatic overload protection)
- Enhance the monitoring of LFDD operation
- Review the dedicated resynchronisation devices settings for interconnection tie-lines

In all these areas, the ICS Expert Panel has provided numerous recommendations for further assessments and corresponding improvements. The implementation of these recommendations will thus help to prevent similar incidents in the future.

LIST OF TSOs (ALPHABETICAL ORDER)

Company	Country (abbreviation)
50Hertz	Germany (DE)
Amprion	Germany (DE)
APG	Austria (AT)
ČEPS	Czech Republic (CZ)
CGES	Montenegro (ME)
Creos Luxembourg	Luxembourg (LU)
ELES	Slovenia (SI)
Elia	Belgium (BE)
EMS	Serbia (RS)
Energinet	Denmark (DK)
ESO EAD	Bulgaria (BG)
Fingrid	Finland (FI)
HOPS	Croatia (HR)
IPTO	Greece (GR)
MAVIR	Hungary (HU)
MEPSO	North Macedonia (MK)
National Grid ESO	Great Britain (GB)

Company	Country (abbreviation)
NOS BiH	Bosnia and Herzegovina (BA)
OST	Albania (AL)
PSE	Poland (PL)
REE	Spain (ES)
REN	Portugal (PT)
RTE	France (FR)
SEPS	Slovakia (SK)
Statnett	Norway (NO)
Svenska Kraftnät	Sweden (SE)
Swissgrid	Switzerland (CH)
TenneT DE	Germany (DE)
TenneT TSO B.V.	The Netherlands (NL)
Terna	Italy (IT)
Transelectrica	Romania (RO)
TransnetBW	Germany (DE)
TEIAS	Turkey (TR)
VUEN	Austria (AT)

LIST OF ABBREVIATIONS

Abbreviation	Meaning
A	Ampere(s)
ACE	Area Control Error
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserves
AGC	Automatic Generation Control
CACM	Capacity Allocation and Congestion Management
CB	Cross border
CC	Coordination Centre
CCC	Coordinated Capacity Calculations
CE	Continental Europe
CET	Central European Time
CSA	Coordinated Security Assessment
DACF	Day-Ahead-Congestion-Forecast
DC	Direct Current
DFR	Digital Fault Recorder
DRS	Protection against Loss of Synchronism – Débouclage sur Rupture de Synchronisme
EAS	ENTSO-E Awareness System
ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	Frequency Containment Reserves
FRM	Flow Reliability Margins
GNSS	Global Navigation Satellites System
GPS	Global Positioning System
GW	Gigawatt
HPPs	Hydro power plants
HVDC	High Voltage Direct Current
ICS	Incident Classification Scale
IGM	Internal Grid Model
IDCF	Intra-day Congestion Forecast
IGCC	International Grid Control Cooperation
LFC	Load Frequency Controller
mHz	Millihertz
mFRR	Manual Frequency Restoration Reserve
MVA	Megavolt ampere
MW	Megawatt

Abbreviation	Meaning
NC ER	Network Code on Emergency and Restoration
NC RfG	Network Code on Requirements for grid connection of Generators
NPPs	Nuclear Power Plants
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OHL	Overhead Line
OPC	Outage Planning Coordination
PATL	Permanently Admissible Transmission Loading
PMU	Phasor Measurement Unit
PV PPs	Photovoltaic Power Plants
RG CE	Regional Group Continental Europe
ROCOF	Rate of Change of Frequency
RSC	Regional Security Coordinator
SA CE	Synchronous Area Continental Europe
SAFA	Synchronous Area Framework Agreement
SAM	Synchronous Area Monitor

Abbreviation	Meaning
SCADA	Supervisory control and data acquisition
SO GL	System Operation Guideline
SPS	Special Protection Schemes
SS	Substation
STA	Short-Term Adequacy Assessment
SVC	Voltage source converter
TATL	Temporarily Admissible Transmission Loading
TPPs	Thermal power plants
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TRM	Transmission Reliability Margin
kV	Kilovolt(s)
VSC	Voltage Source Converter
WAM	Wide Area Monitoring
WPPs	Wind Power Plants
XBID	Cross-Border Intraday

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