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Table of Contents

Executive Summary	7
1 Introduction	9
1.1 Task 7.6	10
1.2 Objectives of the Work Reported in this Deliverable	10
1.3 Outline of the Deliverable	10
1.4 How to Read this Document	11
2 Cyprus-Greece HVDC Interconnection Case Study	12
2.1 Overview of the Cyprus-Greece HVDC Interconnection	12
2.2 Use Case for Regional Frequency Support Through HVDC	13
2.2.1 Description	13
2.2.2 Scenarios	15
2.2.3 Assumptions and Prerequisites	15
2.2.4 Key Performance Indicators	16
3 Digital Twin Framework	17
3.1 Digital Twin Architecture	17
3.2 Real time simulation environment of the digital twin	18
3.2.1 Multi-link HVDC interconnection modeling	18
3.2.2 Country-level equivalent power systems modeling	20
3.2.3 FCR-FSM Coordination	23
3.2.4 Real-time and historical field data integration	26
3.2.5 Realizing the real time simulation framework for digital twinning	27
3.3 Actors within the digital twin framework	28
3.4 Systems within the digital twin framework	29
3.5 Information exchange in the digital twin framework	31
4 Digital Twin Implementation	33
5 Demonstration and Evaluation	35
5.1 Demonstration of Digital Twin Operation	35
5.2 Scenario-Based Demonstration and Stability Evaluation	39
5.2.1 Disturbance in Cyprus - normal inertia conditions	40
5.2.2 Disturbance in Cyprus - low inertia conditions	45
5.2.3 Disturbance in Greece	50
5.3 Key Performance Indicator based Evaluation	58
6 Conclusion	62
References	64

List of Figures

Figure 1: Great Sea Interconnector map	12
Figure 2: Digital twinning for HVDC interconnection use case framework based on a market-based regional coordination level for frequency support and a real-time operation level.....	14
Figure 3: Actors and systems interactions in the digital twinning for HVDC interconnection investigations.....	17
Figure 4: Brief diagram of the multi-link HVDC interconnection developed and executed within the real time simulator.....	18
Figure 5: HVDC controller considering (a) a $V_{dc}&Q$ control mode (left HVDC terminal) and (b) in $P&Q$ control mode (right HVDC terminal).....	19
Figure 6: Dynamic behaviour of a country-level power system based on single-unit equivalent modelling approach to emulate synchronous generators, inverter-based RES, inverter-based FSPs, and load consumption.	21
Figure 7: Inverter controller of the FSP battery system within the country-level system	22
Figure 8: Inverter controller of the RES within the country-level system	22
Figure 9: HVDC and FSP frequency support control and coordination. FCR – FSM regional coordination scheme	25
Figure 10: Communication Layers of the Digital Twin	26
Figure 11: Integrated system of the Digital Twin Implementation in a unified platform including the Real-Time Digital Twin Model (right), Backend and Middleware Layer (center), Monitor and Control Interface (top left), Web-based Management Interface (bottom left), Overall data flow (how information moves between all components).	34
Figure 12: Demonstration of Digital Twin Operation through a dedicated monitoring interface (under normal operating conditions).	35
Figure 13: Configuration of Digital Twin Operation through a dedicated control interface.	36
Figure 14: Demonstration of Digital Twin Operation during the scenario of a disturbance in Cyprus, through a dedicated monitoring interface.	37
Figure 15: Demonstration of Digital Twin Operation during the scenario of a disturbance in Cyprus, through a dedicated control interface.....	37
Figure 16: Demonstration of Digital Twin Operation during the scenario of a disturbance in Greece, through a dedicated monitoring interface.	38
Figure 17: Configuration of Digital Twin Operation during the scenario of a disturbance in Greece, through a dedicated control interface.....	38
Figure 18: Baseline Scenario for Disturbance in Cyprus with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.	41
Figure 19: Shared FCR and Fixed FSM support scenario for Disturbance in Cyprus with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.	43

Figure 20: Shared FCR and Adaptive FSM support scenario for Disturbance in Cyprus with normal inertia conditions. . For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.44

Figure 21: Baseline scenario for Disturbance in Cyprus with low inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency. 46

Figure 22: Shared FCR and Fixed FSM support scenario for Disturbance in Cyprus with low inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power, (d) systems' frequencies. 48

Figure 23: Shared FCR and Adaptive FSM support scenario for Disturbance in Cyprus with low inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power, (d) systems' frequencies. 49

Figure 24: Baseline scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency. 51

Figure 25: Shared FCR and Fixed FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency. 53

Figure 26: Shared FCR and Adaptive FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.55

Figure 27: Unconstrained HVDC power exchange with Shared FCR and Fixed FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency. 56

Figure 28: Unconstrained HVDC power exchange with Shared FCR and Adaptive FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency..... 57

List of Tables

Table 1: Summary of evaluation results for the Cyprus – Greece HVDC interconnection digital twinning use case..... 59

List of Abbreviations and Acronyms

Acronym	Meaning
DER	Distributed Energy Resource
EMT	Electro-Magnetic Transient
FCR	Frequency Containment Reserve
FSM	Frequency Sensitivity Mode
FSP	Flexibility Service Providers
HVDC	High Voltage Direct Current
KPI	Key Performance Indicator
MO	Market Operator
PCC	Point of Common Coupling
PMU	Phasor Measurement Unit
RES	Renewable Energy Source
RoCoF	Rate of Change of Frequency
RSC	Regional Security Coordinator
TSO	Transmission System Operator
WAC	Wide Area Controller

Executive Summary

The TwinEU project aims to advance the development and deployment of digital twin solutions that support the secure, resilient, and coordinated operation of the future European power system. Within WP7, Task 7.6 focuses on the digital twinning of High Voltage Direct Current (HVDC) interconnections, with particular emphasis on the future Cyprus-Greece HVDC interconnection and its role in enabling cross-border system support, higher renewable energy source (RES) integration, and enhanced frequency stability. In this context, this deliverable reports the work carried out in Task 7.6 on the development and demonstration of a real-time digital twin framework for investigating the dynamic behaviour of this planned HVDC link before its physical deployment. The objective of this digital twin is to enable the proper coordination and control of the HVDC link, allowing effective cross-border frequency support while enhancing the frequency stability of the interconnected power systems.

To achieve this, a digital twin environment has been established to replicate the dynamic behaviour of the interconnected power systems of mainland Greece, Crete, and Cyprus, together with the future multi-terminal HVDC interconnector. Each country-level digital twin is modelled by considering the aggregated behaviour of synchronous generation, renewable energy sources, load consumption, inverter-based resources, and battery-based Flexibility Service Providers (FSPs). The HVDC interconnection is represented through voltage-source converter stations, DC cable models, and dedicated converter controllers, enabling the investigation of different control modes and cross-border frequency support mechanisms. The overall framework has been developed in MATLAB/Simulink and executed on the OPAL-RT real-time simulation platform, allowing realistic dynamic investigations and studies under representative operating conditions.

The developed digital twin combines real-time simulation with communication, monitoring, market interactions, frequency support mechanisms, and wide-area control. This integrated environment enables the exchange of real-time measurements, historical operational data, market-clearing results, and control commands between the simulation environment and external applications. Dedicated middleware supports data acquisition, synchronization, and storage, while web-based dashboards and operator interfaces provide monitoring, visualization, and configuration capabilities. This cyber-physical setup is particularly important for future grid expansions such as HVDC interconnections, since it allows operators and stakeholders to investigate system behaviour, validate control strategies, and fine-tune operational settings in a safe and non-intrusive environment before implementation in the real system.

A key outcome of the work is the implementation of a coordinated regional frequency support framework that combines market-based Frequency Containment Reserve (FCR) allocation with Frequency Sensitive Mode (FSM) operation. The proposed approach considers both cross-country HVDC-based support and intra-country inverter-based FSP support. In addition to conventional fixed FSM settings based on grid regulations, a new adaptive FSM scheme has been introduced, where the FSM droop settings are dynamically adjusted according to the real-time available rotating inertia in each interconnected system. This enables stronger support during low-inertia operating conditions, while avoiding unnecessary converter intervention when system inertia is sufficiently high. A Wide Area Controller (WAC) further coordinates the bidirectional frequency support provided through the HVDC interconnection by considering market-cleared reserve allocations, operational transfer limits, and the need to limit disturbance propagation across the interconnected grids.

The framework was evaluated under representative disturbance scenarios in Cyprus and Greece, considering different inertia levels, controlled and uncontrolled HVDC power transfers, and both fixed and adaptive FSM implementations. The results show that coordinated HVDC and FSP operation can significantly improve frequency stability compared to conventional operation without coordinated support. In particular, under low-inertia conditions, the adaptive FSM scheme strengthens the dynamic response of the weaker grids by exploiting the available flexibility of both the HVDC converters and local inverter-based FSP resources. Compared to fixed FSM operation, the adaptive approach improves both the frequency nadir and the post-disturbance steady-state frequency, demonstrating its ability to enhance the overall frequency stability of the interconnected systems under different operating conditions.

The evaluation also demonstrates that constraining and coordinating HVDC power exchanges during frequency events is particularly important when a weak grid is expected to support a stronger interconnected system through the HVDC link. Unrestricted HVDC support can maximize the assistance provided to the disturbed system; however, it can also impose increased frequency deviations on the supporting systems. This is especially critical when enabling bidirectional support between weak and strong grids. While the HVDC link can allow a weak grid to contribute support to a stronger interconnected system, this support must be carefully coordinated to avoid compromising the stability and integrity of the weaker grid. The proposed regional coordination and WAC-based control framework therefore provides a balanced mechanism for sharing support across countries while maintaining secure operation in all interconnected systems.

Overall, the developed digital twin establishes a real-time cyber-physical platform for analysing and supporting the future operation of the Cyprus-Greece HVDC interconnection. The work demonstrates that digital twinning can provide valuable insight into the dynamic behaviour of future interconnections, the impact of inertia variations, the coordination of cross-border frequency support, and the interaction between HVDC converters and inverter-based flexibility resources. Beyond the scenarios examined in this work, the developed framework can be further used to investigate upcoming developments in the interconnected systems, fine-tune the performance of new inverter-based resources, assess operational limits under higher RES penetration, and support the design of secure control strategies for future low-inertia European power systems.

1 Introduction

As power systems evolve to meet the pressing demands of decarbonization, decentralization, and digitalization, their operational complexity is increasing dramatically. Among the key enablers of this transformation are High Voltage Direct Current (HVDC) interconnections, which offer an efficient and flexible means of exchanging power between countries while supporting the integration of renewable energy sources (RES). As a result, HVDC interconnections can enhance regional energy security, and support frequency stability across interconnected systems. However, the introduction of large-scale HVDC links introduces new challenges related to the dynamic behaviour of coupled power grids, particularly when interconnecting systems with markedly different characteristics, such as an isolated grid like Cyprus and a well-interconnected grid like Greece.

In this context, digital twinning has emerged as a pivotal technology to model, monitor, analyse and optimize the operation of power systems and their interconnections. A digital twin is a dynamic virtual representation of a physical system that replicates its real-time behaviour and enables predictive insights under a wide range of operating conditions. For HVDC interconnections, digital twins provide a critical platform for analysing control strategies, testing frequency support mechanisms, and ensuring that both sides of the link can maintain stability and resilience, even during extreme disturbances or cyber-physical threats that cannot really be investigated in the real-life systems.

The Cyprus–Greece HVDC interconnection, known as the Great Sea Interconnector [1], represents a landmark initiative in the Eastern Mediterranean, aimed at integrating Cyprus into the European electricity grid. This 2,000 MW HVDC link (to be implemented in two stages) is expected to significantly enhance the stability and flexibility of both national power systems, enabling higher penetration of RES and supporting Cyprus's transition away from fossil fuels. Given the unique characteristics of this project, especially Cyprus's isolated grid status and the long-distance submarine cable, the development and validation of a comprehensive digital twin framework is essential to ensure the secure and reliable operation of the interconnection.

This deliverable focuses on the development of a digital twin framework for the Cyprus-Greece HVDC interconnection. By simulating both national grids and the HVDC link in a unified real-time environment, the framework enables system operators, market actors, and regional coordinators to test frequency stability strategies, coordinate ancillary services, and evaluate cross-border support mechanisms. This work leverages realistic operational scenarios and incorporates Frequency Containment Reserve (FCR) market results, as well as Frequency Sensitive Mode (FSM) coordinated support schemes with fixed and adaptive support intensity. These mechanisms are applied to both the HVDC interconnection and the FSP response, enabling the stability of the interconnected power systems to be assessed using key performance indicators such as frequency nadir, post-disturbance steady-state frequency, Rate of Change of Frequency (RoCoF), and the volume of power provided for frequency support during disturbances.

Through this effort, the TwinEU project contributes to the advancement of digital twin technologies for cross-border power system management, offering practical insights into how HVDC links can be optimized for resilience, efficiency, and reliability in interconnected electricity markets and grids.

1.1 Task 7.6

Task 7.6, titled "HVDC interconnection digital twinning," focuses on developing a holistic digital twin framework to emulate and evaluate the behaviour of an HVDC interconnection (1,000 MW in its first stage) between the Cyprus and Greek power systems. Led by UCY, in collaboration with ELIA, CINT, EAC, TSOC, TPAD, 50HertzT, 3SI, and TGT, this task spans from month 9 to month 33 of the TwinEU project. The methodology combines advanced power system modelling, enhanced inverter-based control systems, a coordinated frequency support framework, real-time digital twin simulation, and scenario-based testing to assess how the HVDC link can enhance the resilience and frequency stability of the interconnected power systems. The digital twin environment replicates the representative power system behaviour of Cyprus, Crete, and mainland Greece, along with the future multi-link HVDC interconnection and associated market and coordination mechanisms, enabling detailed analysis of cross-border frequency support and system stability under various operational and disturbance scenarios.

1.2 Objectives of the Work Reported in this Deliverable

The primary objective of the work reported in this deliverable is to develop, implement, and demonstrate a real-time digital twin framework for the Cyprus–Greece HVDC interconnection, facilitating the assessment of cross-border frequency stability and resilience enhancement. Specifically, the deliverable aims to:

- **Develop a modular and scalable digital twin architecture** representing the Cyprus, Crete, and Greece power systems, the multi-link HVDC interconnection, and key market and operational actors.
- **Implement real-time simulation of HVDC control strategies**, enabling testing of both $P\&Q$ and $V_{dc}\&Q$ operating modes under different disturbance scenarios.
- **Develop a wide area controller** for coordinating the HVDC link enabling enhanced frequency support while regulating the disturbance propagation between interconnected systems.
- **Establish a coordinated context** involving Transmission System Operators (TSOs), Market Operators (MOs), Regional Security Coordinators (RSCs), HVDC Operators, and Flexibility Service Providers (FSPs) to manage FCR procurement and real-time frequency support.
- **Develop an adaptive FSM support provision** by HVDC and FSP controllers to respond to frequency disturbances according to grid regulations and real-time grid operating conditions.
- **Define a Key Performance Indicator (KPI)-based evaluation framework**, considering frequency nadir, post-disturbance steady-state frequency, RoCoF, and the volume of active power provided for frequency support, to assess the dynamic performance and stability of the interconnected power systems under severe disturbances.

1.3 Outline of the Deliverable

This deliverable is structured as follows. Chapter 2 introduces the Cyprus–Greece HVDC interconnection case study, detailing its technical specifications, operational context, and the use case for regional frequency support. It also presents the main scenarios, assumptions, and KPIs that guide the digital twin simulation and evaluation. Chapter 3 describes the digital twin framework, covering its architecture, real-time simulation environment, actors, systems, and information exchange

processes. The chapter explains how the digital twin integrates grid modeling, market dynamics, and wide-area coordination to support frequency stability. Chapter 4 presents the Digital Twin implementation, showing how the overall integrated system works. The demonstration of the digital twin investigated scenarios and the evaluation of solutions for frequency stability are included in Chapter 5. Finally, the conclusions drawn from the overall work are summarized in Chapter 6.

1.4 How to Read this Document

To fully benefit from this deliverable, readers are expected to have a foundational understanding of power system operations, HVDC technologies, and digital twin concepts. This document is closely linked to other activities within the TwinEU project, particularly the work conducted in WP2 and WP3.

The use cases, scenarios, and Key Performance Indicators (KPIs) that form the basis of the digital twin framework described in this deliverable were defined in WP2 and are detailed in Deliverable D2.2. In particular, the Business Use Case EM-CY-02 focuses on frequency support management of HVDC-interconnected systems at a regional level. This use-case establishes the framework for regional coordination of frequency support services through the HVDC link, taking into account the specific stability requirements and constraints on both sides of the interconnection, with the goal of enhancing system resilience under severe disturbance conditions.

Additionally, the functional and non-functional requirements, as well as the Smart Grid Architecture Model (SGAM) design, including its component, communication, and information layers, were established in WP3 and reported in Deliverables D3.1 and D3.2. These foundational elements have guided the design and implementation of the digital twin framework to ensure consistency with the broader system architecture of the TwinEU project.

While this deliverable focuses specifically on the HVDC interconnection between Cyprus and Greece, it complements the wider TwinEU objective of advancing cross-border system stability and resilience through digital twinning and enhanced operational coordination. Readers seeking deeper insight into the business use case context, system requirements, and architecture model are encouraged to consult Deliverables D2.2, D3.1, and D3.2, which provide the essential background for understanding the scope and implementation of the framework presented here.

2 Cyprus-Greece HVDC Interconnection Case Study

2.1 Overview of the Cyprus-Greece HVDC Interconnection

The Great Sea Interconnector is a major High Voltage Direct Current (HVDC) initiative envisioned to connect the electricity grids of Greece, via Crete, and Cyprus, as demonstrated in Figure 1, and eventually stretching to Israel through the Mediterranean Sea, establishing a crucial link between Europe and the Eastern Mediterranean. This interconnection aims to enhance energy security, facilitate the integration of renewable energy sources (RES), and improve grid stability in interconnected countries. The development of the interconnector is planned in two stages.

The first stage involves the construction of an HVDC submarine cable linking Cyprus and Greece (Crete) with a transmission capacity of 1,000 MW. The system will operate at ± 500 kV, with an estimated cable length approximately 898 km with a maximum depth of 3000 m [2]. In the second stage, the project will expand its transmission capacity to 2,000 MW by adding a second 1,000 MW HVDC bipole and the corresponding converter station infrastructure along the same route, addressing growing energy demands and facilitating greater RES integration.

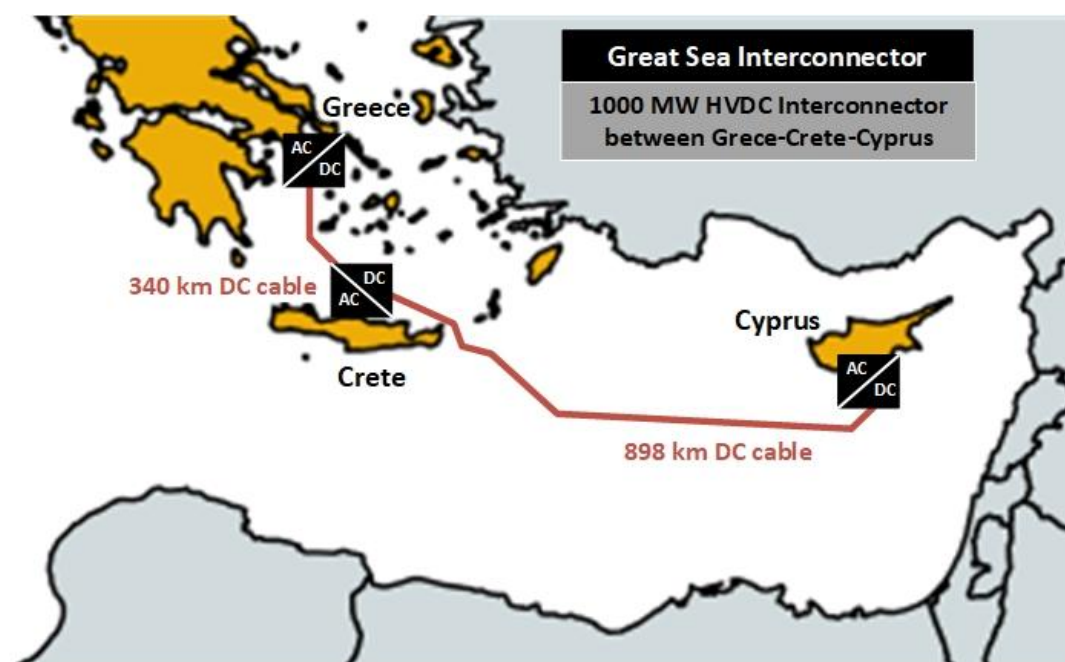


Figure 1: Great Sea Interconnector map

Converter stations will be based on Voltage Source Converter (VSC) technology, which enables flexible power flow control and is particularly well-suited for supporting weak grids such as Cyprus. HVDC cables ensure efficient long-distance electricity transmission with minimal losses and can operate under grid-following and grid-forming control modes. Therefore, tuning the HVDC controllers at each side of the interconnection and regulating the intensity of frequency support provided by the HVDC link are crucial for maintaining the stability of the coupled power systems.

Cyprus operates as an isolated electricity grid without interconnections to neighbouring countries. This isolation limits the system's flexibility and resilience, facing challenges related to frequency stability and RES integration. The installed capacity of conventional generation is 1478 MW, from which the total available capacity is 963 MW. Cyprus has an operational renewable energy capacity of

approximately 991.14 MW. Photovoltaic (PV) systems accounted for the largest share with 823.64 MW, followed by onshore wind farms at 155.1 MW, and biomass systems at 12.4 MW [3].

Greece's power system is fully integrated into the European electricity grid, offering enhanced operational stability, flexibility, and access to regional energy markets. The country's installed capacity of synchronous generators, including natural gas, lignite, and hydroelectric units, is approximately 8,500 MW. In parallel, Greece has made significant strides in renewable energy deployment, with around 5,300 MW of wind power and approximately 5,500 MW of photovoltaic (PV) systems installed as of 2023 [4]. This growing renewable base contributed to about 43% of the country's total electricity production in 2023, reflecting its commitment to decarbonization and sustainable energy goals. Strong international interconnections with neighbouring countries, such as Italy, Bulgaria, North Macedonia, Albania, and Turkey, reinforce the stability and reliability of the Greek power system, facilitating cross-border energy exchange and supporting the integration of high levels of renewable energy.

The Great Sea Interconnector is expected to play a key role in Cyprus's transition to a more sustainable energy future by reducing its dependence on fossil fuels and enabling a higher penetration of renewable energy sources. It will also enhance regional energy security and contribute to the stability of interconnected power networks.

2.2 Use Case for Regional Frequency Support Through HVDC

In the context of the ongoing project of the Great Sea Interconnector, which aims to connect the power systems of Cyprus and Greece via an HVDC link, Use Case EM-CY-02 (Frequency support management of HVDC-interconnected systems in a regional level) of the TwinEU project focuses on developing a digital twin environment to replicate the two interconnected power systems, facilitating advanced investigations and enabling the implementation of a regional coordination framework that enhances the stability of both systems. This framework manages the coordinated provision of FCR services and FSM support while considering the stability requirements, operational constraints, and grid-code requirements of each country on either side of the HVDC link. Through the digital twin, the stability of each country can be analysed during intense power imbalance disturbances. Therefore, the frequency stability in each interconnected country can be enhanced and cascading effects between countries can be minimized, through an effective regional coordination and a real-time wide area control of the HVDC link.

2.2.1 Description

In this Use Case, the Regional Security Coordinator (RSC) collaborates with the Transmission System Operators (TSOs), Market Operators (MOs), the HVDC Operator, and Flexibility Service Providers (FSPs) to coordinate frequency support across the Cyprus–Greece HVDC interconnection. The objective is to improve the frequency stability of the interconnected power systems while respecting the operational constraints, stability requirements, and grid-code specifications of each country. The use-case framework, illustrated in Figure 2, is organized into two complementary layers: (a) market-based regional coordination and (b) real-time operation.

The market-based regional coordination layer determines the frequency support resources that will be available during the subsequent operational period. The day-ahead energy market first establishes the scheduled power exchange through the HVDC interconnection. Based on the expected operating conditions, each TSO determines its Frequency Containment Reserve (FCR) requirements and exchanges the relevant operational constraints with the RSC using the country-level Digital Twin. In parallel, the HVDC Operator and participating FSPs submit bids to provide FCR services through the

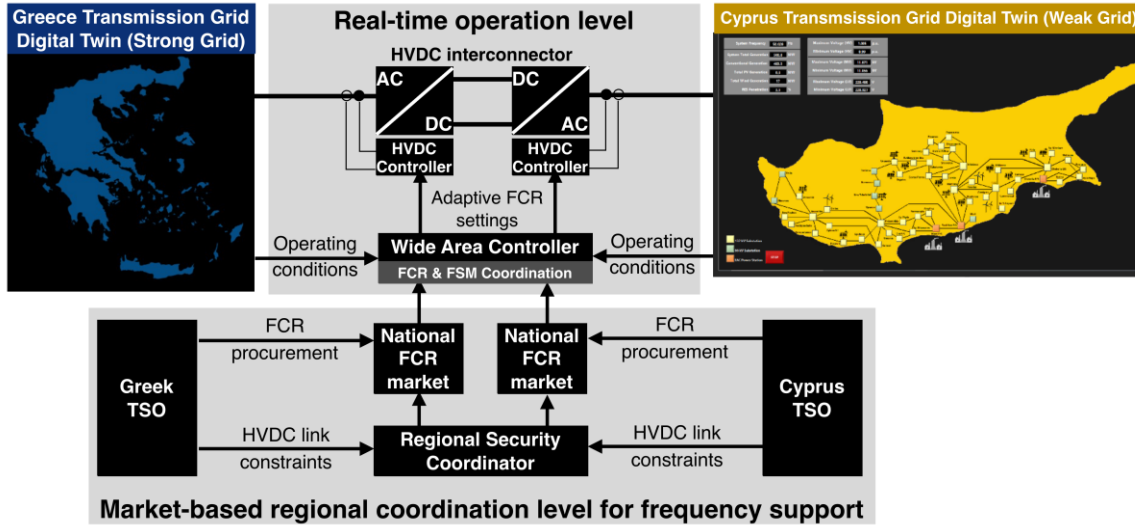


Figure 2: Digital twinning for HVDC interconnection use case framework based on a market-based regional coordination level for frequency support and a real-time operation level.

ancillary services market. The RSC evaluates the cross-border operational constraints and determines the maximum FCR contribution that can be exchanged through the HVDC interconnection. The ancillary services market subsequently clears the available FCR capacity, and the resulting allocations define the mandatory reserve obligations of the participating resources for the next operational period.

The real-time operation layer uses the market-cleared FCR allocations together with the applicable Frequency Sensitive Mode (FSM) grid-code requirements to configure the frequency support parameters of the inverter-based resources, including the HVDC converters and the FSPs. While the FCR response follows the market-cleared reserve allocation, the FSM response follows the applicable grid-code requirements. In the proposed framework, the conventional fixed FSM droop is further enhanced by continuously adapting the droop coefficient according to the real-time kinetic energy of the interconnected power system, enabling stronger converter support during low-inertia operating conditions and a reduced response when the available system inertia is high.

During real-time operation, the HVDC converters and participating FSPs provide coordinated frequency support following frequency disturbances. Depending on the HVDC operating mode, the converters respond either to local frequency measurements or to coordination signals generated by a regional Wide Area Controller (WAC), enabling controlled cross-border power support while respecting the operational constraints of the interconnected systems.

In the context of this work, the Digital Twin is primarily used as a pre-deployment investigation, validation, and fine-tuning environment for the future Cyprus–Greece HVDC interconnection. Since the physical HVDC link is not yet in operation, the Digital Twin provides a safe and non-intrusive environment in which the expected dynamic behaviour of the interconnected systems, the coordinated FCR and adaptive FSM response, and the associated control and data-exchange mechanisms can be evaluated before their implementation in the real system. Different operating conditions and disturbance scenarios can therefore be reproduced to assess frequency stability, identify potential limitations, tune control parameters, and verify that the required coordination and communication between the involved actors and controllers can be achieved reliably.

Real-time execution is particularly relevant for this purpose because it enables the dynamic models, controllers, communication interfaces, and external control functions to interact with the same timing constraints that would apply in an operational environment, including the possibility of Control-Hardware-in-the-Loop testing. This complements conventional offline and faster-than-real-time simulations, which may be used for broader scenario screening, while real-time Digital Twin execution enables detailed validation of the closed-loop control and communication behaviour. Once the physical HVDC interconnection becomes operational, the same Digital Twin framework could be updated and synchronized with field measurements to support monitoring, what-if analysis, operator training, and further controller assessment and fine-tuning; however, in the framework investigated in this deliverable, the Digital Twin itself is not assumed to form part of the primary real-time frequency-control loop.

2.2.2 Scenarios

In this case study which focuses on digital twinning for HVDC interconnection investigations, two main scenarios will be examined.

- **Scenario 1 - Regional Coordination Between Interconnected Systems:** This scenario evaluates the regional coordination process preceding real-time operation. The Digital Twin is used by the TSOs to determine the required FCR capacities and assess system constraints, while the RSC coordinates cross-border constraints and the ancillary services market clears the FCR capacities offered by the HVDC operator and FSPs. These market-clearing results, together with the TSO-defined FSM operating requirements, are subsequently used by the coordination unit, in order to configure the real-time frequency support parameters of the HVDC converters and FSP controllers.
- **Scenario 2 - Real-Time Operation for Frequency Stability Enhancement:** Scenario 2 evaluates the real-time behaviour of the interconnected power systems following severe frequency disturbances. The previously configured FCR allocations and adaptive FSM settings are used by the coordination unit, which sends the coordinated FCR and FSM gains to the digital twin, in order to be activated by the HVDC converters and FSPs to provide coordinated frequency support. Following intense frequency disturbances, HVDC converters and FSPs in each country quickly adjust their settings to provide timely support, enhancing the overall frequency stability of the interconnected power systems. Depending on the converter operating mode, the response is either based on local frequency measurements or coordinated by the regional WAC to enable cross-border support through the HVDC interconnection. The Digital Twin is used to assess the effectiveness of the proposed coordination strategy under different disturbance scenarios. By testing these scenarios, operators can better understand the vulnerabilities and enhance the resilience of the system to disturbances.

2.2.3 Assumptions and Prerequisites

The use case is implemented and validated in a controlled, non-intrusive environment through a real-time digital twin. This digital twin accurately represents both the current and future states of the Cypriot and Greek power systems, including their future HVDC interconnection. The TSO, FSPs, market and RSC are emulated in the demo digital twin environment considering different realistic scenarios. Wide-area communication is established between both sides of the HVDC interconnection and HVDC converters will be operating under different control modes.

For accurate and reliable testing, specific data is required from both the Cypriot and Greek power systems for each case study. This data includes transmission grid structure and parameters, committed synchronous generation units' characteristics, inverter-based renewable penetration, and load demand measurements.

2.2.4 Key Performance Indicators

To evaluate the effectiveness of the frequency support framework, the following KPIs will be analysed:

- **Volume of Available Power for FCR Services:** This indicator measures the total volume of power procured by the TSO, offered by FSPs, and cleared by the market operator for FCR services. It reflects the availability of FCR service in MW/Hz over the examined time period and plays a crucial role in assessing system readiness and responsiveness to frequency disturbances.
- **Volume of Power Provided by HVDC Link During Frequency Events:** This KPI quantifies the amount of additional power supplied by the HVDC link to the interconnected systems during frequency events. By analysing this indicator, the project can assess the HVDC link's ability to stabilize frequency deviations and support system balancing under various conditions.
- **Frequency Nadir:** The lowest frequency level observed after a significant disturbance is captured by this indicator. Frequency nadir provides insight into the severity of frequency deviations and the ability of frequency support mechanisms to mitigate extreme frequency drops. Maintaining an acceptable frequency nadir is critical to preventing power outages and ensuring system reliability.
- **Post-Disturbance Steady-State Frequency:** This indicator measures the stabilized frequency level reached after the initial transient response and the activation of FCR and FSM support. It reflects the ability of the system to settle at an acceptable operating frequency after the disturbance, before slower frequency restoration actions are applied. This value is important for assessing whether additional corrective actions, such as aFRR or mFRR activation, may be required to restore the frequency closer to its nominal value and maintain secure system operation.
- **Rate of Change of Frequency (RoCoF):** This metric measures the maximum rate at which frequency changes (in Hz/s) following a major disturbance. A high *RoCoF* value indicates a rapid frequency shift, which can lead to system instability if not adequately controlled. Monitoring *RoCoF* helps in understanding the resilience of the interconnected systems and the effectiveness of implemented mitigation strategies. *RoCoF* was estimated by calculating the difference between consecutive frequency measurements and dividing by the sampling interval, yielding an instantaneous *RoCoF* estimate. The resulting *RoCoF* signal was then smoothed using a 1-second moving-average filter. In this work, a 1-second averaging window was selected, although alternative averaging windows (e.g., 0.25, 0.5, 1.0, and 2.0 s) may also be considered in line with RfG 2.0. Finally, the maximum absolute value of the filtered *RoCoF* signal was identified and reported as the maximum *RoCoF* magnitude as a key indicator for system stability. Lower *RoCoF* indicates a more stable system.

3 Digital Twin Framework

3.1 Digital Twin Architecture

The digital twin architecture provides a comprehensive framework for monitoring, simulating, and analysing the operation of HVDC interconnections. By creating a realistic virtual representation of the power grid, the digital twin enhances system reliability, frequency stability, and operational efficiency. It integrates real-time simulation, multiple actors, and interconnected systems to facilitate coordination and decision-making in power transmission and market operations.

Figure 3 illustrates the interactions between key actors and systems in the digital twinning for HVDC interconnections. It highlights the flow of information between Transmission System Operators (TSOs), Market Operators (MOs), the Regional Security Coordinator (RSC), HVDC Operators, and Flexibility Service Providers (FSPs). Each of these actors is responsible for their allocated systems, and each system can either serve market operations for FCR clearing results, or real-time simulations to enhance frequency stability based on the market clearing results and TSO regulations. Real-time simulation within the digital twin enables continuous assessment of grid conditions and rapid response to frequency disturbances.

As described in section 2.2.2, the communication flow starts with the TSO in each country, which is responsible for procuring FCR bids and calculating HVDC link constraints. These constraints are communicated to the RSC, which ensures compliance with operational limits and facilitates bilateral communication to ensure secure grid operation. The Market Operator processes bids from TSOs, HVDC Operators, and FSPs, and performs market clearing based on technical and economic criteria, integrating HVDC constraints provided by the RSC. An FCR – FSM coordination unit receives the market cleared results and calculates the adaptive parameters for coordinated FCR and FSM action, k_{FCR} and k_{FSM} , respectively. The HVDC Operator and FSPs receive these parameters and provide FCR support based on the market-clearing results, and FSM support based on grid regulations and prevailing grid operating conditions, including the available system inertia. In the present implementation, the

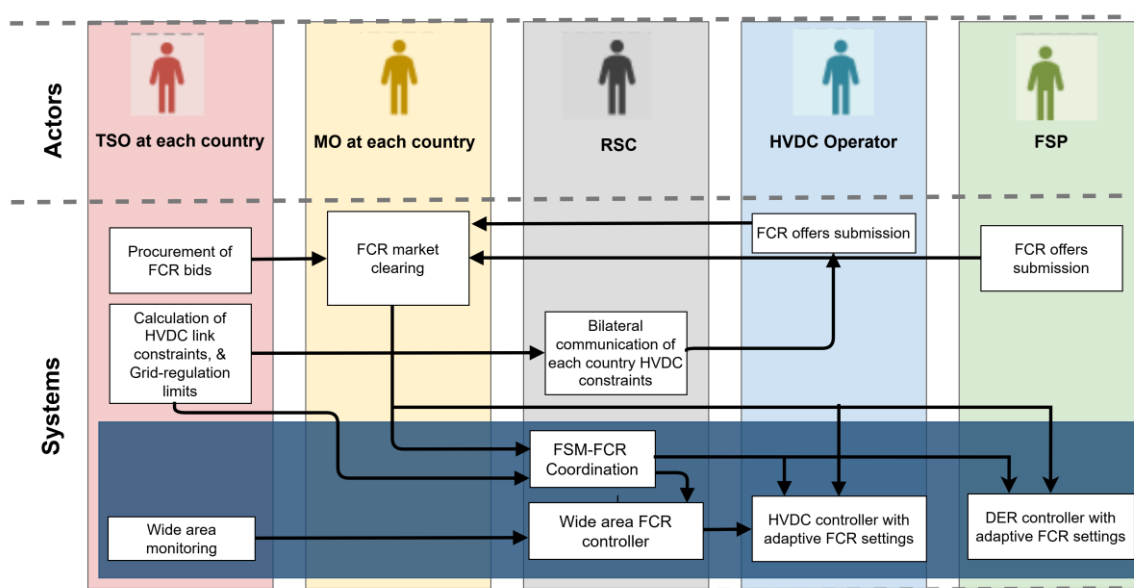


Figure 3: Actors and systems interactions in the digital twinning for HVDC interconnection

available inertia is provided by the TSO and is primarily determined from the inertia contribution of the committed synchronous generation units. More generally, the framework can also accommodate a broader TSO-provided or estimated system inertia value that accounts for additional contributions, such as load-side rotating inertia, where such information or estimation methods are available. The HVDC and DER controllers then respond to real-time frequency deviations and autonomously implement the corresponding corrective actions to support system stability. All systems are integrated into the Digital Twin environment, enabling real-time simulation and testing of the interconnected grid's dynamic performance.

3.2 Real time simulation environment of the digital twin

3.2.1 Multi-link HVDC interconnection modeling

The diagram of the real time simulation model of the HVDC interconnector is shown in Figure 4. In this context, the power systems of Cyprus, Crete and Mainland of Greece were modeled using a country-level equivalent power system that emulates the dynamic behaviour of each grid. Each country's system is connected to an HVDC converter station, consisting of voltage source converter (VSC). This is responsible for converting AC power to DC for efficient long-distance transmission and back to AC for integration into the receiving grid. The submarine HVDC cable has transmission capacity of 1000 MW, operates at ± 500 kV and has an approximately distance length of 340 km between Mainland of Greece and Crete, and around 898 km between Crete and Cyprus [4], **Error! Reference source not found.**, [6].

Each HVDC converter is controlled by its HVDC controller with adaptive FCR and FSM settings, as presented in Figure 5. The converters in Crete and Cyprus operate in $P&Q$ control mode, meaning

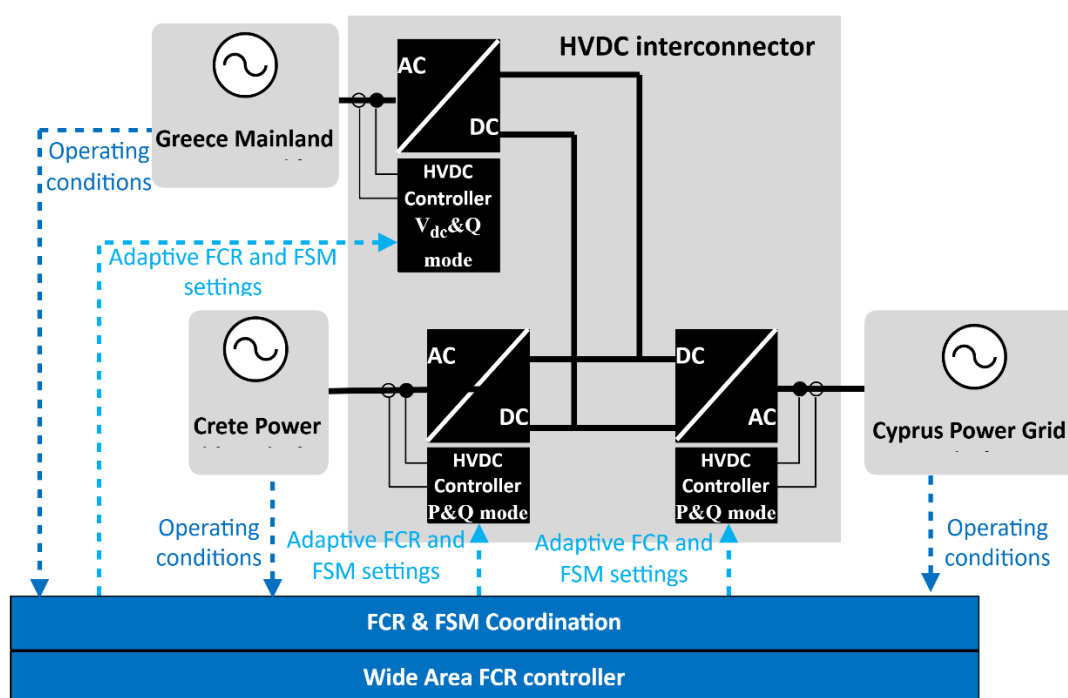


Figure 4: Brief diagram of the multi-link HVDC interconnection developed and executed within the real time simulator.

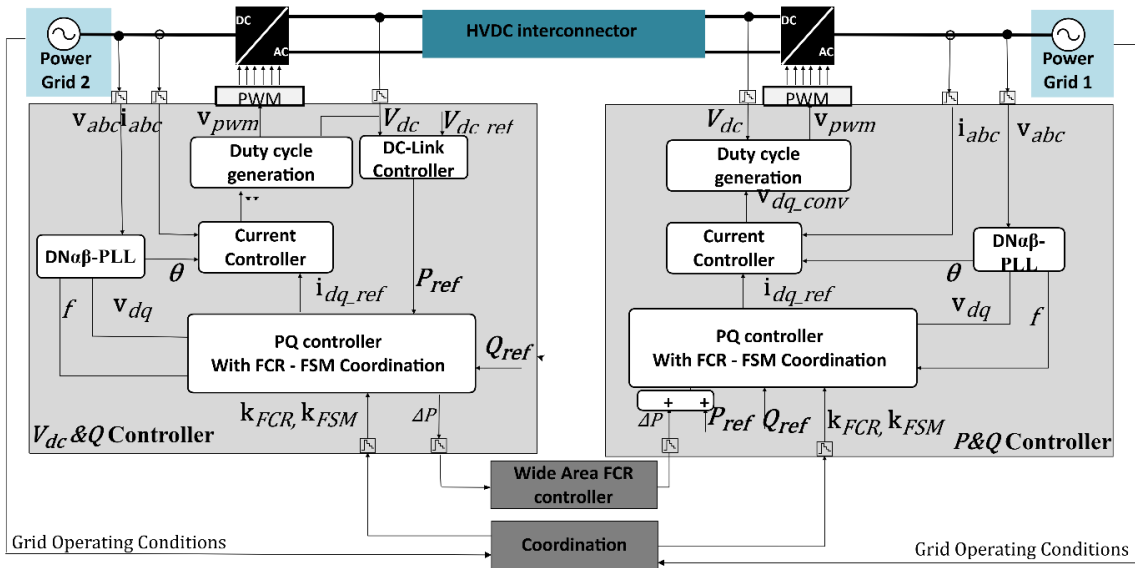


Figure 5: HVDC controller considering (a) a V_{dc} & Q control mode (left HVDC terminal) and (b) in P & Q control mode (right HVDC terminal).

they control the active and reactive power flow into the HVDC link, while the converter in Greece mainland operates in V_{dc} & Q control mode, meaning that it is responsible to control the voltage of the HVDC link and the reactive power flow. Wide-area monitoring systems measure each grid's real-time conditions and track real-time frequency fluctuations. In case of a frequency deviation in Cyprus or Grete, the controller in P & Q mode activates FCR and FSM support based on local measurements and dynamically adjusts active power injection based on the adaptive FCR and FSM settings received from the coordination unit. Alternatively, when frequency deviation is detected in the side of Athens (Greece Mainland), the V_{dc} & Q mode controller calculates the required active power adjustment considering FCR service and FSM mode, based on local measurements, but since it has no control over the local active power injection, a WAC sends a signal to the interconnected countries to adjust their active power injection. Therefore, the HVDC link is designed to maintain grid stability by enabling controlled power exchange between the regions.

Figure 5 demonstrates in detail the two types of HVDC controllers that are used in the simulation models, and their interactions. Both controllers use a DN $\alpha\beta$ PLL (Decoupled Network alpha-beta Phase-Locked Loop), which estimates the phase angle and frequency of a grid voltage in $\alpha\beta$ -frame and dynamically decomposes the voltage at the PCC into its positive and negative sequence **Error! Reference source not found.** It ensures that the converter stays in sync with the grid for proper power exchange, especially important for maintaining stability. The PQ controller unit calculates the active and reactive current references, $i_{dq,ref}$, based on the reference active and reactive power values, P_{ref} and Q_{ref} , respectively. These current references are then tracked by a proportional-integral (PI)-based current controller [8]. Based on the current tracking error, the controller generates the converter voltage reference, $v_{dq,conv}$, which is used to derive the duty cycles and switching pulses for the converter. Frequency support capabilities are embedded in the PQ controller, thus when a local frequency event is detected, the controller estimates the requirements in active power flow, based on the FCR and FSM coordination schemes, determined by the grid regulations [9], [10], [11].

The difference between the two types of controllers lies in the operation of the PQ controller unit. When the controller operates in P & Q mode, as shown the right side of Figure 5, the PQ controller

directly regulates the active power (P) and reactive power (Q) based on predefined setpoints. This converter actively injects or absorbs the desired power into the HVDC link, helping manage loading and power flow. During a local frequency event, the controller automatically activates the frequency support scheme and dynamically adjusts the active power output to provide support and stabilize its local grid, based on the settings received from the FCR & FSM coordination unit.

Alternatively, a V_{dc} & Q controller maintains the DC voltage (V_{dc}) and manages reactive power (Q). In this configuration, illustrated in Figure 5 (left side), the active power flow is not set by this terminal; rather, it is implicitly determined by the power injected by the other P & Q -controlled terminals. The P_{ref} input for the PQ controller is calculated by an embedded DC-link controller which regulates the DC-link voltage (V_{dc}), based on the error between the reference DC-link voltage ($V_{dc_{ref}}$) and the V_{dc} of the HVDC interconnector [9]. Therefore, during a local frequency event, as the converter cannot autonomously adjust power output, it relies on a wide-area controller (WAC) to send control signals to the other P & Q controlled converters, which then adjust their power flow according to the necessary active power support (i.e., ΔP). In this use case, the terminals of Cyprus and Crete (i.e. P & Q mode), with the terminal of Athens (i.e., V_{dc} & Q mode) operate in complementary control modes to enable stable and coordinated power flow between interconnected grids. The FCR and FSM coordination block is responsible for the calculation of the FCR and FSM droop constants (i.e., k_{FCR} , k_{FSM}) based on the grid operating conditions and TSO requirements. The WAC also receives also the grid conditions of each terminal in order to apply the appropriate limits to control disturbance propagation.

3.2.2 Country-level equivalent power systems modeling

A scalable country-level equivalent modelling approach was developed in MATLAB/Simulink using components from the Simscape Electrical and SimPowerSystems libraries. The objective of this modelling approach is to reproduce the aggregated dynamic behaviour of each interconnected power system within the real-time digital twin, while keeping the model computationally efficient and suitable for real-time execution. As illustrated in Figure 6 each country-level power system is represented through single-unit equivalent models for the main system components, including synchronous generation, inverter-based RES, inverter-based battery/FSP resources, and load consumption. The inverter-based FSP equivalent is further detailed in Figure 7, while the inverter-based RES equivalent is further detailed in Figure 8.

The synchronous generation part is represented by an equivalent synchronous generator, including the main electromechanical dynamics of the aggregated conventional generation fleet. This allows the model to capture the frequency response associated with rotating inertia, governor action, and generator active-power contribution following disturbances. In parallel, inverter-based RES and battery-based FSP resources are represented through equivalent converter-interfaced units, while the demand is represented by an aggregated load block. This single-unit equivalent representation provides a flexible and computationally efficient way to emulate the dynamic response of country-level grids with different sizes, inertia levels, RES penetration, and demand conditions.

Scalability is achieved through the application of user-defined scaling factors, which allow the equivalent model to be adapted to different countries or operating conditions by considering the synchronous generation capacity and inertia, the RES penetration level, the installed inverter-based flexibility capacity, and the overall load demand. A load-flow analysis is performed to initialize the three-phase networks and machines so that each simulation starts from a consistent steady-state operating point. This modelling approach provides a unified framework for emulating different

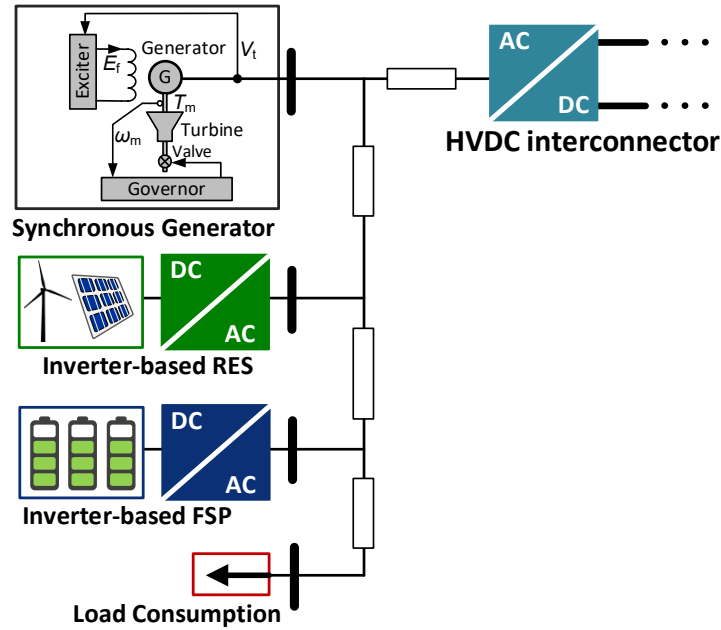


Figure 6: Dynamic behaviour of a country-level power system based on single-unit equivalent modelling approach to emulate synchronous generators, inverter-based RES, inverter-based FSPs, and load consumption.

national grid conditions and investigating their dynamic interaction through the HVDC interconnection.

In an indicative configuration, the Cyprus power system is emulated with 1000 MW of synchronous generation capacity, Crete with 1026 MW, and mainland Greece with 8100 MW. Based on these equivalent capacities and the corresponding inertia characteristics, mainland Greece is represented as a stronger power system, while Cyprus and Crete are represented as weaker, lower-inertia grids in this use case.

3.2.2.1 FSP Modeling

The FSP controller, shown in Figure 7, is based on the converter control architecture described previously in Section 3.2.1 and therefore comprises the same PLL, PQ control, current control, and PWM generation stages. It is DERs-based and responsible to provide frequency support. The coordination unit, based on the grid operating conditions and the TSO static requirements, it defines the FCR and FSM droop constants, k_{FCR} and k_{FSM} , respectively. The detailed operation of the coordination scheme is presented in Section 3.2.3.

For Cyprus and Crete power system, an FSP of 500 MW rated power is integrated in the country-level power system, while an FSP of 1000 MW rated power is incorporate in Athens Mainland country-level power system.

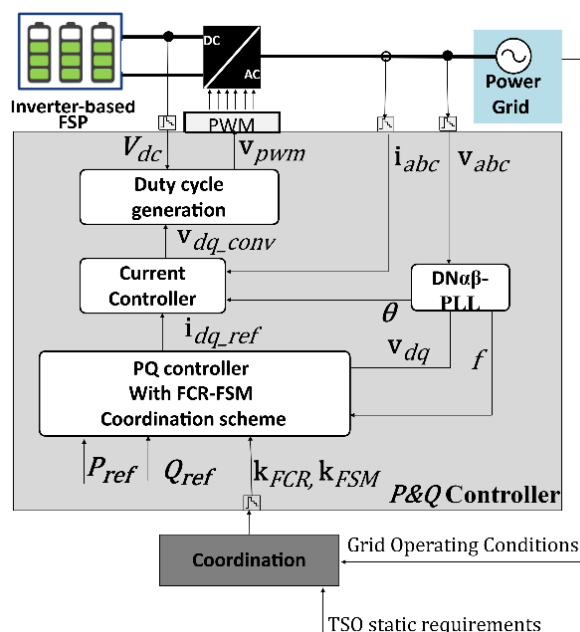


Figure 7: Inverter controller of the FSP battery system within the country-level system

3.2.2.2 RES Modeling

The RES controller, shown in Figure 8, follows the same converter control architecture as the FSP controller, comprising a PLL, a PQ controller, an inner current control loop, and a PWM generation stage. However, unlike the FSP controller, it does not participate in frequency support services and therefore does not include communication with the coordination layer. The controller operates solely in PQ mode, regulating the converter output to track the specified active and reactive power

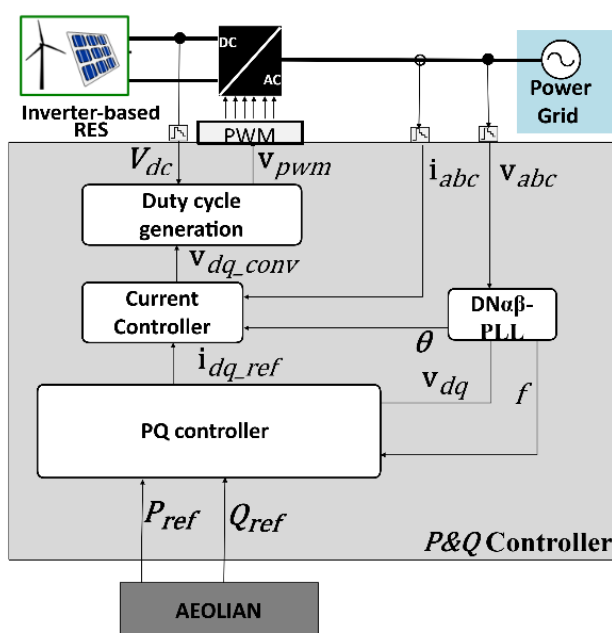


Figure 8: Inverter controller of the RES within the country-level system

references. These references are acquired from historical or real-time operational field data of AEOLIAN plant.

3.2.3 FCR-FSM Coordination

The coordination unit coordinates FCR and FSM responses from flexible inverter-based resources (i.e., HVDC links and FSPs). The objective is to provide the mandatory FCR contribution, based on the market clearing results, and additional FSM support according to grid regulations, with the enhancement of an adaptive coefficient considering the real-time inertia condition of the power system. The overall coordination action is presented Figure 9, showing the logic behind calculating adaptive frequency support coefficients for HVDC and FSP controllers, considering the system operating conditions and the TSO static requirements.

When the system frequency falls below $f_{FCR-max}$, the required FCR power for each region is shared among synchronous generators, HVDC systems, and FSPs. The FCR response follows a fixed droop characteristic k_{FCR} , which is calculated using the mandatory allocated FCR power $P_{FCR-max}$ and the FCR frequency range $\Delta f_{FCR-max}$, as:

$$k_{FCR} = \frac{P_{FCR-max}}{\Delta f_{FCR-max}} \left(\frac{MW}{Hz} \right) \quad (1)$$

where:

$$\Delta f_{FCR-max} = f_{FCR-max} - f_{FCR-min} \quad (2)$$

and $f_{FCR,max}$ and $f_{FCR,min}$ denote the upper and lower frequency limits of the FCR activation range, respectively. More specifically, $f_{FCR,max}$ represents the frequency threshold below which FCR activation starts, while $f_{FCR,min}$ represents the frequency level at which the full allocated FCR power, $P_{FCR,max}$, is activated. Therefore, the FCR droop response is applied within the following frequency range:

$$f_{FCR-min} < f \leq f_{FCR-max} \quad (3)$$

Thus, the inverter active power output is increased proportionally to the frequency deviation, within the FCR operating range, and must provide the total allocated amount of $P_{FCR-max}$ when the operating point reaches the minimum point, $f_{FCR-min}$.

The FSM support function can be activated by the HVDC and FSP inverter controllers in parallel with the FCR response when the frequency reaches the FSM activation threshold, $f_{FSM,max}$. Unlike FCR, FSM does not require a predefined reserve capacity. Instead, grid codes specify an admissible range of FSM droop coefficients, between $k_{FSM,min}$, corresponding to the minimum support intensity, and $k_{FSM,max}$, corresponding to the maximum support intensity. This provides flexibility in defining the converter response.

However, instead of selecting a fixed coefficient within the range specified by grid regulations, an adaptive FSM coordination scheme is developed to adjust the FSM coefficient, k_{FSM} , according to the real-time inertia conditions of the power system. The system inertia condition is represented through the real-time available kinetic energy indicator:

$$E_{k-rt} = \frac{H S_n}{f_n} \left(\frac{MW \cdot s}{Hz} \right) \quad (4)$$

where H is the inertia constant, f_n is the nominal frequency, and S_n is the available synchronous generation capacity, which varies according to the committed synchronous generation units and the system operating conditions. Therefore, E_{k-rt} represents the real-time available kinetic energy of the system. This value can either be calculated by the Transmission System Operator (TSO) based on the characteristics and commitment status of the synchronous generators, or estimated using inertia estimation methods based on ambient PMU measurements [12]. As system operating conditions change, the available kinetic energy varies within the range $E_{k-l} \leq E_{k-rt} \leq E_{k-h}$.

Considering that during low inertia conditions (i.e., E_{k-l}) the system is more vulnerable to frequency disturbances, a larger FSM droop gain is needed for a stronger inverter response (i.e., $k_{FSM-max}$), while during high inertia conditions (i.e., E_{k-h}) the system needs a lower inverter response and therefore a smaller FSM droop gain (i.e., $k_{FSM-min}$), avoiding unnecessary utilization of inverter-based resources and activation of support actions. To account for changing system conditions, the FSM droop coefficient is continuously adjusted according to the real-time kinetic energy of the system.

For developing an adaptive FSM support scheme, a linear interpolation between these two operating points is used to continuously adapt the FSM droop coefficient according to the available system kinetic energy:

- $k_{FSM-max}$ at the minimum kinetic energy E_{k-l} ,
- $k_{FSM-min}$ at the maximum kinetic energy E_{k-h} .

This results in the real-time adaptive FSM coefficient k_{FSM-rt} , dynamically calculated by:

$$k_{FSM-rt} = \frac{k_{FSM-max} - k_{FSM-min}}{E_{k-l} - E_{k-h}} \cdot (E_{k-rt} - E_{k-l}) + k_{FSM-max} \quad (5)$$

Therefore, the active power reference P^* of the HVDC and FSP inverters is determined by the combined action of the FCR and adaptive FSM control, as a deviation for the business-as-usual initial power reference operation point P_{ref} , while respecting the physical rated power limit P_{rated} of the converter P_{rated} , and can be calculated by:

$$P^* = \min(P_{ref} + \min(k_{FCR} \cdot \Delta f_{FCR}, P_{FCR}) + k_{FSM-rt} \cdot \Delta f_{FSM}, P_{rated}) \quad (6)$$

where:

$$\Delta f_{FCR} = \max(0, f_{FCR-max} - f) \quad (7)$$

$$\Delta f_{FSM} = \max(0, f_{FSM-max} - f) \quad (8)$$

represent the frequency deviations measured from the respective activation thresholds of the FCR and FSM functions.

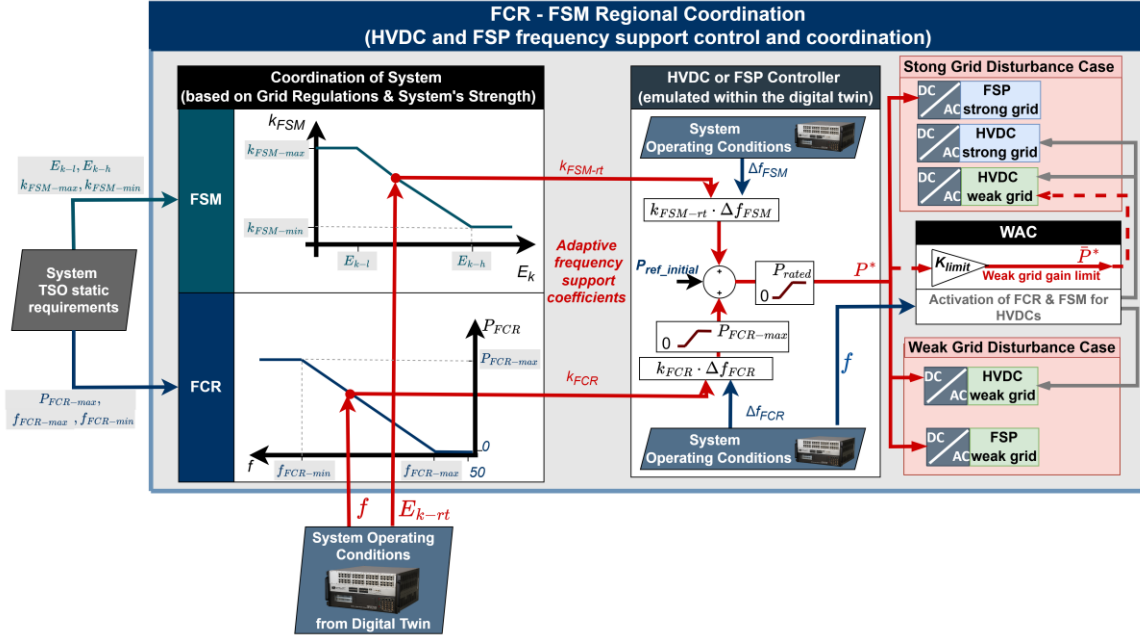


Figure 9: HVDC and FSP frequency support control and coordination. FCR – FSM regional coordination scheme

The term $k_{FCR} \cdot \Delta f_{FCR}$ corresponds to the mandatory FCR contribution and becomes active when the system frequency f falls below the FCR activation threshold $f_{FCR-max}$. The delivered power increases proportionally to the frequency deviation until the full allocated reserve $P_{FCR-max}$ is reached at $f_{FCR-min}$. Similarly, the term $k_{FSM-rt} \cdot \Delta f_{FSM}$ corresponds to the additional adaptive FSM contribution and becomes active when the frequency falls below the FSM activation threshold $f_{FSM-max}$. The FSM response is determined by the real-time adaptive droop coefficient k_{FSM-rt} , which varies according to the available kinetic energy of the system.

Therefore, the FCR and FSM contributions allow HVDC links and FSPs to simultaneously satisfy their mandatory FCR obligations while providing additional inertia-dependent FSM support. As the frequency decreases below the respective activation thresholds, both contributions increase proportionally to their corresponding frequency deviations.

During the real-time operation, the FCR-FSM Coordination Unit receives from the TSO of each nation the required FCR contribution $P_{FCR-max}$, the frequency limits for FCR action ($f_{FCR-min}$, $f_{FCR-max}$), the permitted range of FSM coefficient ($k_{FSM-min}$, $k_{FSM-max}$) and the range of system inertia in kinetic energy (E_{k-min} , E_{k-max}). Additionally, the real-time operating conditions, such as the operating frequency f and current kinetic energy of the system (E_{k-rt}), are known through the communication of the FCR-FSM Coordination unit with the Digital Twin.

To avoid disturbance propagation between interconnected systems, the HVDC controller enforces the active power transfer to be limited according to a gain k_{limit} , as indicated in Figure 9, where the FCR-FSM regional coordination scheme is illustrated. After the coordination scheme indicates the adaptive frequency coefficients, the HVDC and FSP controllers calculate the active power requirement as P^* . In the case of a disturbance in the weak grid, P^* is directly used as reference in the HVDC and FSP inverters of the weak grid. Contrary, in the case of a disturbance in the strong grid, the FSP controller uses the calculated P^* as reference to locally control the FSP inverter of the strong grid, while the HVDC controller sends the P^* to the WAC, which after applying the limitation it transfers the

limited power signal $\bar{P}^*$ to the HVDCs of the supporting systems (weak grid). This way, a severe frequency disturbance in one area (strong grid) can only be partially supported by the neighbouring system (weak grid), ensuring that the disturbance remains mainly localized and does not severely compromise the frequency stability of the interconnected area. The WAC is also responsible for activating or deactivating the FCR and FSM support of the HVDC controllers of all interconnected systems based on their frequency level. When one interconnected system transfers power to support another system, the resulting slight frequency deviation in the supporting system is not treated as a local event requiring compensation. The corresponding FCR/FSM response is therefore deactivated during the support period, preventing counteractive actions that could oppose the intended power transfer.

3.2.4 Real-time and historical field data integration

The Digital Twin communication architecture is organized into three interconnected layers (as shown in Figure 10): (a) the Field Layer, (b) the Data Exchange Layer, and (c) the Digital Twin Layer. This multi-layer architecture enables real-time data acquisition, storage, and exchange between the physical system and its digital representation.

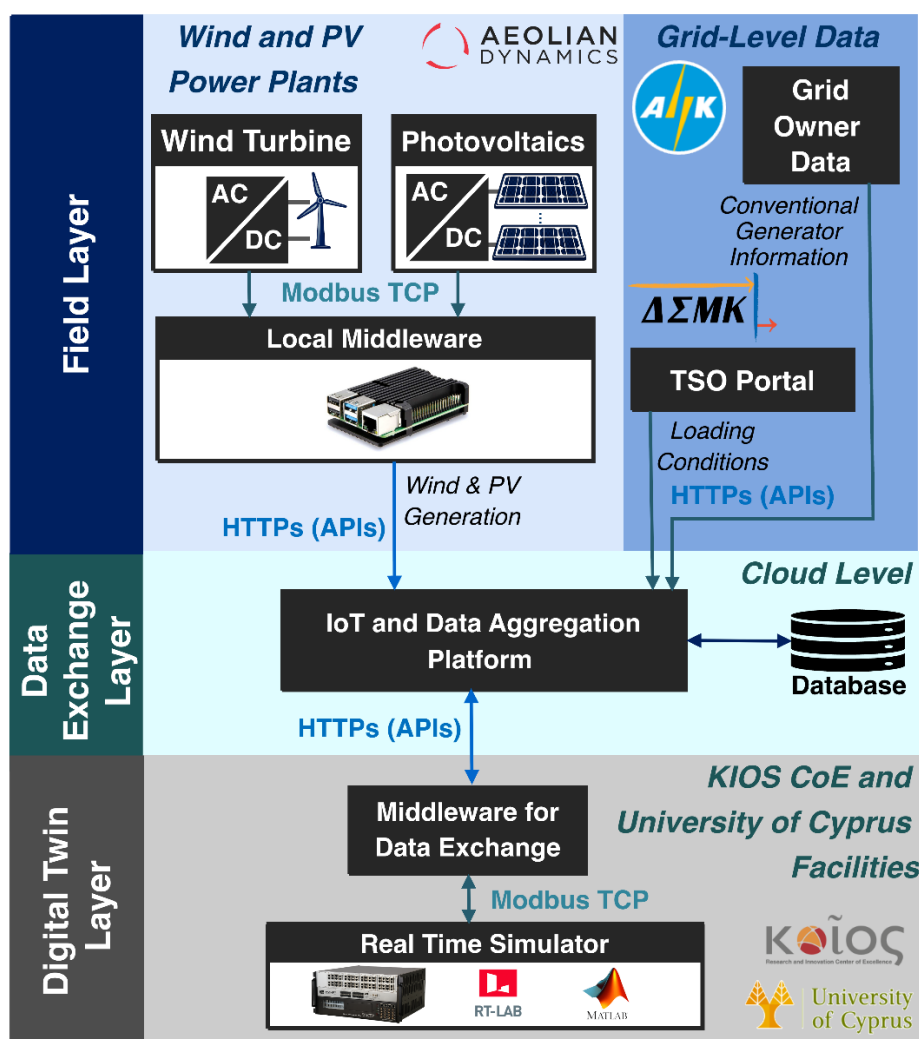


Figure 10: Communication Layers of the Digital Twin

The Field Layer represents the physical equipment from which real-time and historical data are acquired. Specifically, wind and photovoltaic (PV) power plants (e.g., the AEOLIAN Dynamics plant) transmit generation data to a local middleware using the Modbus TCP communication protocol. In addition, grid-level loading conditions are obtained from the Transmission System Operator (TSO) Portal (TSOC), while information on conventional generators is provided by the Grid Owner (EAC).

The Data Exchange Layer serves as the cloud-based communication and integration platform between the Field Layer and the Digital Twin Layer, as depicted in Figure 10. It securely collects real-time measurements from the local middleware using HTTPS-based Application Programming Interfaces (APIs). This edge-processing approach reduces communication latency while providing a standardized interface between heterogeneous field devices and higher-level applications. Furthermore, the platform continuously integrates data from the TSO Portal and the Grid Owner via HTTPS-based APIs. The cloud-based IoT and data aggregation platform stores both historical and real-time operational data in a centralized cloud database, ensuring data availability for monitoring, analytics, and simulation.

The Digital Twin Layer contains the real-time simulation model of the HVDC interconnection system. The simulation model was developed in MATLAB/Simulink, while the RT-LAB platform was used for real-time execution and integration with the OPAL-RT OP5707 real-time simulator. Dedicated middleware is responsible for exchanging data between the cloud platform and the simulator using Modbus TCP. This enables the simulator to receive live measurements from the physical system while simultaneously transmitting simulated outputs and performance indicators back to the cloud platform via HTTPS-based APIs. As a result, the Digital Twin enables real-time monitoring, performance assessment, and validation of the HVDC interconnection system.

3.2.5 Realizing the real time simulation framework for digital twinning

The developed high resolution EMT models in Sections 3.2.1 and 3.2.2 are quite demanding and complex and require a high execution time. Therefore, to convert these models into a real time digital twin framework the following process needs to be followed:

- **Configure the models based on real-life use case characteristics:** Using required data from each country power system and considering the HVDC characteristics of the Great Sea Interconnector, an electromagnetic transient (EMT) simulation model is developed in MATLAB/Simulink by using components and modules from Simscape Electrical and SimPowerSystems libraries of Mathworks. This model is designed for compatibility with the OPAL-RT OP 5707 simulator and employs a microsecond-scale fixed-step discrete solver to achieve high fidelity. Debugging and testing is necessary to ensure that the model remains stable and operates effectively under varying grid conditions.
- **Enable real time execution:** To facilitate the real-time emulation of the digital twin, the developed simulation model is adapted for the OPAL-RT platform using eMEGASIM [13], ARTEMIS [14], and RT-LAB [15] software. This adaptation involves partitioning the model into smaller subsystems, replacing MATLAB components with ARTEMIS components, and optimizing execution across multiple cores to balance execution time requirements. The modified model is compiled and loaded into the simulator (OPAL-RT OP5707) through the RT-LAB software for real-time execution.
- **Realistic operating conditions:** For replicating realistic operating conditions, real-life data, such as load consumption and power generation time series, are incorporated into the Digital

Twin. These measurements can either be pre-loaded from historical datasets or streamed in real time through standardized communication interfaces and IoT services and standardized APIs (explained in Section 0), allowing the simulation to accurately reproduce the dynamic behaviour of the physical power system. This continuous synchronization between field measurements and the simulation environment enhances the realism of the Digital Twin and enables the validation of control strategies under representative operating conditions.

- **Configuration of communication interfaces for control Hardware-In-the-Loop (HIL):** The Digital Twin interacts with digital controllers (Control-HIL) and external actors through configurable communication interfaces that enable the real-time exchange of measurements, control commands, and operational data. Standard industrial communication protocols, such as TCP/IP, Modbus TCP, IEC 61850, and IEEE C37.118, are employed to ensure seamless interoperability between the real-time simulator, field devices, external control applications, and supervisory systems. These communication interfaces are configured according to the requirements of each use case, allowing the Digital Twin to integrate heterogeneous devices and support realistic testing, validation, and evaluation of advanced monitoring and control strategies under representative operating conditions. In addition, the communication infrastructure supports the integration of the real-time Monitoring and Control Interface, which enables operators to visualize system measurements, supervise the operating status of the Digital Twin, modify controller setpoints, and coordinate the provision of ancillary services.

As a result, after executing these steps, an emulation of the HVDC interconnected power systems of Cyprus, Crete and Greece mainland in real time is achieved. This environment serves as a digital twin system to perform the investigations needed in this use case.

3.3 Actors within the digital twin framework

The Business Use Case EM-CY-02 of the TwinEU project focuses on frequency support management of HVDC-interconnected systems at a regional level. This use case involves the following actors:

- **TSO:** The Transmission System Operator (TSO) of each country who is responsible for operating, managing, and maintaining the power system within a designated area, including its interconnections with other systems. The TSO ensures the transmission grid can reliably meet demand while maintaining both frequency and voltage stability. In this use case, the TSO will procure FCR services through the flexibility market to enhance system frequency stability. Additionally, the TSO will define operational constraints for the HVDC link, particularly in terms of the maximum power disturbance that the interconnection can handle during critical events in an interconnected country, helping to mitigate cascading failures across the grid.
- **TSO:** The Transmission System Operator (TSO) of each country is responsible for operating, managing, and maintaining the power system within its designated area, including its interconnections with other systems. The TSO ensures reliable transmission grid operation while maintaining frequency and voltage stability. In this use case, the TSO procures FCR services through the flexibility market and defines the operational constraints of the HVDC link, particularly the maximum allowable power disturbance that the interconnection can handle during critical events. The TSO also provides the necessary frequency-support parameters to the FCR-FSM Coordination Unit, including the required FCR contribution, FCR activation limits, admissible FSM droop range, and system inertia range, as explained in

Section 3.2.3, which are used to configure the coordinated real-time frequency support strategy.

- **MO:** The Market Operator (MO) facilitates the matching of electricity supply and demand by managing transactions in electricity markets. In this use-case, the MO will oversee the clearing and allocation of market-based FCR products within each country, considering bids procured by the TSO, offers from FSPs, and offers from the HVDC operator. Additionally, MO will consider the interconnection constraints, as communicated by the RSC, to ensure efficient and stable market operation.
- **RSC:** The Regional Security Coordinator (RSC) plays a vital role in ensuring the security and reliability of the interconnected power systems by monitoring cross-border electricity flows in real-time and enforcing compliance with grid regulations. It coordinates with TSOs to establish interconnection constraints, particularly regarding the amount of power that can be exchanged via the HVDC link for frequency support. The RSC ensures that these constraints are met, preventing instability in the interconnected regions while facilitating collaboration among different power system operators. In addition, the RSC is responsible to provide the market-cleared FCR allocations, operational constraints, and grid-code requirements to the regional coordination unit, which computes the k_{FCR} and adaptive k_{FSM-rt} coefficients which are communicated to the HVDC and FSP inverter controllers. Furthermore, the RSC hosts the regional Wide Area Controller (WAC), which supervises the coordinated activation of cross-border frequency support by generating the control signals required for the HVDC interconnection during real-time operation.
- **HVDC operator:** The HVDC Operator is responsible for operating, managing and maintaining the HVDC link, ensuring efficient and stable power transmission between interconnected regions. This role includes real-time monitoring and control of HVDC equipment while adhering to system constraints imposed by the connected power systems and TSOs. In this use-case, the HVDC operator will actively participate in electricity markets by submitting offers for FCR services related to the HVDC link. Additionally, the operator will regulate the HVDC link to deliver coordinated FCR services and FSM support, providing essential frequency support during disturbances.
- **FSP:** The Flexibility Service Provider (FSP) supplies flexibility services to energy system stakeholders through either bilateral agreements or participation in flexibility markets. In this project, FSPs will engage in the FCR market, offering FCR services as determined by market-clearing results, together with adaptive FSM support. These services will be automatically activated based on real-time local frequency measurements, ensuring a rapid and efficient response to frequency deviations.

3.4 Systems within the digital twin framework

The Business Use Case EM-CY-02 of the TwinEU project requires the development and interaction between the following systems:

- **Procurement of FCR bids:** The Procurement of FCR bids is managed by the TSO in each country. Every three hours, the TSO determines the flexibility requirements for FCR to maintain frequency stability in the transmission grid. This process is supported by a what-if

digital twin analysis that simulates different operational scenarios. Once calculated, the FCR bids are submitted to the flexibility market.

- Calculation of HVDC link constraints:** The calculation of HVDC link constraints is also a responsibility of the TSO in each country. Three hours in advance, the TSO determines the maximum power disturbance the HVDC interconnection can handle during a major event in an interconnected country while ensuring its own system remains stable. These constraints are derived using a digital twin model that simulates expected conditions. The calculated HVDC constraints are then communicated to the MO of the interconnected country via the RSC during the FCR market clearing process.
- Bilateral communication of HVDC constraints:** The bilateral communication of HVDC constraints is managed by the RSC, which facilitates a data-exchange framework for the seamless sharing of critical information between countries. This ensures that each country's stability related constraints are considered during the clearing the FCR market of the interconnected country.
- FCR offers submission by HVDC:** The submission of FCR offers by HVDC is handled by the HVDC Operator, who evaluates the available flexibility of the HVDC link in the short term, according to the expected power exchange, to generate reliable FCR offers. These offers are then submitted to the flexibility market to optimize the HVDC profitability.
- FCR offer submission by FSPs:** The submission of FCR offers by DERs is performed by FSPs. Each FSP assesses the available flexibility of DERs in the short term according to forecasted operation and submits FCR offers to the flexibility market, aiming to maximize profitability.
- FCR market clearing:** The FCR Market Clearing is the responsibility of the MO. The market-clearing mechanism matches the FCR bids procured by the TSO with the flexibility offered by FSPs, ensuring an optimal allocation that maximizes social welfare while considering the operational limitations of the HVDC interconnection.
- FCR & FSM Coordination:** The FCR & FSM Coordination unit is responsible for determining the frequency support parameters of the HVDC converters and participating FSPs during real-time operation. It receives the market-cleared FCR allocations, the applicable FSM operating requirements, and information on the prevailing system conditions, including the estimated system kinetic energy. Based on these inputs, it calculates the k_{FCR} and adaptive k_{FSM-rt} coefficients and distributes them to the corresponding controllers, ensuring coordinated and efficient frequency support while complying with operational constraints and grid-code requirements.
- Wide Area Monitoring:** The wide area monitoring system, operated by the TSO, receives real-time Phasor Measurement Unit (PMU) data with 20 ms reporting rate from interconnection points. This system provides live measurements of frequency and Rate of Change of Frequency ($RoCoF$), which are also reported to the RSC for enhanced grid visibility.
- Wide Area Control:** The WAC, managed by the RSC, determines the power required from the DC-link control side of the HVDC (Greece mainland side) for frequency support during a severe disturbance in this system. It then transmits the calculated setpoints to the other two terminal of the HVDC, operating in P-Q control mode (Cyprus and Crete side), to regulate their active

power exchange to indirectly support the frequency in the other system (Greece mainland power system).

- **HVDC Controller with Adaptive FCR and FSM Settings:** The HVDC controller with adaptive FCR and FSM settings is operated by the HVDC Operator and dynamically adjusts the HVDC link settings to provide the necessary frequency support. It responds to real-time frequency and *RoCoF* measurements while also incorporating inputs from the WAC and the FCR and FSM Coordination. This ensures compliance with both system constraints, grid requirements, market-clearing decisions and system operating conditions.
- **DER Controller with Adaptive FCR and FSM Settings:** The DER controller with adaptive FCR and FSM settings, managed by FSPs, regulates the active power output of DERs during frequency events. This controller autonomously activates FCR services and FSM support based on local frequency and *RoCoF* measurements while ensuring the coordinated FCR and FSM settings it receives from the coordination actor.

3.5 Information exchange in the digital twin framework

The exchange of information within the digital twin framework is explained in this section. In Scenario 1 (Regional Coordination Between Interconnected Systems), as described in Section 2.2.2, the following information exchange is taking place:

- **ID1-1 - Day-ahead energy market results:** Day ahead energy market clearing results are sent to the TSOs of the two countries to know the HVDC interconnection power exchange.
- **ID1-2 - FCR products procurement:** TSO procures FCR products for the FCR market operator in each country.
- **ID1-3 - System constraint submission:** TSO submits system constraints to the RSC to ensure system stability in case of a frequency event in the interconnected region.
- **ID1-4 - Bids submission to FCR markets:** FSPs at the two countries, as well the HVDC operator, submit their bids to the market of each country.
- **ID1-5 - Submission of the two system constraints:** RSC sends the constraints of the two countries for FCR services that will be provided by the HVDC interconnection to the market operators and the HVDC operator.
- **ID1-6 - Information on Market clearing results:** Market clearing results are announced to the FCR-FSM Coordination actor.
- **ID1-7 - Calculation of FCR – FSM gains:** Adaptive gains k_{FCR} , k_{FSM} are calculated by the FCR – FSM Coordination and are sent to all FSPs and HVDCs.

In Scenario 2 (Real-Time Operation for Frequency Stability Enhancement), as described in Section 2.2.2, the information exchange is as indicated below:

- **ID2-1 – FCR – FSM Adaptive gains:** The FCR – FSM Coordination defines the adaptive gains k_{FCR} , k_{FSM-rt} , for each FSP and HVDC controller, and are sent to each country's HVDC and FSP operators.
- **ID2-2 - RSC wide area coordination signals:** The RSC wide area controller monitors the grid frequency conditions in one country (where the HVDC controller is configured in $V_{dc}&Q$ mode

P&Q mode), and then is able to send a wide area coordination signal (ΔP) to control the HVDC converter in the second country (where HVDC is configured in V_{dc} & Q mode) in order to timely provide adequate frequency support from the first country to the second.

4 Digital Twin Implementation

The Digital Twin platform has been developed to provide real-time monitoring, analysis, and control of the Cyprus–Greece HVDC interconnection. The platform integrates real-time power system simulation, field measurements, data management services, and operator interfaces into a unified environment capable of supporting operational decision-making and advanced frequency control applications. As illustrated in Figure 11, the platform consists of four main components: (i) the Real-Time Digital Twin Model; (ii) the Backend and Middleware Layer, which provides centralized data acquisition, communication, API services, historical and real-time data management, and database storage; (iii) the Monitor and Control Interface; and (iv) the Web-based Management Interface.

The “Real-Time Digital Twin Model” constitutes the core of the platform and comprises three interconnected subsystem models representing mainland Greece, Crete, and Cyprus, which exchange power through the simulated HVDC interconnection. The simulation model includes synchronous generation units, inverter-based renewable energy sources (RES), battery-based Flexible Service Providers (FSPs), load demand models, and the HVDC converter stations and transmission link, as described in Sections 3.1–3.2. The model was developed in MATLAB/Simulink and deployed using the RT-LAB real-time simulation platform on the OPAL-RT OP5707 simulator. By continuously receiving operational measurements and control signals, the Digital Twin reproduces the current operating state of the interconnected power system, enabling real-time analysis, validation of control strategies, and system operation under both normal and disturbed conditions.

The “Monitoring and Control Interface” is developed using MATLAB App Designer and provides operators with a comprehensive real-time visualization of the Digital Twin. Through this interface, users can monitor the operating status of all major power system components, modify equipment setpoints, initiate predefined frequency disturbance scenarios, and supervise the overall system operation in real time. The interface also enables the configuration and coordination of frequency support services by the HVDC interconnection and the FSPs through the adjustment of the FCR and FSM droop settings assigned to each participating resource.

The “Backend and Middleware Layer” forms the central communication and information management infrastructure of the Digital Twin platform. It comprises three main components: the Data Exchange Middleware, which manages communication between the different platform services; the IoT and Data Management Platform, which acquires, processes, and organizes operational data; and the Database, which ensures the secure storage and availability of both real-time and historical information.

The “Data Exchange Middleware” acts as the communication hub of the platform, routing operational measurements, control commands, and simulation outputs between the real-time simulator, the IoT platform, external data providers, and the operator interfaces. Through this middleware, the Digital Twin receives both real-time and historical measurements from external data providers, including the grid operating data from TSOC and EAC, and the wind and photovoltaic plants operating data from AEOLIAN Dynamics. In parallel, the middleware transfers user-defined settings, control actions, and coordination parameters from the operator interfaces to the simulation model. Simulation results, calculated system variables, and performance indicators are simultaneously transmitted back to the operator interfaces and the IoT platform for visualization, analysis, and storage.

The “IoT and Data Management Platform” is responsible for collecting, organizing, and managing all operational data exchanged within the Digital Twin ecosystem. It provides standardized API-based

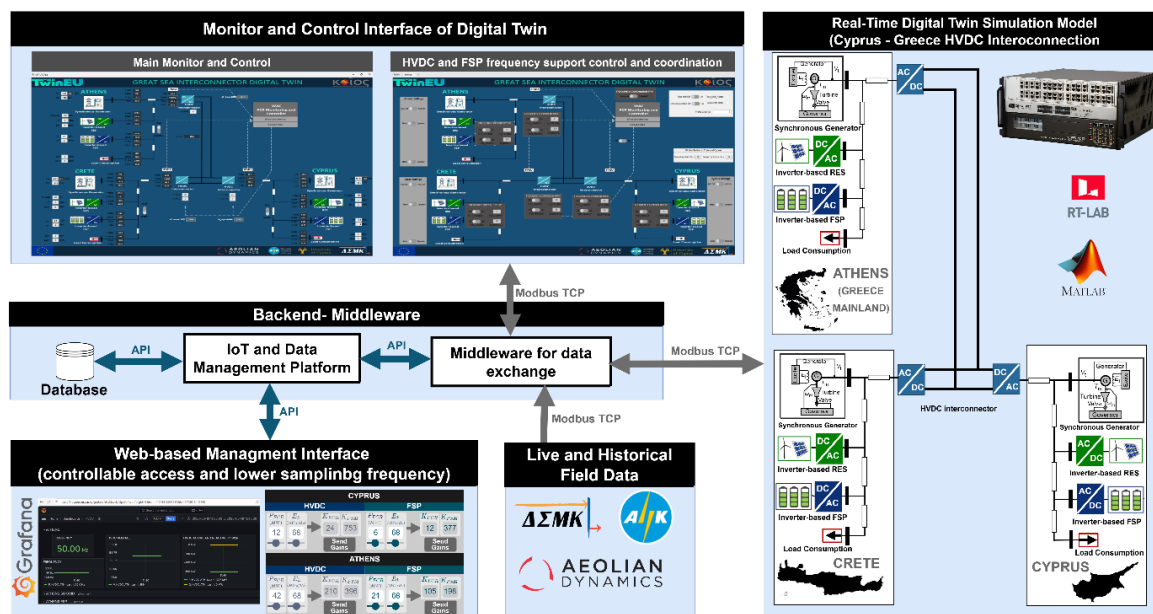


Figure 11: Integrated system of the Digital Twin Implementation in a unified platform including the Real-Time Digital Twin Model (right), Backend and Middleware Layer (center), Monitor and Control Interface (top left), Web-based Management Interface (bottom left), Overall data flow (how information moves between all components).

data services that enable seamless communication among the platform components, including the Database, the Monitoring and Control Interface, the Web-based Management Interface, and other platform services. These standardized APIs enable secure access to operational data across the Digital Twin ecosystem. This architecture ensures reliable data synchronization, secure information exchange, and long-term storage of operational data for subsequent analysis and validation.

The “Web-based Management Interface”, implemented using Grafana, provides browser-based access to real-time and historical operational data. It enables visualization of key performance indicators, monitoring dashboards, and historical trends using lower sampling frequencies than the real-time monitoring interface. Through API services provided by the IoT and Data Management Platform, users can securely access system information without requiring direct interaction with the real-time simulator. It also enables users to configure the coordination unit responsible for providing the FCR and FSM coefficients to the Digital Twin environment, as described in Section 3.2.3.

5 Demonstration and Evaluation

This chapter demonstrates the operation of the developed Digital Twin framework and evaluates the proposed frequency support coordination scheme for the Cyprus-Greece HVDC interconnection use case. First, Section 5.1 presents the integrated Digital Twin operation through the monitoring and control interfaces, highlighting how the user can observe the real-time behaviour of the interconnected systems, initiate disturbances, and configure the available control functions. Then, Section 5.2 focuses on the scenario-based demonstration and evaluation of the frequency support use case, where different operating conditions, scenarios and control schemes are investigated. Finally, Section 5.3 summarizes the evaluation results using the defined KPIs, including frequency nadir, post-disturbance steady-state frequency, and $RoCoF$ and the volume of active power provided for frequency support.

5.1 Demonstration of Digital Twin Operation

The developed Digital Twin framework is implemented as an integrated real-time environment that combines the country-level equivalent power system models, the multi-terminal HVDC interconnection, the inverter-based RES and FSP resources, the communication layer, and the monitoring and control interfaces. The objective of this section is to demonstrate the operational capability of the Digital Twin platform before presenting the detailed scenario-based frequency support evaluation.

Figure 12 demonstrates the monitoring interface of the Digital Twin environment under normal operating conditions. Through this interface, the Digital Twin user can observe the real-time operation of each interconnected power system, namely Athens, Crete, and Cyprus. For each system, the interface provides information on the active and reactive power contribution of the main equivalent components, including the synchronous generator, inverter-based RES, inverter-based FSP/battery resource, and load consumption. In addition, the user can monitor the voltage and frequency

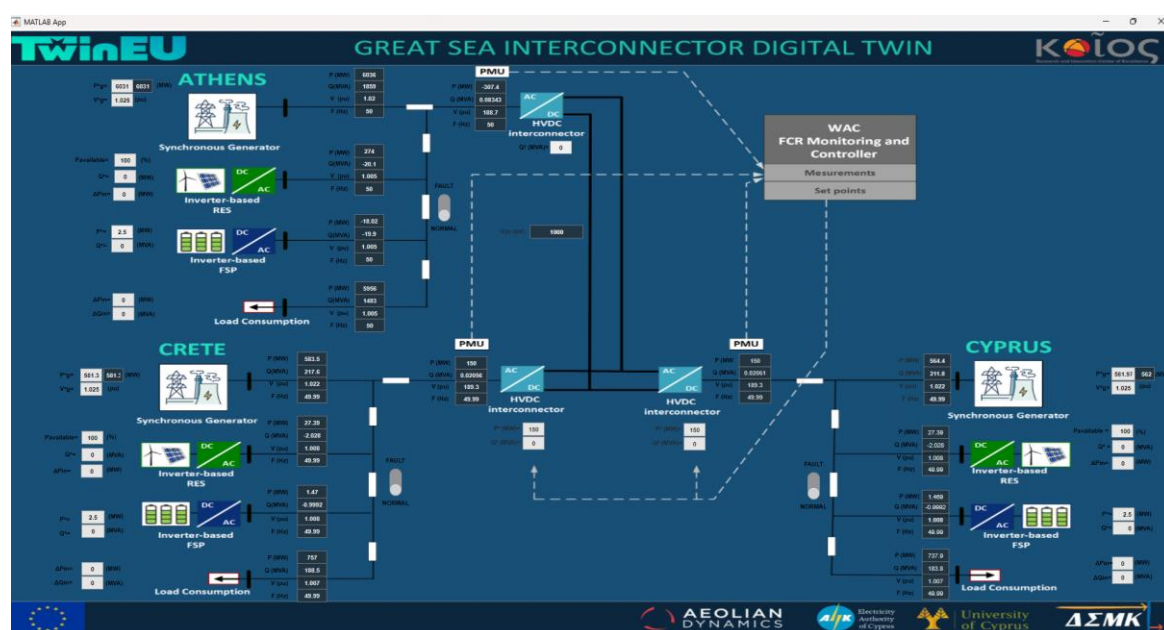


Figure 12: Demonstration of Digital Twin Operation through a dedicated monitoring interface (under normal operating conditions).

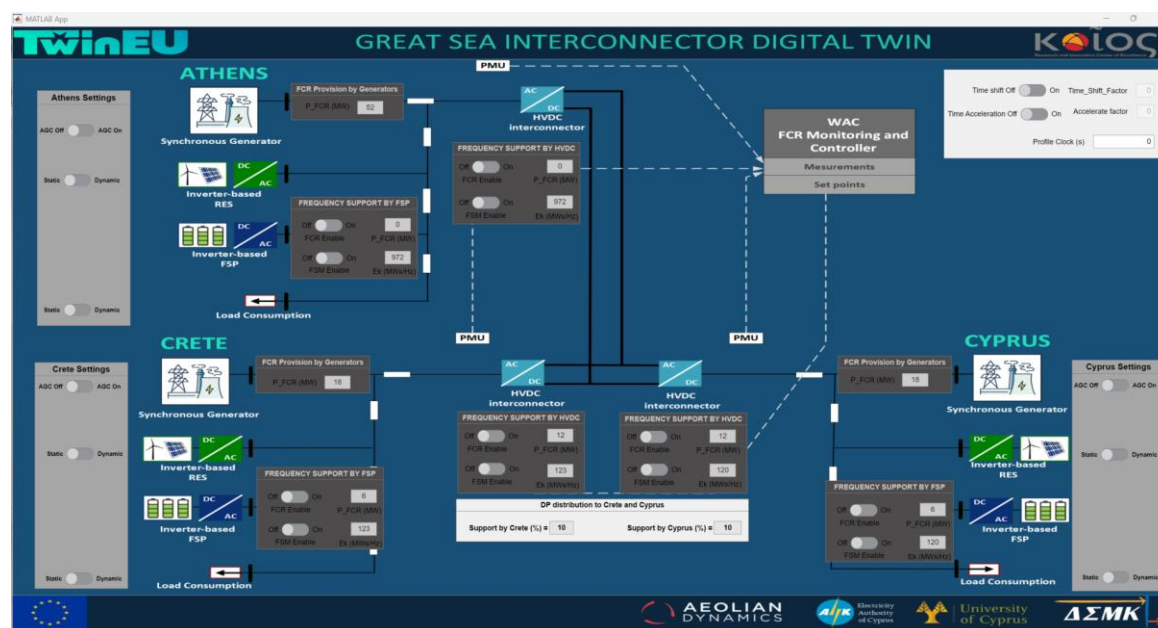


Figure 13: Configuration of Digital Twin Operation through a dedicated control interface.

conditions at each country-level power system, as well as the active power exchange through the HVDC interconnection. This enables the stable operation of the Digital Twin environment to be verified under each examined operating scenario, while also confirming that the aggregated operating conditions of the actual systems are properly replicated within the real-time simulation environment.

The monitoring interface also allows the user to initiate power disturbance events in selected areas of the interconnected system. By introducing controlled disturbances, the user can investigate how the interconnected grids respond under different operating conditions and control configurations. This functionality is essential for evaluating the dynamic behaviour of the HVDC-interconnected systems, the effectiveness of the frequency support mechanisms, and the ability of the proposed coordination framework to limit disturbance propagation across the interconnected grids.

Figure 13 presents the control interface of the Digital Twin environment. Through this interface, the user can activate or deactivate different control functions for each equivalent unit and converter. For example, the user can enable Automatic Generation Control (AGC) for the synchronous generators, activate or deactivate FCR and FSM support in the inverter-based FSP resources and HVDC converters, and configure whether the support intensity is internally defined using fixed gains or externally provided by the FCR-FSM Coordination Unit through a control-HIL approach. In addition, the user can enable or disable the overall FCR-FSM coordination scheme, allowing the comparison between conventional operation, fixed-support operation, and adaptive coordinated frequency support. This FCR-FSM enabling or disabling can be also done automatically by the WAC, depending on the frequency level of each country and the priority between receiving local support or providing support through HVDC transfer.

Figure 14 and Figure 15 demonstrate the monitoring and control interfaces, respectively, of the Digital Twin during an illustrative scenario involving a frequency disturbance in the Cyprus power system. The monitoring interface demonstrates the resulting frequency deviation in Cyprus and the corresponding active-power response, with support provided through the HVDC interconnection from Athens, as well as through power provision from the FSP in Cyprus. This support requires a change in the HVDC power transfer from Greece towards Cyprus, which results in a small frequency deviation in

Athens. The control interface shows the corresponding support requirements of FCR power (P_{FCR}) and kinetic energy (E_k) set internally to calculate the support coefficients k_{FCR} and k_{FSM} , for both HVDC and FSP controllers. The local FCR and FSM support in Crete and Cyprus is enabled and remains available to respond to a potential local disturbance, as in this scenario where Cyprus provided local support. In Athens, the local frequency-support function of the HVDC remains disabled to prevent counteractive control actions that could oppose or partially cancel the HVDC power transfer initiated

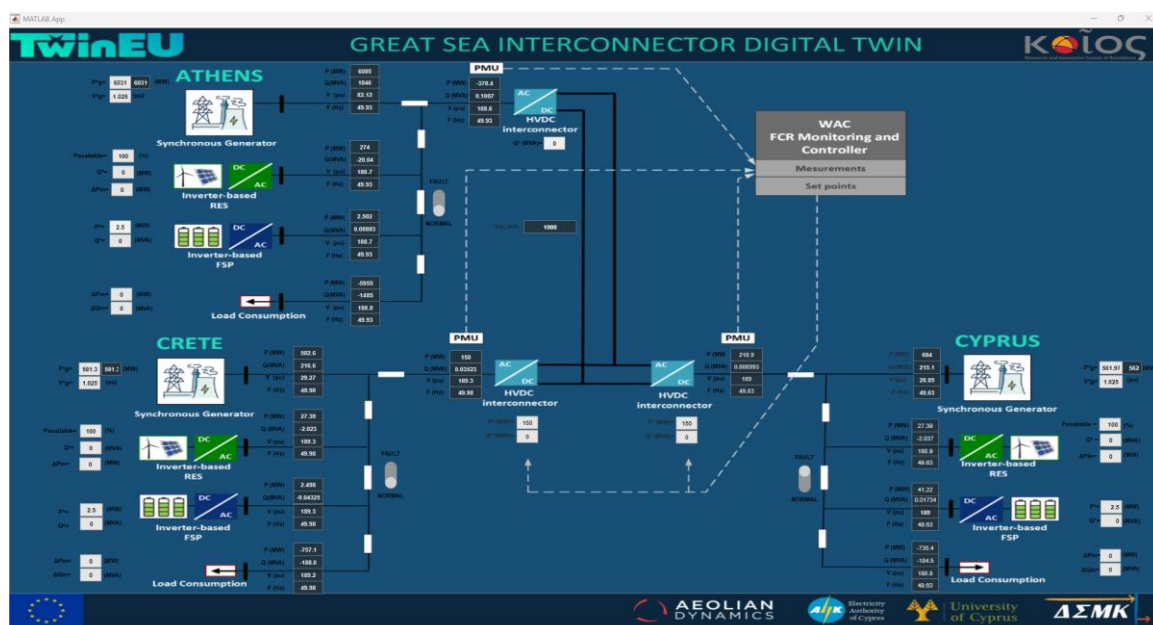


Figure 14: Demonstration of Digital Twin Operation during the scenario of a disturbance in Cyprus, through a dedicated monitoring interface.

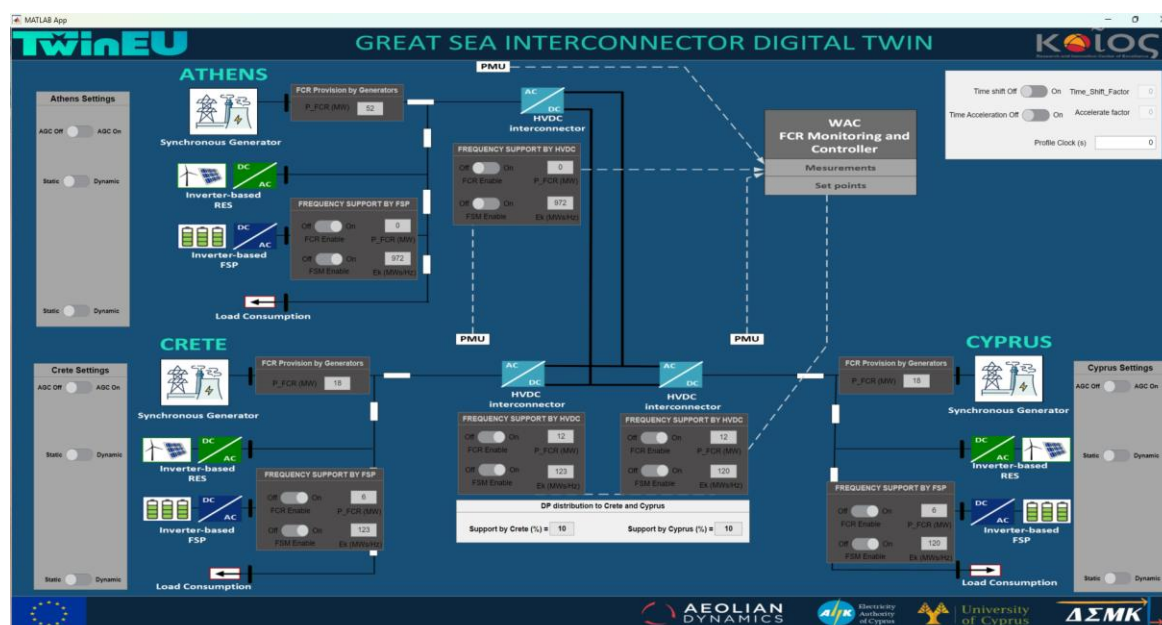


Figure 15: Demonstration of Digital Twin Operation during the scenario of a disturbance in Cyprus, through a dedicated control interface.

to support Cyprus, as explained in Section 3.2.3.

Figure 16 and Figure 17 demonstrate the monitoring and control interfaces of the Digital Twin during an illustrative scenario involving a disturbance in the Athens power system. Figure 16 demonstrates the monitoring interface following the disturbance, where the resulting frequency deviation in Athens is observed together with the signal of the calculated active power demand (i.e., ΔP_{demand}) that is sent to the WAC. At the same time, the WAC requests support from the interconnected systems, with Crete and Cyprus each contributing 10% of the required support through the HVDC interconnections, as indicated by the signal $\Delta P_{support}$. This coordinated response is reflected in the corresponding HVDC active power exchanges and the slight frequency deviations observed in the supporting systems.

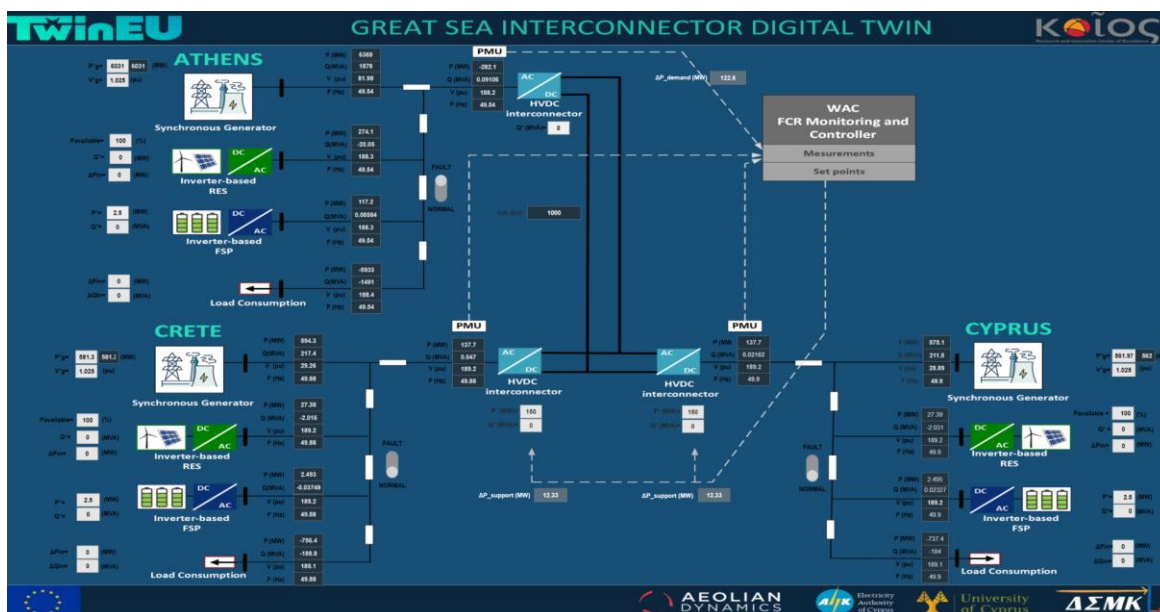


Figure 16: Demonstration of Digital Twin Operation during the scenario of a disturbance in Greece, through a dedicated monitoring interface.

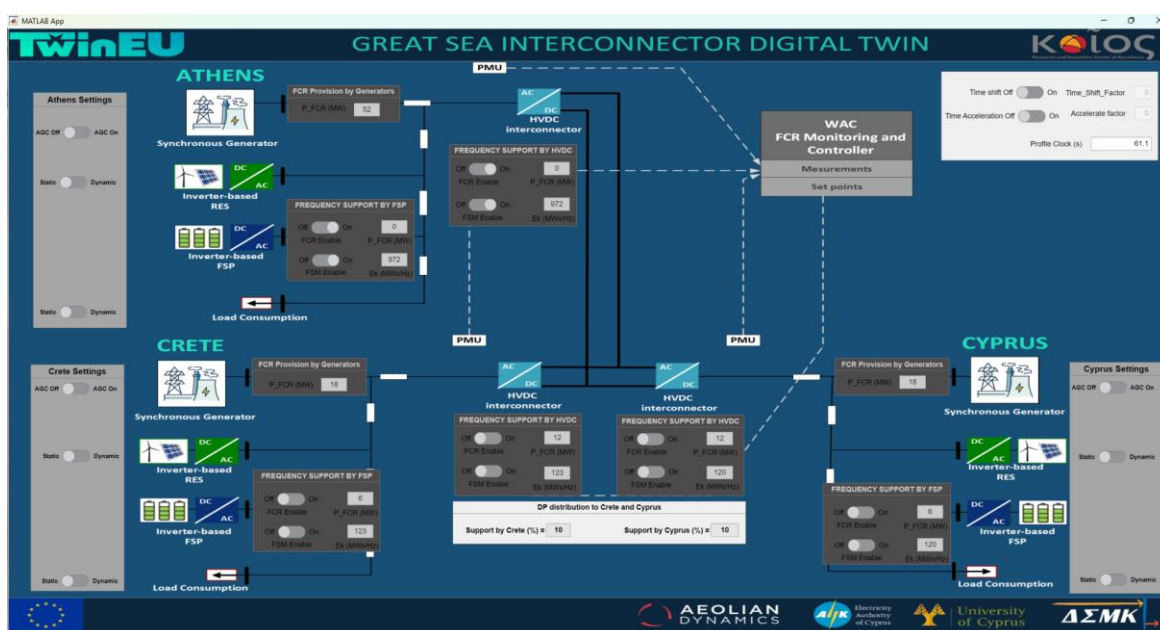


Figure 17: Configuration of Digital Twin Operation during the scenario of a disturbance in Greece, through a dedicated control interface.

Figure 17 presents the corresponding control interface during the same operating condition. The interface shows the activation of the FCR and FSM support functions for the Athens HVDC and FSP controllers, together with the associated requirements of FCR power (P_{FCR}) and kinetic energy (E_k) set internally to calculate the support coefficients k_{FCR} and k_{FSM} . The selected gain k_{limit} of 10% support participation from both Crete and Cyprus is also displayed. The enable switches for local FCR and FSM support in Cyprus and Crete remained deactivated in the HVDC controllers to prevent any counteractive actions as explained in Section 3.2.3.

The scenarios demonstrate how the Digital Twin enables the real-time visualization and configuration of the coordinated frequency support strategy during disturbance conditions and the selectively activated control (manual or automatic) according to the location of the disturbance while the HVDC controllers maintain the required power transfer without interference from conflicting local frequency-control actions.

Overall, the monitoring and control interfaces provide the required interaction layer between the Digital Twin user and the real-time simulation environment. They enable the visualization of system conditions, the configuration of control and coordination schemes, and the initiation of disturbance events in a controlled and repeatable manner. Therefore, the developed Digital Twin can be used not only to observe the operation of the future Cyprus–Greece HVDC interconnection, but also to test and validate alternative control strategies before their implementation in the physical system.

5.2 Scenario-Based Demonstration and Stability Evaluation

To validate the Digital Twin operation and evaluate the proposed frequency support coordination scheme, 11 scenarios were investigated in total under three different power system operating conditions. For each operating condition, different frequency support control schemes were applied and compared.

First, the Cyprus power system was evaluated under normal-inertia operating conditions, where a frequency disturbance was initiated. In the baseline scenario, FCR and FSM coordination were disabled in both the HVDC and FSP inverter controllers, and the entire FCR requirement was supplied by the conventional generator. In the second scenario, the FCR requirement was shared among the generator, HVDC, and FSP resources, while the HVDC and FSP controllers provided a minimum level of FSM support using a droop coefficient fixed at the lower limit of the TSO-defined range. In the third scenario, the shared FCR provision was maintained, but the HVDC and FSP controllers provided adaptive FSM support, with the droop coefficient dynamically adjusted according to the real-time inertia conditions of each system.

The same three control schemes were then evaluated for the Cyprus power system operating under low-inertia conditions. Finally, the disturbance in the Athens power system under normal-inertia conditions was examined using the same three coordinated control schemes, together with two additional scenarios considering uncontrolled HVDC power transfer. These additional scenarios were included to assess the impact of unrestricted cross-border support on both the disturbed system and the supporting interconnected grids. Overall, these scenarios allow the impact of coordinated HVDC and FSP support to be assessed under different system strengths, inertia conditions, frequency disturbance locations, and HVDC transfer-control configurations.

5.2.1 Disturbance in Cyprus - normal inertia conditions

This set of scenarios focuses on the case where the Cyprus power system operates under normal-inertia conditions. In the Digital Twin model, this operating condition is represented by 1000 MVA of committed synchronous generation in the Cyprus power system, providing the corresponding rotating inertia and conventional frequency response capability. The objective of this scenario set is to evaluate how the Cyprus system responds to an intense local power imbalance when different frequency support configurations are applied to the HVDC interconnection and the inverter-based FSP resources.

For this operating condition, the following parameters are provided as inputs to the FCR-FSM Coordination Unit, based on the information exchanged with the Cyprus TSO:

- Total FCR requirement: $P_{FCR,max} = 36\text{MW}$
- FCR activation range (in Cyprus): $49.5\text{ Hz} \leq f \leq 49.95\text{ Hz}$
- Cyprus power system kinetic energy range: $36 \frac{\text{MW}\cdot\text{s}}{\text{Hz}} \leq E_k \leq 144 \frac{\text{MW}\cdot\text{s}}{\text{Hz}}$
- Permitted FSM droop range: $P_n/6 \leq k_{FSM} \leq P_n$
- FSM activation threshold (in Cyprus): $f \leq 49.8\text{Hz}$

For the three scenarios demonstrated in Sections 5.2.1.1-5.2.1.3, the Digital Twin response is examined under the same disturbance event in Cyprus. Specifically, a constant load of 149 MW is connected to the Cyprus power system, creating an active power imbalance and causing a frequency decrease. Using the same disturbance across the three cases enables a direct comparison between baseline operation, fixed FSM support, and adaptive FSM support.

5.2.1.1 Baseline: Deactivated both FCR and FSM

In the baseline scenario, the HVDC and FSP inverter controllers do not participate in frequency support, as both FCR and FSM functionalities are disabled. Therefore, the entire FCR requirement of 36 MW is provided by the conventional generators in Cyprus, while the HVDC interconnection and the FSP battery systems remain inactive with respect to frequency support provision.

The system frequency response, shown in Figure 18(d), exhibits a significant frequency deviation following the disturbance in Cyprus. The frequency decreases rapidly from its nominal value of 50 Hz, reaching a frequency nadir of 48.88 Hz. It then stabilizes around 48.93 Hz until the disturbance is cleared at 30 s, after which it gradually recovers toward the nominal operating point. The frequencies of the other two HVDC-interconnected systems remain close to their nominal values, indicating that, in the absence of HVDC-based frequency support, the disturbance remains mainly localized within the Cyprus power system. Since no frequency-support functionality is enabled in either the HVDC interconnection or the FSP battery systems, the observed response is mainly determined by the conventional generator dynamics and the available FCR contribution in Cyprus.

This behaviour is confirmed by the active power trajectories presented in Figure 18(a) and Figure 18(b). The HVDC converters maintain essentially constant power transfers throughout the event, remaining close to their pre-disturbance operating points and not any frequency-recovery response is observed. Similarly, the FSP battery systems do not provide any sustained active power injection or absorption to contribute to frequency regulation. Only minor transient oscillations associated with converter dynamics are observed in the HVDC and FSP responses during the transient stage of the disturbance.

Consequently, the burden of balancing the disturbance falls entirely on the generator-based FCR deployed in Cyprus, as shown in Figure 18(c). Following the frequency drop, the generator output increases from approximately 563 MW, prior to the disturbance, to 707 MW, covering the full 36 MW of allocated FCR while providing an additional 108 MW to compensate for the disturbance-induced power imbalance. This prevents a further frequency decline and establishes a new power balance point. However, it is insufficient to restore the system frequency to its nominal value. Consequently, the frequency remains below 50 Hz throughout the disturbance period.

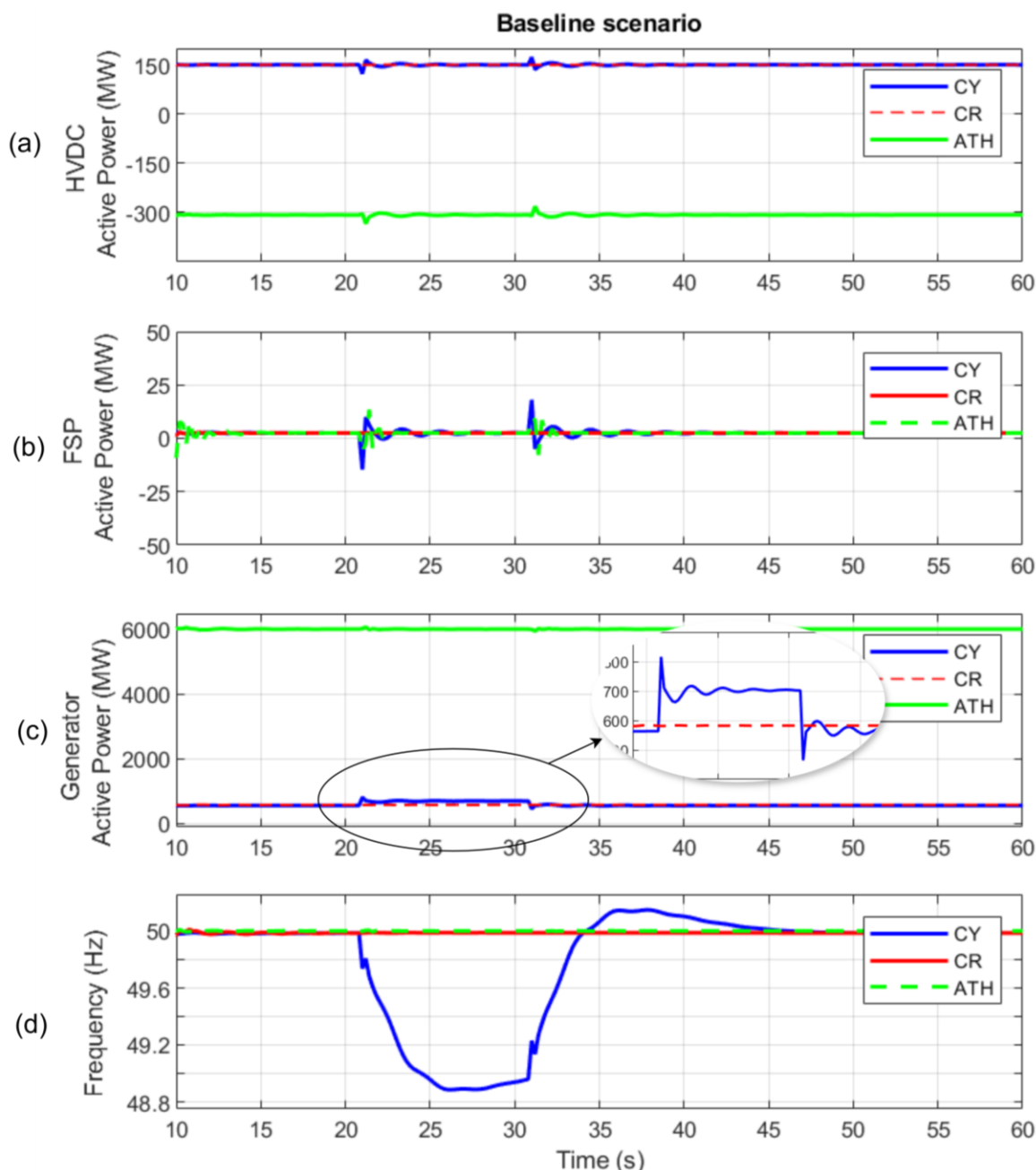


Figure 18: Baseline Scenario for Disturbance in Cyprus with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

Overall, the baseline scenario highlights the dependence of the Cyprus power system on conventional generation for frequency control when no support is provided by the HVDC or distributed battery-based resources. The results demonstrate the potential benefit that fast-acting converter-based resources could provide in improving frequency stability and reducing the depth of the frequency nadir and post-disturbance steady-state frequency during disturbances.

5.2.1.2 Fixed support: Shared FCR and fixed FSM

In this scenario, the same disturbance is applied in Cyprus between 20 s and 30 s. However, the required 36 MW of FCR is now shared between the Cyprus generator (18 MW), the FSP battery (6 MW) and the HVDC converter (12 MW), following the market clearing results. In addition, the HVDC and FSP controllers are equipped with FSM functionality operating with a fixed FSM coefficient of $\frac{P_n}{6} \text{ MW/Hz}$, which corresponds to the minimum support permitted by the Cyprus TSO grid-code requirements, where P_n denotes the rated power of the corresponding converter. Therefore, the HVDC uses a droop coefficient of 166.67 MW/Hz, and the FSP 83.33 MW/Hz.

The frequency response for the FCR and fixed FSM support scenario is shown in Figure 19(d). The frequency response demonstrates a substantial improvement compared with the baseline scenario. Following the disturbance at 20 s, the system frequency decreases but reaches a nadir of only approximately 49.43 Hz, and later stabilizes at approximately 49.49 Hz. The reduced frequency deviation is a direct consequence of the fast active-power response delivered by the converter-interfaced resources, and especially due to the FSM support provision.

The active-power plots shown in Figure 19(a) and Figure 19(b), confirm the coordinated response of the different resources. Immediately after the disturbance, and while the system frequency remains above the FSM activation threshold of 49.8 Hz, the HVDC and FSP converters are gradually providing only their allocated FCR contributions, proportionally to the frequency deviation. As the system frequency falls below 49.8 Hz, the FSM controller is activated, and the converters rapidly increase their output, due to the higher FSM droop constant compared to FCR. The FSP battery reaches approximately 34 MW, while the HVDC converter connected to Cyprus reaches 215 MW, providing an additional active power transfer of approximately 65 MW beyond its pre-disturbance operating point, for FCR and FSM support. These responses are significantly larger than the allocated FCR shares alone, indicating the additional contribution provided through FSM operation. The HVDC power import is also shown in the active power of the Athens HVDC in Figure 19(a), which increases the exported power by the required amount from Cyprus. Due to the high inertia of Athens power system, this power transfer does not actually affect the frequency stability of the country, as only a negligible frequency deviation is observed.

In contrast, the Cyprus generator exhibits only a modest increase of around 52 MW in output power, which compensates the remaining power imbalance, as presented in Figure 19(c). Throughout the disturbance period, the combined support from the HVDC converter and FSP battery compensates for a significant portion of the power imbalance, thereby limiting the frequency drop and improving overall frequency stability.

Overall, this scenario demonstrates the effectiveness of coordinated HVDC and battery-based FSM support in enhancing frequency containment performance. Even with the minimum FSM droop setting, the fast converter response substantially reduces the frequency nadir depth and the steady-state frequency and decreases the reliance on conventional generator reserves compared with the baseline scenario.

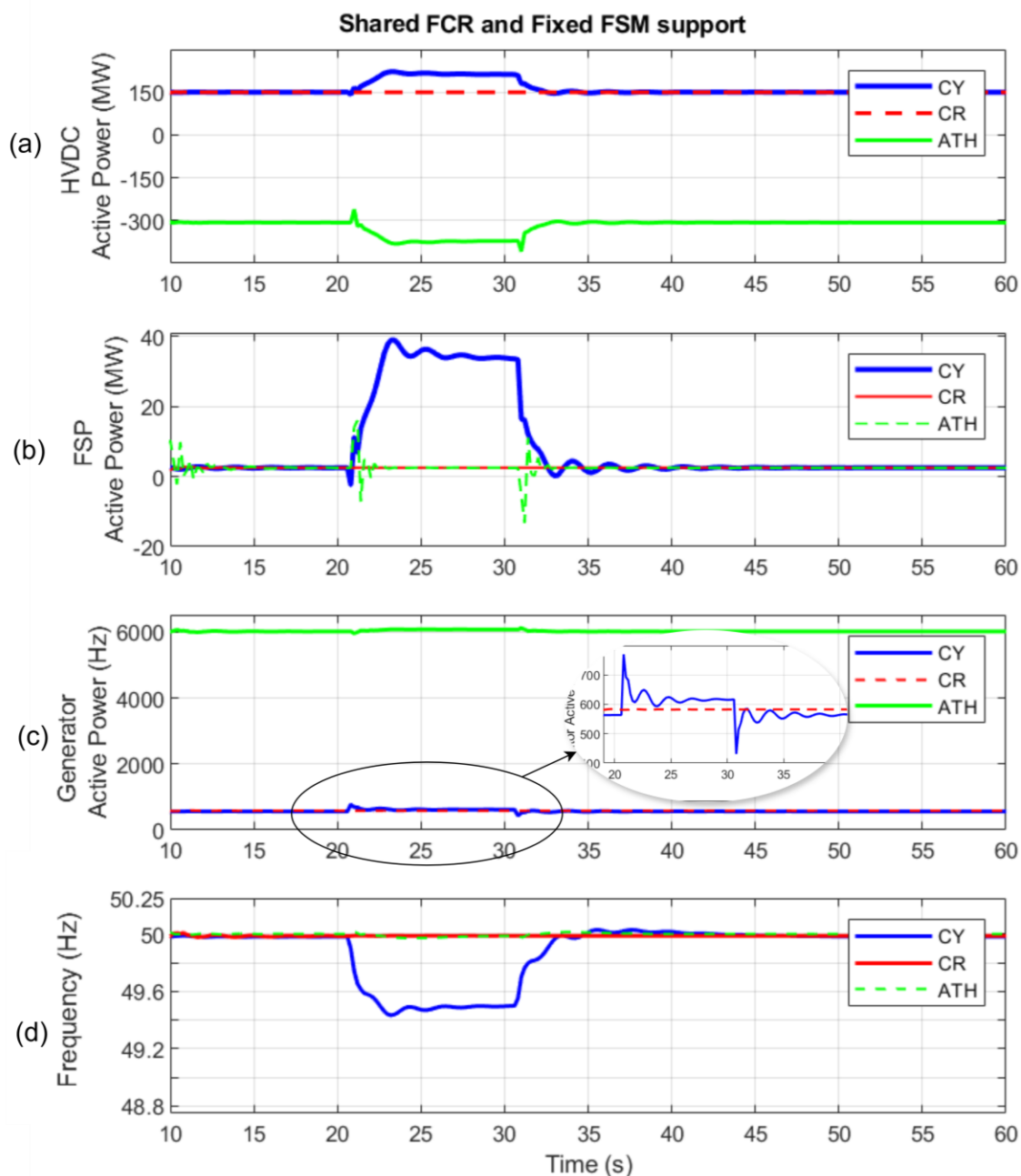


Figure 19: Shared FCR and Fixed FSM support scenario for Disturbance in Cyprus with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

5.2.1.3 Coordinated support: Shared FCR and Adaptive FSM

As in the previous case, the disturbance is applied in Cyprus between 20 s and 30 s, and the 36 MW FCR requirement is similarly shared. The key difference is that the FSM droop coefficient is no longer fixed at the minimum value corresponding to a high-inertia system. Instead, it is calculated dynamically according to the real-time kinetic energy of the Cyprus power system, which is determined by the inertia characteristics of the 1000 MVA committed synchronous generation

considered in this operating condition, as explained in Section 3.2.3. This enables the converter-interfaced resources to adapt their frequency support according to the actual system strength.

Since the system operates under normal-inertia conditions, the inertia characteristics of the 1000 MVA committed synchronous generation result in a real-time kinetic energy of 120 MW·s/Hz, calculated using (4). Based on this operating condition, the FSM droop constant is adaptively set to 351.85 MW/Hz according to (5).

The frequency response for the FCR and adaptive FSM support scenario is shown in Figure 19(d), which demonstrates a further improvement in frequency containment performance. Following the disturbance at 20 s, the frequency in Cyprus declines to a nadir of approximately 49.56 Hz, which is noticeably higher than the nadir obtained with the fixed FSM setting, and then stabilizes around

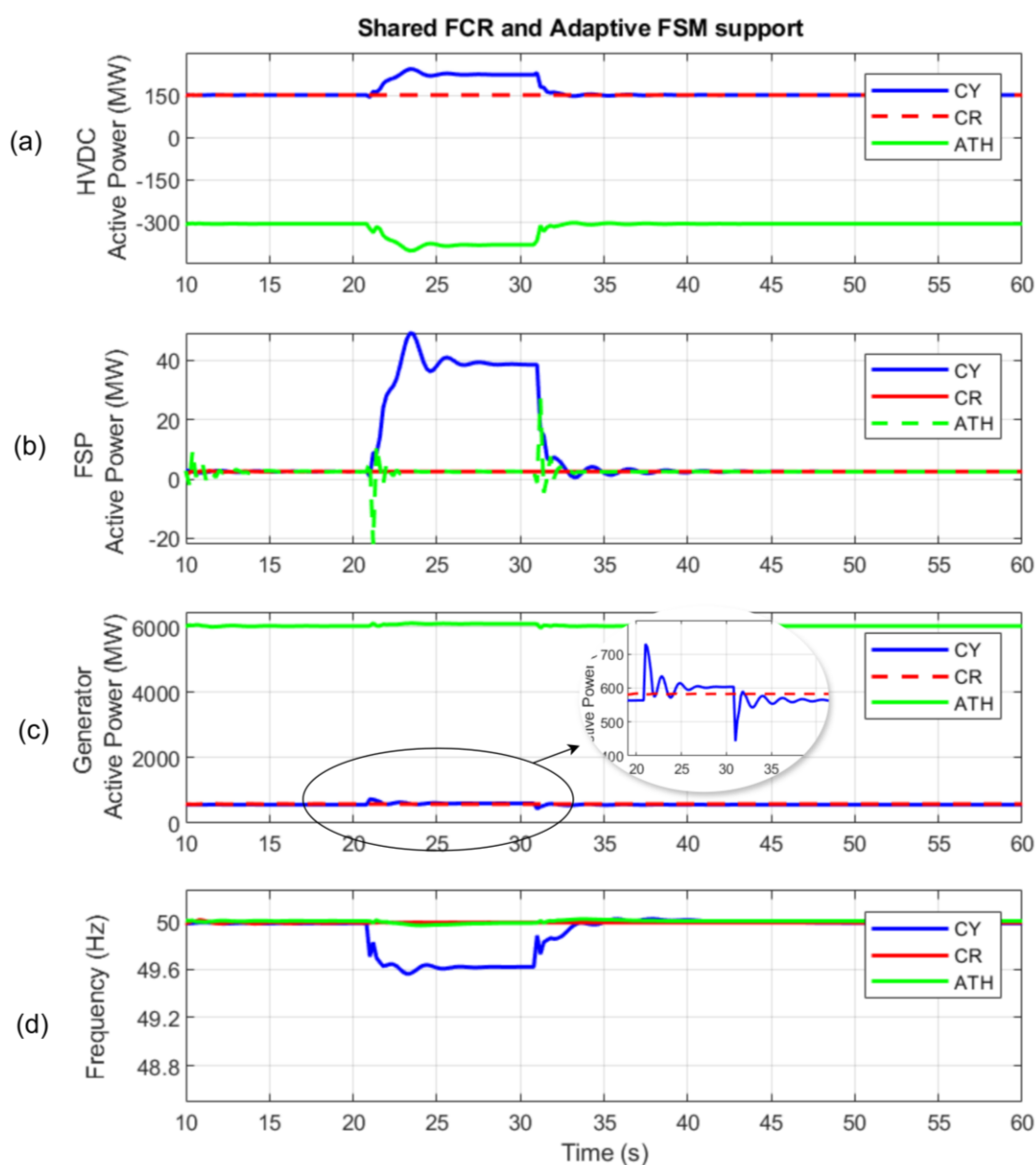


Figure 20: Shared FCR and Adaptive FSM support scenario for Disturbance in Cyprus with normal inertia conditions. . For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

49.62 Hz. The adaptive droop calculation therefore provides a more effective frequency response by recognising the available system kinetic energy and increasing the support delivered by the HVDC converter and FSP battery accordingly.

This behaviour is reflected in the active-power responses shown in Figure 19(a) and Figure 19(b). Both the HVDC converter and the FSP battery deliver larger amount of power during the disturbance period compared with the fixed-droop scenario. The FSP output increases to approximately 39 MW, while the HVDC power transfer to Cyprus rises by approximately 72 MW above its pre-disturbance operating point, which is also reflected in the Athens HVDC power export. Again, due to the higher inertia of Athens power system, the local frequency is negligibly affected. These fast converter-based responses provide the majority of the frequency support immediately after the disturbance, reducing the rate of frequency decline and limiting the depth of the frequency nadir and steady-state deviation. According to Figure 19(c), the increased converter contribution reduces the frequency disturbance and the dependence on conventional generation for frequency containment, as the generator contribution is now only around 40MW.

Overall, the above three scenarios demonstrate the effectiveness of combining market-based FCR allocation with FSM support from the HVDC interconnection and battery-based FSPs. Even with the minimum FSM droop specified by the Cyprus TSO grid code, the frequency nadir and the post-disturbance steady-state frequency are significantly improved, while the reliance on conventional generation compared is significantly reduced, compared to the baseline scenario. The adaptive FSM strategy provides the best frequency performance among the investigated cases. The HVDC and battery resources deliver a more appropriate and effective frequency response, resulting in a better frequency nadir and lower steady-state deviation from the nominal frequency compared with both the baseline and fixed-FSM scenarios. Furthermore, the coordinated HVDC power transfer enables frequency support to be shared between the interconnected systems, illustrating the benefits of regional frequency support coordination.

5.2.2 Disturbance in Cyprus - low inertia conditions

This set of scenarios focuses on the case where the Cyprus power system operates under low-inertia conditions. Compared with the normal-inertia operating condition examined in Section 5.2.1, where 1000 MVA of synchronous generation was committed, the low-inertia condition is represented in the Digital Twin model by only 450 MVA of committed synchronous generation in the Cyprus power system. This reduced synchronous generation commitment results in lower available rotating inertia and therefore makes the system more sensitive to active-power imbalances and frequency disturbances.

For this operating condition, the same FCR and FSM coordination framework is applied, using the TSO-defined FCR requirement, FCR activation limits, FSM activation threshold, and admissible FSM droop range. However, the lower committed synchronous generation capacity leads to a reduced real-time kinetic energy value, which is used by the adaptive FSM scheme to increase the support intensity of the HVDC and FSP inverter controllers according to the actual system strength.

For the three scenarios demonstrated in Sections 5.2.2.1-5.2.2.3, the Digital Twin response is examined under the same disturbance event in Cyprus. Specifically, a power disturbance of 69.35 MW is imposed to the Cyprus power system at 20 s, creating an active-power imbalance and initiating a frequency drop. Although the disturbance magnitude is lower than the 149 MW event examined under normal-inertia conditions, the reduced inertia of the system makes the frequency response

more critical and allows the impact of coordinated HVDC and FSP support under low-inertia operation to be assessed.

5.2.2.1 Baseline: Deactivated both FCR and FSM

For this baseline scenario, a disturbance is initiated in Cyprus power system, and the entire FCR requirement or 36 MW is set to be provided by the conventional generation, as the HVDC and FSP converters deactivated their FCR services and FSM support.

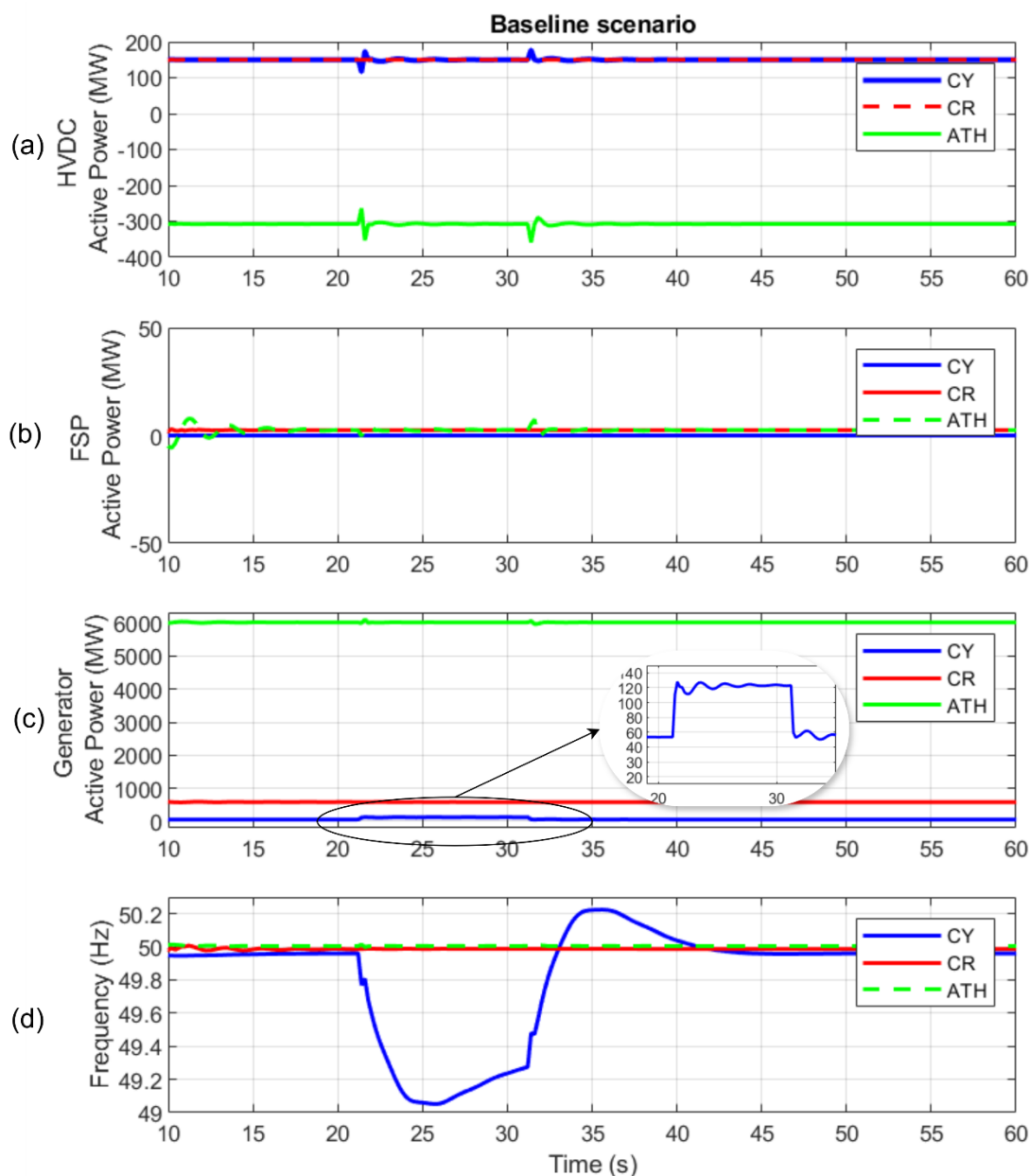


Figure 21: Baseline scenario for Disturbance in Cyprus with low inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

The frequency response of the Cyprus power system is presented in Figure 21 (a). Due to the reduced amount of available synchronous generation, the system exhibits a higher rate of change of frequency (RoCoF) and a lower frequency nadir following the disturbance compared to the normal-

inertia operating condition. As the conventional generators provide the entire frequency containment response, the resulting frequency nadir is 49.05 Hz and the settling frequency around 49.19 Hz. Due to the low inertia of the power system, the frequency does not completely settle during the 10 s of disturbance. The frequencies of Athens and Crete remain close to their nominal values as there is not any cross-border HVDC power transfer. After the disturbance is cleared at 30 s, the frequency gradually returns towards the nominal value of 50 Hz.

Figure 21(a) and Figure 21(b) illustrate the active power transfer of the HVDC interconnection and the active power injection of the FSP controllers, respectively. In the baseline scenario, the HVDC converters maintain their pre-disturbance power transfer throughout the event, indicating that no frequency support is provided. Similarly, the FSP battery systems remain inactive. Consequently, the conventional generators in the Cyprus power system supply the entire frequency containment response, as shown in Figure 21(c). Following the disturbance, the generator output increases the injection by approximately 70 MW, compensating for the active power imbalance and restoring the system to a new steady-state operating condition.

Overall, the baseline scenario highlights that low-inertia systems present an even higher need for fast-acting converter-based resources to improve frequency stability, the frequency nadir and post-disturbance steady-state frequency during disturbances.

5.2.2.2 Fixed support: Fixed FCR and FSM

The same disturbance (69.35 MW) is applied to the Cyprus power system between 20 s and 30 s, and similarly to the scenario in Section 5.2.1.2, the required FCR is shared in this scenario. The HVDC converters and FSPs participate in FSM using a fixed droop coefficient corresponding to the minimum support level specified by the Cyprus grid regulations.

The corresponding frequency response is presented in Figure 22(d). Compared to the baseline scenario, the coordinated frequency support significantly improves the system response, with the frequency reaching a minimum value of approximately 49.51 Hz, after presenting some oscillations due to the sensitivity of the low-inertia system, and then stabilizes around 49.65 Hz.

Figure 22(a) and Figure 22(b) present the power plots of HVDC terminals and FSP converters, respectively. After the disturbance and as long as the frequency is still higher than 49.8 Hz, the HVDC and the FSP converters are increasing their output, proportionally to the frequency deviation, to provide the FCR power that were allocated. By the time the frequency falls below 49.8 Hz, the FSM is also activated and the converters are significantly increasing their output due to the additional FSM support. The HVDC converter of Cyprus increases its import from 150 MW to 183 MW, providing around 33 MW for both FCR and FSM support, and similarly the FSP converter reaches approximately 17 MW. The active power of Athens HVDC increases the export to provide Cyprus the demanded power, showing the cross-border power transfer for frequency support. In contrast, the Cyprus generator exhibits only a modest increase of around 22 MW in output power, as presented in Figure 22(c), which is slightly higher than its assigned FCR contribution, to cover the remaining power imbalance. This confirms the importance of the contribution in frequency support by the HVDC power transfer and the FSP power injection.

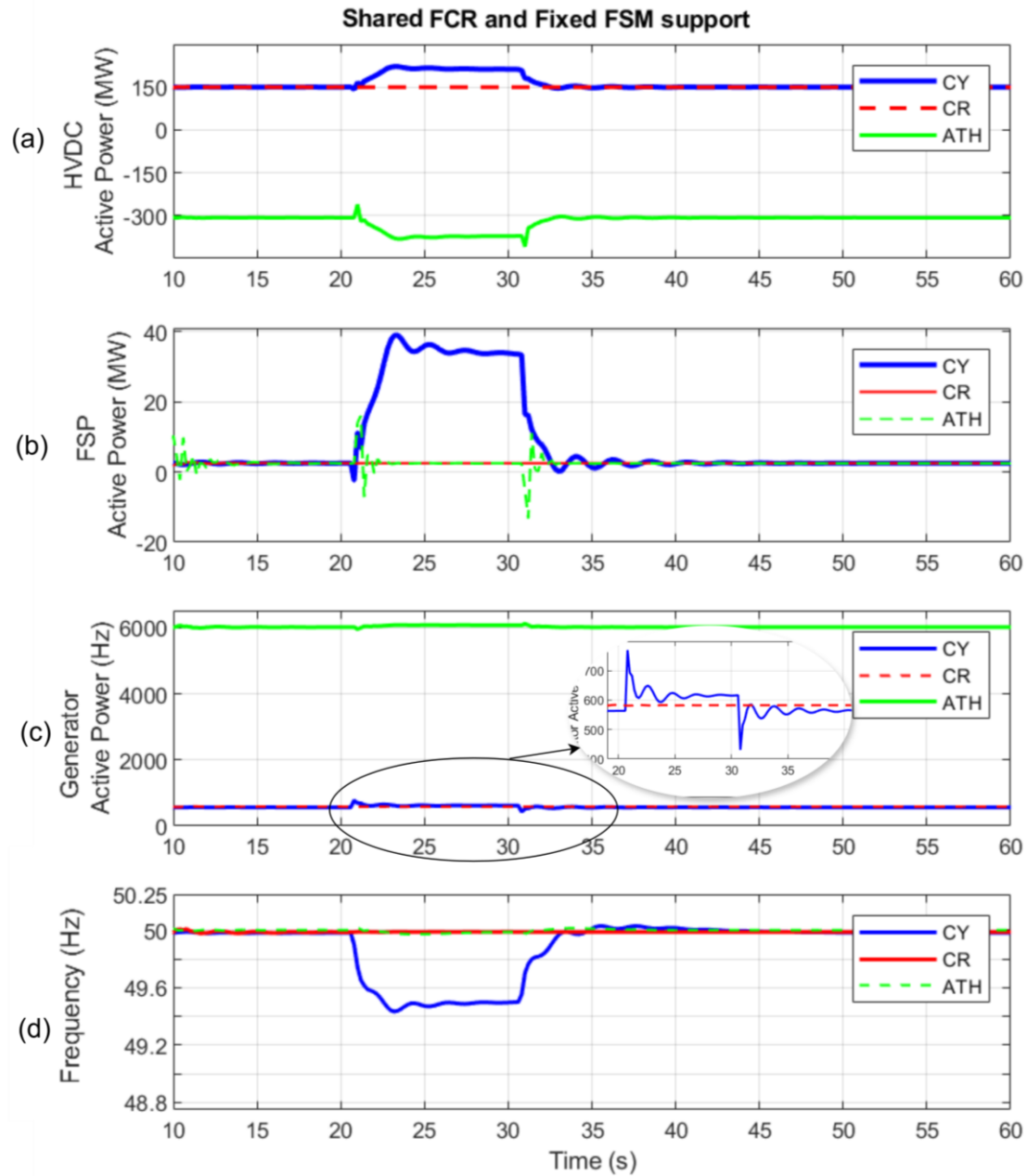


Figure 22: Shared FCR and Fixed FSM support scenario for Disturbance in Cyprus with low inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power, (d) systems' frequencies.

5.2.2.3 Coordinated support: Adaptive FCR and FSM

For the last scenario of Cyprus under low-inertia, the same disturbance (69.35 MW) is applied in between 20 s and 30 s, and the sharing of the 36 MW FCR requirement is kept as the previous scenario. The difference is that instead of a fixed FSM droop coefficient at the higher limit of the range, the system's low inertia is considered, and the droop coefficient is adapted according to equation (5).

Figure 23(d) shows the frequency response of each country. The frequency measured in the low-inertia Cyprus power system demonstrates a nadir of approximately 49.53 Hz and a settling

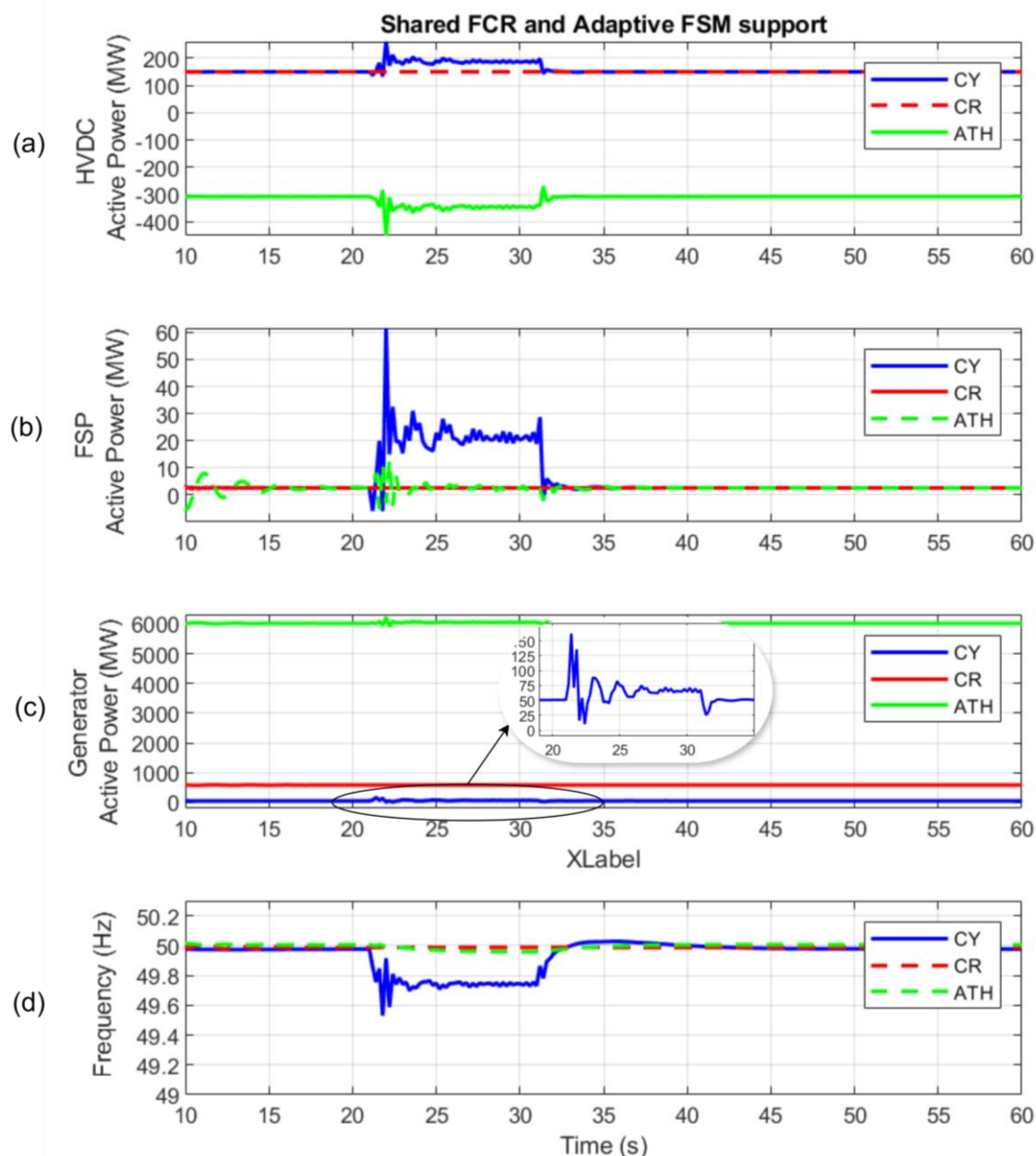


Figure 23: Shared FCR and Adaptive FSM support scenario for Disturbance in Cyprus with low inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power, (d) systems' frequencies.

frequency of 49.76 Hz, which shows the overall improvement compared to the fixed FSM droop in the previous scenario.

Figure 23(a) and (b) reflect the behaviour of the HVDC interconnections and the FSP controllers, respectively. During the disturbance period, both the HVDC and the FSP converters deliver larger active power compared with the fixed-droop scenario. The Cyprus HVDC power rises by approximately 40 MW above its pre-disturbance power level, while the FSP output increases to approximately 19.5 MW. This increased contribution by the HVDC and FSP converter reduces the dependence on conventional generation for support, as confirmed by the response of conventional generator of

Cyprus shown in Figure 23(c). The contribution of conventional generation is now only around 16.5 MW.

Among the investigated cases, the adaptive FSM strategy provides again the best frequency performance. As the HVDC and FSP converters provide a more intense response, leading to a better significantly frequency nadir and smaller frequency steady-state deviation after the disturbance.

5.2.3 Disturbance in Greece

This set of scenarios focuses on the case where a frequency disturbance occurs in the mainland Greece power system, represented by the Athens equivalent system in the Digital Twin model. Compared with the Cyprus cases examined in Sections 5.2.1 and 5.2.2, the Athens system represents a stronger and higher-inertia power system, with a larger committed synchronous generation capacity (8100 MVA) and therefore a slower frequency response following active-power imbalances. The objective of this scenario set is to evaluate how the HVDC interconnection can support a disturbance in the stronger system, while also assessing the impact of this support on the weaker interconnected systems of Crete and Cyprus.

For this operating condition, the following parameters are provided as inputs to the FCR-FSM Coordination Unit, based on the information exchanged with the Greece TSO:

- Total FCR requirement: $P_{FCR,max} = 52\text{MW}$
- FCR activation range (in Greece): $49.8\text{ Hz} \leq f \leq 49.98\text{ Hz}$
- Greece power system kinetic energy range: $240 \leq \frac{\text{MW}\cdot\text{s}}{\text{Hz}} \leq E_k \leq 1440 \frac{\text{MW}\cdot\text{s}}{\text{Hz}}$
- Permitted FSM droop range: $0.4P_n \leq k_{FSM} \leq 10P_n$
- FSM activation threshold (in Greece): $f \leq 49.8\text{Hz}$

For the scenarios demonstrated in Sections 5.2.3.1-5.2.3.4, the Digital Twin response is examined under the same disturbance event in Athens. Specifically, an intense power disturbance of 514 MW is imposed to the Athens power system, creating an active-power imbalance and causing a frequency decrease. The first three scenarios compare baseline operation, fixed FSM support, and adaptive FSM support under coordinated HVDC operation, while the fourth scenario examines the effect of uncontrolled HVDC power transfer. This additional case is included to assess how unrestricted cross-border support from weaker systems may affect their own frequency stability while supporting the disturbed higher-inertia system.

For the coordinated HVDC support scenarios, an operational transfer limit is applied to the HVDC terminals of Cyprus and Crete to avoid excessive disturbance propagation from the disturbed Athens system to the weaker interconnected systems. Specifically, each supporting HVDC terminal is allowed to contribute up to 10% of the requested HVDC frequency-support power. This constraint is applied in both the fixed FSM and adaptive FSM scenarios, enabling cross-border support to Athens while limiting the impact on the frequency stability of Cyprus and Crete.

5.2.3.1 Baseline: Deactivated both FCR and FSM

In the baseline scenario, the HVDC and FSP inverter controllers do not participate in frequency support, as both FCR and FSM functionalities are disabled. Therefore, the entire FCR requirement of 52 MW is provided by the conventional generators in the Athens system, while the HVDC

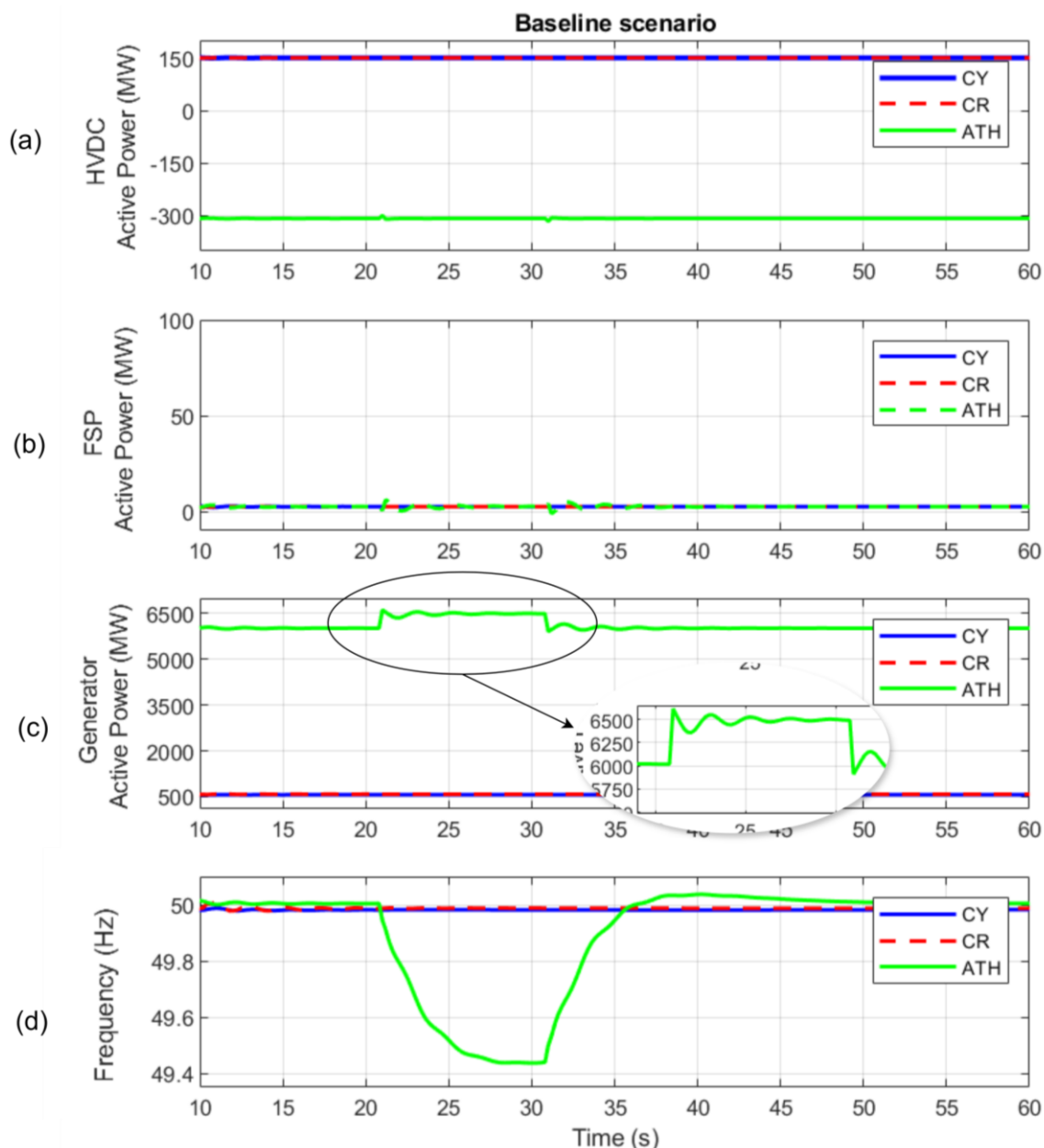


Figure 24: Baseline scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

interconnection and the FSP battery systems remain inactive with respect to frequency support provision.

The system frequency response shown in Figure 24(d) exhibits a significant frequency deviation following the disturbance. The frequency in Athens decreases, with a relatively low *RoCof*, from its nominal value of 50 Hz, reaching a nadir of approximately 49.44 Hz, and remaining around that level during steady-state post disturbance. The frequencies of Crete and Cyprus remain close to their nominal values, since the HVDC support is deactivated in this scenario and the disturbance is not propagated to the interconnected systems. After the disturbance is cleared at 30 s, the frequency gradually returns towards the nominal operating point. The lower *RoCof* comparing to the previous scenarios in Cyprus, confirms the difference in the frequency response of a high-inertia power system

like mainland Greece. This behaviour is confirmed by the active power responses shown in Figure 24(a) and Figure 24(b). The HVDC converters maintain their active power transfers throughout the disturbance, and no sustained frequency-support action is observed. Likewise, the FSP battery systems remained inactive to any frequency provision.

Consequently, the conventional generators in Athens provide the entire frequency containment response, as illustrated in Figure 24(c). Following the disturbance, the generator output increases significantly from 6020 MW pre-disturbance operating point to 6500 MW, to compensate for the active power imbalance and establish a new operating equilibrium.

Overall, the baseline scenario demonstrates the dependence of the interconnected system on conventional generation for frequency control when HVDC and battery-based frequency support are unavailable. The results highlight the potential benefits of converter-based frequency support for improving system frequency stability following large disturbances.

5.2.3.2 Fixed support: Fixed FCR and FSM

In this scenario, the same disturbance (514 MW) is applied in Athens between 20 s and 30 s. The total required FCR power is 52 MW, and it is shared between the conventional generators (24 MW), the HVDC interconnection (18 MW), and the participating FSP battery systems (10 MW) according to the market-clearing results. In addition, the HVDC converters and FSPs provide FSM support using a fixed droop coefficient corresponding to the minimum support level defined by the grid-code requirements for Greece. Therefore, the HVDC link (with 1000 MVA capacity) and FSP resources (with 1000 MVA capacity) of Greece Mainland (Athens) power system provide FSM support, both with a fixed coefficient of $k_{FSM} = 400 \text{ MW/Hz}$, according to the minimum FSM support gain required by the grid codes in Greece. As defined in the common scenario settings, the HVDC support from Cyprus and Crete is constrained by the 10% contribution limit to avoid excessive disturbance propagation toward the weaker supporting systems.

The corresponding frequency response is presented in Figure 25(d). Compared with the baseline scenario, the frequency deviation is slightly improved, with the Athens frequency reaching a nadir of approximately 49.53 Hz, and remaining constant during post-disturbance steady-state. Cyprus and Crete also experience small frequency deviations due to the coordinated power transfer limit applied at the cross-border support through the HVDC interconnection, with frequency in Cyprus stabilizing around 49.87 Hz.

The active power responses shown in Figure 25(a) and Figure 25(b) confirm the coordinated contribution of the HVDC and FSP converters. Prior to the disturbance, the Athens HVDC terminal exports 300 MW, equally distributed between the Cyprus and Crete terminals (150 MW each). Following the frequency disturbance in Athens, the local HVDC controller calculates the required FCR and FSM support and sends the corresponding request to the WAC. The WAC then coordinates with the HVDC terminals in Cyprus and Crete, instructing them to equally reduce their imported power. According to the applied 10% contribution limit, the HVDC terminals of Cyprus and Crete provide only a constrained share of the requested support to Athens. Consequently, the active power transfer from Athens decreases by approximately 26 MW, effectively reducing the loading of the Athens power system, as shown in Figure 25(a). From the perspective of the Athens grid, this reduction in exports acts as an immediate frequency support mechanism, enabling more generation to remain available locally. Therefore, the HVDC power transfer (export) from Athens is reduced to support local frequency, initially according to the allocated FCR capacity. Once the system frequency falls below the FSM activation threshold of 49.8 MW, the fixed FSM controller provides an additional reduction in

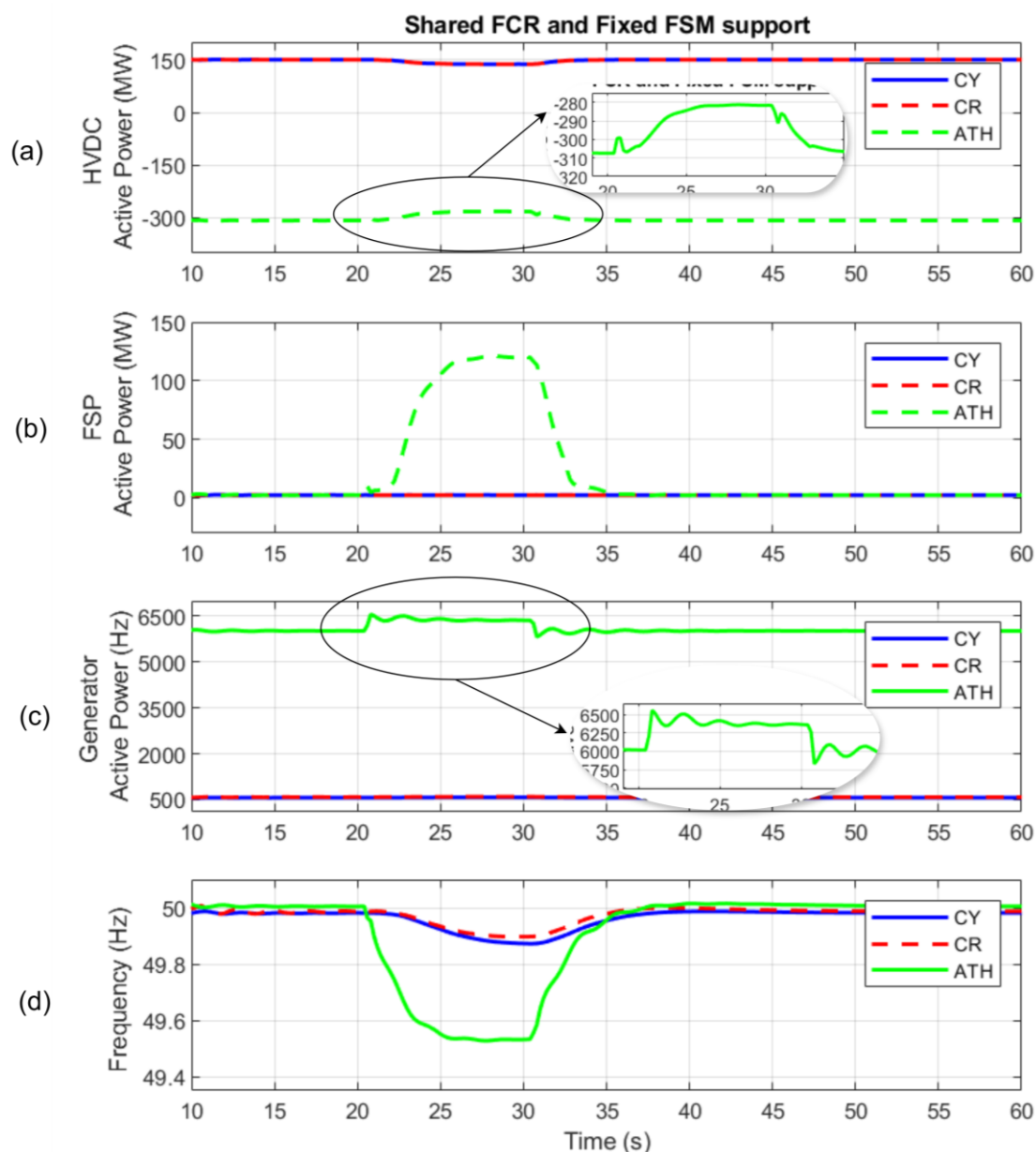


Figure 25: Shared FCR and Fixed FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

the HVDC transfer, further supporting the frequency recovery. The FSP battery response in Figure 25(b) shows an increase of approximately 120 MW, contributing directly to the frequency support.

According to Figure 25(c), the generator initially outputs approximately 500 MW above the pre-disturbance power, then this contribution is reduced to 336 MW. This happens due to the FSM activation threshold which is at 49.8 Hz. Before this threshold is exceeded, the HVDC converter and FSP battery provide only an amount of their allocated FCR contributions, proportional to the frequency deviation. As a result, the conventional generator provides the majority of the frequency response to restore the power imbalance, significantly exceeding its allocated 24 MW FCR contribution. Once the frequency falls below 49.8 Hz, the FSM functionality of the HVDC and FSP is activated, and both

converters increase their active power output beyond the allocated FCR values, reducing the generator contribution from 500 MW to around 336 MW.

5.2.3.3 Coordinated support: Adaptive FCR and FSM

In this scenario, the same disturbance (514 MW) is applied in Athens between 20 s and 30 s, and the FCR sharing allocation remains the same with the previous scenario. However, the FSM droop coefficient is not fixed at the minimum value specified by the grid code but is continuously adapted according to the estimated real-time kinetic energy of the interconnected power system. The same 10% HVDC contribution limit from Cyprus and Crete is also applied in this scenario to restrict disturbance propagation while allowing coordinated cross-border support to Athens.

For the examined system-level operating condition, the real-time kinetic energy of the mainland Greece power system is $E_{k-rt} = 972 \text{ MW}\cdot\text{s}/\text{Hz}$, as calculated by the TSO using (4). Based on this value and the FSM droop range provided by the Greece TSO, the adaptive FSM droop coefficient is calculated using (5) as $k_{FSM-rt} = 4144 \text{ MW}/\text{Hz}$ applied for both HVDC link (with 1000 MVA capacity) and FSP resources (with 1000 MVA capacity as well).

The corresponding frequency response is presented in Figure 26(d). Following the disturbance at 20 s, the frequency in Athens decreases to a nadir of approximately 49.71 Hz, before settling to a steady state of 49.74 Hz, indicating significant improvement compared to the baseline (Section 5.2.3.1) and fixed FSM support (Section 5.2.3.2) scenarios. Due to the cross-border support, the Cyprus frequency also exhibits a small but non-negligible deviation, dropping to 49.75 Hz.

The active power responses shown in Figure 26(a) and Figure 26(b) demonstrate the increased contribution of the converter-based resources. Following the frequency disturbance in Athens, the WAC coordinates with the HVDC terminals in Cyprus and Crete and instructs them to reduce their imported power according to the requested FCR and FSM support from Athens, while respecting the 10% contribution limit. Consequently, the HVDC active power transfer from Athens decreases, effectively reducing the loading on the Athens power system by 53 MW, as shown in Figure 26(a). This provides stronger HVDC-based frequency support than in the fixed FSM scenario due to the adaptive FSM droop coefficient. In parallel, the FSP battery response shown in Figure 26(b) increases by approximately 250 MW. This contribution is higher than the HVDC support in the same scenario, since the FSP is a local resource and is not constrained by cross-border HVDC transfer limits. It is also higher than the FSP contribution in the fixed FSM scenario, reflecting the increased support intensity introduced by the adaptive FSM scheme.

Initially, the HVDC converter and the FSP battery provide a part of their allocated FCR contributions, while the conventional generator provides the majority of the frequency response, exceeding its allocated 24 MW FCR contribution, as presented in Figure 26(c). Once the frequency is below 49.8 Hz and the FSM functionality of the HVDC and FSP is activated, and both converters increase their active power output beyond the allocated FCR values, limiting the generator contribution to around 216 MW, which is the lowest comparing the three scenarios.

Overall, the adaptive FSM strategy provides the best frequency containment performance among the investigated cases. By continuously adapting the FSM droop coefficient according to the prevailing system inertia, the HVDC interconnection and battery-based FSPs deliver stronger and more effective converter-based frequency support than with the fixed FSM approach. Furthermore, the increased active power exchange through the HVDC link demonstrates the effectiveness of the proposed regional coordination strategy, enabling frequency support to be shared across the interconnected systems while reducing the dependence on conventional generation. Intense disturbance propagation

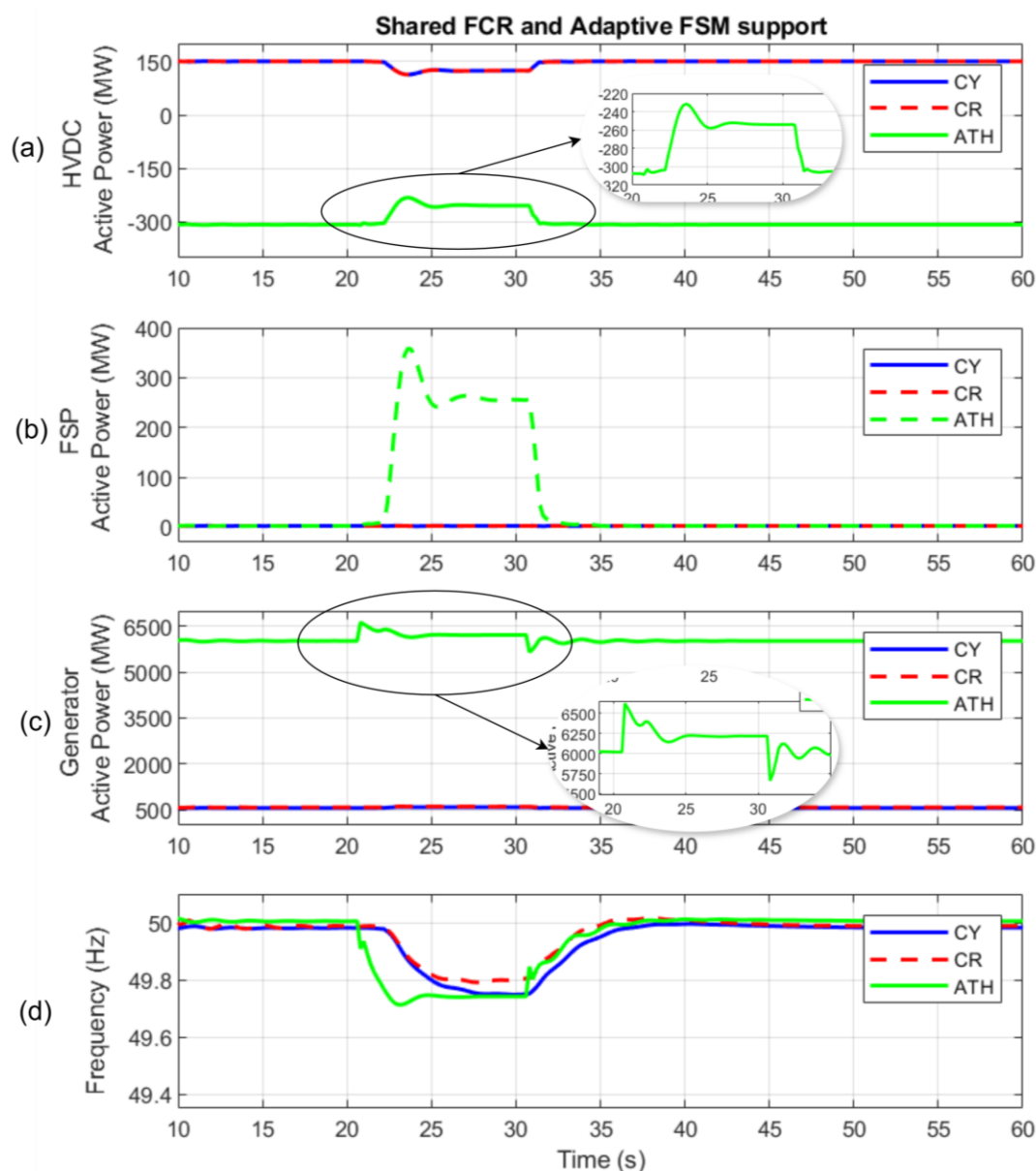


Figure 26: Shared FCR and Adaptive FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

is successfully prevented by effectively limiting the power transfer through HVDC from Cyprus and Crete to Athens.

5.2.3.4 Uncontrolled HVDC Transfer

To demonstrate the importance of coordinated regional control, the previous two scenarios were repeated with the HVDC transfer limits disabled. In this case, the HVDC converters are allowed to exchange power without considering the operational constraints of the supporting systems. Consequently, although the same FCR allocation and FSM strategies are maintained, the supporting systems are no longer protected from excessive power export during the disturbance.

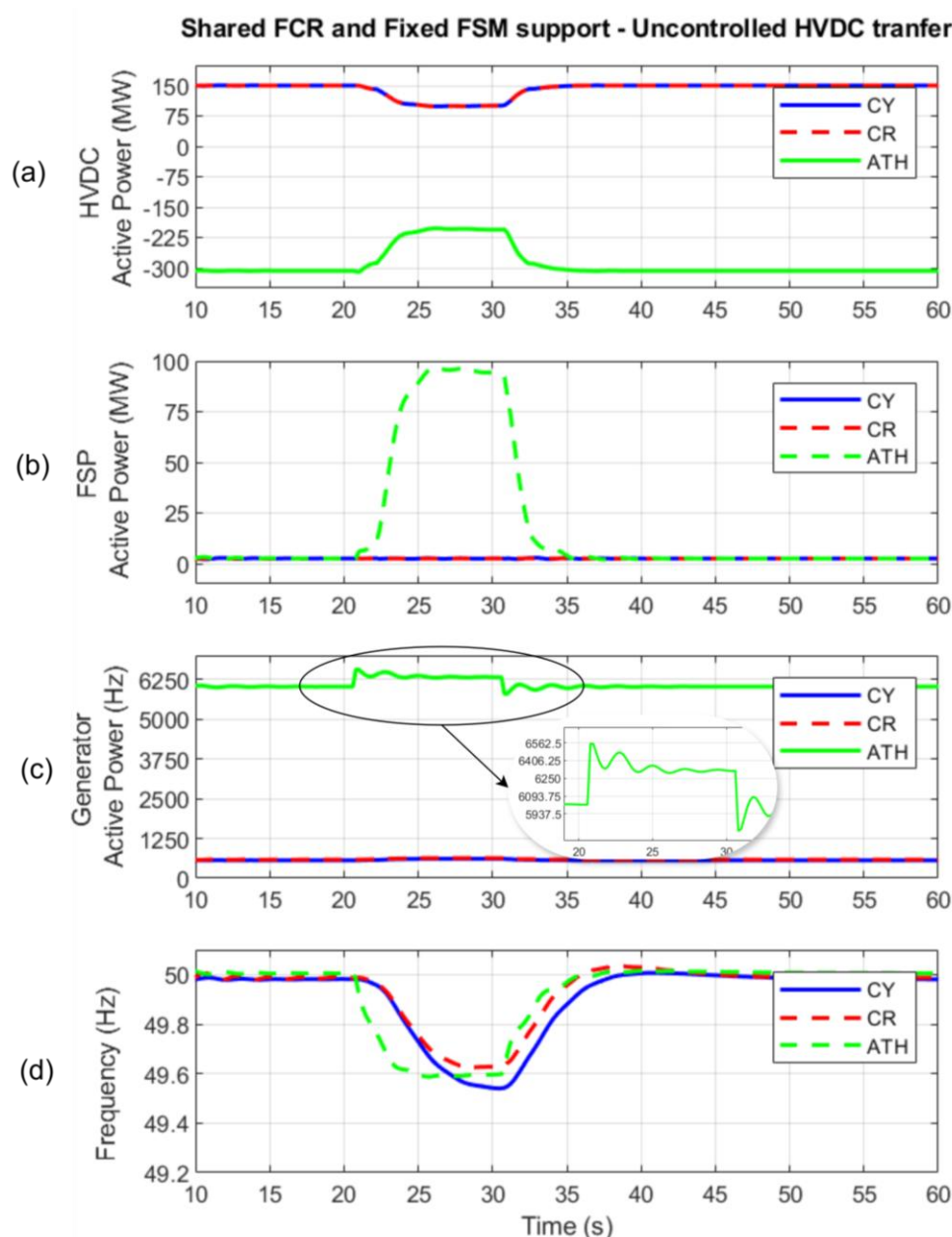


Figure 27: Unconstrained HVDC power exchange with Shared FCR and Fixed FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

Figure 27 and Figure 28, present the uncontrolled operation for the fixed and adaptive FSM strategies, respectively. As expected, the absence of HVDC transfer limitations allows a substantially larger amount of active power to be transferred from Cyprus and Crete (weak grids) towards Athens (strong grid), as shown in Figure 27(a) and Figure 28(a). This increased power exchange by HVDC is able to reduce frequency deviation which is reducing the supporting contribution by FSP battery systems, as shown in Figure 27(b) and Figure 28(b). Consequently, the frequency deviation in Athens is further reduced compared with the constrained cases, demonstrating the capability of the HVDC interconnection and converter-based resources to rapidly support the disturbed system.

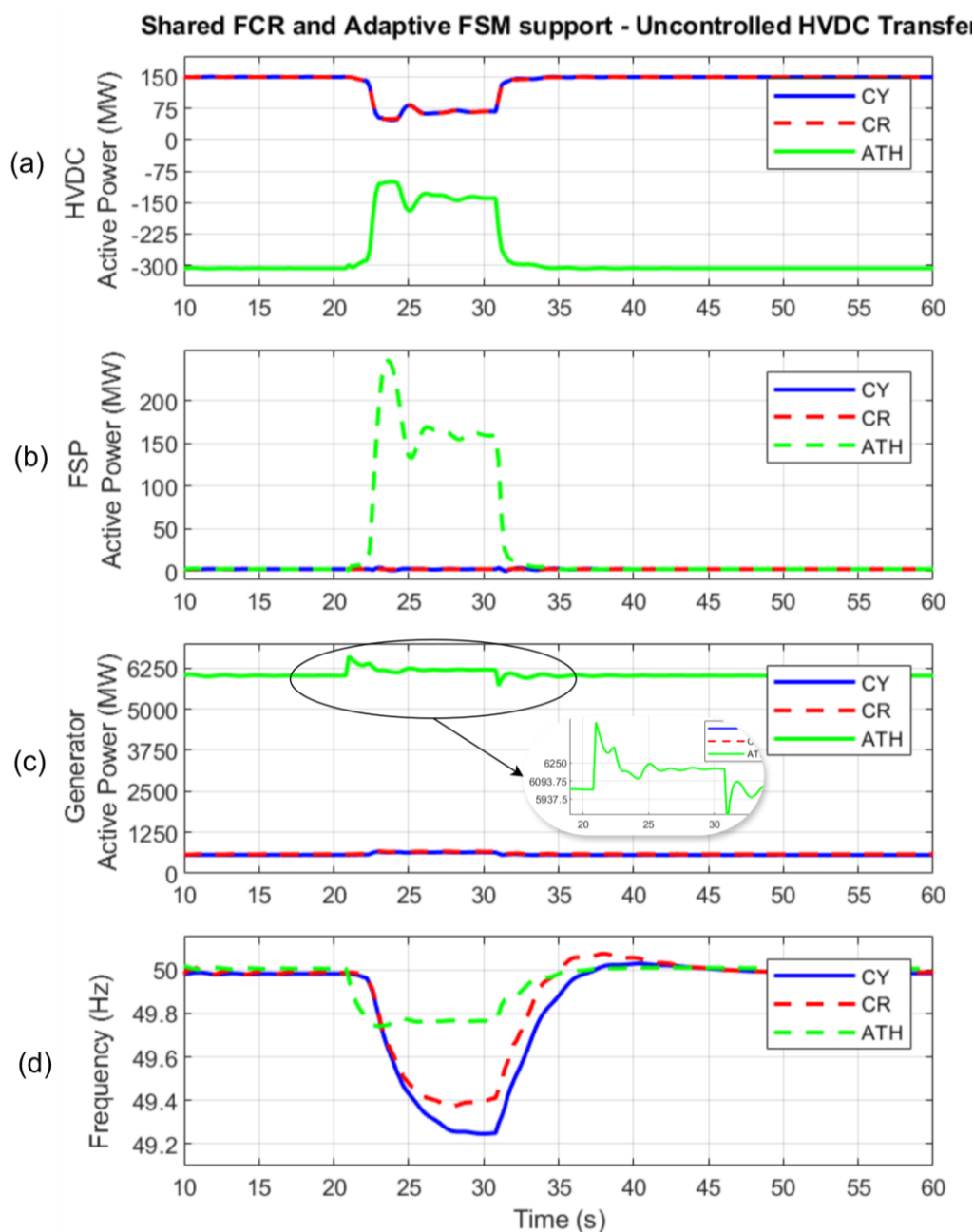


Figure 28: Unconstrained HVDC power exchange with Shared FCR and Adaptive FSM support scenario for Disturbance in Greece with normal inertia conditions. For each region (i.e., Athens (ATH), Crete (CR), Cyprus (CY)): (a) HVDC active power output, (b) FSP Active power output, (c) Generator Active power output and (d) System frequency.

However, this improvement is achieved at the expense of the stability degradation at the interconnected supporting power systems. As illustrated in Figure 27(d) and Figure 28(d), the frequencies of Cyprus and Crete experience significantly larger frequency deviations due to the unrestricted export of active power through the HVDC interconnection. The effect is particularly evident in the adaptive FSM scenario, where the stronger converter response causes a considerably deeper frequency reduction in the supporting systems, reaching as low as 49.25 Hz in Cyprus and 49.39 Hz in Crete. These results clearly demonstrate that maximizing the support delivered to the disturbed system through HVDC does not necessarily improve the overall regional stability of the

interconnected network and can lead to significant disturbance propagation if left unconstrained. Overall, the uncontrolled transfer scenarios highlight the necessity of the proposed regional coordination framework. While adaptive FSM is capable of providing superior frequency support, its operation must be coordinated through the Regional Security Coordinator and the Wide Area Controller by enforcing HVDC transfer limits that consider the operational constraints of all interconnected systems. This coordinated approach ensures that frequency support is shared effectively between countries without compromising the frequency stability of the supporting networks, thereby achieving a balanced and secure operation of the entire HVDC-interconnected system.

5.3 Key Performance Indicator based Evaluation

Table 1 summarizes the performance of the proposed coordinated frequency support framework for all investigated operating scenarios presented in Section 5.2. The key performance indicators include the active power contributions from the HVDC interconnection and the battery-based FSPs through FCR and FSM, together with the resulting frequency nadir, the post disturbance steady-state frequency and the maximum *RoCoF* magnitude, in both the disturbed and supporting power systems. The investigated cases consider disturbances occurring in either Cyprus or Greece, under different system inertia conditions and alternative HVDC operating strategies, allowing a comprehensive assessment of the proposed regional coordination framework.

For disturbances occurring in Cyprus under normal inertia conditions, the coordinated activation of FCR and FSM significantly enhances the frequency response compared with the baseline case, where no coordinated support is provided. The frequency nadir improves from 48.88 Hz to 49.43 Hz when shared FCR is combined with a fixed FSM strategy, and further increases to 49.56 Hz when the proposed adaptive FSM controller is employed, as summarized in the first three columns of Table 1. Similarly, the post-disturbance steady-state frequency improves from 48.93 Hz in the baseline case to 49.49 Hz with the fixed FSM strategy and further to 49.62 Hz using the adaptive FSM controller, indicating a faster and more effective restoration of the system frequency following the disturbance. This improvement is achieved by increasing the participation of converter-interfaced resources. The HVDC support rises from 53 MW to approximately 61 MW, while the battery-based FSP contribution increases from 28 MW to 34 MW. Consequently, the burden on conventional synchronous generators is reduced, demonstrating that the adaptive controller more effectively exploits the available flexibility of the converter-based resources to enhance both the transient frequency containment and the subsequent steady-state frequency recovery. The maximum *RoCoF* magnitude also decreases when the adaptive FSM strategy is employed compared with the fixed FSM strategy, indicating that the proposed controller not only improves the frequency nadir but also mitigates the initial rate of frequency decline. This behaviour is expected, as the adaptive controller provides faster and more effective active power support.

Table 1: Summary of evaluation results for the Cyprus – Greece HVDC interconnection digital twinning use case.

Scenario		HVDC		FSP		System Performance in Cyprus			System Performance in Greece		
		P_{FCR} (MW)	P_{FSM} (MW)	P_{FCR} (MW)	P_{FSM} (MW)	Frequency Nadir (Hz)	Post- disturbance frequency (Hz)	RoCoF (Hz/s)	Frequency Nadir (Hz)	Post- disturbance frequency (Hz)	RoCoF (Hz/s)
Disturbance in Cyprus – Normal Inertia Conditions	Baseline	0	0	0	0	48.88	48.93	0.432	50	50	0.147
	Shared FCR & Fixed FSM	12	53	6	28	49.43	49.49	0.392	49.98	49.99	0.101
	Shared FCR & Adaptive FSM	10.67	61.33	5.33	33.67	49.56	49.62	0.353	49.97	49.99	0.153
Disturbance in Cyprus – Low Inertia Conditions	Baseline	0	0	0	0	49.05	49.19	0.502	50	50	0.101
	Shared FCR & Fixed FSM	11.73	21.27	5.87	11.13	49.51	49.65	0.579	49.96	49.96	0.095
	Shared FCR & Adaptive FSM	9.87	30.13	4.93	14.57	49.53	49.75	0.416	49.958	49.958	0.037
Disturbance in Greece – Normal Inertia Conditions – Controlled HVDC support	Baseline	0	0	0	0	50	50	-	49.44	49.44	0.190
	Shared FCR & Fixed FSM	18	8	10	110	49.87	49.87	0.037	49.53	49.53	0.175
	Shared FCR & Adaptive FSM	18	35	10	242.5	49.75	49.75	0.088	49.71	49.74	0.178
Disturbance in Greece – Normal Inertia Conditions – Uncontrolled HVDC support	Baseline	0	0	0	0	50	50	-	49.44	49.44	0.190
	Shared FCR & Fixed FSM	18	84	10	82.5	49.55	49.55	0.096	49.58	49.6	0.185
	Shared FCR & Adaptive FSM	18	157	10	153.5	49.25	49.25	0.256	49.74	49.76	0.192

A similar trend is observed under low-inertia conditions, as illustrated in columns 4-6 of Table 1. In these scenarios, the frequency stability becomes more sensitive due to the reduced rotating inertia of the Cyprus system and an intense frequency disturbance is imposed by a lower power disturbance of 69.35 MW (instead of 149 MW of the previous case). In this set of scenarios, baseline frequency nadir is 49.05 Hz. When both coordinated support strategies are applied, the frequency response is substantially improved, with the adaptive FSM increasing the nadir to 49.53 Hz, compared with 49.51 Hz obtained using the fixed FSM. Likewise, the post-disturbance steady-state frequency increases from 49.19 Hz in the baseline case to 49.65 Hz with the fixed FSM strategy and reaches 49.75 Hz with

the adaptive FSM. The adaptive strategy requires a more effective redistribution of active power, increasing the HVDC contribution from 21 MW to 30 MW and the FSP support from 11 MW to approximately 15 MW compared to the fixed DSM support strategy. These results indicate that adaptive coordination becomes increasingly valuable as system inertia decreases, enabling converter-based resources to compensate for the reduced kinetic energy available in the network and enhanced the frequency stability of low inertia power grids.

For disturbances occurring in Greece with controlled HVDC operation (summarized in columns 7-9 of Table 1), the proposed coordination framework also provides significant improvements in frequency stability. Without coordinated support via the HVDC (baseline scenario), the Greece frequency nadir falls to 49.44 Hz, while the Cyprus system remains unaffected at its nominal frequency. Introducing shared FCR and fixed FSM increases the Greece frequency nadir to 49.53 Hz, whereas the adaptive FSM further improves it to 49.71 Hz. This enhancement is achieved through substantially higher converter participation, with HVDC support increasing from 8 MW to 35 MW, and battery support rising from 110 MW to approximately 243 MW. Due to the limited HVDC power transfer, more burden falls to the FSP power converter for support. Overall, the adaptive controller utilizes the available converter flexibility more effectively, providing rapid power injection during the transient period and improving the post-disturbance frequency recovery, while maintaining the stability of both interconnected systems. Similarly, the maximum RoCoF magnitude is reduced under the adaptive FSM strategy despite the lower system inertia. This confirms that the proposed coordination framework becomes increasingly effective in limiting the rapid frequency variations associated with low-inertia operation.

The influence of the proposed regional coordination framework becomes more evident when comparing the controlled (columns 7-9 of Table 1) and uncontrolled (columns 10-12 of Table 1) HVDC operating modes. When the HVDC transfer limits are removed (columns 10-12 of Table 1), considerably larger active power exchanges become possible. Under the adaptive FSM strategy, the HVDC contribution increases to approximately 157 MW, compared to the limited 35 MW in the controlled case. This shows that when no limitation is applied, since the HVDC and FSP controllers have the same FSM droop coefficient and same power ratings, they correctly provide a similar FSM support. All these lead to a better frequency nadir of 49.74 Hz in the disturbed Greece system (strong grid) and a post-disturbance steady-state frequency of 49.76 Hz. However, this additional support is obtained at the expense of the supporting Cyprus system, whose frequency nadir decreases from 49.75 Hz under controlled operation to 49.25 Hz under uncontrolled operation. This demonstrates that unrestricted HVDC power transfers can propagate significant disturbance to the supporting system (weak grid), deteriorating the regional stability and the frequency stability of the weak grids. Regarding the maximum RoCoF magnitude in both the controlled and uncontrolled operation changes only marginally and exhibits a slight increase with the adaptive FSM strategy. This behaviour is consistent with the relatively high inertia of the Greece system, where the initial frequency decay is already slow and the principal benefit of the adaptive controller is reflected in the improved frequency nadir and steady-state recovery rather than in a substantial reduction of RoCoF. The unrestricted HVDC operation also results in a higher maximum RoCoF magnitude compared with the controlled case. This is expected, as the significantly larger and faster power exchanges through the HVDC link increase the transient dynamics. Although this improves frequency support to the disturbed Greece system, it simultaneously transfers a stronger disturbance to the supporting Cyprus system, leading to larger frequency gradients.

It is also observed that in the Greece disturbance scenarios, the frequency nadir is almost identical to the post-disturbance steady-state frequency. This behaviour is attributed to the higher inertia of

the Greece system, which reduces the initial *RoCoF* and slows the frequency decline. Consequently, the HVDC interconnection and FSPs are able to deploy their fast frequency support before the frequency experiences a significant additional drop. As a result, the minimum frequency is reached very close to the new equilibrium operating point, resulting in negligible post-nadir recovery. In contrast, the lower inertia of the Cyprus system leads to a faster frequency decline, causing the frequency to continue recovering after the nadir until the converter-based support is fully established.

Across all investigated scenarios, the proposed adaptive FSM consistently outperforms the fixed FSM strategy, achieving the highest frequency nadirs and the best post-disturbance steady-state frequencies while making more effective use of the available converter-based resources. Rather than relying on predefined support levels, the adaptive controller dynamically adjusts the HVDC and FSP power injections according to the prevailing system conditions, allowing faster and more efficient frequency containment as well as improved frequency restoration.

The results also highlight the complementary roles of the HVDC interconnection and battery-based FSPs. The HVDC provides rapid bulk power transfer between interconnected areas, whereas the FSPs supply localized fast frequency support, together forming an effective coordinated response. Their combined action reduces dependence on conventional generators and enhances frequency resilience under both normal- and low-inertia operating conditions by improving both the transient response and the post-disturbance steady-state operating point.

Furthermore, the comparison between controlled and uncontrolled HVDC operation demonstrates the necessity of coordinated regional control. Although unrestricted HVDC operation maximizes support to the disturbed system, it simultaneously exposes the supporting system (in case of weak supporting grids) to larger frequency deviations. By enforcing appropriate HVDC transfer limits while adaptively coordinating converter-based resources, the proposed framework successfully balances two competing objectives: maximizing frequency support to the disturbed area and preserving the frequency stability of the interconnected supporting system. This coordinated approach therefore provides a practical and scalable solution for future low-inertia interconnected power systems with high penetrations of converter-based resources.

6 Conclusion

The work carried out in Task 7.6 demonstrates that real-time digital twinning can provide a practical and technically meaningful environment for analysing the future Cyprus–Greece HVDC interconnection before its physical deployment. The developed Digital Twin makes it possible to study the dynamic interaction between mainland Greece, Crete, and Cyprus, while also assessing how HVDC converters, battery-based Flexibility Service Providers (FSPs), market-cleared Frequency Containment Reserve (FCR), and Frequency Sensitive Mode (FSM) control can be coordinated to improve regional frequency stability. The main conclusion is that the HVDC interconnection should not be considered only as an energy-transfer asset, but also as an actively controlled flexibility resource whose frequency-support contribution must be carefully configured according to the operating conditions of the interconnected systems.

The scenario-based demonstrations and KPI-based evaluation show that coordinated HVDC and FSP support can significantly improve the frequency response of weak and low-inertia systems. In the Cyprus normal-inertia disturbance case, the activation of coordinated converter-based support increased the frequency nadir from approximately 48.88 Hz in the baseline case to 49.43 Hz with fixed FSM and 49.56 Hz with adaptive FSM. The post-disturbance steady-state frequency was also improved, indicating that converter-based support not only limits the initial frequency drop but also helps the system settle closer to nominal frequency after the disturbance. The benefit becomes even more important under low-inertia operation, where the reduced committed synchronous generation makes the system more sensitive to active-power imbalances. In this case, the adaptive FSM strategy allows the HVDC converters and battery-based FSPs to increase their support intensity according to the lower available kinetic energy, resulting in a stronger and more effective frequency containment response.

A key lesson learned is that adaptive FSM control provides a more suitable mechanism than fixed FSM settings for systems whose inertia varies significantly with operating conditions. Fixed droop settings based only on grid-code limits may be too conservative during low-inertia periods or may not fully exploit the available converter flexibility. By contrast, adapting the FSM droop coefficient according to the real-time kinetic energy of the system enables inverter-based resources to provide stronger support when it is most needed, while avoiding unnecessary intervention during high-inertia operation. This is particularly relevant for future power systems with high renewable energy penetration, where the number of committed synchronous units and the available rotating inertia may vary substantially over time.

The investigations also highlight that HVDC-based cross-border frequency support must be coordinated and constrained to avoid transferring disturbances from one system to another. This is especially important when a weaker grid is requested to support a stronger interconnected system. Although unrestricted HVDC power transfer can improve the frequency response of the disturbed system, it may also increase frequency deviations in the supporting systems and compromise their stability. The proposed Wide Area Controller and regional coordination framework provide a more balanced solution by limiting disturbance propagation while still enabling effective support sharing through the HVDC link. The results therefore suggest that operational limits and coordination rules should be explicitly included when defining future HVDC frequency-support services.

From an operational perspective, the work indicates that future HVDC interconnections should be accompanied by coordinated control schemes that consider market-cleared reserve allocation, converter capabilities, local inertia conditions, and cross-border security constraints. Battery-based

FSPs can play a complementary role by providing fast local support without being affected by HVDC transfer limits, while the HVDC link can enable regional support sharing when properly coordinated. The combined use of local FSP response and controlled HVDC support provides a more robust and flexible frequency-support mechanism than relying only on conventional generation.

The developed digital twin also provides a valuable platform for future studies and pre-deployment validation. It can be used to fine-tune HVDC controller settings, assess the impact of different FCR and FSM allocation strategies, test the integration of new inverter-based resources, and identify the operational limits of the interconnected systems under increasing RES penetration. It can also support further investigations on grid-forming converter operation, additional ancillary services, cyber-physical disturbances, communication delays, and more detailed market-based coordination mechanisms. In this sense, the developed digital twin provides a safe and repeatable environment for testing new technologies and operational strategies before their implementation in the real system.

Overall, the results support the recommendation that the future operation of the Cyprus-Greece HVDC interconnection should include coordinated and adaptive frequency-support mechanisms rather than relying only on static control settings or unrestricted power transfers. The proposed digital twin framework can assist system operators, regional coordinators, and technology providers in defining these mechanisms, validating their performance, and ensuring that the interconnection contributes to improved resilience, reliability, and secure integration of renewable and flexibility resources across the interconnected European power system.

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