MITIGATION OF THE TECHNICAL SCARCITIES ASSOCIATED WITH HIGH LEVELS OF RENEWABLES ON THE EUROPEAN POWER SYSTEM

D2.6

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ABBREVIATIONS AND ACRONYMS

APC	Active power control
BAU	Business as Usual
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbine
CE	Continental Europe
CHP	Combined Heat and Power
CRM	Capacity Remuneration Mechanisms
DER	Distributed Energy Resource
DRR	Dynamic Reactive Response
DSM	Demand-Side Management
DSO	Distribution System Operator
DSU	Demand side unit
EAC	Equivalent Asset Cost
EFR	Enhanced Frequency Response
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
EOC	Enhanced Operational Capability
EU	European Union
EV	Electric vehicles
FFR	Fast Frequency Response
HV	High Voltage
HVDC	High Voltage Direct Current
IOI	Impact Overload Index
LEU	Large Energy User
LFSM	Limited Frequency Sensitive Mode
LSAT	Look-Ahead Security Assessment Tool
LSI	Largest Single Infeed
MSC	Mechanically Switchable Capacitor
MV	Medium Voltage
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
NC	Nodal Controller
NI	Northern Ireland
OCGT	Open Cycle Gas Turbine
OI	Overload Index
PPM	Power Park Module

PSS	Power System Stabilisers
PSS/E	Power System Simulation for Engineers
PU	Per unit
PV	Photovoltaic
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources for Electricity
RoCoF	Rate Of Change Of Frequency
SIR	Synchronous Inertial Response
SFM	Single-bus Frequency Model
SNSP	System Non-Synchronous Penetration
SVC	Static VAR Compensator
TES	Tomorrow's Energy Scenarios
TIOI	Total Impact Overload Index
TOI	Total Overload Index
TSAT	Transient Security Assessment Tool
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UC	Unit Commitment
UCED	Unit Commitment and Economic Dispatch
VPP	Virtual Power Plant
VRES	Variable Renewable Energy Sources
VSAT	Voltage Security Assessment Tool
WP	Work Package
WTG	Wind Turbine Generator

1. EXECUTIVE SUMMARY

The EU-SysFlex project aims to identify the challenges that will be faced by the European Power System with the transition to high levels of variable, non-synchronous Renewable Energy Sources (RES). In addition, EU-SysFlex seeks to propose mitigations and solutions to those challenges to ensure that the European power system can continue to be operated safely, securely and efficiently. These solutions can include technical options, procurement of system services (both new and existing), operational strategies and new market designs.

Work Package (WP) 2 is the starting point of the project as its goal is to evaluate the challenges, both technical and financial, arising in the future European power system. Task 2.1 reviewed the state of the art literature to identify the potential technical scarcities that could arise when operating power systems with high levels of renewable generation, and in particular with high levels of variable, decentralised and non-synchronous sources. A scarcity can be loosely defined as a shortage of something that the power system has traditionally had in good supply; for example, inertia is a commonly cited scarcity in high renewable systems [1].

The scarcities identified through the literature review were grouped into six categories: stability issues (frequency, voltage and rotor-angle), congestions issues, operating processes such as black-start and system restoration issues and balancing and system adequacy issues. The subsequent studies, which would seek to determine if these technical scarcities are likely to materialise in the future European power system, were to be scenario driven and thus scenarios and network sensitivities were developed in Task 2.2. Detailed models and methodologies were developed in Task 2.3, and Task 2.4 then utilised the developed scenarios and models and identified the technical scarcities and challenges that will be faced by the European power system when operating with high shares of non-synchronous renewable generation penetration. Studies were also carried out to identify the changes in power flows and their impact on congestions with the decentralised and distributed aspects of these power sources. Task 2.5 evaluated issues associated with incorporating high levels of renewables into the energy-only market and revealed that financial gaps could occur for many technologies in the portfolio with high levels of renewables. System services were identified in Task 2.5 as having the potential to provide an additional revenue stream to generating technologies and service providers, thereby mitigating the financial gap challenges.

Task 2.6 is the final task of WP2 and is the focus of this report. **Task 2.6 aims to demonstrate, via simulations, potential mitigations and technology options that could be utilised to provide the needed system services capability to solve the technical issues,** when possible based on the technologies demonstrated within the EU-SysFlex project. The primary objective is to facilitate the modelling of the capabilities that are needed to solve these technical scarcities rather than focussing on the technologies themselves. Like the scarcities observed in Task 2.4, the mitigation of scarcities is power system specific. Investigations for combinations of system and proposed mitigations are preformed using detailed models of the Ireland and Northern Ireland power system for all scarcities observed in Task 2.4, a detailed model of the Polish transmission system that is connected to an approximate model of neighbouring countries observing voltage and rotor angle scarcities, and a reduced six nodes model of continental Europe for frequency scarcities in conjunction with a detailed dispatch model.

This report successfully demonstrates, through simulations, and utilisation of specific technologies as a means of representing capability, the ability to mitigate some of the key technical scarcities identified in Task 2.4.

In general, each technology or mitigation measure is largely demonstrated in isolation, but it should be acknowledged that in reality a range of solutions will be needed. The mix of solutions which will be required will need to be assessed holistically in order to take account of any interactions and synergies. The reason is that some scarcities, as is shown in this report, can be mitigated by a range of different technologies and strategies, while some technologies can be effective in mitigating a selection of different issues. The key will be to identify the mix of technologies that will be needed to ensure safety and reliability of the system and to deliver value to consumers.

The most efficient way to deliver the right mix of technologies would be to develop the correct electricity markets and incentivise investment, providing choice. For more information the reader is directed to both the Task 3.1 [2] and the Task 3.2 [3] reports, which detail a range of different innovative system services products and potential market designs for procuring, activating and remunerating innovation system services products, respectively.

Network technologies, such as synchronous condensers, STATCOMS and Static VAr Compensators (SVCs), as well as renewable technologies such as wind and solar generation, plus batteries and the demand-side, are found to be suitable technologies for mitigating a range of scarcities that will manifest themselves at high levels of renewables. This is a critical result as these are the technologies that are inherently going to be online and operating at times of high renewables and it will become more and more unlikely that conventional synchronous will be online at such instances. While some aspects of the economics of the various technologies have been touched upon, the specifics are largely out of scope of this study. However, it has been demonstrated in Deliverable 2.5 of EU-SysFlex that there is significant value to the power system in utilising system services capability in order to enable the evolution of the system operation [4].

A range of system services that provide support in mitigating a number of system scarcities identified in Task 2.4 were represented by the utilisation of specific technologies. System services have proven that they can incentivise investment in new technologies that can provide a needed capability. It is important to note that the technologies discussed in this report are not exhaustive; they are typical examples of technologies that may provide the needed capability in mitigating these scarcities. The high level outcomes of these investigations are summarised below.

Frequency Stability Control:

A number of different mitigations and technologies have been demonstrated for both the Continental European power system and the Ireland and Northern Ireland power system to help with the significant frequency issues that were identified in Task 2.4. Crucially, many of the technologies which are modelled to illustrate those mitigations are non-conventional and thus would be mitigation measures that would be available at times of high renewable generation.

Synchronous inertial response (SIR) capability from Synchronous Condensers and conventional synchronous generators are demonstrated in both the Continental European system and the Ireland and Northern Ireland power system. Synchronous Condensers are shown to be good alternatives to conventional synchronous generating plants for inertia provision in the Continental European power system, while, in the Ireland and Northern Ireland power system, they are found to be effective in slowing the rate of RoCoF resulting in a delayed nadir thereby facilitating frequency recovery provision from resources such as DSU's and pumped hydro.

It is important to note that Synchronous Condensers alone cannot mitigate frequency stability issues, but in combination with other mitigation measures they can be very beneficial. Synchronous Condensers contribute to the system inertia without impinging upon the generation levels of non-synchronous renewables. More importantly still is the fact that synchronous condensers are very cost effective technologies for providing synchronous inertial response.

Whilst the use of carbon intensive conventional synchronous generators to provide inertia is counter to the overall objective of progressing along the path to decarbonisation of the power system, it is important to acknowledge the significant role conventional plants still have to play over the coming years in the transition to a more decarbonised system and the huge contribution they make to not only system inertia, but also to long-term frequency response. It has been proven in Ireland and Northern Ireland to-date that if the right incentives are in place, and it is technically feasible, it is possible for large synchronous generators to reduce their minimum stable generation level, thereby enabling greater penetrations of renewables but also crucially continuing to provide the same level of inertial response.

Fast frequency response (FFR) capability from Battery Energy Storage Systems (BESS) and wind turbines are demonstrated for the Ireland and Northern Ireland power system. Analysis shows the significance of FFR provision in terms of frequency stability especially during times of high SNSP levels. FFR has a dual effect in that it can increase and delay the frequency nadir thereby enabling other system resources with a slower frequency response provision to contribute.

Studies also indicate that the frequency response capability from wind farms can be beneficial in supporting frequency stability particularly at times of high SNSP levels, through the provision of Primary Operating Reserve (POR)[1] . Frequency control of wind farms in Ireland and Northern Ireland is often used to address over frequency issues through downward frequency response, however, this frequency control capability could potentially be used to address under frequency issue by providing additional active power output for upward frequency response during times where wind is either curtailed or constrained.
A number of considerations for potential operational policies are also explored in addition to the demonstration of system services capability in both the Continental European power system and the Ireland and Northern Ireland power system. The potential operational policies that are explored include:

[1] Frequency Containment Reserve in EGBL

1. Occasional limitations of the cross-borders flows in the Continental European Power system or the occasional decreasing of the magnitude of the Largest Single Infeed (LSI) in the Ireland and Northern Ireland power system (i.e. limitation of flows on interconnector);
2. Maintaining a minimum number of conventional units on the Ireland and Northern Ireland power system in order to ensure a minimum amount of inertia thereby occasionally reducing generation from variable renewable resources.

These **operational mitigations could be effective options for supporting the transition or evolution of the power system towards decarbonisation**, in conjunction with the arrival of system services provision from non-synchronous technologies and until such technologies are more widespread and prolific.

Voltage Stability Control:

It is demonstrated for both the Continental European power system and the Ireland and Northern Ireland power system that there are many different mitigations and technologies that can help with the significant voltage issues that were observed in Task 2.4.

Mitigation of the steady state voltage scarcity will require the provision of Steady State Reactive Power support (SSRP) capabilities from non-conventional technologies deployed in specific geographical locations. The reactive power reserve activation from wind generation, capacitors and shunts are shown to be good alternatives to conventional synchronous generating plants for reactive power provision in the Continental European power system. While, in the Ireland and Northern Ireland power system, mitigation to the steady state reactive power scarcity is established by the results of QV analysis whereby an increased reactive requirement is identified for weak buses in order to maintain acceptable levels at all nodes under normal operating conditions and following a system disturbance. **Static and dynamic reactive resources are found to be effective in mitigating this scarcity**. These additional resources may include, but are not limited to Capacitor Banks, STATCOMS; Static VAr Compensators (SVCs), Synchronous Condensers and potentially the reactive capability from some DSO connected wind farms to complement the existing reactive capability from TSO connected wind.

Task 2.4 also established the emergence of a dynamic voltage scarcity during fault recovery due to a reduction in system reactive power with the number of synchronous generators decreasing to enable higher shares of RES on the system, leading to degradation in dynamic voltage performance. There is a range of system services to support the voltage stability scarcity. **Dynamic Reactive Response (DRR) capability from Synchronous Condensers, Statcoms and SVC's was demonstrated** in the Ireland and Northern Ireland power system to help mitigate this dynamic voltage scarcity. Synchronous Condensers provide instantaneous reactive power support while ramping reactive power support is obtained from STATCOMs and SVCs. Analysis shows that the fast provision of DRR is vital in mitigating a dynamic voltage scarcity and also reveals that the location of a DRR provision resource is key in mitigating the scarcity identified in Task 2.4. Additional future studies would be required in determining the optimal placement of DRR resources.

Importantly, many of these reactive power providing technologies will be available at times of high variable renewable generation and, apart from the renewable technologies themselves, they typically do not provide active power and so utilising these technologies to provide reactive support would not displace renewable generation and thus would support the overall objective of reaching high renewable penetrations and ultimately decarbonisation of the power system.

Rotor Angle Stability Control:

A number of different mitigations and technologies have been demonstrated in alleviating some of the rotor angle stability issues observed in Task 2.4 in both the Continental European power system and the Ireland and Northern Ireland power system.

The **tuning of Power System Stabilisers (PSS)** of relevant conventional synchronous generators was demonstrated for the Continental Europe power system in order to mitigate **damping oscillation scarcities**. Results indicate that optimal tuning of power system stabilisers alongside automatic voltage regulators of the conventional synchronous machines may contribute to the augmentation of the oscillation damping in the power system. This is important as conventional plants still have a crucial role to play over the coming years in the transition to a more decarbonised system and it is critical that all technologies can work in harmony to deliver upon the end goal.

A number of options are investigated in the Ireland and Northern Ireland power system focusing on potential technical solutions and their capabilities including the addition of Power System Stabiliser (PSS) to specific oscillating units and the addition of Synchronous Condenser and STATCOMS to provide the needed capabilities. Examinations on the Ireland and Northern Ireland power system **demonstrate that the addition of PSS or STATCOM provides significant damping**, while a slightly more limited mitigation effect is observed for the Synchronous Condenser.

Dynamic Reactive Response (DRR) capability from Synchronous Condensers, STATCOMS and SVC's is demonstrated in the Ireland and Northern Ireland power system for **mitigating synchronising torque scarcities**. Analysis shows large quantities of these technologies would be required to alleviate this localised issue. Studies reveal that the most appropriate mitigation option appears to be consideration of an operational policy under specific circumstances and system conditions that would result in the modification of the considered unit commitment by dispatching down the unit that loses synchronism and increasing the output of another generator to accommodate the shortfall in generation from the dispatch down process.

The development of a new damping product may be necessary in order to incentivise sufficient capabilities and performances to deal with this specific scarcity. System services have already proven that they can incentivise investment in new technologies that can provide a needed capability.

Congestion:

Indications across Europe suggest that transmission network congestions may become one of the most difficult challenges in dealing with high levels of Renewable Energy Sources (RES) integration. Respective cost-benefit analyses and societal pressure demonstrate that it may not be economically viable to develop transmission networks that would guarantee compliance with the traditional security/planning criteria under all conditions/scenarios.

The experience of the countries dealing with a high level of RES integration undoubtedly shows that the pace of transmission network development may not be capable of following the pace of RES integration. This uneven balance can at times result in the imposing of constraints on renewable generation such as wind. Analysis carried out in Task 2.4 to assess the impact of increasing high levels of RES on the Ireland and Northern Ireland power system indicated that as SNSP levels increase there will be a significant rise in the frequency of transmission line overloading above 100% of thermal capability.

A number of mitigations demonstrate potential solutions for the challenge of congestion and illustrate the capability of certain measures or specific technologies. Although the strategy applied by many TSOs across Europe in relation to the system congestion is to maximise the use of the existing transmission networks and to minimise new build, results in Task 2.6 indicate that in some areas there may be no alternative except to invest in new infrastructure. Uprating existing lines could be seen to be an alternative to investing in completely new lines or circuits. Additionally, it should be noted that in the case that no new network can be built for social and/or environmental reasons, alternative, novel mitigations would need to be considered for managing congestion.

Results from the Ireland and Northern Ireland power system show that a number of **reinforcements** (addition of 110kV & 220kV Circuits) are required in terms of reducing the total overload index (TOI) and **mitigating the congestion challenge** for some critical hours, however further reinforcements or operational mitigation measures are required for less critical hours. While it is evident that these reinforcements have a positive impact on network congestion, the planning process must have cognisance of the potential risks associated with relying on network reinforcements (cost, societal and environmental pressures and build times).

Results also demonstrate that reinforcements are not the solution to all congestion related issues, and **alternative mitigation mechanisms also need to be seriously considered**. A Preventive Security Constrained Optimal Power Flow (PSCOPF) tool was utilised for the Ireland and Northern Ireland power system as a novel approach in identifying optimised load shifting, generation adjustments, phase shifter angle and tap changes requirements in order to eliminate congestion in the less critical hours. The operational mitigation results indicate a combination of **load shifting and optimised adjustments of the PST angle are sufficient in removing overloading violations** under consideration without the need for any further reinforcements.

As previously alluded to, congestion can be mitigated in a number of ways, including infrastructural investment, network reconfiguration and re-dispatching as well more innovative concepts such as **smart power flow**

controllers and demand-side management (DSM). From the studies on the concept of smart power flow controllers, it is demonstrated that such devices can bring about a modest reduction in the degree of overloads and they can be used as a single mitigation for modestly overloaded lines. However, power flow control devices alone are not sufficient to completely remove overloading violations for lines. They would need to be used in conjunction with other mitigation options.

A key benefit of DSM for congestion mitigation is that at high levels of renewables demand will still be available to some extent and also due to the fact that loads are dispersed throughout the system. However, one limitation is that it is inherently tied to specific end-users and the inconvenience to them needs to be minimised or avoided. In addition, in some areas where congestion management is most needed, there are limited load centres (i.e. North-West region of the island of Ireland) and thus, the ability of DSM to provide congestion mitigation is limited. However, the proof of concept study demonstrated that there is potential for DSM to provide decreases in overall system costs plus a decrease in network loading on certain lines, an indication of some mitigation of congestion.

The overarching conclusion from the work on congestion management is that **a range of different measures and options will be required to reduce network load, whilst minimising or avoiding network build**. In order to optimise use of all the solutions required, coordination at system level, between all system players, would be necessary.

Maintaining Generation Adequacy and Supporting Renewables Integration:

In addition to the suite of technical challenges and instabilities associated with transition to high levels of renewables, a potential reduction in system adequacy has also been identified as a challenge associated with displacement of conventional generation. As power systems transition to having portfolios with higher levels of vRES, the capacity of vRES that is required to displace conventional capacity, and still maintain the same level of generation adequacy, increases dramatically. This is a result of the variable nature of these resources and the fact that renewable generation availability may not coincide with peak demand times. Uncertainty of generation capacity and system interdependencies were also identified in the state of the art review in Deliverable 2.1 as scarcities to achieve a capacity-adequate European power system [5].

It should be noted that although a portfolio may be sufficient from the point of view of generation adequacy and having sufficient capacity to meet peak demand, there is no guarantee that the portfolio also has the requisite fast responding capability that has been shown in Task 2.1 and confirmed in T2.4 to be vital for secure power system operation. Adding a large amount of interconnections and peaking plants will address the 3h loss of load criteria/adequacy standard, but leads to low load factors for peaking units and does not result in a portfolio with the right level of capability to support the integration of variable renewables.

The aim of the adequacy work in this report is to provide a first order indication of the magnitude and global tendencies linked to the integration of stationary batteries and EV smart charging in Continental Europe and demonstrate that they have a positive impact on overall system commitment and dispatch, and thus can support the goal of integrating high shares of renewables and maintaining generation adequacy. It is **demonstrated that,**

for the Continental power system, batteries and EVs have a positive impact on the ability to satisfy the 3h loss of load criteria whilst supporting vRES integration through a reduction of curtailment levels and a reduced use of CO_2-emitting peaking units.

EV development and battery deployment supports vRES integration onto the power system. The need for gas power plants is reduced with the integration of batteries, while EV smart charging displaces twice as many gas units compared to batteries alone. Additionally, batteries and EVs both have a positive, downward effect on renewable curtailment levels and system production costs, indicating their net benefit to the overall power system.

The role of networks and system interdependency in transmitting power across Europe was also demonstrated as an enabler for the integration of higher levels of vRES. However, as discussed in relation to mitigating congestions, networks development is limited by cost, societal and environmental pressures and lead times.

Summary:

It has been demonstrated throughout this report that renewables and non-conventional technologies are well positioned to provide a range of different system services capability which is needed to mitigate the technical scarcities. This is vital as these are the mitigation measures that would be available at times of high renewable generation, times when the scarcities are typically more severe due to the displacement of tradition service providers such as conventional synchronous plants.

In general, each technology, concept or mitigation is demonstrated in isolation, but it should be acknowledged that in reality **a range of solutions will be needed.** The required mix of solutions will need to be assessed holistically in order to consider trade-offs and synergies. The reason is that some scarcities, as is shown in this report, can be mitigated by a range of different technologies and strategies, while some technologies can be effective in mitigating a selection of different issues. The key will be to identify the mix of technologies that will be needed to ensure safety and reliability of the system and to deliver value to consumers. Future markets will need to be designed such that they successfully promote a choice for investors and incentivise investment in technologies which will ultimately have the right capability needed to support the power system in the transition to high levels of variable renewable generation and ultimately towards decarbonisation.

It can be concluded from WP2 that there is a clear **need** for system services (Task 2.4), that the **capability** of system services from many technologies to mitigate scarcities exists and can be successful in resolving the challenges of the future power system (Task 2.6) and that the **value** of system services (Task 2.5) is considerable and system services markets will be needed to manage the challenges associated with falling energy market prices and falling generator revenues, whilst incentivising the required system services capability.

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2. INTRODUCTION

2.1 CONTEXT

The EU-SysFlex project seeks to enable the European power system to utilise efficient, coordinated flexibilities in order to integrate high levels of renewable energy sources and to meet European decarbonisation objectives. One of the primary goals of the project is to examine the European power system with at least 50% of electricity coming from renewable energy sources (RES-E). In order to transition to a decarbonised power system and to reach at least 50% RES-E on a European scale, Europe needs to develop low carbon and renewable technologies. In some countries, these low carbon technologies could be predominately variable non-synchronous renewable technologies such as wind and solar. In the context of the EU-SysFlex project, high levels of renewable generation are defined as being installed capacities of renewables that succeed in meeting at least 50% of the total annual electricity demand. As hydro power potentials are largely exploited in many regions, and biomass growth is limited by supply constraints, an increasing part of the growth is expected from variable non-synchronous renewables [6]. In addition to developments in renewable electricity, there is also a trend towards sector coupling with, for example, increased electrification of heat and transport, which is seen to be an enabler of the power system transition. While this is clearly an advantage and an opportunity, this can also create challenges for the transmission and distribution networks. Distribution networks in particular were not designed for accommodating embedded generation and this can lead to the need for expensive infrastructure investment.

Transitioning from power systems which have traditionally been dominated by large synchronous generating units to systems with high levels of variable non-synchronous renewable technologies has been shown to result in technical challenges for balancing and operating power systems safely and reliably. This is due to the non-synchronous nature of these technologies as well as the variable, distributed and decentralised nature of the underlying resources. Deliverable 2.1 of this Work Package [5] has performed a comprehensive review of the literature and identified a number of key technical scarcities associated with integration of variable non-synchronous generation and the associated displacement of conventional synchronous generation. These scarcities, if not mitigated, may impact the security and stability of the power system of the future.

The advent of non-synchronous renewable generation, and the associated displacement of conventional generation, will result in a need for system services traditionally provided by conventional generation to be provided by different technologies. This is to ensure that there will be sufficient frequency control capabilities across multiple time frames. Displacement of conventional technologies can also lead to a range of instabilities and issues with reactive power control. High levels of variable generation can cause an increase in network congestion, especially when generation is situated far away from load centres. Furthermore, displacement of conventional generation can lead to a lack of system restoration capability and a need for additional system services to provide black start services. In addition, the challenge of maintaining system adequacy with increasing variable renewable sources such as wind and solar generation has also been identified.

As a consequence of these technical challenges, there is an increasing need for provision of system services from wind and solar, as well as enhancement of existing technologies and coordination within the whole system, generation, demand and networks, to improve capability and maintain reliable balancing and adequacy.

2.2 WORK PACKAGE 2 AND TASK 2.6 WITHIN EU-SYSFLEX

Work Package (WP) 2 forms a crucial starting point for the EU-SysFlex project. WP2 performs detailed technical power system simulations of the European power system with high levels of renewable generation as well as high levels of electrification. The main objective is the assessment of challenges of the pan-European power system with high levels of renewables.

The first deliverable of WP2 was completed as part of Task 2.1 - D2.1 - State-of-the-Art Literature Review of System Scarcities at High Levels of Renewable Generation [5]. Deliverable 2.1 divided the technical scarcities from the literature into a number of categories;

- frequency stability;
- voltage stability;
- rotor angle stability ;
- network congestion;
- system restoration and
- system adequacy.

Most of these technical scarcities and challenges were identified in Task 2.4. To enable this assessment, it was first necessary to develop scenarios [7] and dynamic models [8]. Task 2.2 defined a set of pragmatic and ambitious scenarios for renewable and low carbon generation deployment in Europe [7], while Task 2.3 developed detailed dynamic models to simulate technical scarcities on the European system. Task 2.4 employed those scenarios and models to perform detailed simulations to determine the technical shortfalls of future power systems. Task 2.5 completed the picture by performing techno-economic analysis using production cost modelling to assess, among other things, the financial gap in revenues available for generating technologies from the energy-only market.

Task 2.6 sets out to provide evidence and simulation-based demonstration of some potential solutions and mitigations. While a range of specific technologies are modelled in this task, the primary aim of this approach is to facilitate the modelling of the capabilities that are needed to solve the technical scarcities and it is less about the technologies themselves. It is important to note that it is acknowledged that the technologies discussed in this report are not an exhaustive list. Instead they are typical examples of technologies that can provide the needed capability.

2.3 SUMMARY OF KEY FINDINGS FROM TASK 2.4 AND TASK 2.5

Analysis in Task 2.4 on the Continental European power system demonstrated technical scarcities associated with certain domains of system stability (e.g. voltage control), whilst also highlighting increasing areas of concern for other domains (e.g. frequency control & congestion). An indication of the evolution of system needs (characterised by scarcities) due to a potential change in the system generation portfolio was evident for the Continental European system. The Ireland & Northern Ireland power system clearly demonstrated technical scarcities across multiple categories of system stability for the scenarios analysed. Across all the considered systems, it is evident that some technical scarcities require mitigation measures to enable secure system operation of the power system in 2030.

As previously mentioned, most of these technical scarcities and challenges were identified in Task 2.4. Adequacy however was not assessed in Task 2.4 as the scenarios were, by design, generation adequate. However, adequacy in the high RES scenarios, for Continental Europe in particular, was ensured by adding flexible Gas Turbines (CCGT, OCGT), a solution that not only limits decarbonisation at European level, but also does not guarantee the correct level of services capability, as was evidenced by the range of technical scarcities and challenges identified in Task 2.4. Additionally, it was found that even generation adequate portfolios can have financial issues for generators in an energy-only market in Task 2.5.

Task 2.5 found that increasing levels of variable renewable generation on the Continental European system will fundamentally change the operation of the power system, with a greater need for flexible plants like OCGT. In addition, the numbers of hours when variable renewable generation exceeds demand levels will increase sharply by 2030. Effectively, if system operations continue with the status quo, the addition of greater levels of variable renewable generation results in increasing levels of curtailment. However, it was found that if operation of the power system can evolve as a result of the introduction of enhanced system services capability, curtailment levels can be maintained at acceptable levels whilst realising the decarbonisation benefits associated with variable renewables. Task 2.5 also demonstrated that enhanced System Services could provide a valuable revenue stream to improve the financial viability of both vRES and conventional technologies, whilst also providing the needed incentive to invest in technologies that will allow for mitigation of the technical scarcities identified in Task 2.4.

The results from WP2 are very relevant to WP3 of the project, which focusses on market design and regulatory options for innovative system services. Task 3.1 [2] provided a range of potential products for system services that would be needed to solve a range of needs and scarcities, as identified in Task 2.1. These system services could be further developed and enhanced, and combined with new innovative services, in conjunction with market design developments [2]. The capability from many of the system services previously described in Task 3.1 is demonstrated through simulation in this report for Task 2.6.

Complementary to the analysis of the potential for new system services to solve technical issues, there is a need to examine remuneration mechanisms and explore the need to employ new and innovative market designs to incentivise the capability. The work on potential new market designs is conducted in Task 3.2 and is described in the associated deliverable [3].

2.4 OUTLINE OF THE REPORT

The report starts with a brief review of the scenarios, generic methodology used for all types of analysis, and provides sufficient context for the reader to comprehend the results presented in subsequent chapters. For more detailed on information on the scenarios and the models, the reader is directed to Deliverable 2.2 and Deliverable 2.3, respectively, of the EU-SysFlex project [7] [8]. Chapter 4 to Chapter 6 present analysis on specific categories of system stability mitigation, with a view towards identifying a number of mitigation options available for the technical scarcities observed in Task 2.4. For each of these chapters, subsections are created to present the results relevant to the system (Continental Europe, and Ireland & Northern Ireland). Chapter 4 focusses on frequency stability, Chapter 5 deals with voltage stability (steady state & dynamic), and analysis and results relevant to rotor angle stability are presented in Chapter 6. Chapter 7 describes potential reinforcement options, as well as novel and innovative mechanisms, such as smart power flow controllers and demand-side management, to limit and manage congestion on the Ireland and Northern Ireland transmission network at very high levels of variable renewables. Chapter 8 investigates the potential of selected technologies, such as battery storage and Electric Vehicles tested in the EU-SysFlex demonstrations, in Continental Europe, to deal with maintaining generation adequacy at high levels of variable renewables.

3. OVERVIEW OF SCENARIOS, MODELS AND METHODOLOGIES

As outlined in the Task 2.2 deliverable [7], two categories of scenarios are being utilised in EU-SysFlex to study the 2030 power system, Core Scenarios and Network Sensitivities:

Core Scenarios – These are the central scenarios which will define the installed generation capacities by fuel type, demand, interconnection and storage portfolios to be used. These scenarios will be used to produce total annual energy demand as well as total annual energy production by source and fuel type. These scenarios will be used throughout the project for technical and production cost simulations on a pan-European basis.

Network Sensitivities – These are sensitivities which examine various parts of the European network in 2030 and will vary the capacities and locations of demand, generation, interconnection or storage in order to examine various scenarios in specific countries of the European power system. These sensitivities will be used to assess more specific technical scarcities in certain parts of the European system.

The two chosen Core Scenarios are **Energy Transition** and **Renewable Ambition**, which have a percentage of electricity from renewable energy sources (RES-E) with respect to overall demand of 52% and 66%, respectively, on a pan-European basis. A short summary of each scenario is provided below. In addition, various Network Sensitivities have been developed which seek to stress particular parts of the European network in order to examine further technical scarcities in greater detail. These Network Sensitivities are used to investigate more onerous or more ambitious generation and demand portfolios for specific areas and countries. The Network Sensitivities are focused on the areas of the European power system which will undergo increased analysis and simulations. Therefore, the areas which were primarily chosen for Network Sensitivities are the Ireland and Northern Ireland power system and a sub-network of the Continental European power system centred on the Polish network.

3.1 EVALUATED SCENARIOS

The evaluated scenarios in Task 2.6 represent a high level vision of each of the pan-European power systems considered, as outlined in Deliverable D2.2 [7]. Each scenario involves assumptions relating to 2030 network configuration, generation portfolio including large shares of renewable energy sources (RES) and the demand level and composition. There are two core scenarios for the pan-European power system. These scenarios define the installed generation capacities by fuel type, demand, interconnection and storage portfolios and these scenarios are used throughout the project for technical and production cost simulations on a European basis. The two core scenarios are the Energy Transition scenario which delivers a 50% RES-E target for the entire European power system in 2030 and the Renewable Ambition scenario which represents a 66% RES-E objective for the entire European power system, also in 2030.

As discussed in deliverable D2.2 [7] additional scenarios, or network sensitivities were also developed. These network sensitivities allow assessment of the impact of higher targets of RES-E on specific systems such as the Ireland and Northern Ireland power system and the European sub-network around Poland. An overview of the scenarios considered in this task and the scarcities and challenges assessed is provided in Table 3-1.

TABLE 3-1: OVERVIEW OF EVALUATED SCENARIOS IN TASK 2.6

Category	Power System	Evaluated scenarios
Frequency Stability and Control	Ireland & Northern Ireland	Low Carbon Living (LCL)
	Continental Europe	Renewable Ambition (RA)
Voltage Control	Ireland & Northern Ireland	Low Carbon Living (LCL)
	Continental Europe	Energy Transition (ET) Going Green (GG) Distributed Renewables (DR)
Rotor Angle Stability	Ireland & Northern Ireland	Low Carbon Living (LCL)
	Continental Europe	Energy Transition (ET) Going Green (GG) Distributed Renewables (DR)
Congestion	Ireland & Northern Ireland	Low Carbon Living (LCL)
System adequacy	Continental Europe	Sensitivities on Renewable Ambition (RA)

3.2 SUMMARY OF ANALYSIS, MODELS AND METHODOLOGIES

The analysis conducted under Task 2.6 focusses primarily on load flow studies, time domain simulations and critical analysis of pre-existing operational practices that were carried out in Task 2.4. Various options for mitigations of system stability issues are evaluated in accordance with one of the aforementioned analysis methods. The analysis has been focused on selected system snapshots relevant to system scarcities observed in Task 2.4. Details regarding snapshot selection are given in the relevant sections of this report. Table 3-2 provides an overview of stimuli, analysis methods and study types considered. Further details on the rationale for consideration of various study types, analysis methods and stimuli is provided in deliverable D2.3 [8].

TABLE 3-2: OVERVIEW OF THE STUDIES AND MODELS BEING EMPLOYED IN TASK 2.6

Power System under Analysis	Aim of Analysis	Model	Analysis Type	Performed by
Continental Power System	Demonstrate mitigations for frequency instability issues	CONTINENTAL PALADYN	Time domain simulation - Interconnected incidents - System splits	EDF
	Demonstrate mitigations for the steady voltage scarcity	DIgSILENT	Load flow analysis: - Intact system and N-1 Faults	PSEi
	Demonstrate mitigations for transient instability issues	DIgSILENT	Time domain simulation: - Short circuit faults	PSEi
	Demonstrate options available for supporting integration of renewables and assisting with maintaining generation adequacy	CONTINENTAL	Unit Commitment and Economic Dispatch Optimisation	EDF
All-Island Power System of Ireland and Northern Ireland	Demonstrate mitigations for frequency instability issues	SFM	Time domain simulation: - Loss of infeed and loss of outfeed/exports	EirGrid
	Demonstrate mitigations for the steady voltage scarcity	VSAT/LSAT	Load flow analysis: - Intact system and N-1 Faults	EirGrid
	Demonstrate mitigations for the dynamic voltage scarcity	TSAT/LSAT	Time domain simulation: - Short circuit faults	EirGrid
	Demonstrate mitigations for transient instability issues	TSAT/LSAT	Time domain simulation: - Short circuit faults	EirGrid
	Demonstrate mitigation options for congestion issues	PSS/E PLEXOS	Load flow analysis: - Intact system and with contingencies AC Power Flow with preventative security constraints UCED with DC load flow.	EirGrid

4. FREQUENCY STABILITY MITIGATIONS

Frequency stability is the ability of a power system to maintain steady state frequency, following a severe system upset, resulting in a significant imbalance between generation and load [9]. Large imbalances are caused by severe system disturbances, such as large load or generation tripping, tripping of HVDC interconnectors, or system splits. Frequency control scarcities were observed in Deliverable D2.4 of EU-SysFlex [1] with the transition to a power system with high levels of non-synchronous renewables. This section explores a number of possible mitigation measures that can be adopted to alleviate/avoid such frequency excursions in Task 2.6, first in the Continental, or pan European power system, followed by the Ireland and Northern Ireland power system.

The demonstration of the capabilities that are needed to solve the technical scarcities is the main focus in Task 2.6; not the technologies themselves. It is important to note that it is acknowledged that the technologies discussed in this section are not exhaustive; they are typical examples of technologies that can provide the needed capability.

4.1 CONTINENTAL EUROPE

4.1.1 SUMMARY OF ISSUES

With increasing penetration of renewable variable generation, based on power-electronic converters, power systems are transitioning away from well-understood synchronous generator-based systems, with growing implications for their stability. As wind and PV penetration levels rise, conventional generation will gradually be displaced, leading to a reduction in the fraction of generation participating in governor control and in the inherent inertia of the system, resulting in faster frequency dynamics following a major network fault or load-generation imbalance.

In order to assess the possible mitigations for addressing the issue of frequency stability in the continental European power system, in the context of high penetration levels of Variable Renewable Energy Resources (VRES), a new methodology has been proposed within Task 2.6 of the EU-SysFlex project The results of analyses for continental Europe will be presented in detail in this chapter.

4.1.1.1 BACKGROUND

The continental European power system is modelled in the EDF-developed simulation platform "PALADYN" by six zones, each including one or several countries, as illustrated in Table 4-1. The assumptions, as well as the modelling approach of PALADYN, can be found in detail in [10] and the validation approach of the models is presented in [11].

TABLE 4-1: FREQUENCY SIMULATION ZONES IN PALADYN

Zone	Reasons to be considered as a zone	% of CE annual consumption
The Iberian Peninsula (Spain, Portugal)	Electrical Peninsula	~11%
France	Central role on the Western Europe grid, and detailed data available	~17%
Northern zone (Austria, Belgium, Denmark, Germany, Luxembourg, Netherlands, Switzerland)	Northern countries, closely integrated in the power system markets and operation	~32%
Eastern zone (Czech Republic, Hungary, Poland, Slovakia)	Eastern Europe countries, some grid information missing for this zone	~12%
Italy	Electrical Peninsula	~12%
The Balkans (Turkey, Albania, Bosnia, Bulgaria, Croatia, Greece, Macedonia, Montenegro, Rumania, Serbia, Slovenia)	Little information available on those countries, historical data has been used (generation dispatch, FCR, aFRR)	~16%

In Task 2.4, for each hour of the year in both the Energy Transition (ET) and Renewable Ambition (RA) scenarios, two types of incident were simulated, as defined by ENTSO-E, one for interconnected operation and one for system splits:

- Interconnected operation: the reference incident corresponds to the simultaneous loss of the two largest generation units in each considered zone. In most zones except France, the largest generation unit has a nominal power around 1 GW. Therefore, incidents of 2 GW were simulated in every zone apart from in France where 3 GW incidents were simulated.
- System splits: a separation of the Iberian Peninsula, a separation of Italy (similar to the 2003 Italian incident), and a split of Continental Europe into three zones (similar to the 2006 historical split) were studied, as illustrated in Figure 4-1.

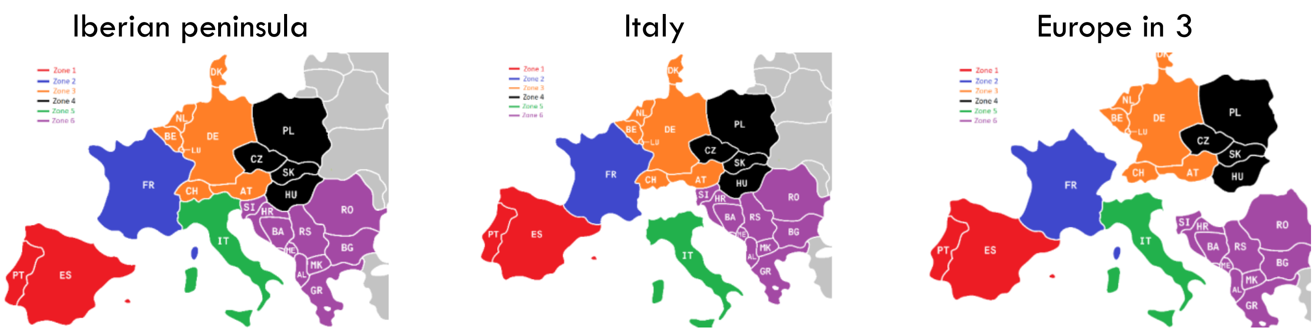


FIGURE 4-1: SIMULATED SYSTEM SPLITS INCIDENTS

In the simulations, system splits implied the disconnection of both AC and DC interconnectors, which could be deemed as an overly pessimistic assumption. Indeed, DC links could be controlled in order to remain connected in case of system splits. This possibility could reduce drastically the severity of the splits consequences and is to be thoroughly explored. However, it was deemed relevant to assess the potential worst cases.

For each simulation case, three indicators were derived from the frequency behaviour during the transient: 1) the nadir and the zenith, which are respectively the minimum and the maximum values of the frequency (Hz); 2) the maximal RoCoF (Rate of Change of Frequency) value, calculated through a sliding window of 500 ms following the simulated incident.

4.1.1.2 CONCLUSIONS DRAWN FROM TASK 2.4

Following the simulated interconnected incidents, in both ET and RA scenarios, frequency nadir values appeared to be manageable in all zones of the Continental power system and no clear situation of black out was encountered over the year. The only frequency stability concern raised was the observation of the possible RoCoF overshooting in the Iberian Peninsula in less than 10% of the time following large generators losses. It is therefore recommended to specifically take into account inertial constraints in the dispatching process and/or to monitor the grid inertia in this area at high penetration levels of VRES, in order to ensure the frequency security in case of interconnected incidents.

Regarding the system splits, they intuitively lead to instantaneous imbalances much higher than the interconnected incidents. The classical frequency control mechanisms can consequently be not sufficient to cope with such incidents, and the system frequency stability can generally only be managed by relying on defence actions such as LFSM-O/U[2] and load shedding.

Table 4-2 sums up the key simulation results from Task 2.4, results which form the basis of the analysis in the next sections. The same trends were observed for the three simulated incidents of system splits, even though the results were exacerbated for the splits of the Iberian Peninsula and of Italy, compared to the split of Europe in three. All the system splits in the context of RA scenario endanger more the frequency stability, as the possible imbalances among zones are higher in RA than in ET, due to the higher development of interconnectors in the RA scenario.

[2] Limited Frequency Sensitive Mode (LFSM) at over frequency (O) or under frequency (U)

TABLE 4-2: SUMMARY OF THE MAIN SIMULATION RESULTS OF THE FREQUENCY BEHAVIOUR FOLLOWING SYSTEM SPLITS

	Energy Transition			Renewable Ambition		
Splitting event	NADIR < 47.5 Hz	ZENITH > 51.5 Hz	RoCoF > 1 Hz /s	NADIR < 47.5 Hz	ZENITH > 51.5 Hz	RoCoF > 1 Hz /s
Iberian Peninsula	0%	0%	~ 38%	~ 1%	~ 14%	~ 72%
Italy	< 1%	< 1%	~ 58%	< 1%	~ 1%	~ 58%
Europe in 3	0%	0%	~ 1%	0%	0%	~ 25%

The load shedding mechanism, as modelled in that study, was globally able to maintain the frequency above 47.5 Hz. There were, however, some few cases for all configurations where the threshold of 47.5 Hz was crossed. Regarding zenith values, the study revealed that the LFSM-O, as modelled, was not always sufficient to maintain frequency below 51.5 Hz, which is the critical level for the European power system. As previously explained, RoCoF values higher than 1 Hz/s represent a challenge for operating the system and this risk was observed in a large part of the year in all the split configurations except in case of the “Europe in 3” split in the ET scenario.

In conclusion, it was observed that there could be **much higher risks associated with unusually high values of RoCoF, and therefore black-out situations, in the RA scenario compared to the ET scenario.** This is, due to the reduced overall inertia from high penetration rates of RES-E and increased levels of interconnections in the RA scenario. **The risks were mainly present if power system splits occurred during times of high penetrations of variable renewables and thus low inherent inertia**.

Some concrete remedy actions, or mitigations, are possible in order to address these issues. The following three options are investigated in the next sections:

- **limiting cross-borders flows** to reduce the imbalances caused by system splits;
- **curtailing VRES** and increasing inertia level with **conventional plants**, preferably decarbonised generation such as hydraulic, biomass or nuclear power plants;
- **encouraging alternatives for inertia provision**, such as synchronous condensers or grid forming control of VRES or storage.

The most cost-effective solution is likely to be an optimal mix of all the aforementioned measures.

Based on these findings, further techno-economic analyses have been performed in Task 2.6 in order to assess the possible mitigations to ensure frequency stability in the most critical conditions of grid operation in continental Europe.

4.1.2 METHODOLOGY AND ASSUMPTIONS TO ENSURE THE SYSTEM FREQUENCY STABILITY IN THE CASE OF A SPLIT EVENT

This section introduces the methodology developed and used to assess the most cost effective mix of the three aforementioned solutions to ensure system resilience in case of split event. This methodology relies on the implementation of local inertial (or kinetic energy) constraints within CONTINENTAL and on an outer Synchronous Condensers (SC) investments loop. The following figure (Figure 4-2) gives an overview of the applied approach. Each of its steps will be further detailed.

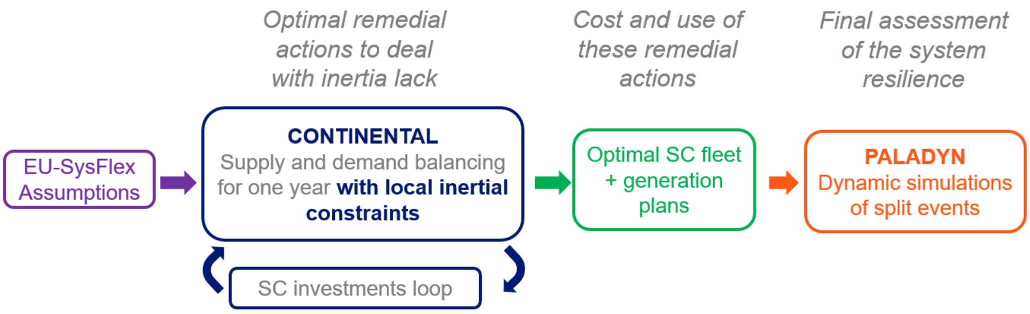


FIGURE 4-2: OVERVIEW OF THE PROPOSED METHODOLOGY TO ASSESS FREQUENCY STABILITY MITIGATIONS IN CONTINENTAL EUROPE

This section also tackles some calibration aspects, such as the relevancy of the local inertial constraints regarding the different split configurations. It also sums up the main assumptions regarding the technical and economic features of a standard type of SC considered by the methodology.

4.1.2.1 IMPLEMENTATION OF NEW LOCAL INERTIAL CONSTRAINTS WITHIN THE CONTINENTAL TOOL

4.1.2.1.1 CONSTRAINT DEFINITION

System splits can happen in reality in all interconnected electrical systems. These events are likely to entail very significant power imbalances which can lead to system collapse. Load shedding plans can be essential to restore power imbalances and stop the frequency drops. However, the RoCoF values during these events must be limited so that generators stay connected and load shedding can be activated in an efficient way.

The following formula exhibits the theoretical absolute RoCoF value following a sudden imbalance:

$$RoCoF(t) = \frac{f_{nom}.\ |Imbalance|}{2.KineticEnergy} \quad \text{(Eq. 4-1)}$$

Where:

- f_{nom} (Hz) is the nominal frequency, e.g. 50 Hz
- *Kinetic Energy (MW.s)* is the amount of rotational kinetic energy stored in the rotating masses of all the online synchronous generators;

- *Imbalance (MW)* is the value of the imbalance.

The following formula can then be derived to express the constraint that, at any time t, a zone z susceptible to a system split would not undergo a RoCoF higher than the defined maximum value *RoCoF Max* (Hz/s).

$$RoCoF(z,t) = \frac{f_{nom}.\ |\sum FlowsIn(z,t) - \sum FlowsOut(z,t)|}{2.KineticEnergy(z,t)} \leq RoCoF\ Max \qquad \text{(Eq. 4-2)}$$

Where:

- *FlowsIn(z,t)* and *FlowsOut(z,t)* are the import / exports power flows of z suddenly cut by the system split

This constraint has been implemented within the CONTINENTAL tool which is discussed in more detail in Deliverable 2.3 of EU-SysFlex [8]. Every European zone likely to suffer from a grid split can be identified as a vulnerable zone where a minimum value of inertia must be ensured. In practice, CONTINENTAL has two ways to ensure that the theoretical RoCoF value would not exceed the defined upper limit ($RoCoF\_max$):

- increasing the local inertia by starting more conventional generators, thereby curtailing VRES
- reducing the interconnector flows.

These could be considered as two separate potential operational mitigations, however, in what follows, they are considered together in order to identify the optimal mix of use of these mitigations.

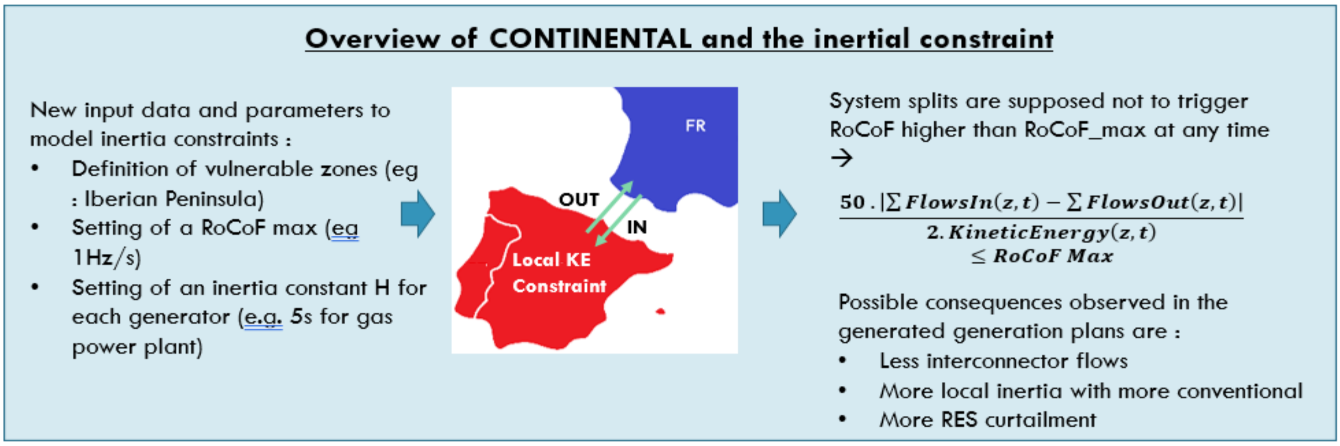


FIGURE 4-3: SHORT DESCRIPTION OF KINERTIC ENERGY CONSTRAINT WITHIN CONTINENTAL

Two maximal values for RoCoF have been chosen for this study: 1Hz/s and 2 Hz/s. As explained in Deliverable 2.4 [1] these values seem to be in the relevant range of the hypothetical uniform European requirement regarding the maximal admissible RoCoF to be withstood by all generators. It is worth reminding that Ireland and Northern Ireland impose [12], or will impose, in their Grid Code a maximal ROCOF value of 1 Hz/s.

4.1.2.1.2 SECURING A SINGLE ZONE CAN IMPLY SEVERAL INERTIAL CONSTRAINTS: CALIBRATION

An electrical zone can suffer from different system split configurations. Our study considers, for instance, three possible split cases for the France zone as illustrated in Figure 4-4: the Iberian split, the Italian split and the disconnection with its eastern neighbours (Belgium, Germany and Switzerland). Each one of these possibilities needs to be secured through a specific inertial constraint.

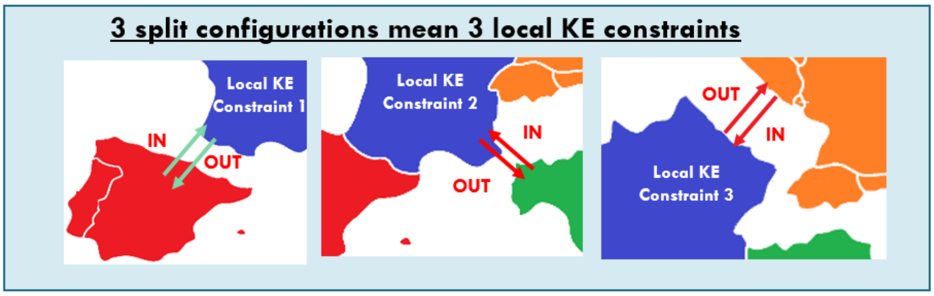


FIGURE 4-4: THREE SPLIT CONFIGURATIONS FOR THE FRANCE ZONE

Defining inertia constraints for each zone may seem to be too conservative in some cases. Indeed, taking the France zone as an example, it would still be connected to the Iberian and Italian peninsulas even if a disconnection happens with its eastern neighbours. Therefore, it may sound reasonable to suppose that France could, to a certain extent, benefit from the inertia contribution of the Iberian and Italian systems.

However, PALADYN dynamic simulations during the calibration step of the methodology revealed that inertial constraints alone located in zones other than France were not effective in reducing the French local initial RoCoF. Figure 4-5 depicts the frequency behaviours in France (red curves) and in the Iberian Peninsula (blue curves) when France is experiencing such a separation. Thus, **in order mitigate the high RoCoF, synchronous condensers were added into the Iberian Peninsula during this calibration step**. In Figure 4-5, the dotted lines correspond to the reference case (i.e. the configurations of the RA core scenario), whereas the solid lines are the same simulations with additionally installed synchronous condensers (SCs) in the Iberian Peninsula. Figure 4-5 demonstrates that SCs installed in the Iberian Peninsula leads to a considerable reduction in the local initial RoCoF while also supporting the containment of system frequency for both zones. This result alone is evidence of the ability of SCs to mitigate RoCoF issues.

In contrast, the installation of Iberian SCs (i.e. additional inertia) appears to offer no support to France in terms of RoCoF. Indeed, as can be seen in Figure 4-5, both solid and dotted red curves overlap in this time window, meaning that the French initial RoCoFs have the same value, with or without additional inertial contribution from its neighbouring and synchronously interconnected zone. This observation thus confirms the need to model local KE constraints in the applied methodology.

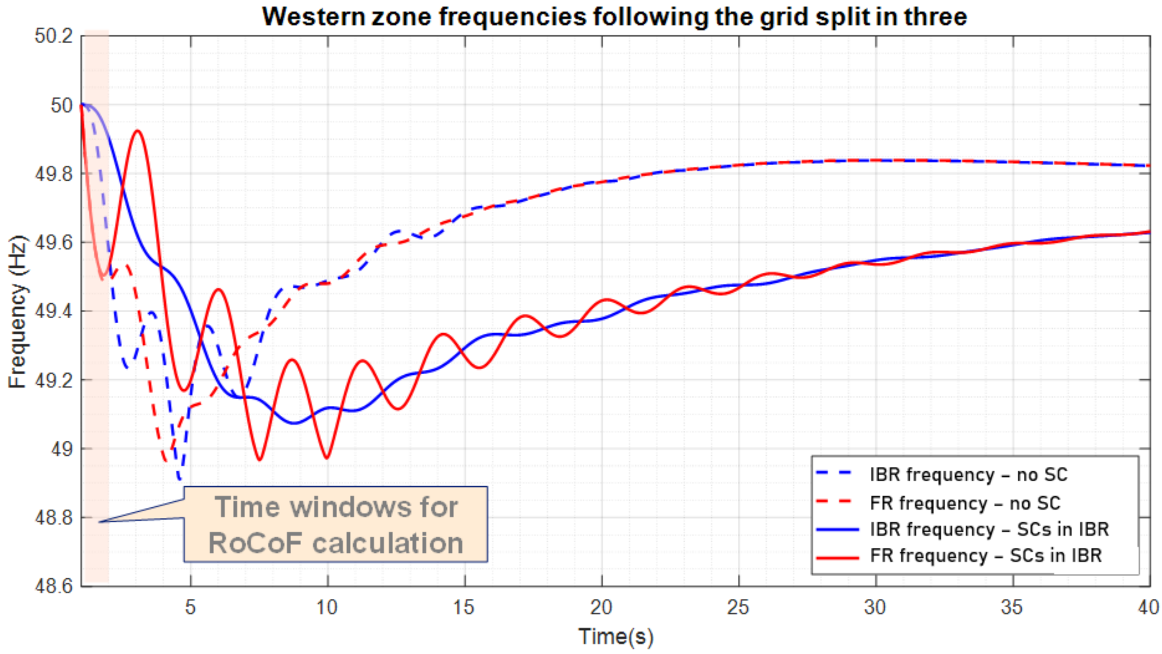


FIGURE 4-5: ILLUSTRATION OF FREQUENCY BEHAVIORS IN FRANCE AND IBERIAN PENINSULA WHEN FRANCE DISCONNECTS FROM ITS EASTERN NEIGHBORS

4.1.2.1.3 CHOSEN SPLIT CONFIGURATIONS

Table 4-3 summarises the chosen split configurations. In the end, eight KE constraints have been modelled within CONTINENTAL.

TABLE 4-3: SPLIT EVENT CONFIGURATIONS

Zone	Chosen split events	Max triggered Imbalance
Iberian Peninsula	1- split from France	12 GW
Italy	1- split from France & Switzerland	18.5 GW
France	1- split from Spain 2- split from Italy 3- split from Belgium, Germany and Switzerland	12 GW 5.5 GW 18 GW
Germany + neighbours	1- split from France & Italy 2- split from Eastern countries	31 GW 13 GW
Eastern countries	1- split from Germany & Austria	13 GW

4.1.2.2 DEVELOPMENT OF AN INVESTMENT LOOP TO OPTIMALLY ADJUST THE SYNCHRONOUS CONDENSERS

This part of the methodology section focuses on an investment loop which relies on iterative CONTINENTAL runs in order to gradually size the optimal SCs fleet in the different areas of Continental Europe.

4.1.2.2.1 GOAL OF THE METHODOLOGY

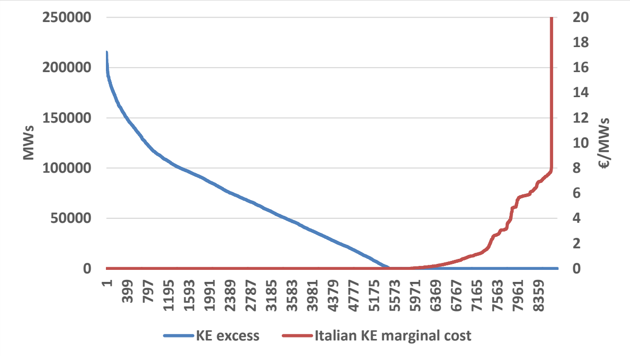
Synchronous Condensers (SCs) have been identified in the literature as an efficient means to increase inherent inertia and maintain frequency stability [13]. Although SCs are not the only grid equipment able to contribute to the system inertia, the applied methodology here only considers these facilities as a possible solution to mitigate this issue. This point presents, to some extent, a limit of this study and will be discussed later. . However, the overarching objective of this study is to demonstrate the capability of different mitigations to tackle the scarcity of inertia and the resultant RoCoF issue.

The goal of the investment loop is to determine the optimal capacity of SCs for each identified vulnerable zone. With no SCs investment, as a result of the inertial constraint, CONTINENTAL's decisions to start up more conventional generators or to reduce the interconnector flows can result in much more fuels costs, much more RES curtailments and ultimately increased CO_2 emissions. Crucially, however, investment in SCs can help reduce the impact of the inertia constraint, which is a necessity in order to ensure frequency stability, but needs to be optimally assessed to avoid overinvestment.

4.1.2.2.2 ASSESSMENT OF THE ECONOMIC IMPACT OF THE INERTIAL CONSTRAINT WITH CONTINENTAL

CONTINENTAL is based on linear programming and, as a consequence, it is possible to compute dual values for every modelled constraint. As for the inertial constraints, computations of dual values have been determined in such a way that they represent the marginal costs of kinetic energy, or inertia, for every hour and for every vulnerable zone. These marginal costs are expressed in terms of €/MW.s and give an economic value of each additional MW.s. available in the system.

As an illustration, the left graph of Figure 4-6 depicts the duration curves for the Italian Peninsula showing the Marginal Cost of inertia (KE MC) as well as the excess of inertia. It is clear from these curves that most of the time the MCs of inertia are equal to zero (red plot), indicating there is sufficient inertia in the system to meeting the inertia constraint and thus keep the RoCoF within acceptable limits and there is no need to redispatch the generation plants or the interconnector flows. However, the right part of these curves shows that when there is no surplus of inertia, the MCs of inertia gradually increase and can amount to around 10€/MW.s. Any MW.s supplied by SCs in these periods would help the system to lower its operational cost and would capture these MCs of inertia. The right graph of Figure 4-6 displays the state "On/Off" of a 50 MVA SC during the simulation and clearly shows those periods with positive MCs if inertia matches with SC "On" state.



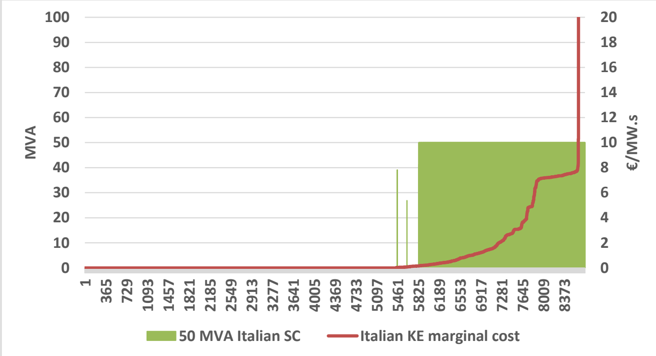


FIGURE 4-6: SCARCITY ILLUSTRATION OF KE WITH DURATION CURVES OF KE MARGINAL COST AND USE OF SC

4.1.2.2.3 SCS CHARACTERISTICS

The SC characteristics that are used in this study are obtained from TERNA's PowerTech article [14], which gives technical and financial information for recent SCs commissioned in Italy. Table 4-4 gives all the information required to apply the present methodology. From this set of data, normalised fixed costs for 1 MW of SC, assuming a lifetime of 45 years and a discount rate of 8%, has been assessed. As indicated in Table 4-5, the final fixed cost utilised for the study was 10 k€/MVA. This value is intendedly conservative to take into account potential extra costs such as land and rent prices or internal engineering cost to build SC. Indeed, this value may look more conservative still considering that retired power plant conversions could lower the SCs costs further. Despite uncertainty about SCs costs, TERNA projects prove that SCs fitted with flywheels are able to provide the system with a lot of inherent inertia at a reasonable cost [14]. Running SCs for a thousand hours per year with MCs higher than 1 or 2 €/MWs appears to be enough to guarantee their profitability.

TABLE 4-4: SC TECHNICAL AND FINANCIAL FEATURE, SOURCE TERNA

SC - TERNA Data of new project with flywheel		
Nameplate apparent power (Sn)	250	MVA
Turnkey investment Cost (IC)	20.5	M€
10 year maintenance contract	3	M€
Inertia constant, including the flywheel (H)	7	S
Auxiliaries consumption (AC)	1.2	% of Sn

TABLE 4-5: ANNUAL FIXED COST OF 1 MWS PROVIDED BY SC

SC - Additional data and calculations		
Normalised Investment Cost	82	k€/MVA
Discount rate	8	%/y
Lifetime	45	Y
Annual normalised maintenance cost	1.2	€/kW/y
Total annual fixed cost for 1 MVA SC	7.5	k€/MVA/y
Conservative total annual fixed cost for 1 MVA SC	10	k€/MVA/y
Conservative annual fixed cost for 1MWs SC	1.4	K€/MWs/y

4.1.2.2.4 VALUE ASSESSMENT OF SCS

As explained above, CONTINENTAL outputs MCs of inertia for every vulnerable zone *z* and for each hour *t*. It is then possible to calculate the Gross Margin (*GM*) of one MVA of a SC, located in the zone *z*, through the following formula:

$$GM_{SC}(z) = \sum_{t \in year} max\left[\sum_{i \in \, KE\ constraints\ in\ z} H_{SC}.KE\_MC(i,\ t) - Consumption_{SC}.EnergyMC(z,t);\ 0\right] \qquad \text{(Eq. 4-3)}$$

Some comments about this formula:

- The SC is assumed to be available during all the year;
- $Consumption_{SC}$ are the costs of its auxiliaries losses compensated at the marginal cost of power in the zone z $EnergyMC(z,t)$;
- When inertia is not profitable on a defined hour, the SC is supposed to be turned off and its yield equals to zero;
- A zone can suffer different system split configurations which imposes to implement several KE constraints within CONTINENTAL. As a consequence, several MCs of inertia are generated and must be all taken into account for the assessment of SCs value.

Finally, it is possible to evaluate the net income of potential new SC by deducting the SC Fixed Cost from the gross margin: $NetIncome_{SC}(z) = GM_{SC}(z) - FC_{SC}$.

4.1.2.2.5 ITERATIVE PROCESS

The SCs investment loop relies on an iterative process as summarided in Figure 4-7. CONTINENTAL is run with all the KE constraints activated. Posttreatment computes the value of SCs for every zone. SC investments are achieved in the zone *z* where $NetIncome_{SC}(z)$ is the highest, provided that $NetIncome_{SC}$ is higher than zero in at least one zone. CONTINENTAL is then re-run with the new SCs capacity.

The investment step for the SC capacity has been set to 1 GVA. The iterative process has also the possibility to remove SCs capacity in case of overcapacity leading to negative $NetIncome_{SC}(z)$. Finally, after around a hundred iterations, the approach outputs the optimal SCs fleet. The entire $NetIncome_{SC}(z)$ is then near to zero.

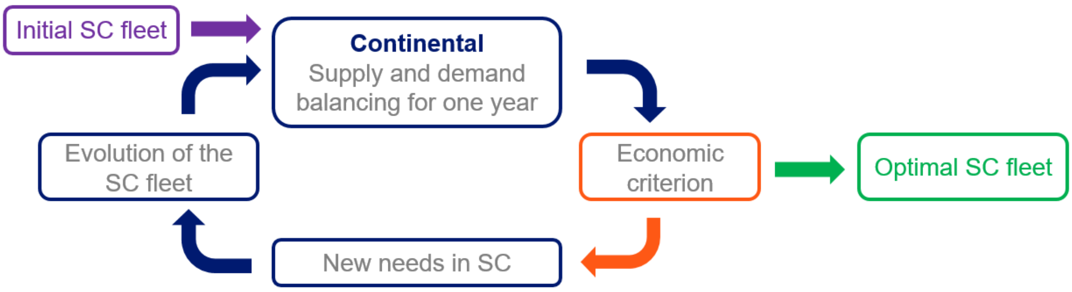


FIGURE 4-7: SC INVESTMENT LOOP PROCESS

4.1.3 RESULTS: EVIDENCE OF MITIGATIONS

This section presents the results achieved with through application of the methodology presented in the previous section. It focuses first in the results output by CONTINENTAL and its SCs investment loop before moving on to the dynamic simulations of the split events with PALADYN.

4.1.3.1 INVESTMENT IN SYNCHRONOUS CONDENSERS

The methodology has been applied to the EU-SysFlex RA scenario. Table 4-6 summaries the SCs investment across Europe as a result of the inclusion of the inertial constraints in the various ones in Europe. Table 4-6also includes information about consumption and VRES installed capacities for the sake of area comparison.

Table 4-6 shows that investment in SCs is considerable for both the Iberian and Italian peninsulas, especially in the case where the maximum acceptable RoCoF of 1 Hz/s (designated hereafter as the "*RoCoF1*" case) needs to be ensured for all the considered splits events. Both of these areas feature a very high penetration level of VRES. Conversely, the Eastern area has lower VRES generation and consequently a lower additional inertia requirement. Therefore, it would appear that no SCs investment is required in this area (at least for inertia and frequency stability reasons). SCs will only be invested in France as well as in Northern countries and its neighbours in the "*RoCoF1*" case. It would be interesting to investigate how these newly installed local SCs capacities could help regulate locally the grid voltage and ensure the level of short circuit power in these areas. This part is, however, out of the scope of this study for Continental Europe. However, as will be seen in later chapters, SCs are shown to be capable of supporting voltage and mitigation voltage scarcities in the Ireland and Northern Ireland power system.

TABLE 4-6: OPTIMAL SCS INVESTMENTS – RA ASSUMPTIONS

Area	SCs Capacities		Annual System consumption (RA)	Wind Capacity (RA)	Solar Capacity (RA)	Max imbalance triggered by split event
	1 Hz/s case	2 Hz/s case				
Iberian Peninsula	39 GVA	18 GVA	342 TWh	54 GW	53 GW	12 GW
Italy	35 GVA	12 GVA	394 TWh	26 GW	57 GW	18.5 GW
France	14 GVA	0 GVA	548 TWh	58 GW	45 GW	18 GW
Germany + neighbours	12 GVA	0 GVA	1016 TWh	124 GW	112 GW	31 GW
Eastern countries	0 GVA	0 GVA	363 TWh	21 GW	5 GW	13 GW

With the assumption that the continental European power system stays resilient in case of RoCoF values reaching up to 2 Hz/s (designated by “*RoCoF2”* In the following), the need for inertia is much lower and the global capacity of SCs investment is three times lower than in the case *RoCoF1* (30 GVA vs. 100 GVA).

4.1.3.2 SYSTEM IMPLICATIONS OF INERTIAL CONSTRAINTS

Table 4-7 displays yearly indicators calculated at the European perimeter from CONTINENTAL outputs. These values are indicated as deviations from the reference case, namely when no inertial constraints were modelled. Two configurations are depicted: with and without optimal investment in SCs. The first configuration (consideration of inertial constraints in each vulnerable zone but without any investment in SCs) seems unrealistic given the fact that SCs are a valuable, viable and low cost option, and has only been analysed as an intermediate methodological step before running the SCs investment loop.

TABLE 4-7: EUROPEAN YEARLY INDICATORS HIGHLIGHING THE IMPACT OF THE INERTIAL CONSTRAINTS ON GENERATION PLANTS – RA ASSUMPTIONS

Yearly Indicators	Deviation from reference case – KE constraints but No SC		Deviation from reference case - KE constraints With SCs	
	1 Hz/s case	2 Hz/s case	1 Hz/s case	2 Hz/s case
Total Production Cost (including SCs costs)	**+21.5 B€/y**	**+ 3.1 B€/y**	**+1.77 B€/y**	**+0.44 B€/y**
	+8.4%	+1.2%	+0.7%	+0.2%
Interconnectors flows	**-111 TWh/y**	**-34 TWh/y**	**-35 TWh/y**	**-7 TWh/y**
	-18%	-6%	-6%	-1%
Curtailment	**+ 35 TWh/y**	**+28.6 TWh/y**	**+0.36 TWh /y**	**0.32 TWh/y**
	146%	+119%	**+2%**	**+1%**
CO_2 emissions	**+10.9 Mt/y**	**+8.5 Mt/y**	**+1.7 Mt /y**	**0.7 Mt/y**
	+6%	+5%	+1%	+0%

The key messages for the first configuration ("No SC" case – first two columns in Table 4-7) are:

- Interconnectors' flows are significantly reduced when inertial constraints are activated.
- As a consequence, VRES cannot be as exported as it was possible in the reference where no KE constraints were considered. Therefore curtailment and CO_2 emissions surge. Most of the new curtailment occurs in the Iberian Peninsula and in Italy.
- Without SCs investment, total production costs increase significantly. Deeper analysis reveals that the inertial constraints can prevent some zones from importing generation which can entail situations with electrical supply shortage and very high failure costs. It is particularly the case for Italy which relies mainly on imports to balance its annual peak load. It is worth highlighting that these situations are not related to very high VRES generation periods in Italy. Importing up to 18 GW is just too risky in case of splits and the model therefore does not succeed in meeting Italian demand.
- Although the increased operating costs as a result of the additional of the inertial constraint are very high, it must be acknowledged that there is really no alternative to the implementation of such a constraint.

Other interesting observations can be drawn from the second configuration ("With SC" case - last two columns in Table 4-7) are:

- With optimal SCs fleet, the additional costs are limited. VRES curtailment, CO_2 emissions and interconnectors' flows have the same orders of magnitude as those of the reference case (i.e. case with no inertial constraint).
- As can be intuitively imagined, setting the maximum acceptable RoCoF at 2 Hz/s is less constraining than that at 1 Hz/s.
- The total cost of ensuring enough KE to secure the system in case of system splits ranges from 0.44 to 1.7 B€/y.

It is important to emphasise, that, as has been demonstrated in Task 2.4 and earlier in this section, it will not be possible to operate the Continental European power system without inertial constraints, or equivalent, as doing so has been shown to have the potential to results in excessive RoCoFs following a split event (see Table 4-2 above and Table 4-12 below), which could lead to system instability and blackout. Thus, while it is interesting to understand the impact on the system and the production costs of adding in the inertial constraint, and as the inertial constraint is unavoidable and has been shown to considerable impact on the dispatch, the more relevant values to consider are those relating to the impact of synchronous condensers once the inertial constraint is included. These values are illustrated in Table 4-8, which demonstrates that synchronous condensers have a very positive contribution to the power system when they are used to provide inertia and to meeting the inertial constraints. As can be seen, synchronous condensers result in a greater ability to accommodate more renewables on the power system as evidenced by the considerable reduction in curtailments, the reduction in CO_2 emissions and the profound reduction in production costs as a result of the displacement of expensive conventional plant. Alternative to SCs could also be envisioned to supply inertia as it is explained in the conclusion of this section (Section 4.1).

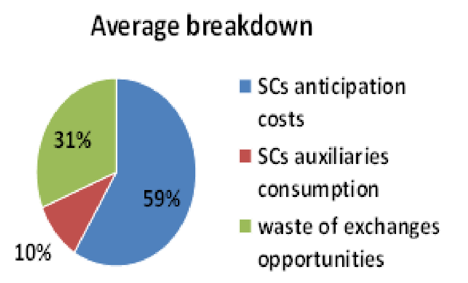
TABLE 4-8: EUROPEAN YEARLY INDICATORS HIGHLIGHING THE IMPACT OF SYNCHRONOUS CONDENSERS ON THE GENERATION PLANTS – RA ASSUMPTIONS

Yearly Indicators	Deviation from case with inertial constraints - inertial constraints With SCs	
	1 Hz/s case	2 Hz/s case
Total Production Cost (including SCs costs)	-19.73 B€/y	-2.66 B€/y
Interconnectors flows	+76 TWh/y	+27 TWh/y
Curtailment	-34.64 TWh/y	-28.28 TWh/y
CO_2 emissions	-9.2 Mt/y	-7.8 Mt/y

It is interesting to focus on the breakdown of the inertial costs with SCs investment that are utilised here Table 4-9 reveals that around 60% of those costs originate from the fixed costs for the SCs. SCs auxiliaries' costs only account for 10%, partly because SCs tend to run when power energy prices are low. Despite the SCs capacities, there are still restrictions in the use of interconnectors to comply with the inertial constraint. This means that expensive conventional generating plants have to be run in the various zones to meet system demand and this accounts for 30% of the inertia costs.

TABLE 4-9: COST OF ENSURING FREQUENCY STABILITY UNDER SPLIT EVENTS WITH OPTIMAL SCS INVESTEMENTS

Extra cost breakdown	1 Hz/s case	2 Hz/s case
SCs auxiliaries losses	192 M€/y	31 M€/y
Waste of exchanges opportunities	580 M€/y	107 M€/y
TOTAL	1770 M€/y	441 M€/y
SCs total annual fixed cost	998 M€/y	304 M€/y



4.1.3.3 INERTIA DURATION CURVES ANALYSES

Figure 4-8 displays the duration curves of the net interconnection flows in Italy and in the Iberian Peninsula in the 3 configurations (reference case without KE constraints, with KE constraints but No SC, with KE constraints & With SCs) for the sensitivity of "*RoCoF1*" case. The effect of the KE constraints is visible since importations are highly limited in both areas. French imports plummet since the implemented inertial constraints impede both Italy and the Iberian Peninsula from exporting their generation to France (see Equation 4-2). The maximum imported power in Italy falls from 18 GW to 10 GW as a result of the need to ensure RoCoF does not breach should a system split occur. This lack of power exchange, as explained before, causes a power inadequacy issue and, as a consequence, power shortages can happen. Obviously, this case is unrealistic and crucially installing SCs enables the restoration of the flows nearly to their optimal level when no KE constraints were modelled. Given the price of not being able to meet load, the investment loop continues to invest in SCs in Italy until the power shortage for inertial reasons completely disappears.

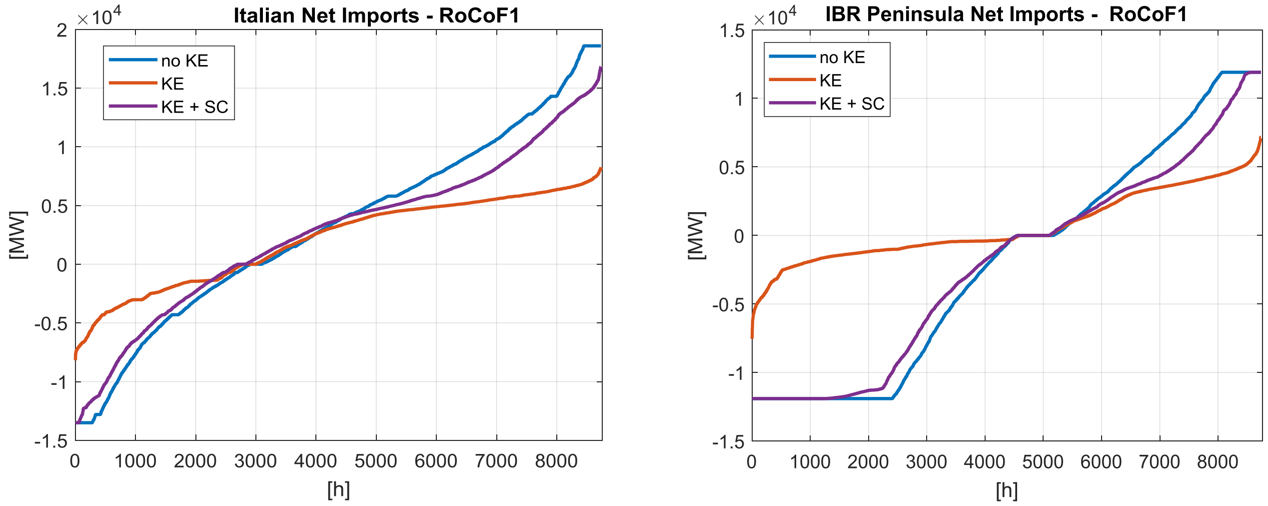


FIGURE 4-8: ILLUSTRATION OF KE CONSTRAINT IMPACT ON INTERCONNECTORS FLOWS

Figure 4-9 depicts the inertia duration curves for the same zones. It is visible that adding SCs capacities will boost the amount of inertia in both areas. If no SCs are installed, the inertia in both zones will not significantly vary. It is found that reducing interconnectors' flows is a more cost-effective method to solve the lack of inertia (i.e. meet the inertial constraint) than substituting the VRES by expensive must-run conventional generators.

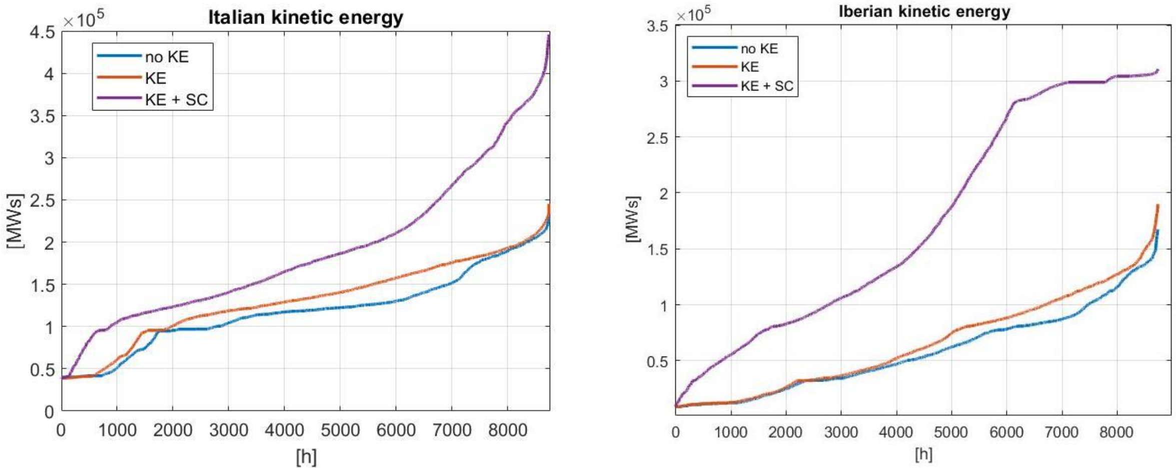


FIGURE 4-9: KE DURATION CURVES IN THE ITALIAN AND IBERIAN PENINSULAS

It has been previously observed that no SCs are installed in the Eastern zone (Table 4-6). However, it is important to note that it cannot be concluded that there are no frequency stability issues related to lack of inertia in that area. Indeed, as depicted in Figure 4-10, interconnectors' flows have to also be occasionally reduced in Eastern countries in order to fulfil the local inertial constraint implemented in CONTINENTAL.

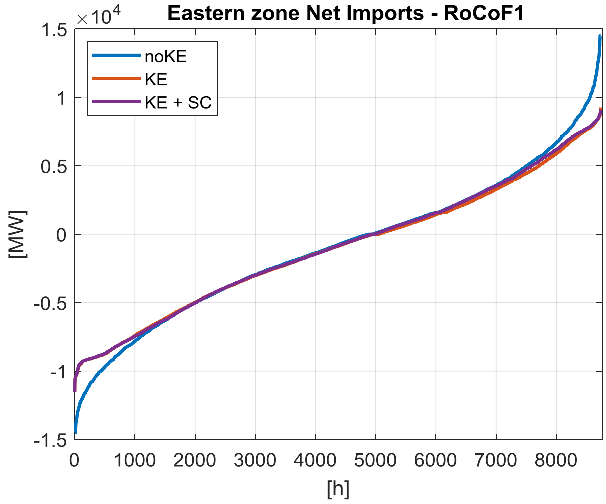


FIGURE 4-10: INTERCONNECTORS FLOWS DURATION CURVES IN THE EASTERN ZONE

Finally, Table 4-10 and Figure 4-11 give information about how many hours out of the years SCs are used in the different area. As can be seen most of the SCs are used more than 2000 hours a year. The significant running time of the SCs is indicating two things: a) the considerable need for SCs to contribute to system inertia and b) the combination of the relatively low CAPEX and OPEX costs of SCs with the high running time seems to indicate that there is a good investable business case for SCs.

TABLE 4-10: SC RUNNING HOURS IN THE DIFFERENT ZONES

Zone	Range of SCs running hours	
	1 Hz/s case	2 Hz/s case
Iberian Peninsula	2000-5100 h/y	1200-4300 h/y
Italy	1500- 3700 h/y	1000-2100 h/y
France	700-2500 h/y	-
Germany + neighbours	2000-2200 h/y	-

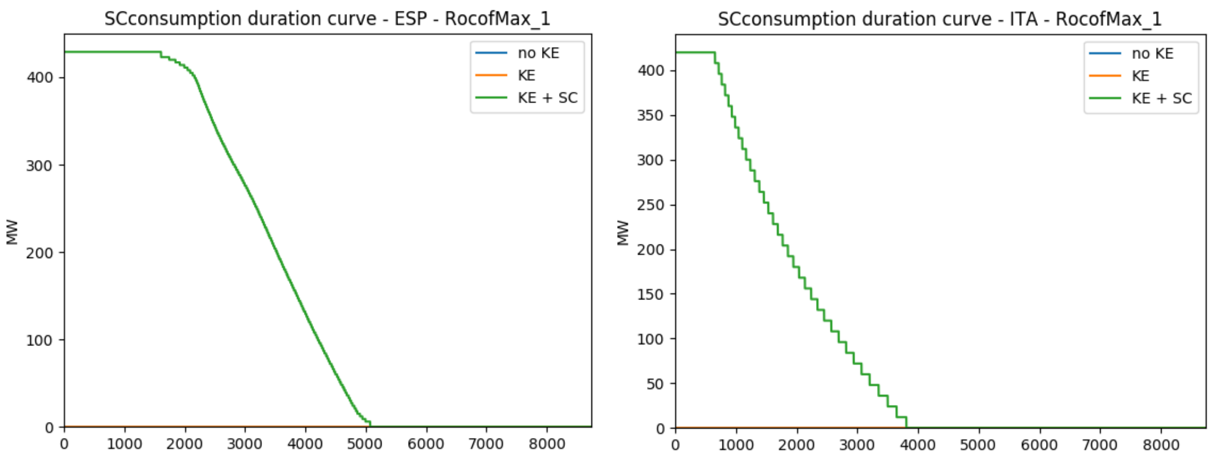


FIGURE 4-11: DURATION CURVES OF SCS USE IN ITALY AND SPAIN

Figure 4-12 displays the use of SCs in Iberian Peninsula depending on the level of SNSP and the net imports from France. It is worth highlighting the cumulative effect of these two drivers on the SCs use. The situations with very high inertia contribution by the SCs (top of the V curve) correspond to periods with high SNSP and high levels of net import. The extreme KE needs located on the top left part of the graphic match with episodes of very high solar generation capable to cover the whole Iberian consumption and saturate the interconnector towards France. The chart also illustrates that the SCs KE needs can be quite high even in case of intermediate or low SNSP if the use of the interconnector is high.

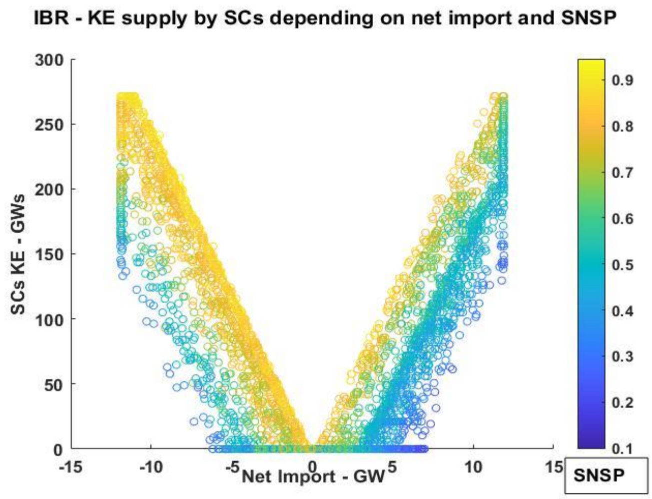


FIGURE 4-12: SNSP AND IMPORT/EXPORT LEVEL ARE KEY DRIVERS OF THE SCS IN IBERIAN PENINSULA

4.1.3.4 DYNAMIC SIMULATION RESULTS

As shown in Figure 4-2, the final step of the proposed methodology to assess the frequency stability of the European system based on the generation plant outputs from the CONTINENTAL model and the SCs investment loop process. It consists of simulating the dynamic behaviour of the frequencies in each zone following the predefined incidents of grid splits, using the PALADYN simulation platform.

The same configurations of system splits as described in 4.1.1.1 (i.e. separation of the Iberian and Italian peninsulas as well as the split of continental Europe into three) were simulated for each hour of the three following scenarios:

- Original Renewable Ambition **reference scenario**, where no specific inertial constraints were implemented to ensure the frequency stability in case of system splits – referred hereafter as *'No KE' scenario*;
- Adapted scenario **with inertial constraints**, which are supposed to limit the RoCoF values within ± 1Hz/s after the incidents, but without any investment in SCs – referred hereafter as *'KE' scenario*;

- Adapted scenario generated **with inertial constraint**s that are supposed to limit the RoCoF values within ± 1Hz/s after the incidents, allowing **also optimal investment in SCs** – referred hereafter as *'KE + SC' scenario*.

Table 4-11 displays the split events simulated, which are not exhaustive as the dynamic simulations are quite time-consuming. However, obtained results, that will be further illustrated and discussed in this section, demonstrate the effectiveness of frequency stability mitigations considered in the present approach.

TABLE 4-11: SUMMARY OF DYNAMIC SIMULATIONS PERFORMED

Split events	Max RoCoF = 1 Hz/s			Max RoCoF = 2 Hz/s		
	No KE	KE	KE + SC	No KE	KE	KE + SC
IBR from Europe	already done in D.2.4	new simulations		already done in D.2.4	*not simulated*	
Italy from Europe	already done in D.2.4	new simulations		already done in D.2.4	*not simulated*	
Europe in three	already done in D.2.4	new simulations		already done in D.2.4	*not simulated*	
Eastern zone from Europe	*not simulated*					

Table 4-12 sums up the results of the performed dynamic simulations. Compared with the '*No KE*' scenario where critical values of RoCoF were observed in many cases, the resulting RoCoF of each zone following different system splits have been maintained within the acceptable limits corresponding to the inertial constraints. It is clearly shown that the inertial constraints implemented within the CONTINENTAL model are sufficient to ensure the power system resilience in case of grid splits. There are very a few cases with RoCoF higher than 1 Hz/s in the "Europe in three" split occur in Italy and in the Eastern zone. These cases will be the subject of more analysis detail later in this section

TABLE 4-12: SUMMARY OF THE DYNAMIC SIMULATION RESULTS ON SYSTEM SPLITS (% OF TIME) – RA ASSUMPTIONS

Splitting event	No KE			KE			KE + SC		
	NADIR < 47.5 Hz	ZENITH > 51.5 Hz	RoCoF > 1 Hz /s	NADIR < 47.5 Hz	ZENITH > 51.5 Hz	RoCoF > 1 Hz /s	NADIR < 47.5 Hz	ZENITH > 51.5 Hz	RoCoF > 1 Hz /s
Iberian Peninsula	~ 1%	~ 14%	~ 72%	0%	0%	0%	0%	0%	0%
Italy	< 1%	~ 1%	~ 58%	0%	0%	0%	0%	0%	0%
Europe in 3	0%	0%	~ 25%	0%	0%	< 1%	0%	0%	< 1%

4.1.3.4.1 SIMULATION RESULTS: SPLIT OF THE IBERIAN PENINSULA

Figure 4-13 illustrates the monotonic functions of the RoCoF values in the Iberian Peninsula zone, which are calculated over a 500-ms time period, for different scenarios. As can be seen, RoCoF can reach more than 10 Hz/s in the *'no KE'* scenario, which is not manageable by system operators in practice and will cause black-outs if the system split happens. However, in both *'KE'* and *'KE + SC'* scenarios, RoCoF values have been well controlled and remain under 1 Hz/s with the help of the KE constraints and the new SC capacities.

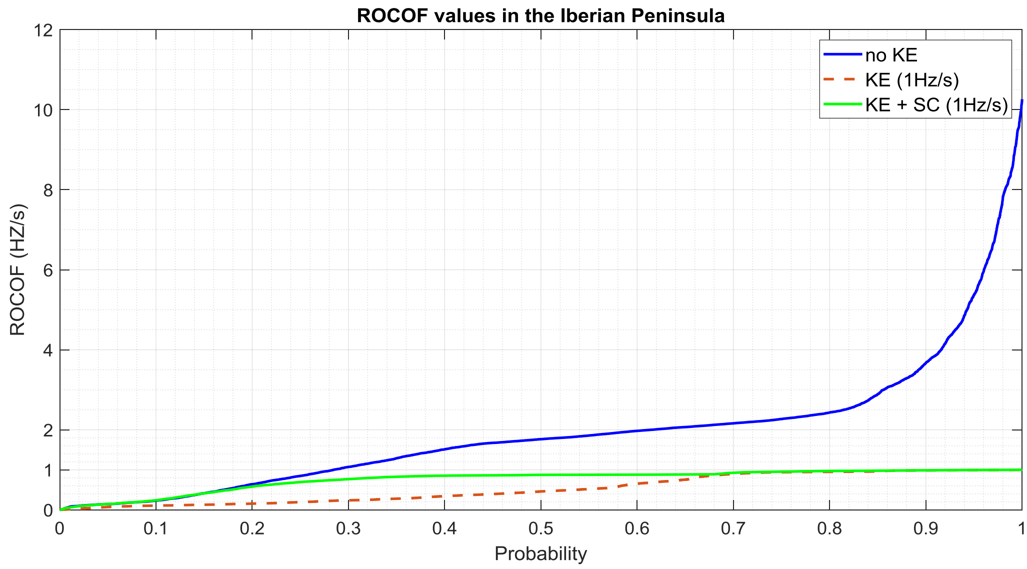


FIGURE 4-13: ROCOF VALUES IN THE IBERIAN PENINSULA FOLLOWING ITS SPLIT FROM THE REST OF CONTINENTAL EUROPE

As can be seen in Figure 4-14, frequency nadirs are less extreme after the incident when KE constraints have been respected. Nadir values as low as 46 Hz are observed for a number of hours in the *'no KE'* reference scenario (which indicates a 'black-out' would occur if the split occurred in these hours), but remain higher than 48.3 Hz in both *'KE'* and *'KE + SC'* scenarios (which means that frequency containment reserve (FCR), load sensitivities and load shedding could then be activated and would be sufficient to protect the system from a total black-out).

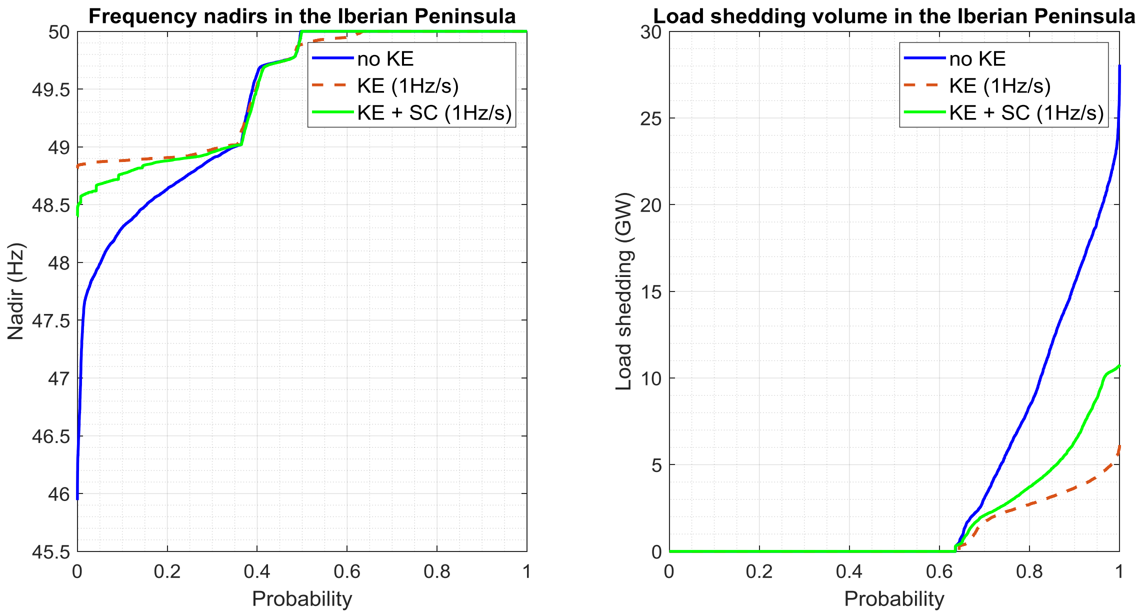


FIGURE 4-14: FREQUENCY NADIRS AND LOAD SHEDDING VOLUME IN THE IBERIAN PENINSULA FOLLOWING ITS SPLIT FROM THE REST OF CONTINENTAL EUROPE

As a consequence of lower RoCoFs and higher frequency nadirs, the load shedding volume required to contain the frequency is lower with the inertial constraints. However, it should be noted that, irrespective of the scenario, the probability of load shedding occurring after the Iberian Peninsula split seems equal, with a probability that load shedding would be required at about 38% of the total time. Nevertheless, it can be observed that, with the additional SCs, 15 GW of load shedding could be avoided in the most extreme case. Since the *'KE'* scenario implies a very significant reduction of the interconnector flows, the associated load shedding is meaningfully lower than the *'KE+SC'* one.

4.1.3.4.2 SIMULATION RESULTS: SPLIT OF ITALY

Similar findings can be observed while focusing on the dynamic simulation results for the Italy. As depicted in Figure 4-15, the critical RoCoF threshold of 1 Hz/s is breached in the '*no KE*' scenario for more than 60% of the time following the split of Italy from the rest of Europe. This risk RoCoF values being excessive can be removed with by implementing inertial constraints in the *'KE'* and *'KE + SC'* scenarios. This results in fewer concerns about the Italian system stability in the case of system splitting events.

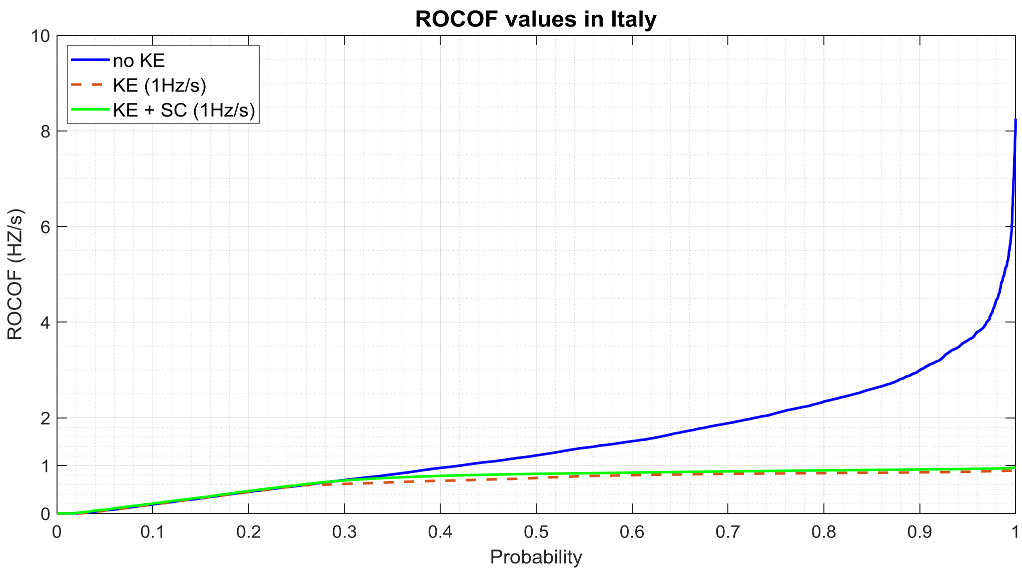


FIGURE 4-15: ROCOF VALUES IN ITALY FOLLOWING ITS SPLIT FROM THE REST OF CONTINENTAL EUROPE

Figure 4-16 shows the monotonic functions of the simulated nadir values and load shedding volumes in Italy after occurrence of a system split incident. It can be observed that in the '*KE*' and '*KE+SC*' scenarios, black-out risks disappear completely as very few cases of frequency nadirs below 48.5 Hz occur. The implementation of the inertial constraints leads also to less load shed in the case of system splits, a reduction of more than 15 GW for the worst case.

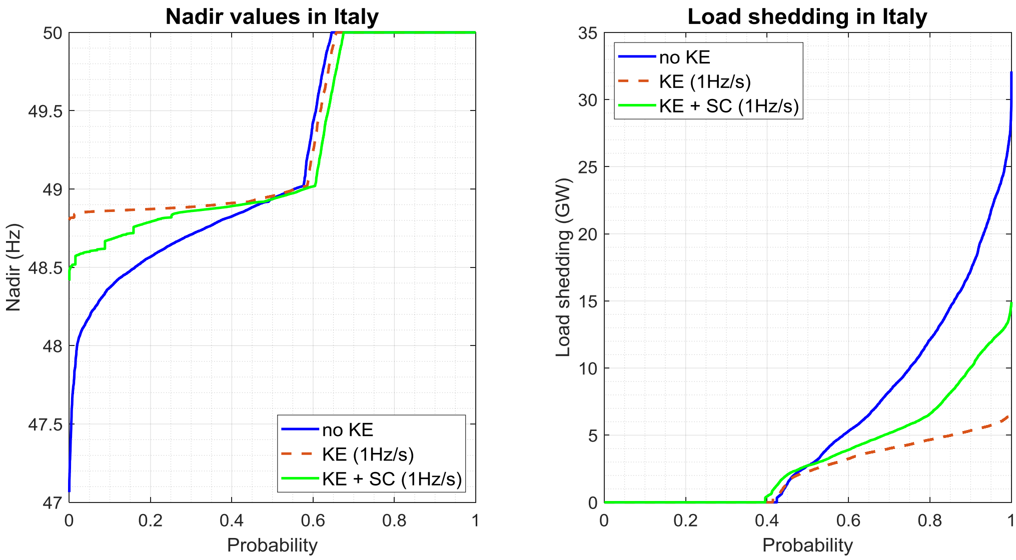


FIGURE 4-16: FREQUENCY NADIRS AND LOAD SHEDDING VOLUME IN ITALY FOLLOWING ITS SPLIT FROM THE REST OF CONTINENTAL EUROPE

4.1.3.4.3 SIMULATION RESULTS: SPLIT OF EUROPE INTO THREE

The monotonic functions of RoCoF values in the different zones modelled in PALADYN have also been recorded for the simulated split of Europe in three (see Figure 4-17). It can be seen from Figure 4-17 that the RoCoF values in the Iberian Peninsula, in France and in the northern zone of European remain all below 1 Hz/s following the split of Europe in three. This demonstrates the effectiveness of the local inertial constraints implemented in these zones and the expected contribution of the SCs capacities additionally installed.

Careful examinations of the frequency behaviour of the Italian and the Eastern Europe zones reveal some cases of RoCoF higher than 1 Hz/s, as shown in Figure 4-17. However, this observation is not inconsistent, since no local KE constraint has been modelled in CONTINENTAL to secure Italy and the Eastern Europe in case of “Europe in three” split. To better understand the phenomenon, a focus on the dynamic behaviour of the frequencies in different zones after the incident is thus necessary.

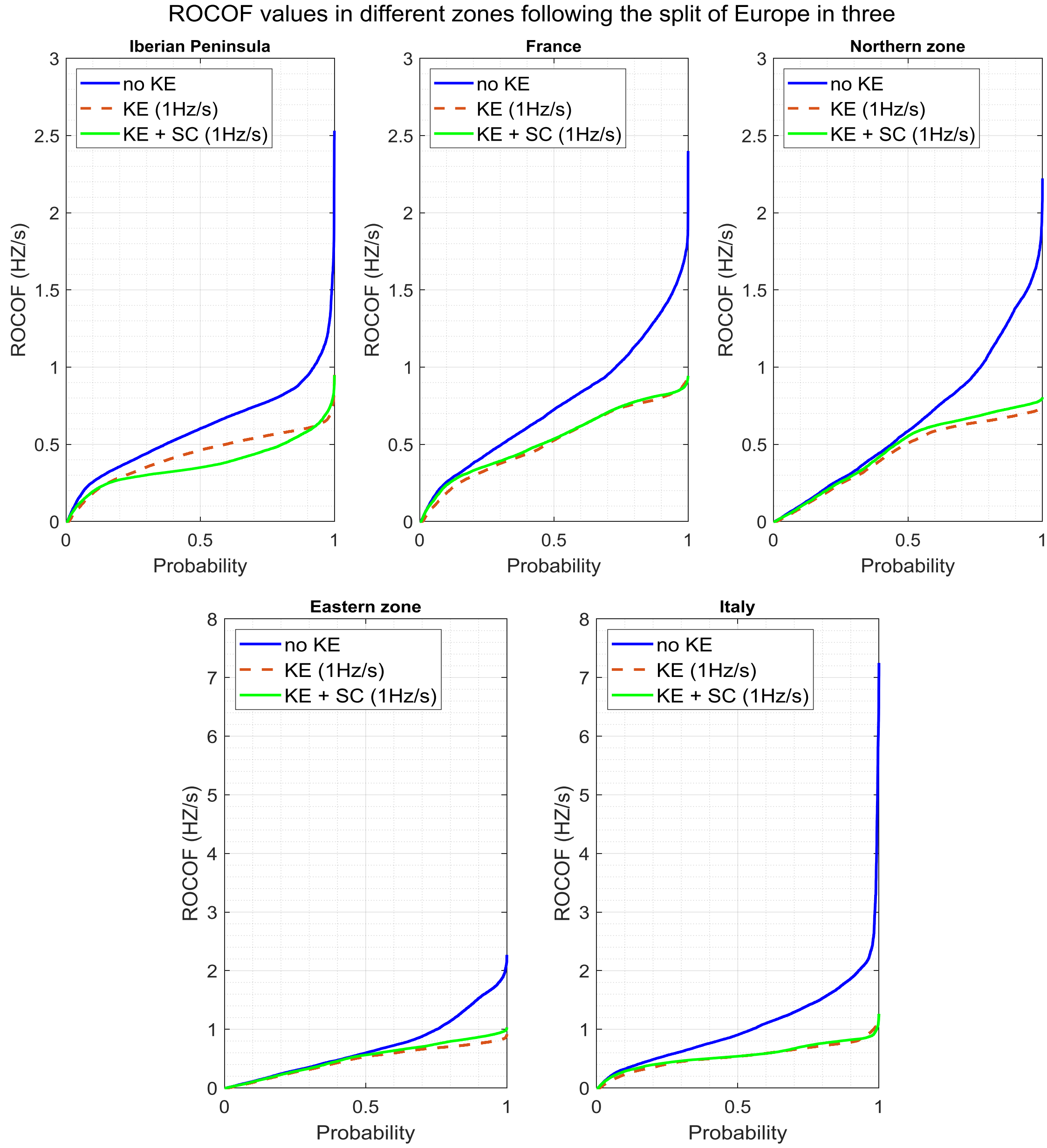


FIGURE 4-17: MONOTONIC FUNCTIONS OF ROCOF VALUES IN DIFFERENT ZONES FOLLOWING THE SPLIT OF EUROPE IN THREE

For Italy, it should be pointed out that although this zone remains in the same synchronous area with France and the Iberian Peninsula in the configuration of the simulated “Europe in three” split (Figure 4-1), the frequencies of these zones do not have the same features during the transient phase, before being totally synchronised in the steady state phase.

An illustrative example of the dynamic behaviour of the frequencies in the western synchronous zone is given in Figure 4-18. The differences of the frequency dynamics in the first 20 seconds following the split incident depends on the electrical distance from the incident, the synchronising torques among the zones as well as the local inertia of each zone. Therefore, even for the same incident simulated, the maximum RoCoF values observed in Italy could be much higher than that in France and in the Iberian Peninsula (Figure 4-17), despite the fact that the same stabilised frequency in the Western Europe is ultimately shared.

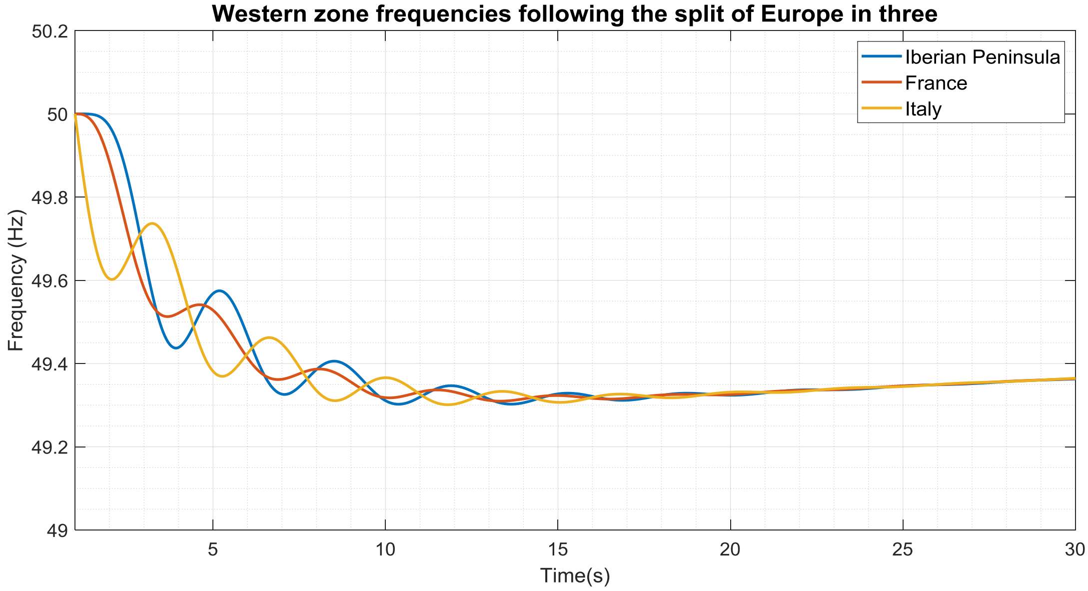


FIGURE 4-18: DYNAMIC BEHAVIOUR OF THE FREQUENCIES IN THE IBERIAN PENINSULA, IN FRANCE AND IN ITALY FOLLOWING THE SPLIT OF EUROPE IN THREE

In addition, it was naively considered, at the beginning of the study, that the split of Italy from the rest of Europe should have always been more stringent than the “Europe in three” split. As a consequence, additional specific constraints to ensure enough KE for the latter split was deemed not to be required. This consideration was actually relevant for most of the cases, as the Italian RoCoFs have been kept below 1 Hz/s after the “Europe in three” split for more than 99% of the time. However, in some exceptional cases, the interruption of the flows between Italy and Switzerland (in the configuration of the “Europe in three” split) can actually be more severe than the simultaneous double interruptions of the flows with France and Switzerland (in the configuration of the split of Italy). This happens when, for example, the Italian flows with the two neighbouring countries are in an opposite direction, leading to a reduced net loss of power after the incident. As a remedial action to provide total cover for the stability risk in case of grid splits, it would be easy to add a specific KE constraint dedicated to the split of “Europe in three” to entirely secure Italy. This is an area for future work.

For the Eastern zone, excessive RoCoF values have also been observed very occasionally (for less than 0.1% of the time), as a consequence of very high imbalances occurring in the neighbouring northern countries, which stay in the same synchronous area, in case of the split of Europe in three. Despite RoCoF values higher than 1 Hz/s not being experienced in the Northern zone thanks to the local inertial constraint considered, the synchronizing torque with the Eastern zone propagates a part of the imbalances, which can trigger high RoCoF values in the Eastern zone.

For illustrative purposes, Figure 4-19 depicts the dynamic behaviour of the frequencies in the Northern and Eastern zones following the split of Europe in three. It can be seen that in the first instances after the split, the movement of the frequency (rotor angle) in the Eastern zone is driven by the synchronizing torque with the Northern zone (with a time lag).

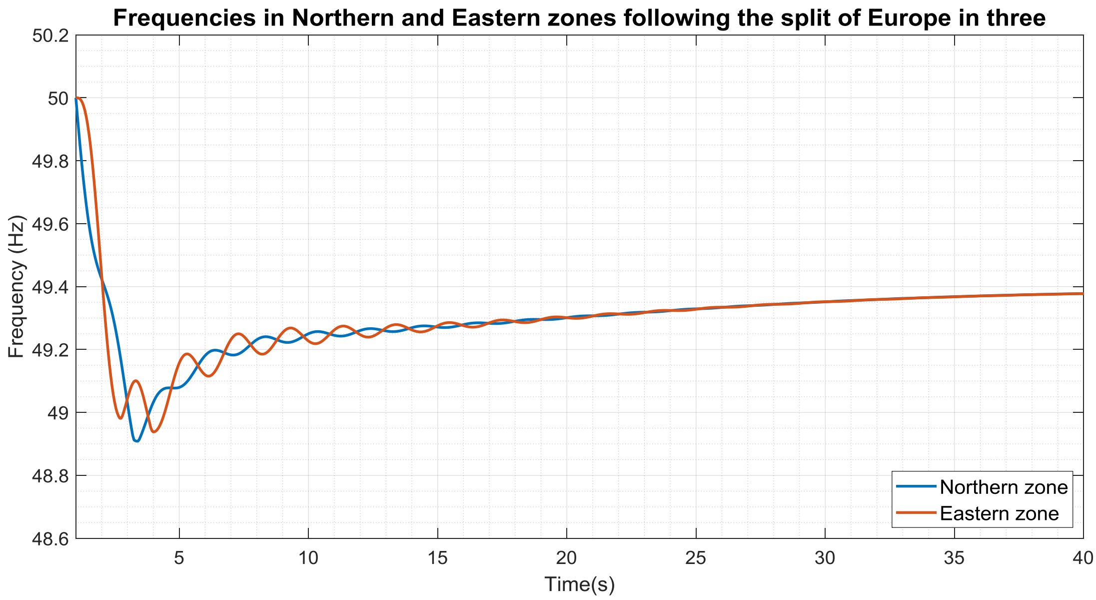


FIGURE 4-19: DYNAMIC BEHAVIOUR OF THE FREQUENCIES IN THE NORTHERN AND EASTERN ZONES FOLLOWING THE SPLIT OF EUROPE IN THREE

The RoCoF values calculated every 500ms in the same time window for the two zones are shown in Figure 4-20. It is observed that the maximum absolute value of RoCoF in the Northern zone occurs at the very beginning following the grid split. Nevertheless, the maximum RoCoF in the Eastern zone is observed one second after and overshoots that in the Northern zone.

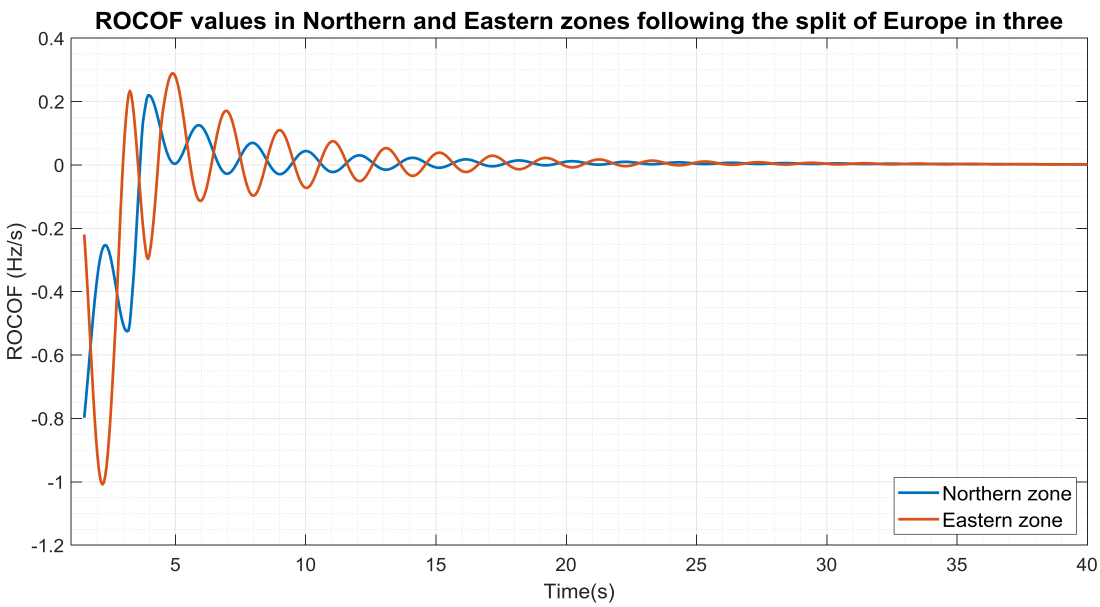


FIGURE 4-20: ROCOF CALCULATED IN THE NORTHERN AND EASTERN ZONES FOLLOWING THE SPLIT OF EUROPE IN THREE

This issue is actually of pure dynamic concern and can only be observed when dynamic simulations are performed. Consequently, it does not seem possible to implement an additional inertial constraint in the Eastern zone to cover this rare risk of over-limit RoCoF values with the current CONTINENTAL modelling. The observations highlighted in this section reflect the limitations of the proposed approach. It also indicates that the used models were sufficient enough to deal with a lot of data to achieve a complex study with long-term assumptions and for a very large perimeter, but unfortunately cannot capture all the phenomena. This is a positive result and provides a good indication of the scope of future work.

4.1.4 KEY MESSAGES AND DISCUSSION: CONTINENTAL EUROPE

A complete methodology has been developed and calibrated in order to assess the mix of solutions and their associated cost to ensure the system stability in the case of split event. These solutions included:

- Occasional limitations of the cross-borders flows to reduce the imbalances caused by the system splits;
- Occasional substitution of VRES by conventional plants in order to ensure a minimum amount of inertia;
- Investments in alternatives for inertia provision, such as Synchronous Condensers (SC).

The developed approach relies on the improvement of CONTINENTAL through the implementation of local inertial constraints. The goal of these new constraints is to secure the European system frequency in case of several predefined split scenarios in the most cost effective way. An investment process has also been implemented in order to fix the size and the location of the optimal European SC fleet. Finally, dynamic simulations have been performed to assess the resilience of continental European power systems in case of severe grid incidents and to confirm that the SC capacity from the investment process is sufficient for mitigating inertia scarcities.

After a methodological validation phase, the approach has been then applied to the EU-SysFlex "Renewable Ambition" scenario. The key messages of the study are:

- In the context of the EU-SysFlex scenarios, it is essential that inertia is assessed and that system inertia is contributed to, for all varying operational conditions.
- It is possible to secure the European system in the case of system split but it is necessary to invest in dedicated assets to provide inherent inertia such as SCs to make up for the shortfall in inertia detected in Task 2.4, and confirmed in the analysis presented here.
- Without any dedicated assets, system costs and CO_2 emissions significantly increase following the introduction of the critical inertial constraints. Without the inertial constraints, the RoCoFs would be excessive and would put the system at risk of blackout.
- Investments in SC capacities range from 30 GVA to 100 GVA at the continental European perimeter.

- With adequate investments and operational practices, the additional costs of dealing with inertial scarcities would be marginal compared to the total generation cost. More than half of these costs are related to the SCs' fix costs (investment and maintenance).
- Both the Iberian and Italian peninsulas are the weakest European areas and SCs investments are concentrated in these areas
- HVDC behaviour will be crucial when split events happen. Gaining confidence in their expected behaviour in case of a grid disturbance is an important issue that could relieve drastically the need of inertia, as the size of the imbalance could be reduced.

Although an important methodological work has been performed to achieve this study, the approach is still an area of on-going investigation and there are several limitations to highlight for future work:

- The considered split events were the result of pragmatic choices since it was impossible to treat all the possible split configurations in Europe. These choices could be questionable and it would therefore be interesting to simulate other cases such as internal splits in Germany or in France and splits in the Balkan region, which were out of the scope of this study.
- Moreover, as will be appreciated, grid splits are very complex incidents. The applied approach was not able to capture every phenomenon experienced during such events. Split simulations with electromagnetic tools and with detailed grid modelling would be very useful to underpin this study and to reveal more precisely its limitations.
- Other stability issues such as voltage regulation or system strength were out of the scope of this particular study. However, since SCs can also be employed to resolve these issues, it would be very useful to assess their potential role in the future system considering all aspects of their capabilities. That also requires the use of dedicated electromagnetic tools. The capabilities of SCs are demonstrated in later chapters of this report as potential mitigations of issues such as dynamic voltage stability and rotor angle stability.
- Only SCs have been considered in the methodology. Indeed other solutions exist, for example enhanced controllers like Grid Forming (GF) which enable the converters to provide an inertial response capacity [15]. Investment in GF-based inverters would have been challenging to be integrated in the present methodology for different reasons. The feasibility of a large scale deployment of such equipment is, for instance, still to be demonstrated, and it is necessary to understand whether the GF controls can be applied to wind farms, solar farms or batteries. Additionally, there is little information about the cost of such equipment.

The general conclusion of this study is that, despite modelling limitations, the inertial issues in continental Europe occur mainly in the peninsulas and SCs could be cost-effective solutions. The optimal mix of solutions, however, of course needs to be assessed with a broader prospective in order to consider all the stability aspects. **Investment in SCs seems to be a relevant option. Other assets such as storage systems providing multi-services could also be considered, but this will be an area of future work.**

4.2 IRELAND AND NORTHERN IRELAND

The All-Island power system has been in a period of evolution over the past number of years driven by European and domestic policies concerning renewable energy targets. Ireland has set an ambitious renewable generation target of 70 % RES-E for 2030. This will require the power system to operate with SNSP levels in excess of 90% at times.

The shift in generation portfolio from one with small amounts of renewable energy sources (RES) to one with a significant amount of energy supplied by variable RES is leading to greater variability and uncertainty around frequency control due to a declining system inertial response. Renewable generation in the Ireland and Northern Ireland Power System is mainly provided by wind, solar, and hydro generation. Wind and solar generation are mainly interfaced with the electric grid through power electronic converters leading to a significant reduction in system inertia.

Coupled with this, changing reserve portfolios and potential changes to the dimensioning events can have significant impacts on system frequency and expected frequency profiles. The rate of change of frequency (RoCoF) due to a loss of infeed for a low inertia system is typically steep causing frequency to decay faster and falls below 49 Hz.

At present, in the Ireland and Northern Ireland power system, frequency reserves are employed for maintaining system frequency. These can be categorised as:

1. Regulating reserves: Synchronous generators fall under this category. The governors of synchronous generators start injecting active power after the occurrence of a frequency event, provided the generator is not operating at its maximum capacity. The provision characteristics of synchronous generators depend on their governor models and their corresponding parameters. These are the prime resources in contributing system inertia. Synchronous Condensers are synchronous generators which provide no active power but contribute to system inertia, as well as controlling reactive power through their excitation control.
2. Non or partially regulating reserves: Battery, interconnectors, pumped hydro and DSUs fall under this category. In this study, four HVDC interconnectors are considered. The maximum capacity of the interconnectors are shown in Table 4-1. Each of the considered interconnectors delivers a maximum of 75 MW of fast reserve. The provision of the interconnector reserves is initiated at 49.8Hz for the interconnectors and 49.7 Hz for batteries with a ramping up provision characteristic limited by the upper provision limit. Both interconnectors and batteries can be considered as fast acting. The pumps act either as a synchronous generator or as a load depending on the system conditions. The total capacity of pumps considered in this report is 652 MW. The pumps disconnect once the frequency drops below 49.65 Hz. Demand side units activate once the frequency drops below 49.3 Hz. Pumps and DSUs act instantaneously unlike that of batteries and interconnectors which have a ramp response.

TABLE 4-13: HVDC INTERCONNECTOR CAPACITIES

MOYLE	EWIC	GREENLINK	CELTIC
500 MW	500 MW	500 MW	700 MW

These frequency reserves which are currently employed and outlined above, for maintaining system frequency were considered in the analysis in EU-SysFlex Task 2.4. However, as will be detailed presently, due to the displacement of conventional plants in the transition to higher levels of variable, non-synchronous generation, significant frequency issues were discovered.

Deliverable D2.4 of EU-SysFlex [1] detailed all frequency control scarcities identified in Task 2.4. Early examinations of frequency stability found that in a 2030 All-Island power system with SNSP levels approaching 90%, RoCoFs can be excessive. A mitigation measure was included in the simulations carried out in Task 2.4 where a 1 Hz/s RoCoF constraint was included in the scheduling dispatch simulations.

Task 2.4 established that while there were frequency nadirs at times below load shedding levels, there were sufficient mitigations available such as a change in dispatched reserve magnitude. The results revealed that cases with higher volumes of fast reserve magnitudes had higher resulting frequency nadirs. In cases where there was insufficient fast acting dynamic reserve capability, lower frequency nadirs were observed.

This section addresses possible mitigation measures that can be adopted to alleviate or perhaps avoid such frequency excursions on the Ireland and Northern Ireland Power System. The aim of this analysis is to demonstrate the capability of a number of proposed technologies to mitigate the issue of frequency excursions As mentioned earlier, the demonstration of the capabilities that are needed to solve the technical scarcities is the main focus here; not the technologies themselves. It is important to note that it is acknowledged that the technologies discussed in this section are not exhaustive; they are indicative of technologies that can provide the needed capability.

4.2.1 METHODOLOGY AND SUMMARY OF ISSUES FROM TASK 2.4: IRELAND AND NORTHERN IRELAND

As outlined in the EU-SysFlex D2.2 [7] & D2.3 [8] reports, Network Sensitivities & Network Models were developed to stress the Ireland and Northern Ireland power system in Task 2.4. The expected installed renewable generation capacities for the All-Island power system vary between about 9,000 MW and 15,000 MW by 2030. Two significant operational constraints were applied in Task 2.4 for the evaluation of the 2030 All-Island Power System:

- System Non-Synchronous Penetration (SNSP) and;
- Maximum instantaneous Rate of Change of Frequency (RoCoF).

In addition, the operational policy constraint for the minimum number of online unit's was relaxed to accommodate greater levels of non-synchronous renewable generation in order to expose technical scarcities.

Traditionally, the loss of an infeed has been the focus of frequency stability phenomena for the Ireland and Northern Ireland power system. However, the loss of a 700 MW HVDC interconnection at full export which is the Largest Single Outfeed (LSO) becomes a credible threat to the system and therefore was evaluated in Task 2.4.

The Ireland and Northern Ireland power system employs an Over-Frequency Generation Shedding (OFGS) scheme for over-frequency situations that can occur during high wind generation periods, which sheds various magnitudes of wind generation on pre-specified over-frequency trigger set points. T2.4 revealed that frequency zeniths remained below the highest acceptable zenith of 50.75 Hz and no resulting under-frequency issues were observed following the activation of this OFGS scheme.

Figure 4-21 shows Task 2.4 under-frequency results for the LCL scenario following the loss of the largest single infeed (LSI) in the All-Island Power System. Analysis carried out revealed a number of cases (approximately 0.6% of all cases) where the frequency nadir deviated below the acceptable level of 49 Hz. Frequency nadirs need to be maintained above 49 Hz to satisfy System Operation Guideline (SOGL) requirements [16] and to provide a margin of safety to avoid the triggering of load shedding which occurs at 48.85 Hz. The figure also reveals a number of cases in which the system frequency oscillates following the loss of the LSI.

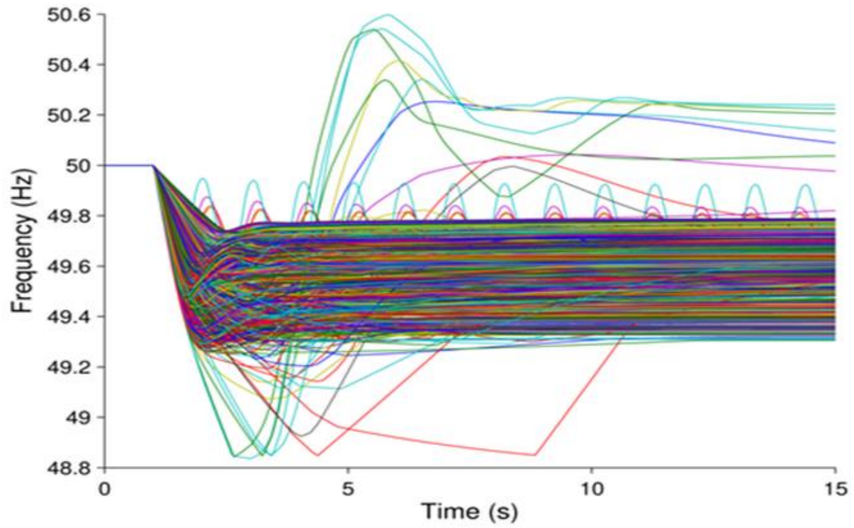


FIGURE 4-21: FREQUENCY PROFILE FOR LCL FOLLOWING LOSS OF LSI

Figure 4-22 shows a key finding from Task 2.4 whereby if the available fast reserves are a significant fraction of the infeed loss, the frequency nadir is higher and vice versa. A careful observation of the figure reveals that where the SNSP level is above 60%, cases with a similar infeed loss volume and SNSP levels have varying frequency nadirs due to different availability of fast frequency reserves. Hence, the higher the fast reserve magnitude available, the better the resulting frequency nadirs.

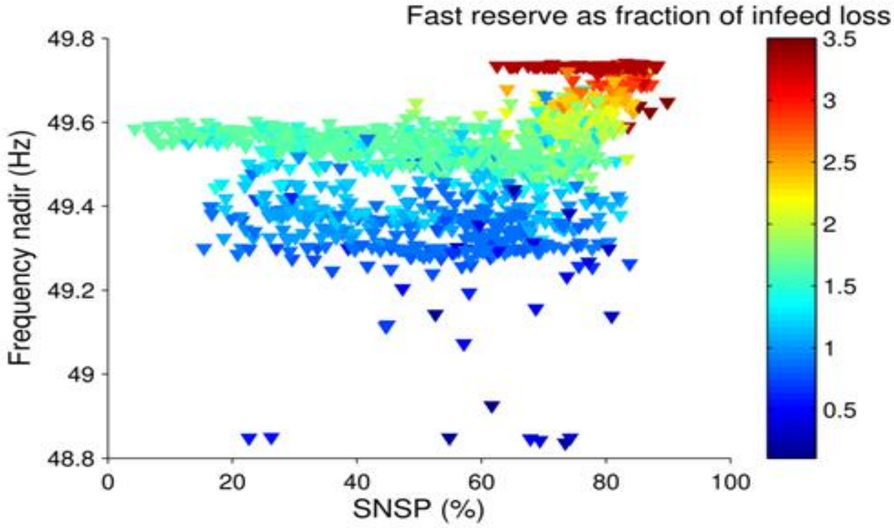


FIGURE 4-22: FREQUENCY NADIR VS SNSP & FAST RESERVE MAGNITUDE FOR LCL

As per the methodology highlighted in Deliverable 2.4 [1], the loss of the largest infeed (LSI) has been used in Task 2.6 as a stimulus to investigate the system response during a significant system event.

In order to identify mitigation measures, a Single bus Frequency Model (a Matlab based tool called SFM) that was utilised in Task 2.4 is again employed here. The SFM mimics a single bus of a power system to which all the generators and loads are connected. The RoCoF is determined by the system swing equation represented by:

$$\frac{\dot{f}}{f_b} = \frac{1}{2H}(P_m - P_e) \qquad \text{(Eq. 4-4)}$$

where $\dot{f}$ (in Hz) is the RoCoF, f_b (in Hz) is the nominal frequency, H (in pu) is the cumulative system inertia, P_m (in pu) and P_e (in pu) are the total mechanical and electrical power respectively. System damping is neglected. The difference of the mechanical and electrical determines the over or under frequency.

The algorithm adopted to identify mitigation measures based on the initial system conditions is as follows:

1. The system conditions before the introduction of mitigation measures is the starting point. These system conditions are based on the cases in Task 2.4 which resulted in frequency issues (0.6% of the cases as stated above). Dispatch information from the PLEXOS unit commitment schedules utilised in Task 2.4 such as the volume of dispatched battery, number of large units online, the system inertia and SNSP level are noted for the cases with frequency issues.
2. The dispatch information from PLEXOS for the cases with frequency issues forms the input to the SFM model. A stimulus is applied at 1s after the start of the simulation start. The worst case frequency event as observed in Task 2.4 is the loss of a 700MW HVDC Interconnector. The 0.6% of cases shown in Figure

4-21 that breach the 49 Hz frequency limit were as a result of the loss of the 700 MW HVDC Interconnector.

3. The proposed mitigation technology or proposed mitigation mechanism is then included in the model, and where applicable, the volume of the technology is increased slowly in a steady manner until the frequency of the system increases above the 49 Hz security limit.
4. The final volume of the resource which mitigates the frequency issues becomes the reported mitigated measure for the particular case studied.

The flowchart of the above algorithm is shown in Figure 4-23.

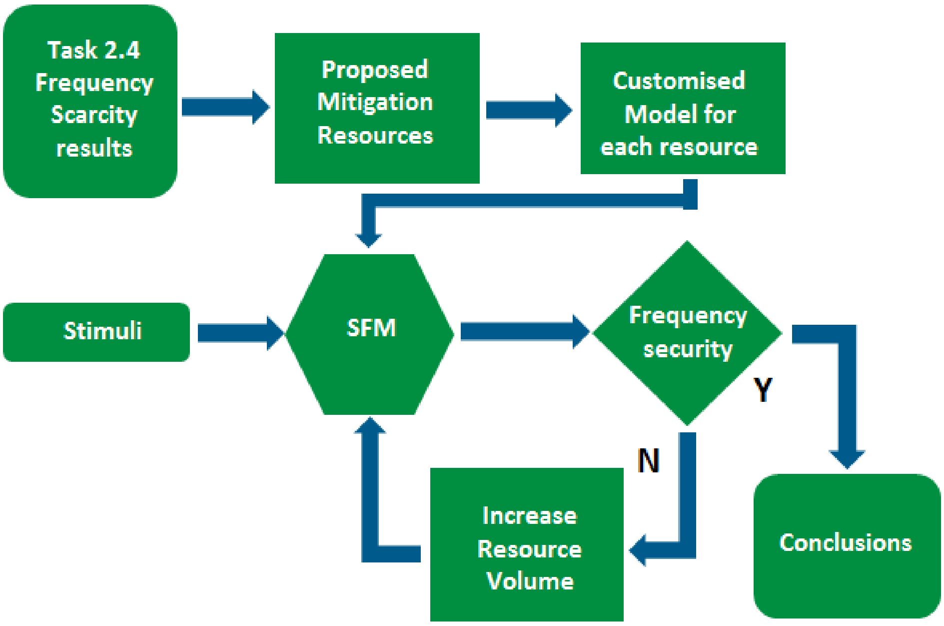


FIGURE 4-23: FLOWCHART SHOWING THE ADOPTED METHODOLOGY

The initial case, which was identified and studied in Task 2.4, in which the system frequency goes below 49 Hz is termed “base case” while the case with a mitigation added is termed “with mitigation” hereafter.

4.2.2 RESULTS: EVIDENCE OF MITIGATIONS

This section of the report proposes mitigation measures for addressing frequency issues. The primary focus is to increase system inertia or to utilise fast reserve provision to limit the RoCoF and to keep the frequency above 49 Hz. Moreover, reserve provision from wind farms has also been investigated and potential changes in operational policy of the system have also been proposed. The impact of the different characteristics such as ramp rate and response time on the effectiveness of the frequency control is also taken into account for each mitigation resource.

The mitigation options considered in this report are:

1. **Increasing system inertia** by installing Synchronous Condensers. These devices can contribute to limiting RoCoF and delaying the nadir which, as will be discussed, helps the triggering of slower static reserve response from resources such as pumped hydro and DSUs.
2. Increasing the level of **fast frequency response** available by incorporating faster acting ramp based sources such as battery energy storage systems (BESS).
3. Increasing the level of fast frequency response available by utilising the capability of wind turbine controls. Modern variable speed wind turbines can offer a short-term controlled response to temporary power imbalances, by harnessing their stored rotational energy, a so called emulated, or synthetic, inertial response. However, unlike conventional frequency response services, the emulated inertial response is dependent on the wind turbine operating condition and provides a response which is distinct to that from synchronously connected plant.
4. **Utilising variable non-synchronous resources, such as wind, to provide reserve**. The frequency response capability of wind farms are currently exploited to respond to overfrequency issues. However, they can also be used to address underfrequency issues, provided the wind is curtailed to provide enough room for the wind turbine to respond and increase it active power.
5. Evolving operational policy for example by decreasing the size of the largest single infeed (LSI) for specific system conditions. The current LSI on the Ireland and Norther Ireland Power System is significantly less than the Celtic HVDC Interconnector which has a capacity of 700 MW and which will be the LSI in 2030. The HVDC Interconnector on high import is one of the key drivers for high SNSP levels but could be useful to identify times when it might be required to limit LSI to aid in the operation of a secure system.
6. Evolving operational policy to maintain of minimum number large units that must be online. The current operational policy stipulates that a minimum of 8 large units are required to operate the current All-Island Power System securely. The analysis in Task 2.4 removed this constraint in order to assess the technical scarcity implications of moving away from such an operational policy. It was identified that there may be hours/circumstances when bringing more synchronous generators at minimum generating levels online would be beneficial. The focus of this particular investigation is to offer some initial insights into whether the corresponding minimum set rules can be relaxed from the frequency stability point of view.

4.2.2.1 INCREASING SYSTEM INERTIA LEVELS

The system inertia is crucial in terms of frequency stability of a power system. The inertia is contributed by the kinetic energy stored in rotating machines. A high system inertia makes the system frequency stable by decreasing RoCoF thereby providing enough time for slow acting devices to respond to frequency change.

Synchronous generators generate active and reactive power besides providing system inertia. Active and reactive power can be prioritised with the help of field excitation. Synchronous Condensers are also rotating machines which do not generate active power but generate reactive power. These devices are generally used to improve system voltage regulation and stability by continuously generating/absorbing reactive power through controlling its excitation current and frequency stability by providing synchronous inertia.

In order to demonstrate the effect of Synchronous Condensers in increasing system inertia and help in mitigating frequency issues, a simplified model of a generator with no governor response was developed for the existing SFM model. The characteristics of this model was based on a 400 MVA unit with 3s inertia constant [17]. The base case was analysed with the addition of the Synchronous Condensers.

The base case SNSP is 69.38% with a potential RoCoF of 1Hz/s and total system inertia is 17,500 MWs. In terms of reserve provision and volumes available for this base case, pumped hydro provides a cumulative reserve of 472 MW while demand side units are providing 180.8 MW of reserve. The remaining three HVDC Interconnectors (one of the interconnectors is the LSI and thus cannot provide reserve) have an available reserve capacity of 75 MW each. The volume of BESS for this case was 39.5 MW. There are three large synchronous units online dispatched to 1,107 MW in total. Two of the three units are operating at their maximum capacity.

The methodology and algorithm shown in Figure 4-23 is employed and the number of Synchronous Condensers is increased one at a time, increasing system inertia levels, until the frequency is restored above the 49 Hz security limit. Under the assumption of using Synchronous Condensers with a 400 MVA capacity and with 3s inertia constant, 13 such devices would be required.

Figure 4-24 shows the system frequency traces for the base case and with the mitigation applied represented by a solid and dashed line, respectively. Comparing the two traces suggests that, all things being equal and in the absence of any other mitigation, a significant reduction in RoCoF would require a considerable increase of system inertia to enable reserve from pumped hydro and DSU to activate before the nadir. Results shown in Figure 4-25 reveal that increasing system inertia results in a slower RoCoF, shifting the occurrence of the nadir from 2.66s to 4.12s. This shift allows 90.4 MW of DSUs to activate before the frequency hits its nadir.

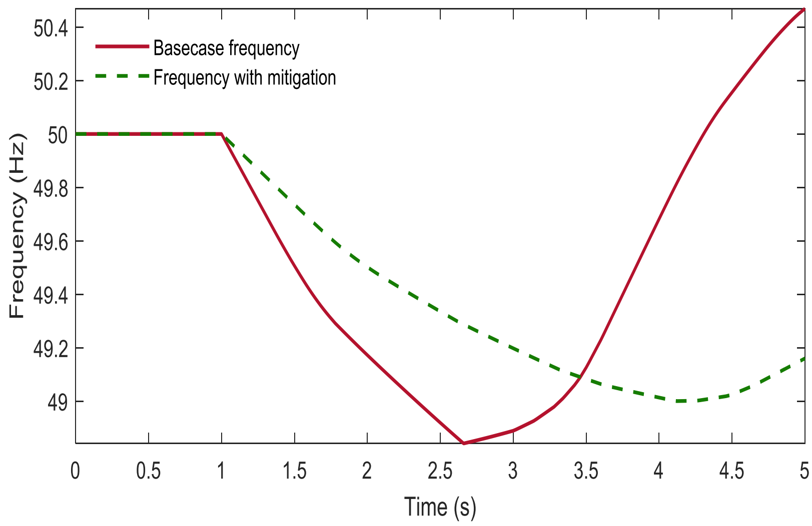


FIGURE 4-24: SYSTEM FREQUENCIES FOR BASE CASE AND WITH MITIGATION

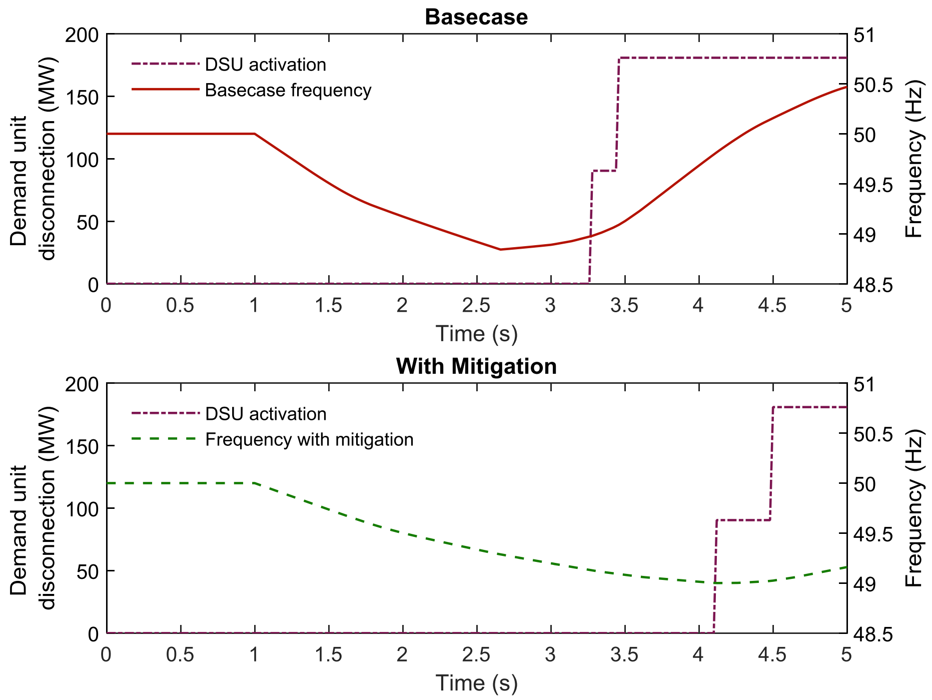


FIGURE 4-25: RESPONSE OF DEMAND SIDE UNITS FOR BASE CASE AND WITH MITIGATION

Figure 4-26 shows the response of pumped hydro units for base case and with mitigation. Careful observation reveals that three pumps disconnect from the system amounting to 219 MW prior to the nadir being reached, due to the increased system inertia, the consequently decrease in RoCoF and the subsequent delay of the nadir.

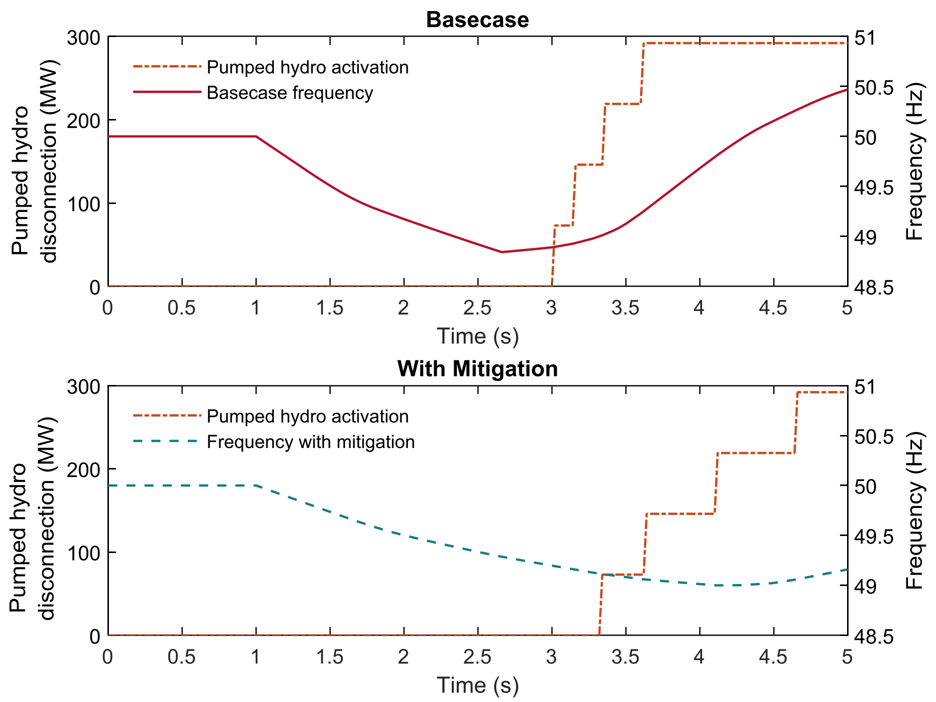


FIGURE 4-26: PUMPED HYDRO RESPONSE FOR BASE CASE AND WITH MITIGATION

Finally, Figure 4-27 shows the governor response of online conventional generators. Due to the shift of nadir, an additional 30.9 MW is available in the form of governor response amounting to 88.18 MW in total at the nadir.

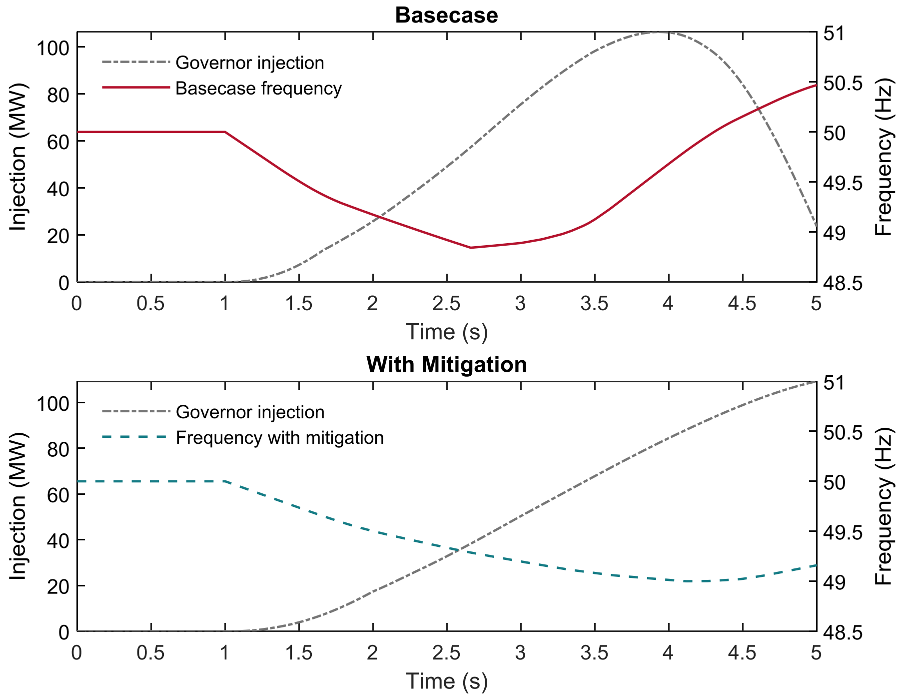


FIGURE 4-27: GOVERNOR RESPONSE OF ONLINE SYNCHRONOUS GENERATORS FOR BASE CASE AND WITH MITIGATION

The capability of Synchronous Condensers to support the containment of system frequency above 49 Hz be summarised as follows:

1. The increased inertia from the Synchronous Condensers delayed the occurrence of the nadir in this particular case from 2.66s to 4.12s. However analysis shows that a large number (13 in this case) of these devices would be required to reduce the RoCoF sufficiently to enable provision of the existing reserve from the pumped units and DSUs and to thus contain the frequency.
2. Due to this delay in the nadir being reached, 90.4 MW of DSUs would be disconnected from the system before the frequency nadir.
3. 219 MW of pumped hydro would be disconnected from the system before the frequency nadir.
4. Finally, governor response at the nadir from online conventional units is increased from 57.28 MW to 88.18 MW due to the delay in the nadir occurring.

It must be noted that Synchronous Condensers will not be sufficient on their own to deal with the frequency stability issues but they will be quite useful in combination with other mitigation measures that are discussed later in this report. Their main characteristic is that they will halt fast frequency decay thereby enabling the slow acting frequency provision to be utilised before the occurrence of the frequency nadir.

4.2.2.2 INCREASING THE LEVEL OF FAST FREQUENCY RESPONSE PROVISION

EirGrid and SONI's Fast frequency response (FFR) product is defined as the additional increase in MW output from a unit, or a reduction in demand, following a frequency event that is available within two seconds of the start of the event and sustainable for at least eight seconds afterwards [18]. It is also stipulated that the extra energy provided by the MW increase, in the timeframe from the FFR response time to 10 seconds, shall be greater than any loss of energy in the ten-to-twenty second timeframe afterwards due to a reduction in MW output [18]. FFR can be provided by various resources such as conventional generators, wind turbines, batteries and HVDC interconnectors.

Due to the transition towards higher levels of renewables and away from conventional fossil fuel technologies, in this section of the report the effect of FFR provided by greater volumes of batteries, as well as utilising emulated inertia of wind turbines for providing FFR, on frequency stability is investigated.

4.1.2.1.1 PROVISION OF FAST FREQUENCY RESPONSE FROM BATTERIES

The same initial conditions for the base case as outlined for mitigation with Synchronous Condensers are considered for this mitigation, due to the fact that the volumes of batteries dispatched is significantly low in the base case. As previously mentioned, the system event leading to this frequency nadir is as a result from a 700 MW HVDC Interconnector trip.

Figure 4-28 shows the system frequency. The solid line represents the base case frequency. It can be seen that the system frequency nadir in this case occurs at approx. 48.84 Hz. The volume of reserve coming from BESS is increased from 39.5 MW in a stepwise manner to 226 MW in order to maintain a secure frequency above 49 Hz. It can also be observed that the nadir occurs almost 500ms later than the base case at 3.14 s, denoted by the dashed line in Figure 4-28 .

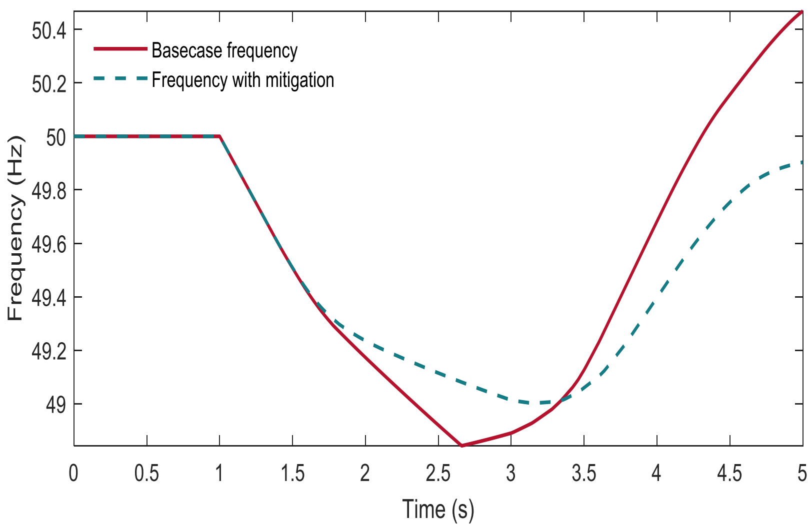


FIGURE 4-28: SYSTEM FREQUENCY FOR BASE CASE AND WITH MITIGATION

Figure 4-29 illustrates the significant increased active power injection by the batteries in the “with mitigation” case.

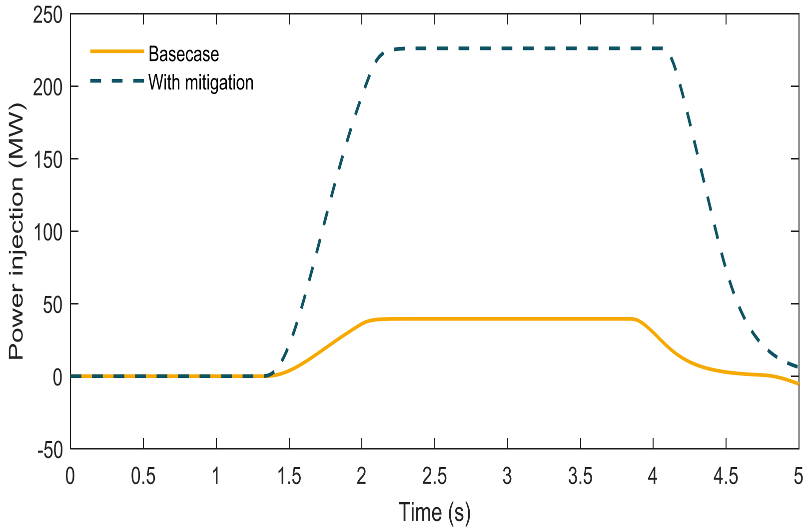


FIGURE 4-29: BATTERY DISPATCH FOR BASE CASE AND WITH MITIGATION

A careful comparison of the above two figures reveals that the RoCoF gradually begins to decrease after 1.5 seconds, coinciding with the additional reserve provision from the BESS.

Figure 4-30 shows the response of pumped hydro units for both the base case and the with mitigation case (dashed lines) along with the system frequency (solid lines). It can be seen that in the base case the frequency already has hit its nadir before the pumped hydro load is disconnected. However, with additional FFR from the BESS being provided, the system nadir is delayed due to a decreased RoCoF thus enabling the first block of 73 MW of pumped hydro load to be disconnected before the frequency hits its nadir.

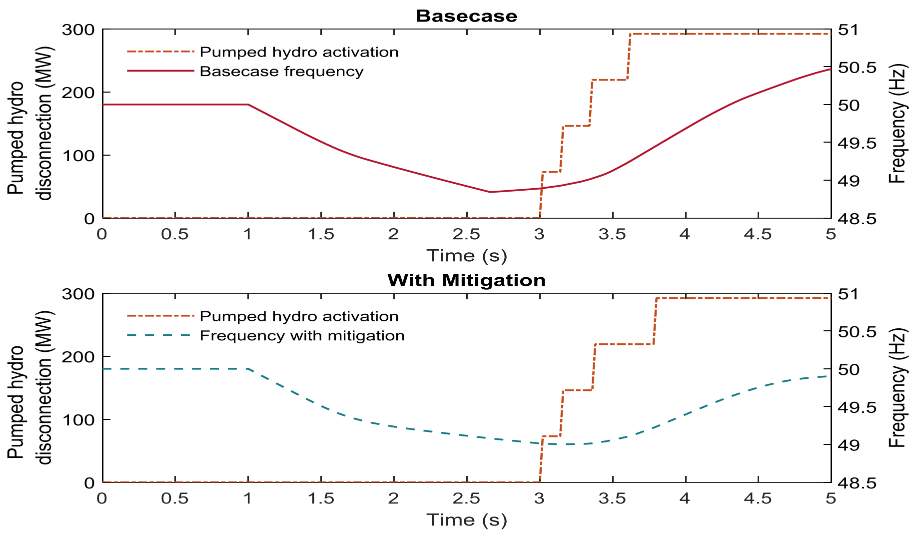


FIGURE 4-30: PUMPED HYDRO RESPONSE FOR BASE CASE AND WITH MITIGATION

Figure 4-31 shows the cumulative governor response for the synchronous generators (dashed lines) along with the system frequency for the base case and with mitigation (solid lines). While the magnitude of the cumulative governor response does not change from the base case to the with mitigation case, because the nadir has been delayed due to the additional provision of FFR from BESS, the actual active power injection at the time of the nadir increases from 57.28 MW to 74.48 MW.

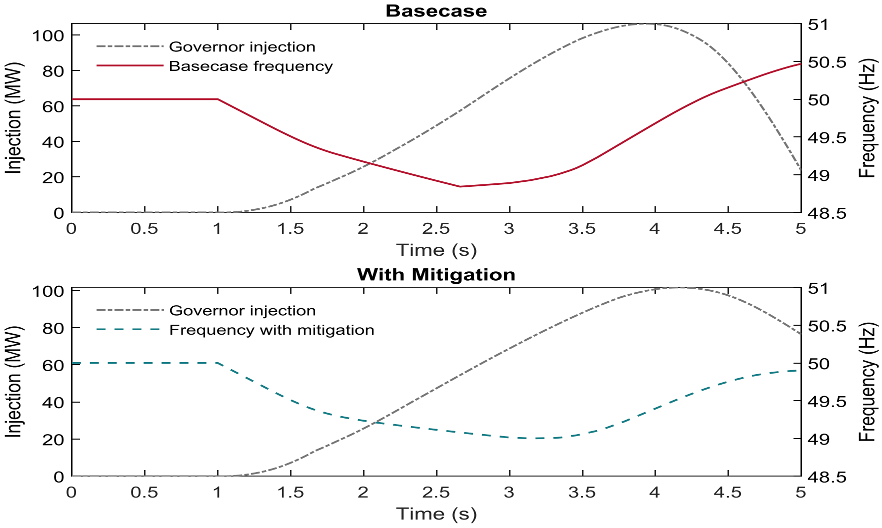


FIGURE 4-31: GOVERNOR RESPONSE OF ONLINE SYNCHRONOUS GENERATORS FOR BASE CASE AND WITH MITIGATION

In summary, maintaining a secure frequency above the 49 Hz limit for this case is achieved due to the following responses:

1. The fast frequency reserve from BESS is increased from 39.5 MW to 226 MW. This has provided supplementary active power injection into the system at a rapid pace which has also helped with decreasing the RoCoF, resulting in delaying the frequency nadir from 2.66 s to 3.14 s, thus enabling the slower initiated reserve provision from other resources to contribute and arrest the frequency decline.
2. Due to the effect of delaying the frequency nadir, 73 MW of pumped hydro can be disconnected before frequency drops below 49 Hz.
3. More active power can be provided from the conventional generators during the period of frequency decay due to the shift of the nadir.

4.1.2.1.1 PROVISION OF FFR FROM WIND TURBINES

The latest developments in wind turbines controllers and grid forming technologies have demonstrated that wind generators can provide an active power injection very quickly after an event occurs on the system. There are a number of implementations world-wide where wind turbines are used to provide fast response by harnessing their stored rotational energy, which is usually called emulated inertial response or synthetic inertial response.

According to ENTSO-E [19], emulated inertia, or synthetic inertia, is defined as the controlled contribution of electrical torque from a unit that is proportional to the RoCoF measured at the terminals of the unit. This provision of electrical torque resists changes in frequency and thus aims mimics the release of energy of rotating synchronous generator. It should be noted that in EirGrid and SONI, emulated inertia is considered to be an FFR product, not a synchronous inertial product.

The model used in SFM to represent emulated inertia is based on GE's WindINERTIA control system [20]. A block diagram of the controller which is implemented in the studies is shown in Figure 4-32.

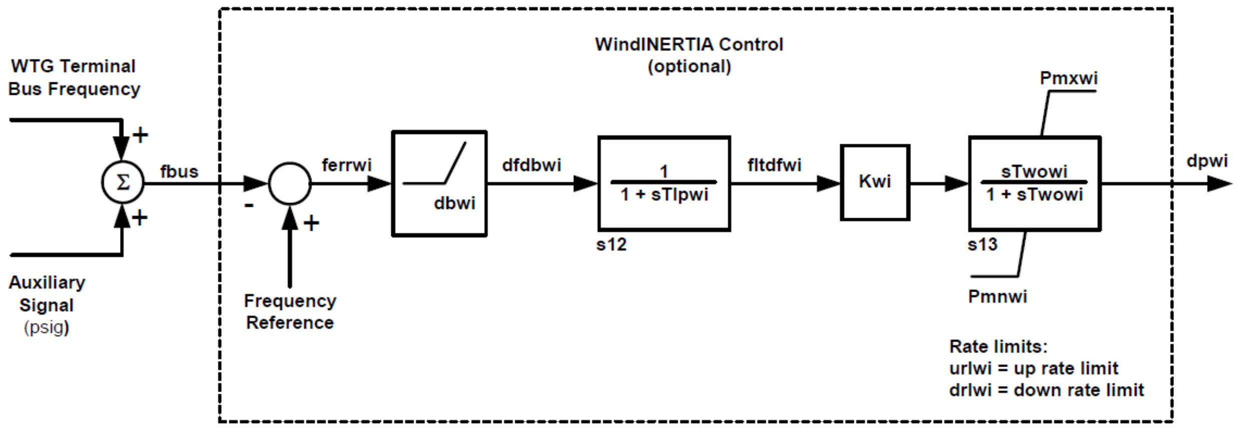


FIGURE 4-32: CONSIDERED SYNTHETIC INERTIA OF GE (WINDINERTIA) [20]

The GE WindINERTIA feature adds fast supplemental controls to the power electronics and mechanical controls of the wind turbine and takes advantage of the inertia in the rotor [20]. For large underfrequency events, this feature temporarily increases the power output of the wind turbine in the range of 5% to 10% of the rated turbine power [20]. The power output is limited by the critical physical limitations of the wind turbine itself; it is crucial that aerodynamic stall of the blades is avoided. Additionally, it is important to note that as the wind turbine is slowed by the controller to provide the inertial energy from the rotor, and thus provide a fast injective of power, the energy extracted will need to be recovered [20]. The parameters utilised in Task 2.6 are shown in Table 4-14.

TABLE 4-14: RECOMMENDED VALUES OF PARAMETERS OF SYNTHETIC INERTIA CONTROL BLOCK [20]

Variable name	Recommended values
Kwi	10
dbwi	0.0025
Tlpwi	1
Twowi	5.5
Pmxwi	0.1
Pmnwi	0

The SNSP for the base case studied is 61.68% with a RoCoF of 0.62 Hz/s following the loss of the 700 MW HVDC Interconnector. The system inertia is approximately 28 GWs. The cumulative reserve provided by pumped hydro is 360 MW. The demand side units provide a reserve of 176.07 MW. Two HVDC interconnectors have available reserve provision of 75 MW and 30 MW respectively, while a third HVDC interconnector does not have any available reserve capacity. The fourth interconnector, in this case, is the LSI. The reserve provision available from BESS for this base case is 100 MW. The large conventional synchronous units online are operating at 1773 MW with a maximum total capacity of 2981 MW available. A low wind scenario (730.17 MW of wind generation) is chosen to demonstrate that the impact of FFR from wind generation is low for a low wind scenario.

Figure 4-33 demonstrates the effect of the power rate limiter parameter Pmxwi which is the anti-windup limit of the virtual injection of the WindINERTIA control system. The solid line shows the result with Pmxwi set at 0.1. This limits the FFR from wind generation contribution to approximately 25 MW. The initial Pmxwi parameter of 0.1 was changed to 0.5 (dash line) based on Figure 4-33 showing the full capability of the control system is not possible due to the anti-windup “Pmxwi” hitting its limit, therefore shaving the peak.

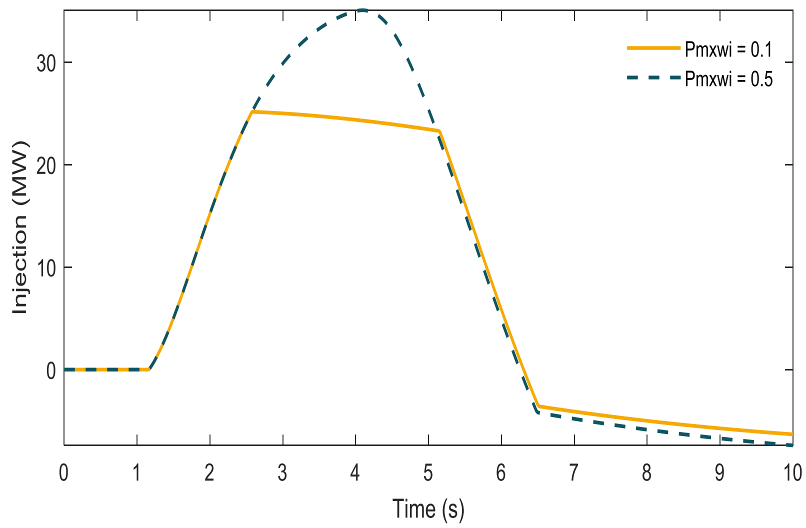


FIGURE 4-33: POWER INJECTIONS OF WIND TURBINE FOR TWO VALUES OF POWER RATE LIMITER

Figure 4-34 shows the frequency traces with and without FFR being provided from wind. It can be seen that the frequency nadir in the base case occurs at 4.02s with a value of 48.93 Hz (represented by the solid line). With the FFR provision from wind generation, the frequency nadir occurs at 4.06s with a value of 48.97 Hz (represented by the dashed line). The traces demonstrated that the FFR contribution both delayed the nadir and improved the frequency nadir but not sufficiently enough to keep the frequency above the 49 Hz limit (see dotted line in Figure 4-34).

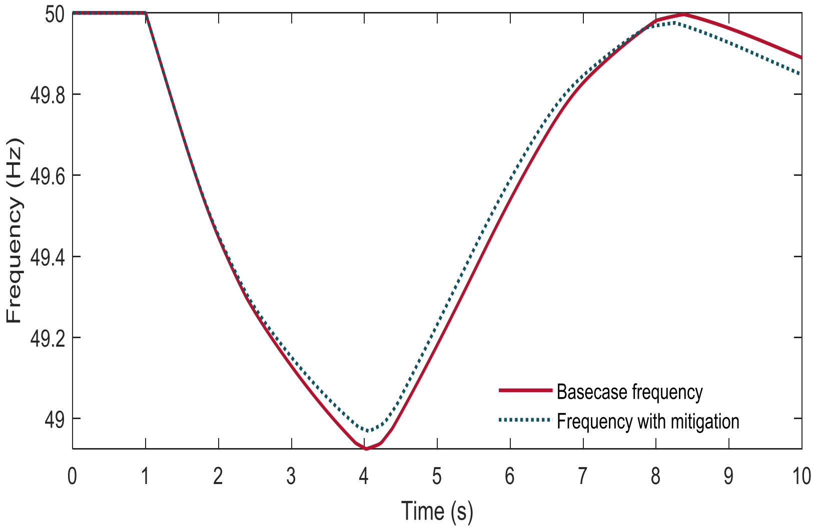


FIGURE 4-34: SYSTEM FREQUENCY WITHOUT AND WITH FFR PROVISION FROM WIND TURBINES

It is found that a higher contribution of FFR from wind cannot be realised with this level of the total wind power output of 730 MW, due to the limitations on the wind turbines themselves. To demonstrate this, the wind generation output is increased gradually from 730 MW until the frequency is restored to 49 Hz, shown in , which occurs when the total wind power output is increased to 1020 MW. Figure 4-35 shows the system frequency when wind is increased from 730 MW to 1020 MW. It is evident that system frequency is above the 49 Hz limit (see dashed line).

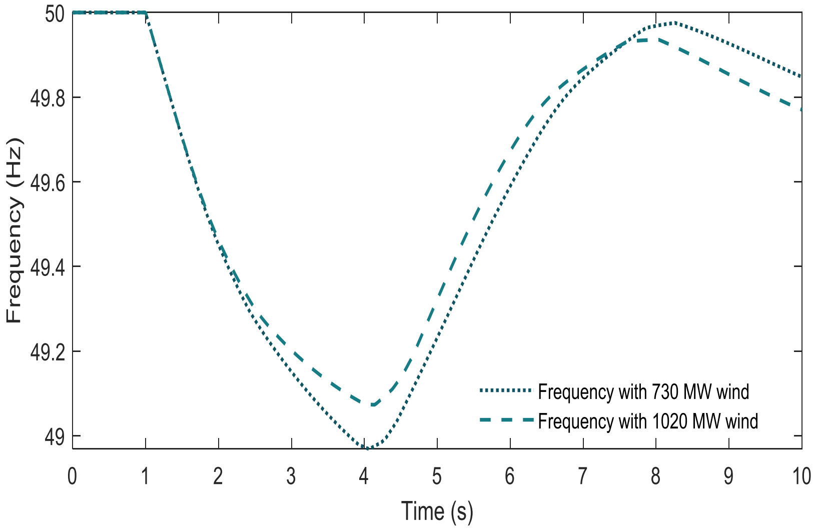


FIGURE 4-35: SYSTEM FREQUENCY WITH INCREASED WIND

Figure 4-36 shows the contribution of emulated inertia when the dispatched wind is increased from 730 MW to 1020 MW. The contribution from the wind is now 100 MW (circa. 10% of the available wind capacity). Due to this increased fast frequency response contribution from wind the system frequency does not dip below the 49 Hz threshold.

It should be observed that once the frequency recovery takes place after 4s the energy generated starts dropping and eventually becomes negative, indicating that the energy taken is returned back to the wind energy system. It should be noted here that the energy which is injected into the system by the wind turbine through synthetic inertia must be returned to it eventually. This is requirement of the emulated inertia/synthetic inertia controller was considered in the design of the FFR product which is utilised in Ireland and Northern Ireland [2].

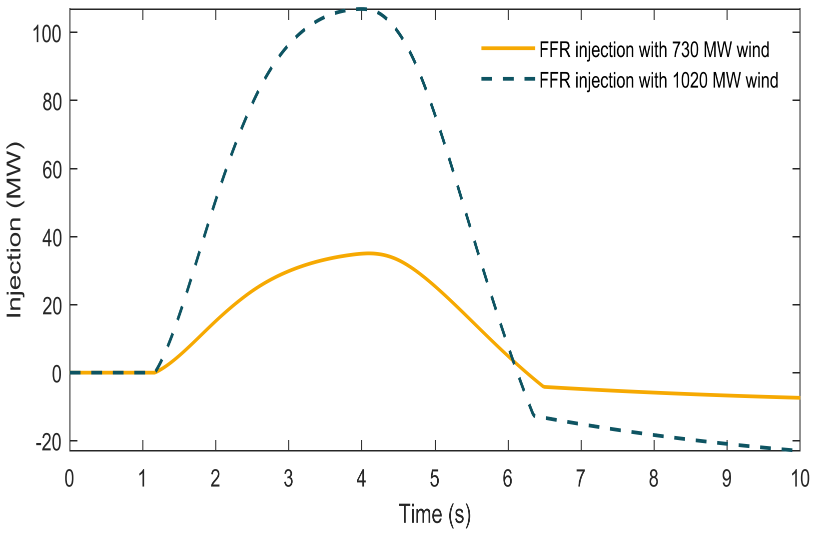


FIGURE 4-36: PROVISION OF FFR FROM WIND GENERATION (SI INJECTION) WITH TWO LEVELS OF WIND GENERATION

The analyses demonstrated above shows that the FFR contribution from wind can be an important mitigation measure and is beneficial for the system in terms of frequency stability. However, it must be noted that, due to the inherent limitations of the wind turbine mechanics and the need to avoid aerodynamic stall, the FFR contribution from wind it limited to about 10% of the available wind generation capacity and thus a significant contribution of FFR from wind is difficult during times of low wind availability.

4.2.2.3 RESERVE PROVISION FROM WIND GENERATION

In order to demonstrate the capability of renewables providing reserve, frequency response control of wind farms is considered in this section. In Ireland, Active power control (APC) of wind farms is often activated through the control room based on selecting and applying pre-set frequency set points on wind farms to control their response to system frequency [21]. APC is usually employed for dealing with over frequency issues where wind farms are required to reduce their outputs. However, it can also be used for under frequency issues but only when a wind farm power output is either being curtailed or constrained due to system operational constraints or network constraints. Only when a wind farm is operating below its maximum available generation point would it be able to increase its output and contribute to improving the system frequency.

At present, most wind farms are operated with frequency response capability on, but with APC off. This ensures that the wind farms are only frequency responsive outside of a deadband of +/-200 mHz [21] and so they are only responding to a contingency event. If APC and frequency response capability are both on, the frequency deadband for the wind farm is reduced to +/-15 mHz which means that the wind farm responds to frequency deviations more dynamically.

In Ireland, APC is usually off, but it is turned on during certain system conditions, for example during periods of high interconnector exports and so the APC can assist with managing over frequency issues in the event of the tripping of an interconnector on export. APC is also turned on during periods where frequency oscillations are detected and required damping [21]. In order to demonstrate frequency response capability of wind farms or primary frequency response, the same system initial conditions as that of Section 4.2.2.1 and 4.1.2.1.1 are considered. The base case has an SNSP of 69.38% with a potential RoCoF of 1Hz/s and total system inertia is 17,500 MWs. In terms of reserve provision and volumes available for this base case, pumped hydro provides a cumulative reserve of 472 MW while demand side units are providing 180.8 MW of reserve. The remaining three HVDC Interconnectors (one of the interconnectors is the LSI and thus cannot provide reserve) have an available reserve capacity of 75 MW each. The volume of BESS for this case was 39.5 MW. There are three large synchronous units online dispatched to 1,107 MW in total. Two of the three units are operating at their maximum capacity.

The dispatched wind in this case is high, at 3040 MW. A high wind scenario is deliberately chosen as more active power would be available from wind farms. It is assumed that the available headroom for the frequency response from wind farms to respond to under frequency issues is 7.5% of the dispatched wind. This value was based on Q2 2020 recorded curtailments of 7.3% in Ireland and Northern Ireland [22]. Two droop values are considered for the demonstration: 4% and 2% with the deadband set to +/-200 mHz.

Figure 4-37 shows the frequency traces for the base case and with mitigation with 4% and 2% droop for the considered LSI incident. The frequency nadir for the base case occurs at 2.66s with a value of 48.84 Hz, represented by the solid line. With 4% droop the frequency nadir merely shifted from 2.66s to 3s as is shown by the dashed line. However, the dotted line shows that if the droop setting of the wind farm is changed to 2% the frequency decay is limited to 49 Hz with its nadir occurring at 3.4s.

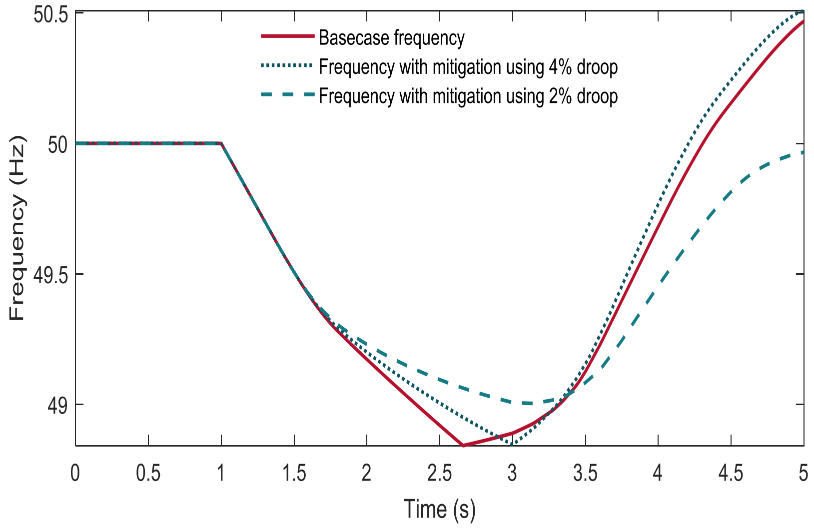


FIGURE 4-37: FREQUENCIES FOR BASE CASE AND WITH MITIGATION (WITH 4% AND 2% DROOPS)

Figure 4-38 shows the active power injection 116.7 MW of active power is injected at the nadir for the 4% droop whereas 226.7 MW (circa. 7.5% of the available wind generation) is injected at the nadir for 2% droop.

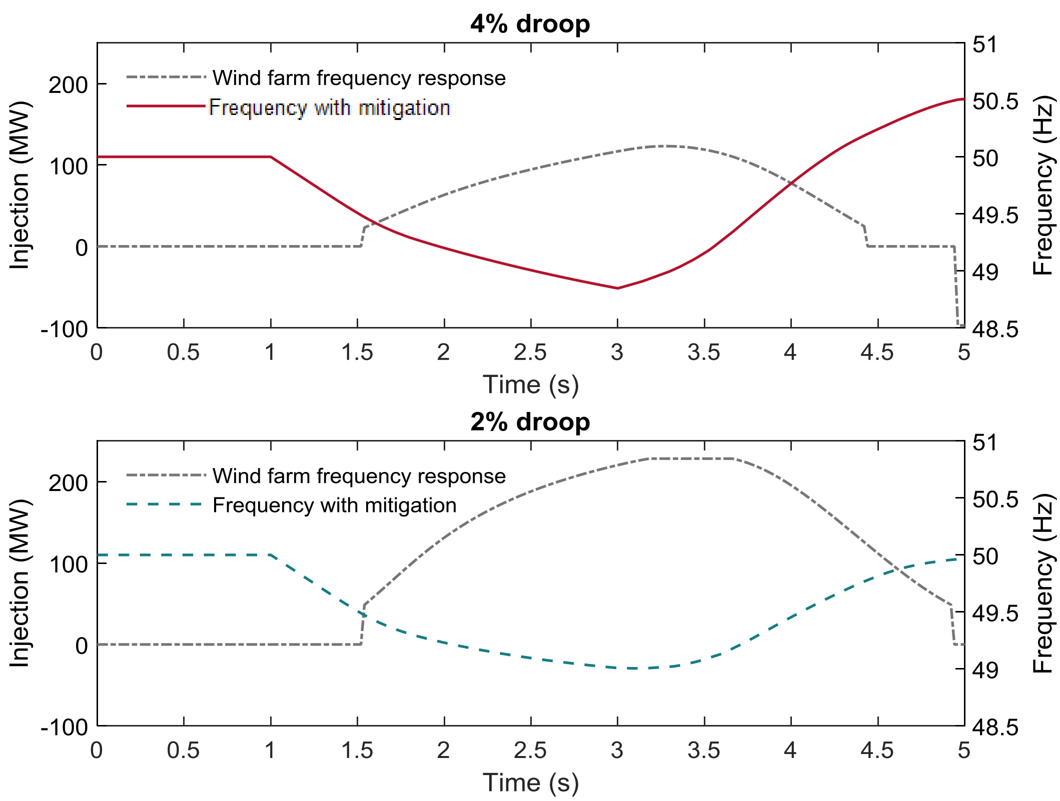


FIGURE 4-38: ACTIVE POWER INJECTION FROM THE WIND FARMS WITH 4% AND 2% DROOPS

The figure shows that the volume of energy (area under the grey lines) injected after the incident determines whether the frequency decay can be limited at above 49 Hz. It can be clearly seen that the area under the solid line with 2% droop is considerably higher than that under the solid line with 4% droop. The 4% droop therefore will only delay the frequency nadir but the energy provided would not be enough to avoid frequency decaying below 49 Hz.

The analysis has demonstrated that frequency response capability from wind farms can be beneficial in supporting frequency stability, particularly at times of high wind generation levels. This is crucial due to the fact that during periods of high wind there will be fewer conventional generators online and thus less frequency response capability available from conventional generators.

4.2.2.4 OPERATIONAL POLICY CONSIDERATIONS

The previous sections in this chapter have focussed on demonstrating capability from various non-conventional technologies to provide synchronous inertial response from Synchronous Condensers, FFR from batteries and FFR and primary frequency response from wind generation.

In this section, we will consider how operational policy changes could help to assist with frequency stability. The two mitigations considered are a) decreasing the magnitude of the LSI during certain specific system conditions and b) maintaining a minimum number of large synchronous generating units online.

4.2.2.4.1 DECREASING THE MAGNITUDE OF THE LSI

As previous mentioned, the current LSI currently in All-island power system is over 500 MW. However, by 2030 the Celtic interconnector is expected to be operational with an import and export capacity of 700 MW. Hence, the LSI would be dramatically increased to 700 MW. The impact of this increase of LSI would need to be carefully evaluated as there might be future operational scenarios where a loss of 700 MW of active power becomes quite onerous in terms of frequency stability, especially when operating with a high SNSP, low inertia system. Hence, limiting the flow through the Celtic interconnector might be beneficial for specific operational scenarios.

This section demonstrates the effect of limiting the LSI. The base case system has an inertia of 16.9 GWs and an SNSP of 73.45% with a RoCoF of 1 Hz/s following the loss of Celtic interconnector importing 700 MW. The pumped hydro units provide a reserve of 652 MW in total. The demand side units provide a reserve of 106.6 MW. Two of the interconnectors have an available reserve capacity of 75 MW and 30 MW in this hour respectively, while one of the interconnectors is operating at its maximum capacity and has no available reserve. The fourth and final interconnector is the LSI in this case and thus cannot provide any reserve. Battery dispatched for reserve at this hour is 111 MW. Only three units are online with a dispatch level of 455 MW, out of an available 1325 MW. None of the units are operating at their maximum capacity.

While it might be noted that there is considerable reserve available in this hour, significantly more than the LSI, it was found that due to the low inertia level, the RoCoF is high and so the frequency nadir is reached quickly following the tripping of the LSI. As a result of the high RoCoF, the 49 Hz limit is breached quickly and the available reserve providing resources do not have sufficient time to respond to delay the frequency decay. Without any other mitigations applied, it was found that the frequency could be contained above 49 Hz if they only step taken is the reduction of the imports on Celtic to 515 MW, for this specific case.

Figure 4-39 shows the system frequency for the base case and with the mitigation. The solid line represents the system frequency for the base case while the dotted line is the frequency for the case with the mitigation. It is evident the system frequency is contained within 49 Hz by limiting the import through the Celtic interconnector from 700 MW to 515 MW in this case.

It should be noted that this result is very specific to the particular hour and specific operating conditions of the case studied. Further work would be required to pinpoint the combination of operating conditions which would trigger the requirement to reduce imports on the IC and therefore the LSI. Additionally, it would be important to validate these results through a unit commitment and economic dispatch tool and to determine the impact reducing the LSI has on the levels of reserve being carried and thus overall frequency stability.

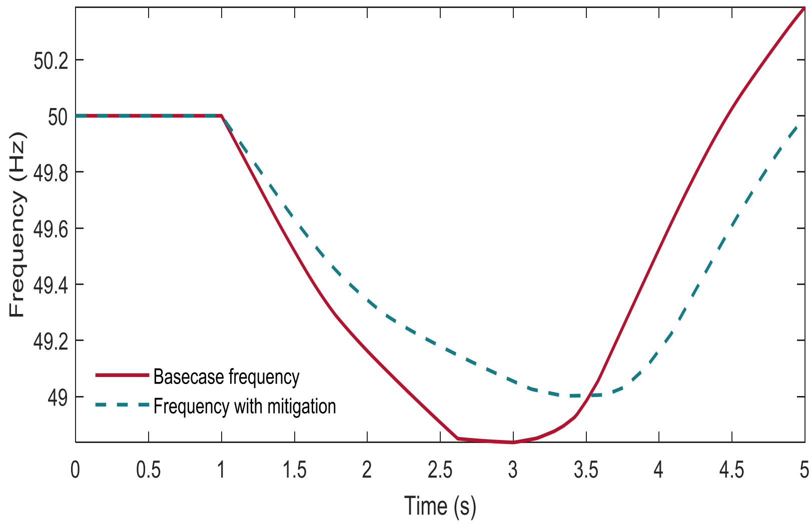


FIGURE 4-39 SYSTEM FREQUENCY FOR BASE CASE AND WITH THE REDUCTION OF THE SIZE OF THE LSI

4.2.2.4.2 MINIMUM NUMBER OF UNITS ONLINE

To enable the efficient and secure operation of the power system, EirGrid and SONI schedule and dispatch units so as to adhere to their respective Operating Security Standards. One of the most important constraints in the aforementioned standard is a requirement to keep a minimum number of units online for the two jurisdictions. Across the two jurisdictions there is currently a requirement of having eight large units on-load at all times, as follows:

- Northern Ireland -There must be at least 3 units on-load at all times in Northern Ireland for dynamic stability purposes.

- Ireland- There must be at least 5 units on-load at all times in Northern Ireland for dynamic stability purposes.

In the unit commitment and economic dispatch simulations, which were an input into the studies conducted in this section, the minimum number of unit constraints are relaxed to push the system to its limit and to reveal the technical scarcities that could emerge. In reality, it is unlikely that, in 2030, the minimum number of unit constraints would no longer apply. However, it is anticipated by EirGrid and SONI that the minimum number of unit constraints will need to be reduced significantly. The exact number is yet to be determined and will be dictated by other changes on the power system and whether conventional generators can lower their minimum operating limits to accommodate renewables whilst still providing inertia and reserve capability.

This section aims to conduct a preliminary analysis to determine what the minimum number of units constraints might be in 2030. It should be noted that this is a qualitative assessment only. The relaxation of this constraint needs to be carefully assessed and that there will be hours where additional conventional units might be required to halt frequency decay.

The base case snapshot involves four large units being online and frequency issues following the loss of an interconnector importing at 700 MW. The base case has system inertia of 19.99 GWs and an SNSP of 74.25%, with a RoCoF of 0.88 Hz/s following the event. Pumped hydro provides a reserve of 652 MW. The demand side units are dispatched to provide a reserve of 152.2 MW. The other three interconnectors have an available reserve capacity of 75 MW each. Battery capacity dispatched at this hour is 66.33 MW. The four large units which are online are dispatched to 928 MW with a total maximum available capacity of 1789 MW. None of the large units are operating at their rated capacity.

The solid line in Figure 4-40 shows the frequency for the base case. The frequency falls below 49 Hz attaining its nadir of 48.85 Hz at 3.44s. It should be noted that no reserve from the DSUs is activated before the frequency reaches its nadir.

The mitigation in this case, in order to limit the frequency nadir to 49 Hz, is the commitment of one large unit and dispatching that unit to 150 MW. Consequently, the system inertia increases to 22.8 GWs with this addition. As a result of the additional inertia, the RoCoF is reduced and the frequency is contained within 49 Hz attaining its nadir of 49.05 Hz at 3.56s, as represented by the dashed green line in the figure.

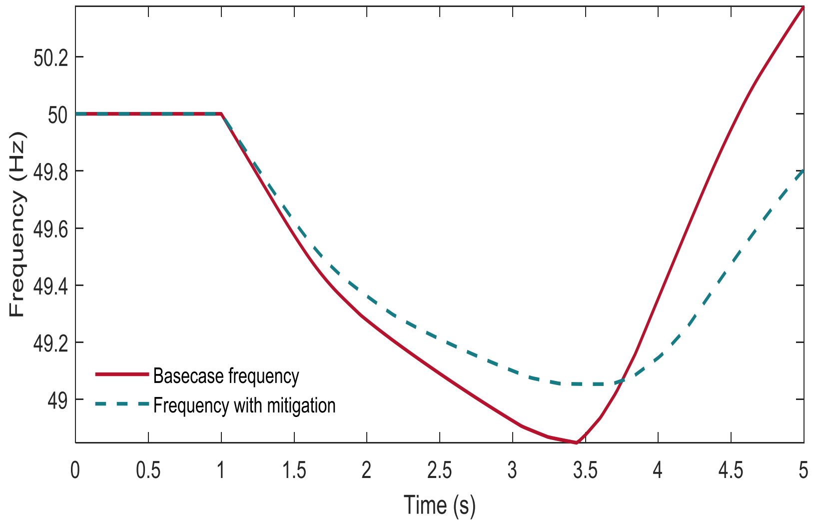


FIGURE 4-40: SYSTEM FREQUENCY FOR BASE CASE AND WITH MITIGATION

Figure 4-41 shows the cumulative governor response for the base case and with mitigation. The governors of the units inject 138.3 MW of active power at the nadir in the base case (grey line in first graph) whereas they inject 213.5 MW of active power at the nadir with mitigation (grey line in second graph). Due to this additional injection of 75.2 MW, the frequency is limited to 49 Hz.

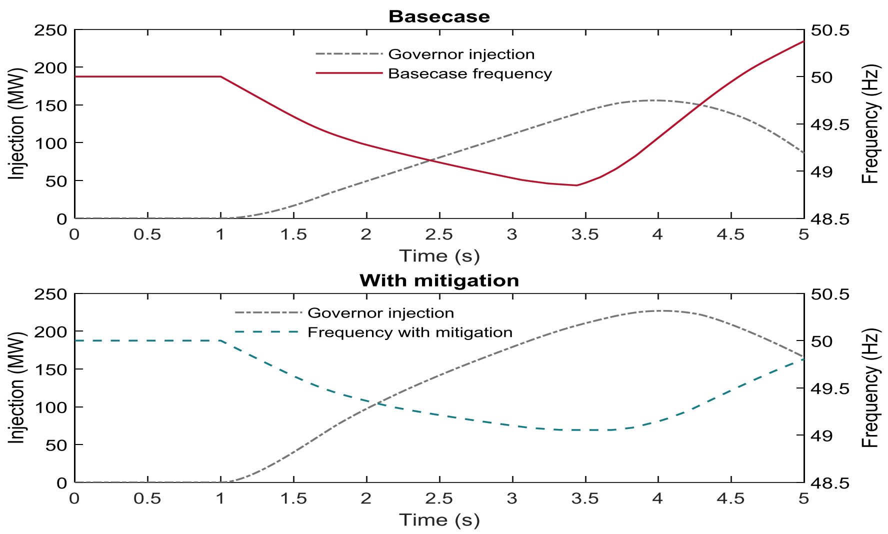


FIGURE 4-41: GOVERNOR RESPONSE OF ONLINE SYNCHRONOUS GENERATORS FOR BASE CASE AND WITH MITIGATION

Hence, the frequency is contained within 49 Hz by adding a large synchronous unit online and therefore increasing the number of large conventional units to 5. As with the analysis for reducing the LSI, it should be noted that this result is very specific to the particular hour and specific operating conditions of the case studied. Furthermore, the evolution of the minimum number of large units constraint between now and 2030 will be contingent on developments in generating units minimum generation levels and the number of Synchronous Condensers that are added to the system in the intervening years.

4.2.3 MITIGATING FREQUENCY OSCILLATIONS IN A LOW INERTIA HIGH SNSP SYSTEM

As mentioned above, in Ireland, currently Active Power Control (APC) of wind farms is usually turned off, but it is turned on during periods where frequency oscillations are detected during normal operation and required damping. In the future, the All Island Power System is expected to be operated at very high SNSP levels and inertia levels below 20 GWs. From EU-SysFlex Task 2.4, it is noticed that for such cases the system may experience sustained frequency oscillations following a system event, even for a low LSI loss. This section addresses one of these extreme scenarios where the total system inertia is significantly lower than 20 GWs and a system event results in frequency decline and sustained frequency oscillations.

The base case system has an inertia level of 4.5 GWs and an SNSP of 83.52%, with a RoCoF of 1 Hz/s following a loss of a small generating unit producing 121 MW. No pumped hydro units are operational in this hour. The demand side units are dispatched to provide reserve of 99.16 MW. All interconnectors have an available reserve capacity of 75 MW each. The battery capacity dispatched at this hour is 100 MW. In the absence of a minimum number of large units constraints the synchronous generating units online are mainly small units with a maximum capacity of 655.8 MW, generating 582.1 MW.

Figure 4-42 shows the system frequency following the loss the unit producing 121 MW. It is evident that there is a sustained oscillation for an indefinite period, although contained within 49 Hz. Considering a very 'light' system with lower inertia levels, this is to be expected.

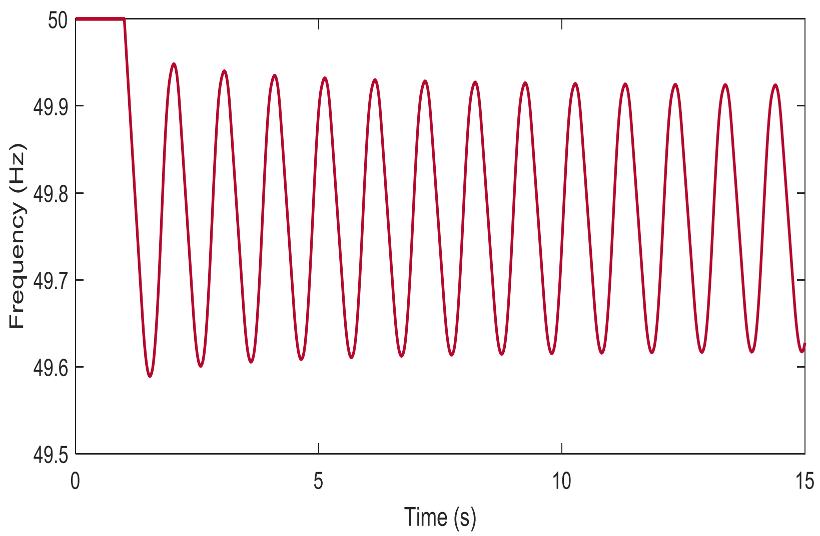


FIGURE 4-42: SYSTEM FREQUENCY FOLLOWING THE LOSS OF 121 MW PRODUCING UNIT

It is of significant importance for such cases that system inertia is increased. This can be achieved by the addition of Synchronous Condensers, as discussed earlier, and/or by maintaining a minimum number of units constraint, which, as well as providing other services, would allow those generating units to contribute to the system inertia.

In order to demonstrate the impact increasing system inertia can have on the frequency oscillations, two mitigation cases are considered:

1. Case 1: Connecting two Synchronous Condensers, each with a rating of 400 MVA with a 3s inertia constant. This number is achieved based on an iterative process until the oscillations reduce to acceptable levels. This can be seen in Figure 4-43 where the oscillations diminish under 15 seconds.
2. Case 2: A combination of connecting two Synchronous Condensers, each with a rating of 400 MVA with 3s inertia constant and bringing at least one of the large units online.

Figure 4-43 shows the system frequency for both the cases. It can be seen that the oscillations are significantly reduced as shown by the dotted line, eventually settling after 15s. The oscillations die out due to increased system inertia. However it takes time for the oscillations to settle down due to the governors of the smaller units being overly sensitive to the frequency changes. The dashed dotted line shows the system frequency of Case 2. The frequency settles after 7s. The oscillations are dampened much faster than that of Case 1 due to:

1. The ability of the governor response from the additional large unit to neutralise oversensitivity of the frequency response of the smaller units.
2. The increased system inertia due to the connection of Synchronous Condensers and the corresponding large unit.

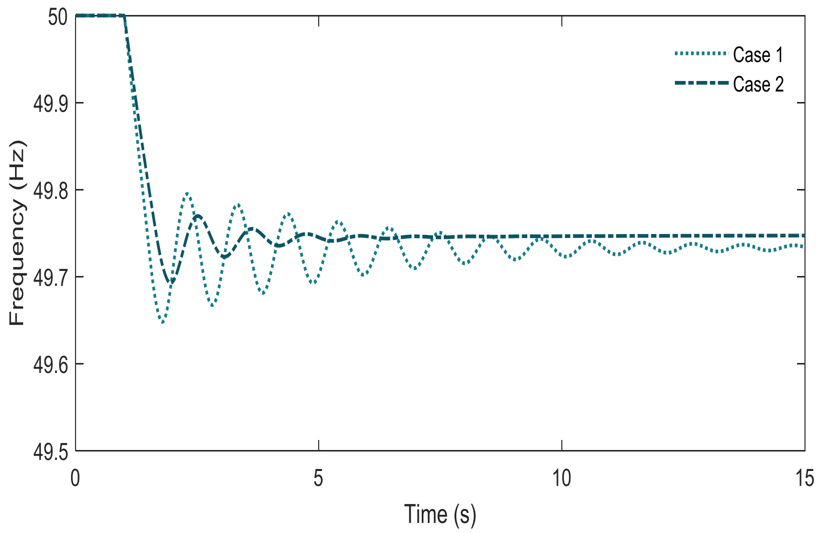


FIGURE 4-43: SYSTEM FREQUENCY FOR TWO CASES

It will become increasingly important for light system conditions to have the right mix of reserve provision. The small extreme case above indicates that the inertia floor and the minimum number of unit’s online constraints can be relaxed to a certain extent but need to remain in place.

EirGrid and SONI are currently, at the time of writing, undertaking a comprehensive public consultation on the future of Ireland and Northern Ireland's power system entitled "Shaping Our Electricity Future" [23]. In this consultation document the need to evolve the inertia floor and the minimum number of units is noted as being of particular importance to facilitate the required reduction in the minimum synchronous generation level, thus enabling the accommodation of greater levels of non-synchronous variable renewables. Whilst the exact details relating to the specific inertia floor level and the minimum number of units which will be required in 2030, and the trajectory of same, are the topics of on-going investigation, it is acknowledged that they will be impacted by technology evolution and generation portfolio changes. For example, the presence of technologies such as synchronous condensers may reduce the need to lower the inertia floor. In addition, if conventional generators can lower their minimum operating limits then the reduction in the number of units may not need to be as large.
With this in mind, a flexible and agile approach will be taken to operational policy changes for these metrics and the development of new metrics as appropriate over the coming decade to take account of new, and existing, non-conventional technologies.

4.2.4 KEY MESSAGES: IRELAND AND NORTHERN IRELAND

The key to frequency stability of a power system is to maintain the active power balance between generation and load. Active power must be injected to the system following an under-frequency event in order to limit the frequency nadir to an acceptable value. This acceptable value for the All-Island power system is 49 Hz according to system operating guidelines. Moreover, RoCoF also depends on total system rotational inertia. By 2030, the All-Island power system will see a significant reduction in conventional synchronous generation, being replaced by renewable generation mainly interfaced through power electronic converters. Such converters do not contribute to system inertia which tends to lead to steep RoCoFs after an under-frequency event. Moreover, in the future the system conditions could make frequency issues a more common occurrence. Hence, mitigation measures need to be identified to address frequency issues and to allow the continued safe and secure operation of the system. Such measures are identified in this chapter.

The key messages from the identified measures employed to contain the frequency above 49 Hz are manifold. The most important message is that while a number of technologies or mitigations might be in a position to ameliorate the frequency issues, it is rare that a single mitigation is sufficient to completely solve the issue. It is clear from the analysis presented for the Ireland and Northern Ireland power system that **a suite of mitigations are required**. In addition, for the periods where system conditions result in low inertia and high SNSP levels, the mix of mitigations will play a key role in avoiding frequency oscillations.

Synchronous Condensers were shown to be effective in supporting the mitigation of frequency issues. Synchronous Condensers contribute to system inertia without producing any active power. These devices on their own may not be sufficient to contain the frequency nadir above the 49 Hz load-shedding threshold but they are a promising mitigation measures in terms of delaying the time it takes for the nadir to be reached. This delay will enable other resources such as demand-side units and pumped hydro to halt frequency decay and support its recovery. It is important to note that Synchronous Condensers alone cannot mitigate the frequency stability issues, but in combination with other mitigation measure they can be very beneficial. It will be seen in other chapters of this report, that Synchronous Condensers can also provide other vital system services which can help to mitigate other technical scarcities.

Fast frequency response provision is shown to be extremely important for halting frequency decay. **Fast frequency response from battery energy storage systems and from wind turbines is demonstrated**, although it must be recognised that many technologies are capable of providing this crucial service. Due to reduced total system inertia, frequency decays quickly following the loss of the LSI outlining the need for timely provision of fast reserve. Providing enough energy quickly within a couple of seconds following an infeed loss can be an effective mitigation measures for secure operation of the future power system with high SNSP levels. Such fast frequency response has a dual effect in that it can:

A) increase frequency nadir
B) Delay the occurrence of the frequency nadir to enable some of the slower frequency response provision to contribute in an efficient way.

Synthetic inertia control or emulated inertia control can play an important role in addressing under-frequency issue by enabling the wind turbine to provide FFR. The wind turbine can inject additional active power immediately after the frequency event in order to limit the RoCoF and provide required MWs. However, if the wind power output is low the contribution from the wind turbines might not suffice and some other mitigation measures would be required.

Frequency control of wind farms is often used to address over frequency issues through downward frequency response. In other words, the output of wind farms is reduced when the frequency exceeds a particular value above its nominal. However, this frequency control capability can also be used to address under frequency issue by providing additional wind power output for upward frequency response assuming that their wind power output can be increased – for example when a wind farm is either curtailed or constrained due to various system or network constraints.

An almost **40% increase in the magnitude of the possible largest infeed loss** compared to today is a significant threat for secure operations of a system with high SNSP levels and low system inertia. A loss of 700 MW import from an interconnector will become the LSI, or dimensioning event, and appears to have a significant impact on the frequency stability for the hours that are analysed here. Analysis confirms that limiting such import levels, for specific system conditions, could be effective. However, if such a new operational constraint is introduced then it must be used as a last resort when other mitigation measures fail to address the frequency issues.

Crucially, it has been demonstrated for the Ireland and Northern Ireland power system that there are numerous mitigations that can help with the significant frequency issues that were identified in Task 2.4. Perhaps most importantly, many of these mitigations, and the technologies which are modelled to illustrate those mitigations, are non-conventional and thus would be **mitigation measures that would be available at times of high wind generation**.

4.3 LINK TO DEMONSTRATIONS AND THE QUALIFICATION TRIAL PROCESS: FREQUENCY

The material and results discussed earlier in this chapter are vital for demonstrating via simulation the capability of various technologies for mitigating the technical scarcities related to inertia and frequency reserves. However, while this is important, it is equally as important to test these technologies in real-life field tests and technology trials. EU-SysFlex has a range of different demonstrations and field test that are on-going at the time of writing this report. The frequency services being tested in the demonstrations are summarised in Table 4-15. A brief description of each trial is then provided.

TABLE 4-15: SUMMARY OF FREQUENCY SERVICES TESTED IN EU-SYSFLEX

Demonstration	Services Being Tested
Finnish demonstration - EVs	Frequency Containment Reserve for disturbances (FCR-D) and normal operational (FCR-N)
French Demonstration	Fast Frequency Response (FFR), Frequency Containment Reserve (FCR) and Frequency Restoration Reserve (FRR)
Portuguese demonstrations - FlexHub (PV + storage)	Manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR)
Portuguese demonstrations - VPP	Frequency Containment Reserve, Frequency Replacement Reserve
QTP – Residential Batteries	Wide range of frequency response services, from FFR to ramping
QTP – PV	Fast Frequency Response and other frequency response services

The goal of the Finnish demonstration is to express how flexibility resources (such as electric vehicles) are connected to the low voltage distribution network and how they can be forecasted and aggregated to meet TSO and DSO needs. The Finnish demonstrator, through the management of active power in order to provide services to the TSO, demonstrates Frequency Containment Reserve for disturbances (FCR-D) and Frequency Containment Reserve for normal operation (FCR-N).

The goal of the French demonstration is to demonstrate the technical feasibility of performing optimal management and coordinated control of a multi-resource aggregator to provide multi-services to the power system. For frequency control the following services were tested Fast Frequency Response (FFR), Frequency Containment Reserve (FCR) and Frequency Restoration Reserve (FRR).

The Portuguese FlexHub demonstrates the provision of manual Frequency Restoration Reserve (mFRR) and Replacement Reserve (RR) services by resources located in the distribution network. Within the FlexHub demonstration, a collaborative MV demo site with a 2.4MW PV farm and a 480kW electrochemical storage facility is tested. The provision of the active power is assumed to be provided by the PV in order to provide RR. The Electrochemical storage plant is also assumed to provide frequency control through provision of FCR, aFRR or mFRR/RR. The provision of aFRR and mFRR services are also demonstrated by the Portuguese VPP concept (RES and large-scale storage assets).

The Ireland and Northern Ireland QTP has three trialists, two residential trials and one solar trial. The 2019 Energia residential trial's fleet of batteries to date have delivered an aggregated response for the provision of SOR1, TOR1 and TOR2. However, FFR and POR1 response are continuing to be investigated. The 2019 SMS residential trial's battery fleet have successfully responded to 8 frequency deviations since June 2020 via their Flexibility Platform and this trial has successfully provided ramping and fast-acting services. For the 2019 PV Solar Trial, the expected outcomes of this trial will be to demonstrate how PV generation has the ability to provide the following services: FFR, POR, SOR, and TOR.

4.4 SUMMARY OF FREQUENCY MITIGATIONS

This chapter has successfully demonstrated, through simulations, and utilisation of specific technologies as a means of representing capability, **a range of system services to support frequency stabilit**y, particular in the time frame immediately following a disturbance. These services include:

- Synchronous Inertial Response (SIR)
- Fast Frequency Response (FFR)
- Primary Operating Reserve (POR) or Frequency Containment Reserve (FCR)

Synchronous inertial response (SIR) capability from conventional synchronous generators as well as synchronous condensers were demonstrated in both the Continental European system and the Ireland and Northern Ireland power system. In the Continental European system, **synchronous condensers were shown to be good alternatives to conventional synchronous generating plants for inertia provision**. While, in the Ireland and Northern Ireland, synchronous condensers were found to be effective in slowing the rate of RoCoF thereby delaying the time it takes for the nadir to be reached. This delay facilitates frequency recovery provision from resources such as DSU's and pumped hydro.

Whilst the use of carbon intensive conventional synchronous generators to provide inertia is counter to the overall objective of progressing along the path to decarbonisation of the power system, it is important to acknowledge the significant role conventional plants still have to play over the coming years in the transition to a more decarbonised system and the huge contribution they make to not only system inertia, but also to long-term frequency response. It has been proven in Ireland and Northern Ireland to-date [24] that if the right incentives are in place, and it is technically feasible, it is possible for large synchronous generators to reduce their minimum stable generation level, thereby enabling greater penetrations of renewables but also crucially continuing to provide the same level of inertial response. As mentioned earlier, a flexible and agile approach will be taken to the evolution of operational policy changes in Ireland and Northern Ireland to account for the potential technical developments that are possible for conventional generators.

From an inertial contribution point of view perhaps more importantly is the huge benefit that can be achieved through the use of synchronous condensers. **Synchronous condensers, since they do not provide active power, contribute to the system inertia without impinging upon the generation levels of non-synchronous renewables.** More importantly still is the fact that synchronous condensers are very cost effective technologies for providing synchronous inertial response [25]. As will be noted later in this report, synchronous condensers can also provide other critical system services and can thus support the mitigation of other technical scarcities.

Fast frequency response (FFR) from battery energy storage systems and from wind turbines was demonstrated in the Ireland and Northern Ireland power system, although it must be recognised that many different technologies are capable of providing this service. Analysis from the Ireland and Northern Ireland power system demonstrated the significance of a fast frequency response provision in terms of frequency stability especially during times of high SNSP levels. Fast frequency response has a dual effect in that it can increase and delay the frequency nadir enabling other system resources with a slower frequency response provision to contribute.

Analysis from the Ireland and Northern Ireland power system has established that **frequency response capability from wind farms can be beneficial in supporting frequency stability through the provision of POR,** particularly at times of high SNSP levels. Frequency control of wind farms in Ireland and Northern Ireland is often used to address over frequency issues through downward frequency response, however, this frequency control capability could potentially be used to address under frequency issue by providing additional active power output for upward frequency response during times where wind is either curtailed or constrained.

In addition to the demonstration of system services capability, **a number of considerations for potential operational policies were explored**. Interestingly, the potential operational policies that were explored by both sets of analysis (i.e. Continental European Power system analysis and the Ireland and Northern Ireland power system analysis), are broadly consistent:

1. Occasional limitations of the cross-borders flows in the Continental European Power system or the occasional decreasing the magnitude of the largest single infeed in the All-Island Power system which in the worst case scenario was one of the interconnectors operating on full import;
2. Maintaining a minimum numbers of units on the system and occasionally reducing generation from variable renewable resources to allow synchronous conventional plants in order to ensure a minimum amount of inertia.

Crucially, it has been demonstrated for both systems that there are many different mitigations and technologies that can help with the significant frequency issues that were identified in Task 2.4. Perhaps most importantly, many of the technologies which are modelled to illustrate those mitigations are non-conventional and thus would be **mitigation measures that would be available at times of high renewable generation**.

The operational mitigations could be effective options for supporting the transition or evolution of the power system towards decarbonisation, in conjunction with the arrival of system services provision from non-synchronous technologies and until such technologies are more widespread and prolific.

It should be noted that in Task 2.4 an increased need for aFRR resources was identified for the Continental European power system with the transition to higher penetrations of variable renewables. However, there is a clear and obvious mitigation for this issue which does not necessarily require simulations to demonstrate the capability - provision of reserve from non-conventional sources. Furthermore, as has been discussed in Section 4.3, there are significant field trials underway within the project demonstrating the ability of novel technologies etc. to provide the full range of reserve services.

5. VOLTAGE STABILITY MITIGATIONS

Voltage stability is the ability of a power system to maintain acceptable levels at all nodes under normal operating conditions and following a system disturbance. The management of system voltage across the network is one of the main fundamentals in the operation and control of a secure power system [9]. Voltage control, unlike frequency control, is a localised process. Every node on the network has an independent voltage level which fluctuates throughout the day due to the time varying nature of the power system, determined and controlled by the real-time balance between demand and generation. In order to maintain system voltage within acceptable levels, both in steady state and during a transient, the system must be operated in a suitable operating condition. Voltage control scarcities were observed in Deliverable D2.4 of EU-SysFlex [1] due to a significant lack of steady state reactive capability with the transition to a power system with high levels of non-synchronous renewables.

This section explores a number of possible mitigation measures that can be adopted in Task 2.6, first in the Continental, or pan European power system, followed by the Ireland and Northern Ireland power system. The demonstration of the capabilities that are needed to solve the technical scarcities is the main focus in Task 2.6; not the technologies themselves. It is important to note that it is acknowledged that the technologies discussed in this section are not exhaustive; they are typical examples of technologies that can provide the needed capability.

5.1 CONTINENTAL EUROPE: STATIC VOLTAGE STABILITY

Steady-state analysis preformed for Energy Transition scenario and its capacity sensitivities Going Green and Distributed Renewables has shown in Task 2.4 that a reactive power level scarcity is expected when there is a high renewables share in the CE power system. Both under and overvoltage problems may only occur for the critical contingency states, on the 110 kV network (which has the highest level of distribution system / sub-transmission system).

Further increase of non-synchronous generation in a particular area (in Poland in this case, Energy Transition → Going Green) increases the scarcity in reactive power as well, both in number of problematic nodes and expected voltage values. When a proportion of the renewables are moved toward the radial distribution systems (Going Green → Distributed Renewables), there are fewer cases of under-voltage problems, but there are individual ones where very low voltage stability margins and even instability is observed. On the other hand, the over-voltage problems are significantly amplified when the Distributed Renewables capacity scenario is investigated. Further moving the non-synchronous generation into the MV and LV distribution network may slightly deepen the under-voltage problems observed. All these observations require the investigation of countermeasures to mitigate the reactive power level scarcity.

The maps of spatial distribution of impermissible voltage levels from Task 2.4 are presented in Figure 5-1–Figure 5-3, for each considered capacity scenario. These maps show 110 kV nodes for which the voltage level decreases below the 0.9 p.u. and exceeds the 1.1 p.u.

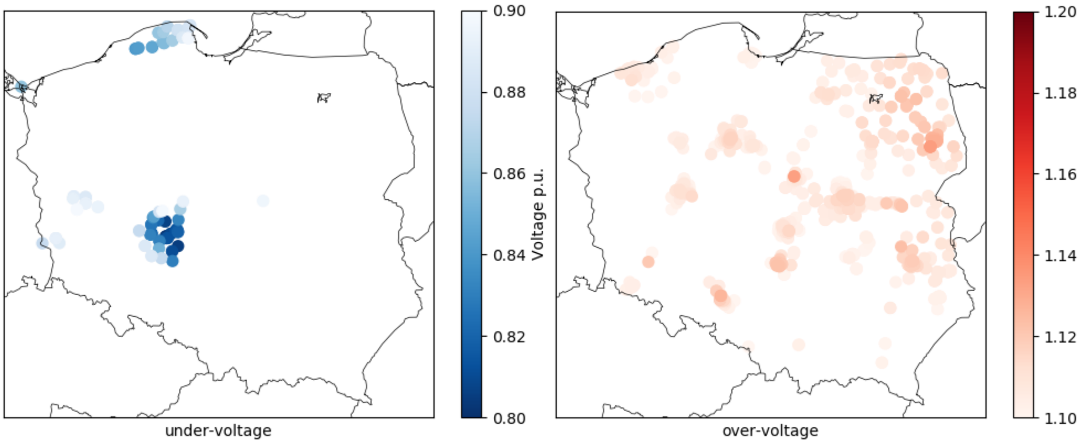


FIGURE 5-1: SPATIAL DISTRIBUTION OF UNPERMISSIBLE VOLTAGE LEVELS IN ENERGY TRANSITION SCENARIO (IDENTIFIED SCARCITY IN TASK 2.4)

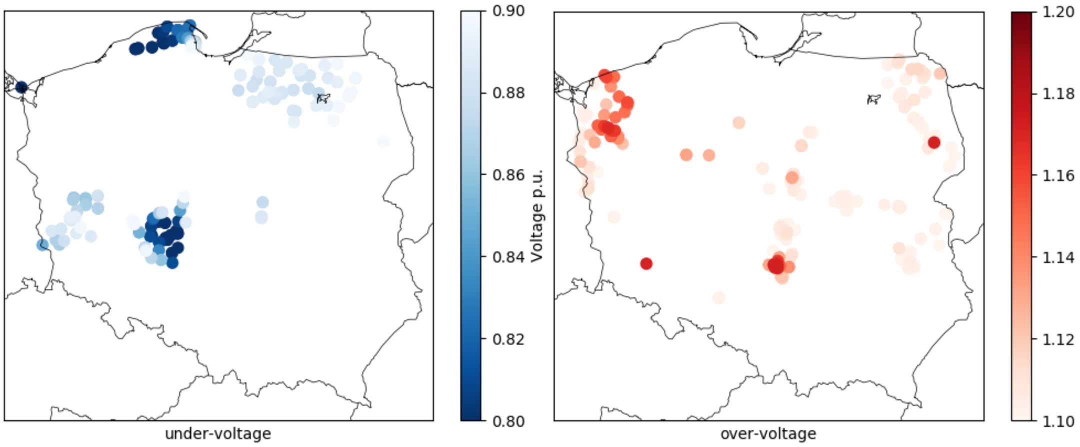


FIGURE 5-2: SPATIAL DISTRIBUTION OF UNPERMISSIBLE VOLTAGE LEVELS IN GOING GREEN SCENARIO (IDENTIFIED SCARCITY IN TASK 2.4)

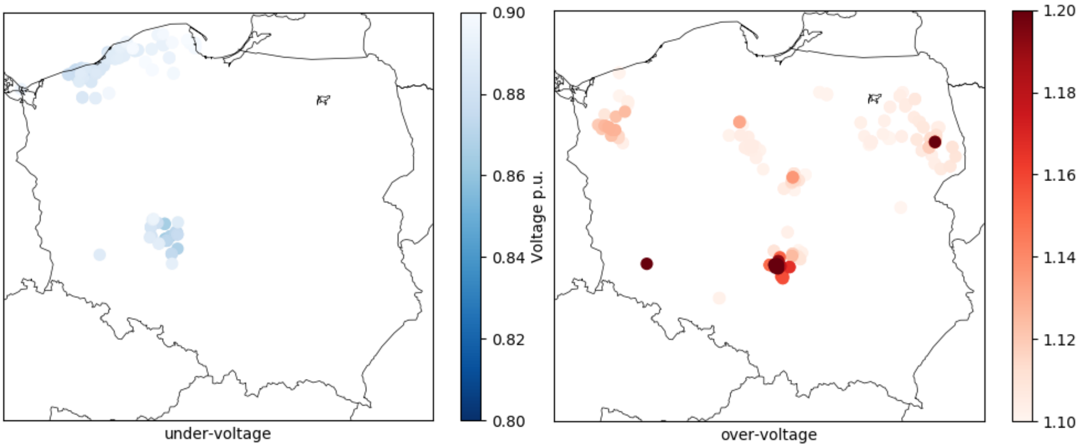


FIGURE 5-3: SPATIAL DISTRIBUTION OF UNPERMISSIBLE VOLTAGE LEVELS IN DISTRIBUTED RENEWABLES SCENARIO (AS IDENTIFIED SCARCITY IN TASK 2.4)

5.1.1 RESULTS: EVIDENCE OF MITIGATIONS

Based on the identified reactive power scarcity, two types of countermeasures are considered:

- Additional reactive power resources;
- Releasing reactive power reserves from non-synchronous energy sources.

A methodology and obtained results have been briefly described in the next subsections.

5.1.1.1 ADDITIONAL REACTIVE POWER RESOURCES

For this kind of countermeasure, the voltage problems have been resolved with the use of capacitor banks or shunt reactor installed at 110 kV nodes. A representation of the algorithm for determining the additional reactive power capacity required is shown in Figure 5-4.

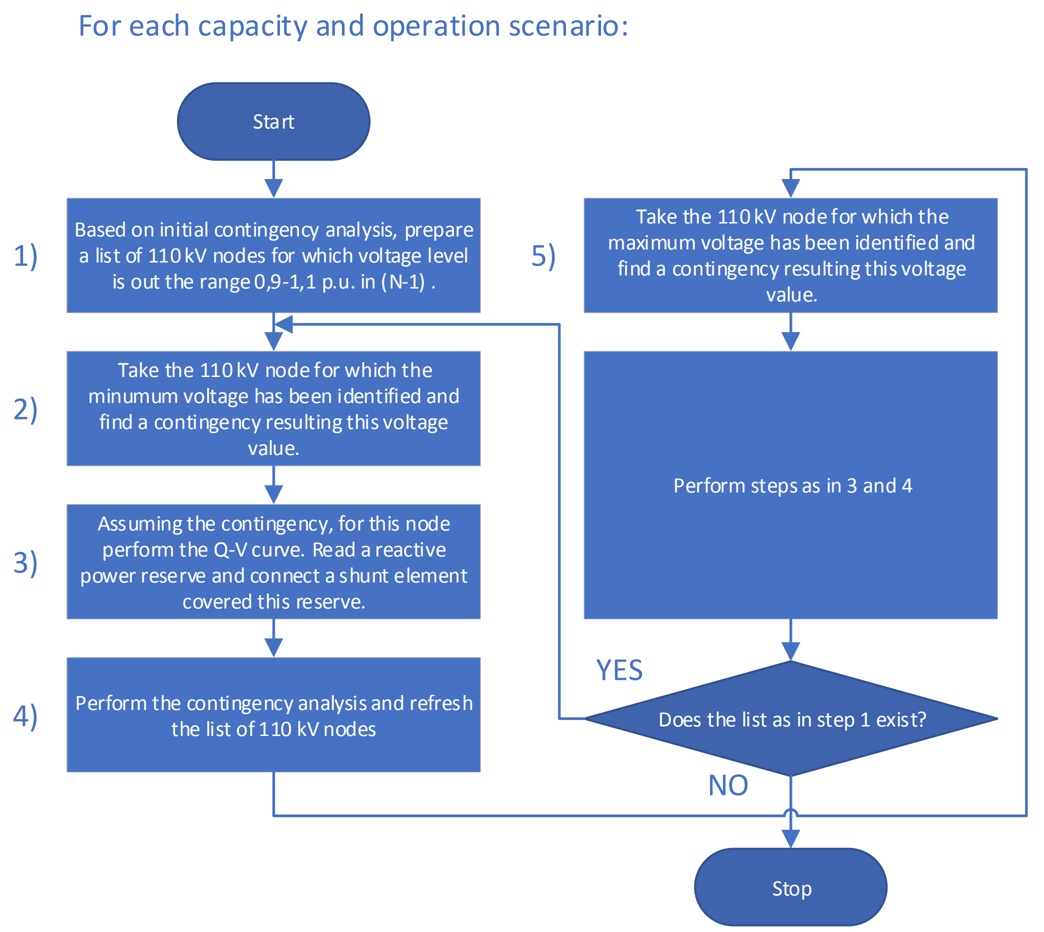


FIGURE 5-4: SIMPLIFIED DIAGRAM OF ALGORITHM DIMENSIONING ADDITIONAL REACTIVE POWER SOURCES.

Assuming that the identified shunts are fully controllable, the reactive power capacity results obtained from each scenario have been merged into one list with the maximum capacity found recorded. In this way, additional reactive power capacity results have been obtained for each renewables capacity scenario.

Table 5-1 presents the obtained results relating to the additional reactive power capacity that would need to be installed in the Polish power system for each particular capacity scenario. The "+" sign means capacitors have been included while conversely a "-" sign indicates that shunt reactors have been included.

TABLE 5-1: NEED FOR ADDITIONAL CAPACITY OF REACTIVE POWER RESOURCES

Capacity scenario	Total capacity of additional reactive power resources [Mvar]	Total capacity of additional inductive (-) shunts [MVAr]	Total capacity of additional capacitive (+) shunts [MVAr]	Maximum capacity of additional inductive (-) shunt in a single 110 kV node [MVAr]	Maximum capacity of additional capacitive (+) shunt in a single 110 kV node [MVAr]
Energy Transition	3813.3	2504.4	1309.0	98.5	73.1
Going Green	3539.0	1914.2	1624.8	148.7	87.6
Distributed Renewables	2320.9	1591.2	729.7	193.8	37.8

Based on the results presented in Table 5-1, it can be observed that increasing the renewables share in Poland (i.e. Energy Transition → Going Green) can cause a reduction in the capacity of reactive power resources that are required in general. However, simultaneously it increases the demand for capacitive reactive power. Higher maximum reactive power for capacitive shunts is observed as well.

Moving a part of the renewable capacity towards the radial distribution system (i.e. Going Green → Distributed Renewables) causes further reduction of the needed capacity of reactive power resources, in terms of both inductive and capacitive capability. On the other hand, higher maximum reactive power for inductive shunts has been noted due to higher overvoltage being observed.

The spatial distribution of results (Figure 5-5) indicates that the installation of the shunt capacitors is performed for those areas where under-voltage level problems occur. This is noticeable especially in the northern part of Poland. The shunt reactors are placed in the east and west regions where voltage exceeds the level of 1.1 p.u. ultimately, the implementation of the shunts mitigate the voltage violations, hence all critical nodes have the voltage level within the range of 0.9 – 1.1. p.u (meeting N-1 conditions).

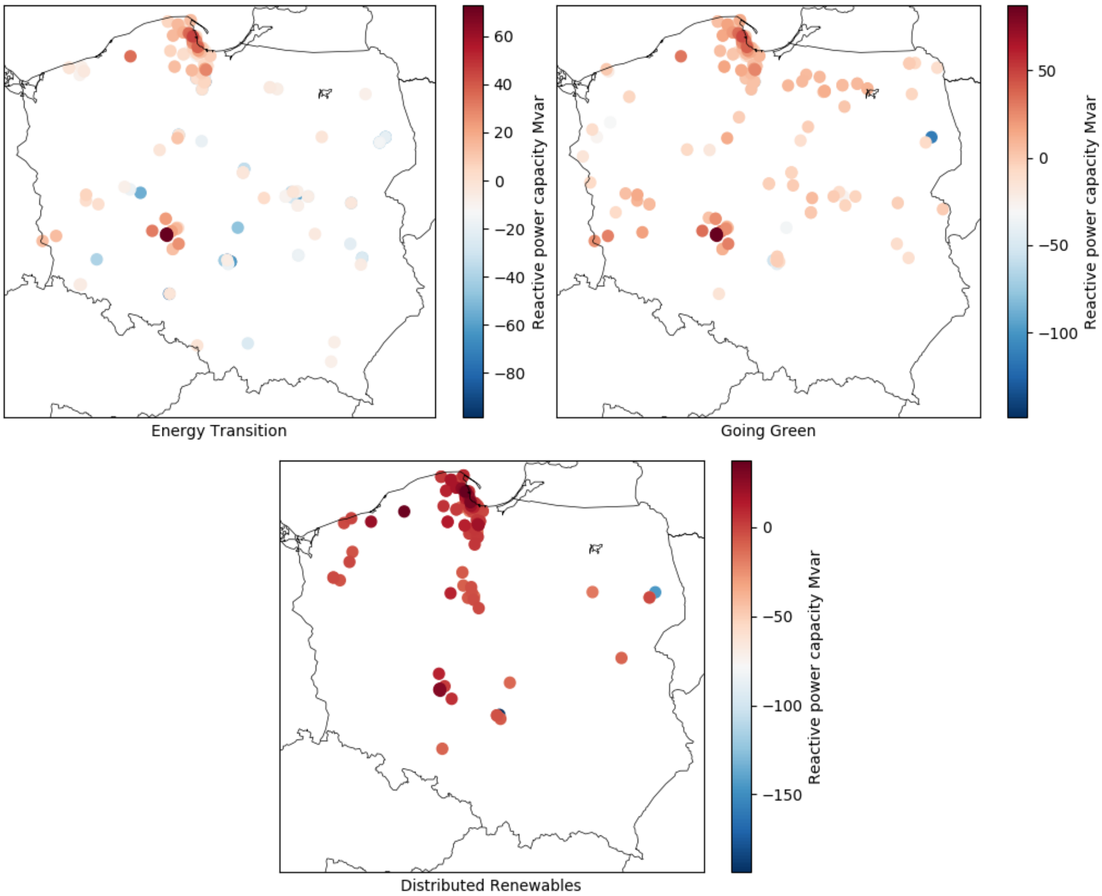


FIGURE 5-5: SPATIAL DISTRIBUTION OF NEEDS FOR SHUNT REACTIVE POWER CAPACITIES FOR DIFFERENT CAPACITY SCENARIOS

5.1.1.2 RELEASING REACTIVE POWER RESERVES OF NON-SYNCHRONOUS ENERGY RESOURCES

Network code Requirements for Generators[3] [26] requires power park modules[4] (PPM) of type A, B and C to operate with the power factor in range of $0{,}95_{lag}$ and $0{,}95_{lead}$. Such an operational mode makes a PPM unit inflexible in V/Q regulation. However, assuming that voltage control will be an ancillary service/system service offered to TSOs and DSOs by DER, power factor control mode will be released and the inherent, natural P-Q capability of the PPM can be utilised. For mitigating the issues associated with the capacity and operation scenarios, only wind power generation connected to the 110 kV network has been assumed as a V/Q-regulation service provider with the capability illustrated in see Figure 5-6.

[3] General application requirements resulting from Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code regarding the requirements for connecting generating units to the network (NC RfG)

[4] Power park module' or 'PPM' means a unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system, distribution system including closed distribution system or HVDC system [NC RfG]

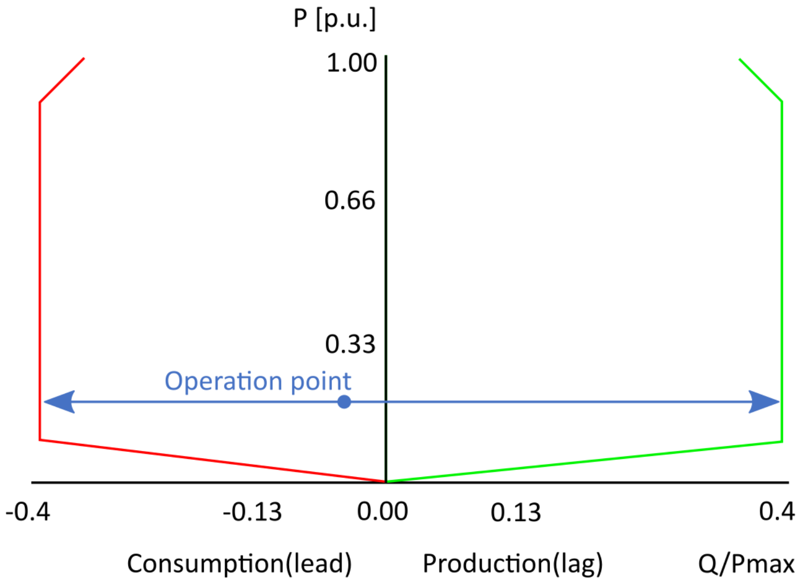


FIGURE 5-6: P-Q CAPABILITY ASSUMED FOR WIND GENERATION MODELS NOMINATED TO V/Q-REGULATION IN DISTRIBUTION NETWORK.

The algorithm for dimensioning the reactive power reserve required from wind generation is shown in Figure 5-7.

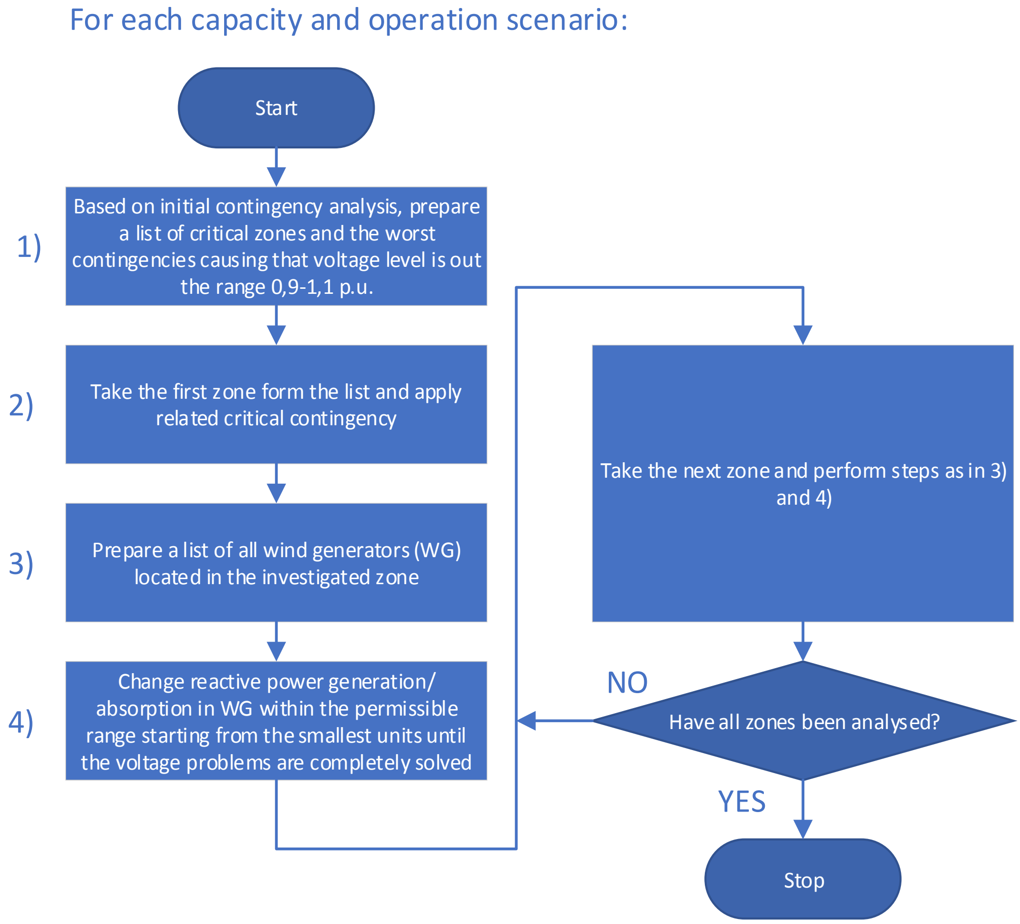


FIGURE 5-7: DIAGRAM OF ALGORITHM DIMENSIONING REACTIVE POWER RESERVES FOR NON-SYNCHRONOUS WIND GENERATION.

The maximum reactive power reserves are calculated for all the operation scenarios in a single capacity scenario. The results obtained for particular zones are added together (considering separate lead and lag reactive power) to represent required values for the Polish power system. The effectiveness of reactive power reserve activation from wind generation has been also noted by indication of the number of cases in which voltage values are still out of the permissible range. The obtained results of releasing reactive power reserves in wind generation are shown in Table 5-2.

TABLE 5-2: RESULTS OF ACTIVATION REACTIVE POWER RESERVES DELIVERED BY WIND GENERATION

Capacity scenario	Reactive power reserve in wind generation (leading)		Reactive power reserve in wind generation (lagging)	
	Activated reactive power [MVAr]	Number of cases in which voltage problems (<0.9 p.u.) still occur after reactive power reserve activation [-]	Activated reactive power [MVAr]	Number of cases in which voltage problems (>1.1 p.u.) still occur after reactive power reserve activation [-]
Energy Transition	478.63	51	-2228.0	856
Going Green	1287.56	71	-2436.95	220
Distributed Renewables	181.15	indeterminate	-871.08	43

As can be seen in the Distributed Renewables capacity scenario, one cannot determine a number of cases in which the under-voltage problems occur after the reactive reserve activation. This is due to the fact that, for the contingency of one of 400 kV busbar, the load flow process is divergent, even if all wind turbines reactive reserves located in the closest area are fully activated. It is worth mentioning that for Distributed Renewables, neglecting the problematic contingency issue, the available reactive power reserve in the leading direction is sufficient to completely restore the voltage level at the 110 kV nodes. It is also necessary to emphasise that for Distributed Renewables the lowest value of activated reactive power is needed (both in leading and lagging direction) in comparison to other two capacity scenarios.

In general, it is found that a lower volume of leading reactive power reserve in wind generation is required compared to the requirement for reactive power in the lagging direction. It can also be observed that much more leading reactive power is activated for the Going Green capacity scenario than for Energy Transition, but the number of unresolved voltage problems is higher as well. It means that the scale of the voltage problem is greater than the available mitigation measures using reactive capacity of wind generation alone (much higher in Going Green than in Energy Transition).

Obtained results of voltage levels after releasing reactive power reserves in non-synchronous energy sources are presented graphically in Figure 5-8 to Figure 5-10.

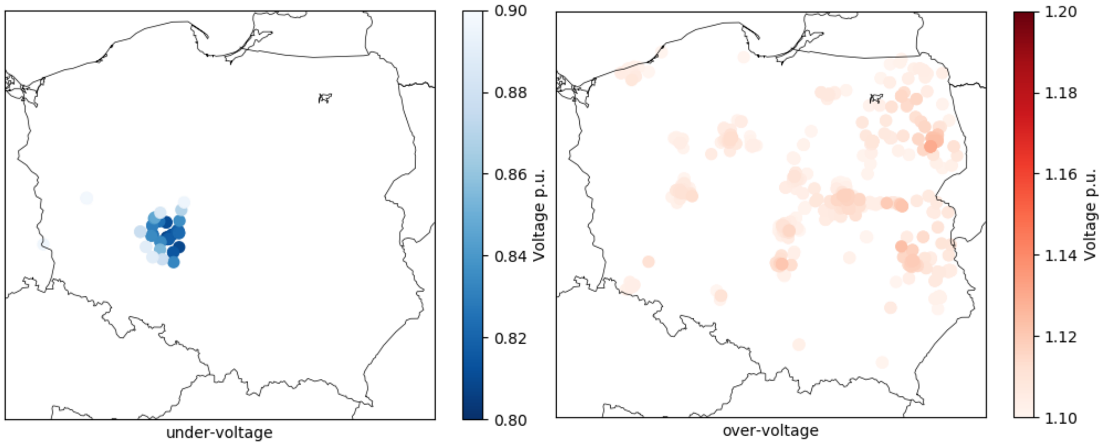


FIGURE 5-8: SPATIAL DISTRIBUTION OF UNPERMISSIBLE VOLTAGE LEVELS IN ENERGY TRANSITION SCENARIO (AFTER RELEASING REACTIVE POWER RESERVES IN PPMS)

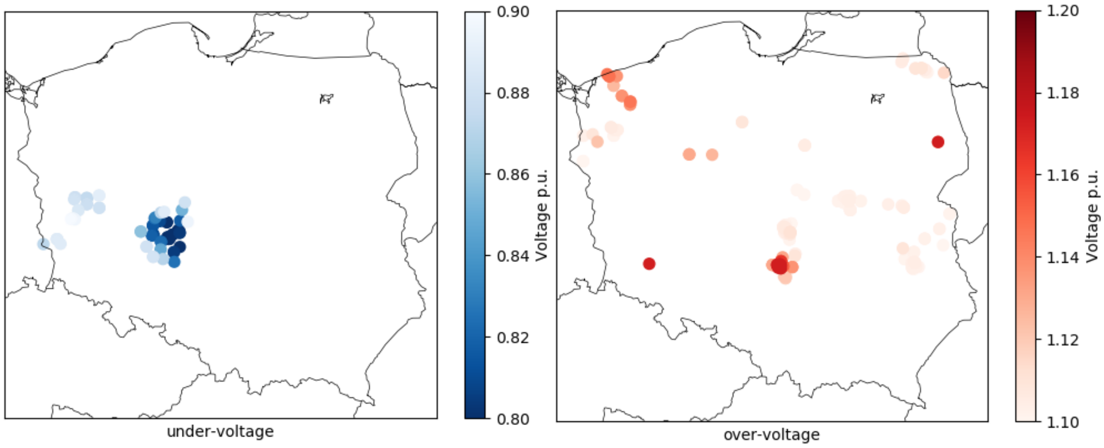


FIGURE 5-9: SPATIAL DISTRIBUTION OF UNPERMISSIBLE VOLTAGE LEVELS IN GOING GREEN SCENARIO (AFTER RELEASING REACTIVE POWER RESERVES IN PPMS)

Most of the voltage violations below the 0.9 p.u. limit still occur in the Northern and Central-West part of Poland, thus for the aforementioned areas it leading reactive power reserve in PPMs is activated. This leading reactive power significantly decreases the number of under-voltage 110 kV nodes for the analysed capacity scenarios. For the Distributed Renewables scenario, no under-voltage problems have been observed.

A number of 110 kV nodes exceed the voltage level limit of 1.1 p.u. in the East and Central-South part of Poland. The vast majority of lagging reactive power capability is released from PPMs located in the East border and Central region of the country. Overvoltages have been reduced to a certain extent for the Going Green and Distributed Renewables scenarios.

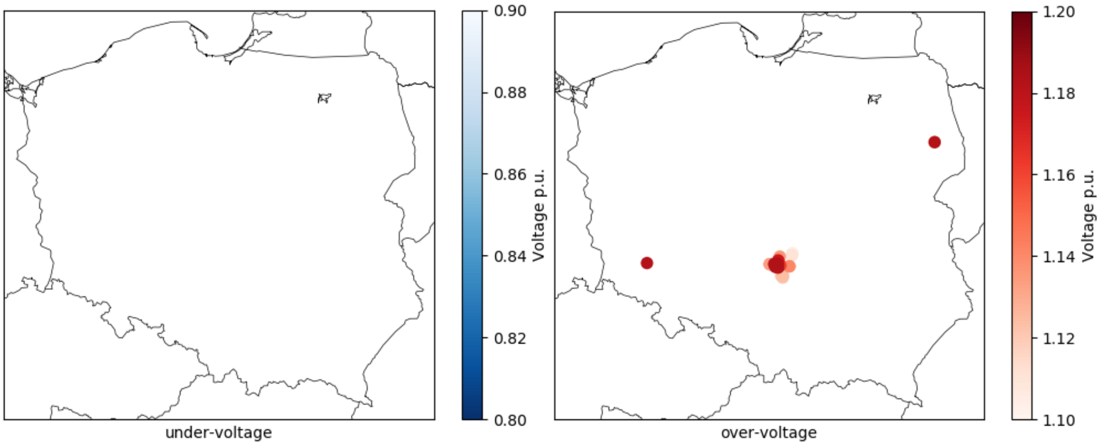


FIGURE 5-10: SPATIAL DISTRIBUTION OF UNPERMISSIBLE VOLTAGE LEVELS IN DISTRIBUTED RENEWABLES SCENARIO (AFTER RELEASING REACTIVE POWER RESERVES IN PPMS)

Ultimately, the leading and lagging reactive power capability from PPMs contributes to an overall decrease of voltage violations. Nonetheless the additional implementation of shunt reactors and capacitors could definitely improve the voltage levels.

Utilising reactive power capability delivered by wind generation is not the only type of voltage mitigation measure. Both DER reactive power provision and additional reactive power shunts must be considered as countermeasures.

5.2 IRELAND AND NORTHERN IRELAND- STATIC VOLTAGE STABILITY

In Ireland and Northern Ireland, the operational security standards and the tranmission planning standards [27] set out the normal voltage operating ranges and the voltage ranges allowed following an N-1 contingency. These values are typically in the range of 0.95-1.1 pu for base case (i.e. N conditions) and 0.9-1.11 pu following an N-1 contingency occurring on the transmission system. To maintain the transmission system voltages within the previously specified limits power system operators can utilise a number of different grid connected resources. Primarily the power system operator will dispatch reactive power from conventional units and/or transmission-connected windfarms; however they can also use the switching in/out of reactive power devices (such as capacitor banks and STATCOMS) as required to maintain transmission system voltages within these limits.

Reactive power is a local phenomenon and cannot be transmitted over long distances. The areas with a lack of reactive power support might suffer from voltage instability that could remain local or widespread over a larger area. The areas with a deficiency of reactive power support are typically determined using P-V analysis as discussed in detail in Deliverable 2.3 and Deliverable 2.4 [8], [1]. Such analyses are used to determine the respective voltage stability margin. Where there is an insufficient stability margin, adequate reactive power planning procedures needs to be put in place to determine additional reactive power support and its type.

Task 2.4 showed that during periods of low SNSP there was sufficient Steady State Reactive Power (SSRP) capability on the system preventing voltage deviations below planning standards for both N and N-1 conditions due to the number of online conventional generation. Analysis revealed as SNSP increases there is a significant lack of steady state reactive capability due to RES displacing conventional generation which results in a large increase in both magnitude and occurrences of low voltage deviations under 0.9 p.u as shown in Figure 5-11. Results in T2.4 indicated that 110 kV transmission buses located in weaker parts of the system such as the North West region of Ireland are primarily impacted by the lack of local SSRP at higher levels of SNSP.

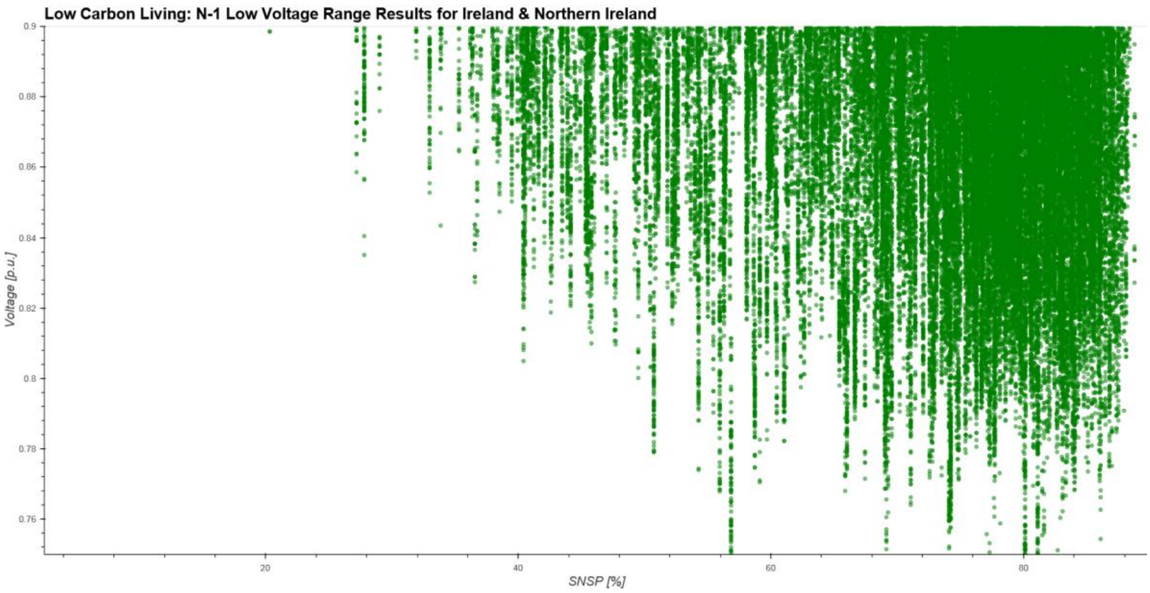


FIGURE 5-11: COMPARISON OF 2030 LOW CARBON LIVING TRANSMISSION BUSSES LOW VOLTAGE DEVIATION AGAINST SNSP [1]

5.2.1 METHODOLOGY: STEADY STATE VOLTAGE Q-V ANALYSIS

As the scarcities in steady state voltage have already been identified in Task 2.4 using P-V analysis, the next step is to determine the reactive power injection that is required to mitigate these scarcities. Q-V analysis allows for the determination of the reactive power injection required at a bus in order to manage the voltage operating range. The proposed methodology in this section is thus based on Q-V analysis. Below, a summary is provided of the practices for sizing additional reactive power compensation and its mix (fast-automatic versus slow-switchable acting reactive power compensation) for a grid location within an area where a need for additional reactive power support is identified. The methodology that is proposed here for sizing of the additional reactive power support and its type is driven by such practices and discussed in literature in CIGRE documentation [28], [29].

The minimum point on the Q-V curve represents the voltage instability point where dQ/dV=0. The region on the right of the curve with respect to this instability point shows that the reactive power injected at the node decreases with decreasing voltage target for the node. This is the stable operating region with positive dQ/dV sensitivity for each of the points in this right plane. Large sensitivity values indicate a stiff system whereas small sensitivity values indicate a weak system. The region on the left of the instability point shows that the reactive power injected decreases with decreasing voltage target at the node. This is the unstable operating region where the curve sensitivity dQ/dV is negative.

The CIGRE recommendations clearly identify the following two cases with respect to the additional reactive power needs:

1. The corresponding Q-V curve is in both the positive and negative Q quadrant and it is crossing the V axis (see Figure 5-12(a)). The CIGRE references [28], [29] suggest that it is not absolutely clear whether additional reactive power compensation is required. If there is a requirement for any post-fault minimum voltage or for a certain reactive power margin there might be a need for additional reactive power compensation.
2. The corresponding Q-V curve is always in the positive Q quadrant and it is not crossing the horizontal V axis (see Figure 5-12(b)). The CIGRE references [28], [29] suggest that this is an indication of a need for additional automatic reactive power compensation in order to prevent voltage collapse.

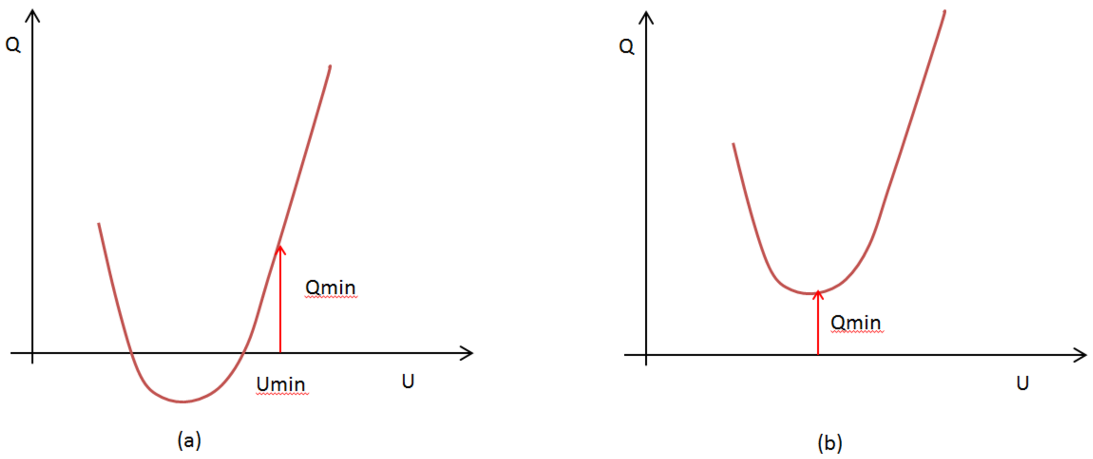


FIGURE 5-12: Q-V CURVE CASES

A more challenging problem is the sizing of the additional reactive support and how to strike to right balance between fast-automatic versus slow-switchable acting reactive power compensation – in other words how to determine the right mix of the two distinctive technologies. It is typical that different Q-V curves are used for these purposes. Such curves are plotted for a number of the buses within an area to determine the weakest grid locations and to identify the best candidates for the installation of reactive power support. The Q-V curves are drawn for different study assumptions and time phases with some realistic assumptions taken with respect to response times for the modelled phenomena/control actions [28], [29]:

1. Short-term voltage performance study (Phase 1) - this is a post-fault study where the following control/event actions and assumptions are considered:
    a. Apply the corresponding contingency
    b. Include load/voltage response
    c. Slow-switchable acting reactive power compensation switching is not allowed

   d. Transmission transformer tap changers locked with fixed tap (obtained for the intact network conditions)
   e. Where possible low voltage network is modelled.

2. Intermediate-term voltage performance study (Phase 2) – this is a post-fault study following the short-term voltage performance study where the following control/event actions and assumptions are considered:
   a. Apply the corresponding contingency
   b. Consider constant PQ load
   c. Only automatic slow-switchable acting reactive power compensation switching is allowed
   d. Transmission transformer tap changers equipped with automatic control should be allowed to move
   e. Where possible low voltage network is modelled.

If the area of the network under investigation is a power evacuation area with a low demand it is possible that there might be an overlap between the two Q-V curves from Phase 1 and Phase 2.

The underlying philosophy behind the Q-V curve concept presented here is that the reactive power reserves required for post-fault voltage stability must be switched in by some automatic control action. For the slow dynamics of progressive monotonic voltage instability these reactive power reserves may be held either by dynamic reserve plants (such as, but not limited to, synchronous machines, transmission connected wind farms, STATCOMs or Static VAR Compensators known as SVCs) or switchable discrete Mechanically Switchable Capacitors (MSCs), as an example. The dynamic portion of the reactive power reserves would ensure stable voltage performance for Phase 1 whereas the static portion would ensure longer term voltage performance for Phase 2.

The Q-V curve based procedure can be applied to any busbar on the transmission system to obtain the nodal SVC/MSC mix requirements. When the procedure is applied sequentially taking into account, at each stage, all the existing reactive power sources, the zonal dynamic/static mix requirement is systematically calculated without the need for making arbitrary percentage assumptions on the mix. The procedure for determination of the dynamic/static reactive power compensation mix can be summarised as follows [28], [29]:

1. The Q-V curves are calculated for a fixed load and power transfer for the most voltage sensitive busbar determined and for the most onerous contingency.
2. It is recommended to perform all Q-V curve calculations using the automations through a series of load flow calculations for both Phase 1 and Phase 2 (constant MVA load see figure below) assuming a range of voltage targets at the corresponding node and having a fictitious unlimited reactive power source to achieve each of the considered voltage targets.

3. For the sizing purposes the critical voltage (Vc) should be determined first from the Phase 1 curve targeting the point where dQ/dV=0 or using the slope(sensitivity) threshold as a criterion – for example the objective can be to surpass the knee point as much as possible.
4. Determine the minimum required voltage assuming that Umin=Vc + x%.
5. The dynamic portion (automatic capacitor requirement see the figure below) is the vertical distance at Umin to the Phase 1 curve.
6. The static portion (switchable capacitor requirement see the figure below) is the vertical distance at Umin to the Phase 2 (constant MVA load see figure below) curve minus the SVC portion calculated in the Step 5.
7. The total static and dynamic requirement is the vertical distance at Umin to the Phase 2 (constant MVA load see figure below) curve plus a margin y%.

The thresholds x% and y% are typically chosen to be between:

- 1.5% to 5% for x
- 10% to 15% for y

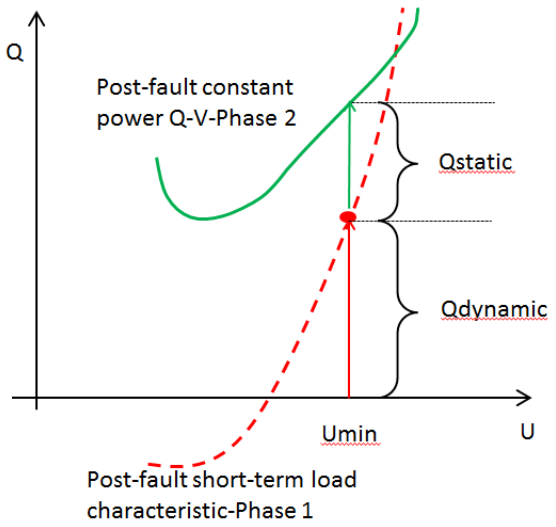


FIGURE 5-13: SIZING AND MIX – ADDITIONAL REACTIVE POWER COMPENSATION

5.2.2 RESULTS: EVIDENCE OF MITIGATIONS

This section presents the results obtained for the sizing and the mix of the additional reactive power support based on the methodology outlined in the previous section. The corresponding steady-state Q-V studies are conducted for two buses in the North-West region of Ireland. This region was found as the most troublesome in terms of voltage issues as per results observed in Deliverable 2.4.

The Q-V analysis was performed (using PowerTech DSA Tool VSAT) for the two most vulnerable buses and the following two conditions: intact and the worst N-1 contingency. Two load models were used for these two conditions: a voltage-dependent load (Phase 1- see section 5.2.1) and constant P-Q load (Phase 2 –see section 5.2.1). The resultant Q-V curves generated for these two most vulnerable buses are presented in Figure 5-14 and Figure 5-15These curves capture the following combinations of the load models and conditions:

- Intact conditions and constant PQ load model
- Post-fault (N-1) conditions and constant PQ load model
- Post-fault (N-1) conditions and a voltage dependent load model

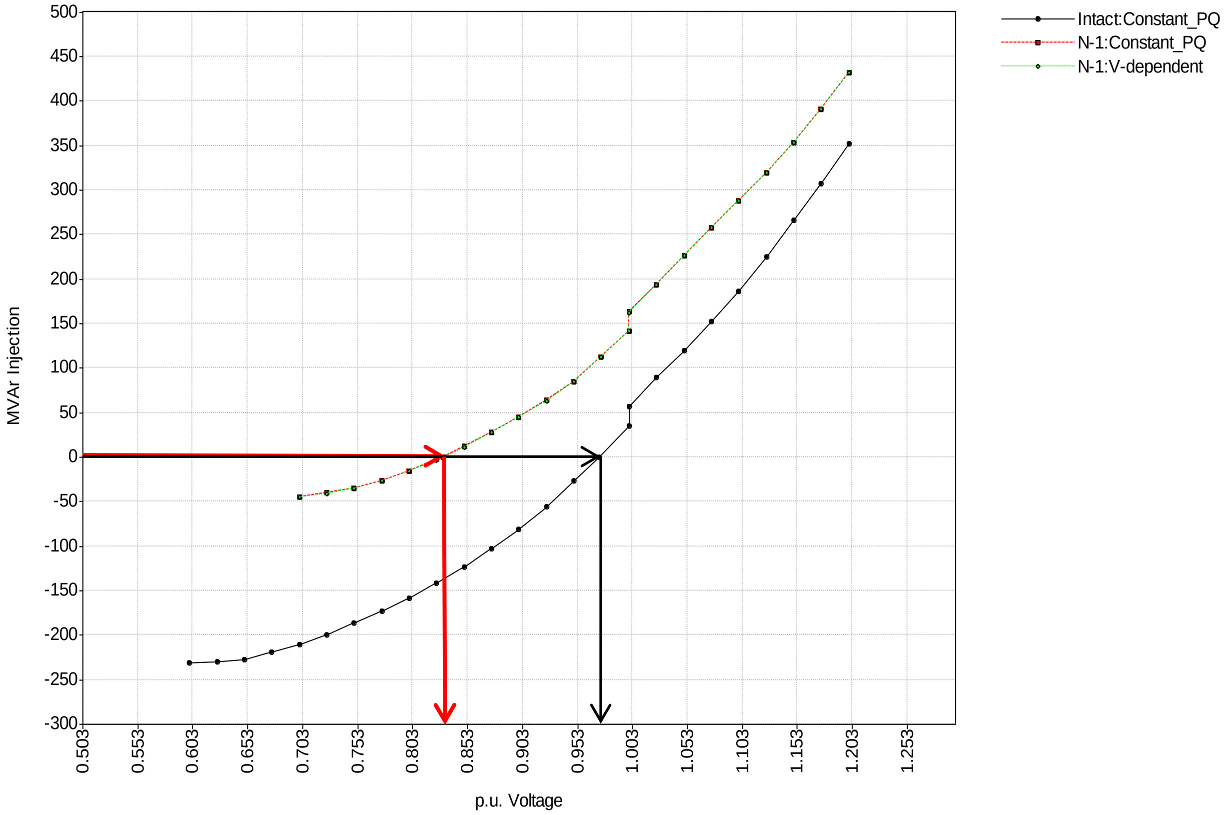


FIGURE 5-14: INTACT AND POST-CONTINGENCY Q-V PLOTS FOR BUS 1 WITH CONSTANT P-Q AND V-DEPENDENT LOAD MODELS

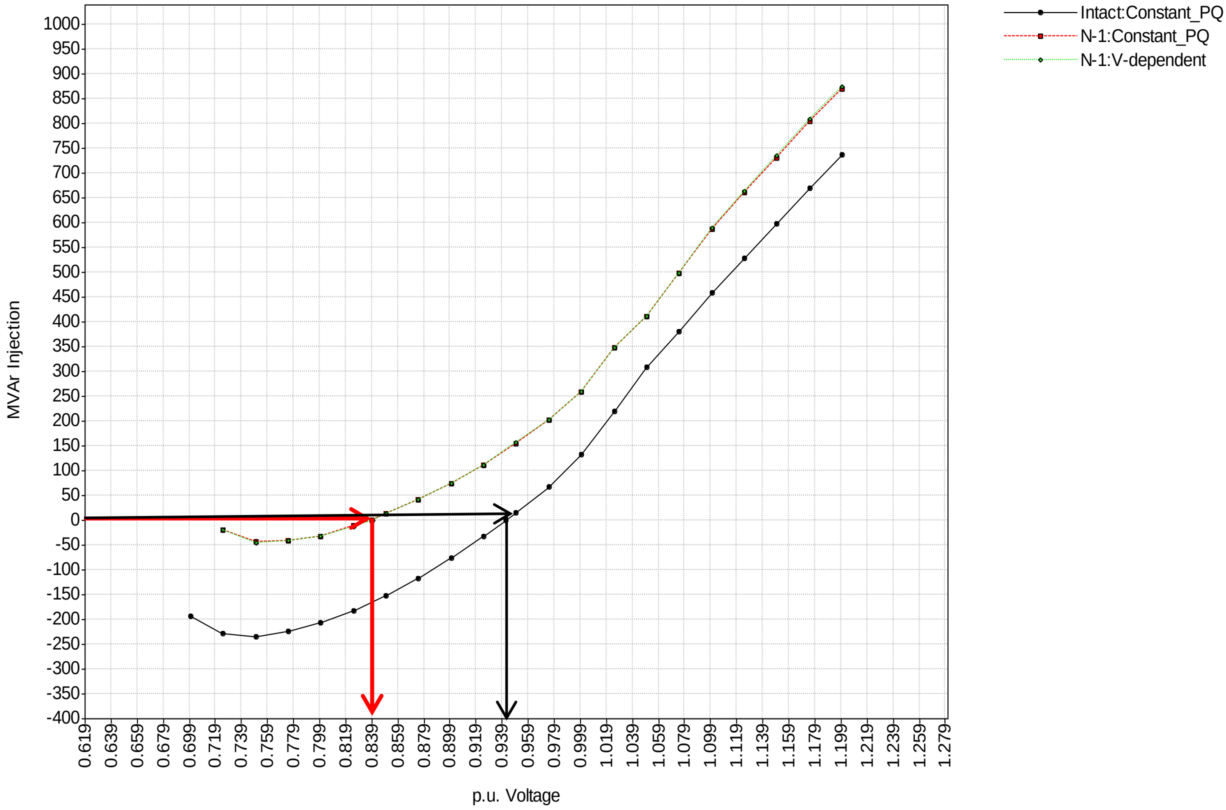


FIGURE 5-15: INTACT AND POST-CONTINGENCY Q-V PLOTS FOR BUS 2 WITH CONSTANT P-Q AND V-DEPENDENT LOAD MODELS

It can be observed from Figure 5-14 and Figure 5-15 that the incorporation of the contingency causes significant under-voltages at the two most vulnerable buses. It can be seen that the voltage drops from 0.97 p.u. in the intact case to 0.83 p.u. post-fault in Figure 5-14 for the first bus (see arrows in the figures above). For the second bus it drops from 0.94 to 0.84 as per Figure 5-15 (see arrows).

For the sizing of additional reactive power compensation the approach outlined in the section 5.2.1 was followed using the following assumptions:

- The critical voltage is 0.9 p.u (Vc=0.9 p.u.) as per transmission planning criteria for the post-fault conditions [27];
- x is selected to be 1.5%, making the Umin=0.915 p.u.;
- The intersection of the 0.915 p.u. ordinate line and the post-fault characteristic indicate that the required additional reactive power support for the two vulnerable buses are 57MVAr and 101 MVAR, respectively;
- Considering additional margin of y=10.0% the final requirements for the additional reactive power for the two most vulnerable buses are 62.7 MVAr and 111.1 MVAR, respectively.

It is important to note that for both buses, the post-fault Q-V plots associated with the two different load models (Phase 1 and Phase 2 curves) are almost the same. This can be attributed to the lack of significant reactive load (only about 167 MVAr) in the North-West area where both buses are located. Given this observation, it can therefore be concluded from Figure 5-14 and Figure 5-15 that for both buses under consideration, only static reactive compensation is required (i.e. no dynamic compensation is necessary). Provision of this static reactive compensation could be provided, and indeed incentivised, by a system services product such as the Steady State Reactive Power (SSRP) [2] which is already deployed in Ireland and Northern Ireland. Indeed, the grid code in Ireland and Northern Ireland stipulates that PPMs (in this case, TSO connected wind farms) should have the technical capabilities to change their power factor control (PF) set point, their reactive power control (Q) set point or their voltage regulation (V) set point within 20 seconds of receiving a control signal from the TSO [30]. Furthermore, PPMs operating in power factor control mode, voltage control mode, or constant reactive power control mode shall be at least capable of operating at any point within the P-Q capability ranges [30]. This means that the SSRP/reactive power capability that will be needed for high levels of renewables is already a requirement in the existing grid code.

5.2.3 KEY MESSAGES: IRELAND AND NORTHERN IRELAND -STATIC VOLTAGE STABILITY

The installed capacity of wind generation in Ireland and Northern Ireland has increased over the last number of years. This value is set to increase over the next 10 years. The addition of such a significant amount of wind generation onto the power system will fundamentally alter the on-line reactive power available to the system operator to manage system voltages.

Primarily the power system operator dispatches reactive power from conventional units and/or transmission-connected windfarms to maintain transmission system voltages within system limits. Owing to the evolution of the generation portfolio, **new sources of Steady State Reactive Power (SSRP) deployed in specific geographical locations are required in order to maintain transmission system voltage levels**. These sources may include, but are not limited to capacitor banks, shunt reactors, HVDCs, STATCOMS, Static VAr Compensators (SVCs), Synchronous Condensers and potentially the reactive capability from wind farms and some batteries [31].

A co-ordinated approach between both the TSO and the DSO is essential in order to manage the transmission system voltage owing to approximately 50% wind generation being embedded within the distribution network in Ireland and Northern Ireland. The Nodal Voltage Controller pilot project was established in late 2017. The main objective of the pilot project was to assess the feasibility and effectiveness of a Nodal Controller (NC) in controlling reactive power capability of wind farms connected at distribution level. Testing is currently ongoing. It is hoped that the controllability of DSO wind farms connected to a transmission node which have no load customers will provide voltage support to the transmission system whilst maintaining a secure distribution system. The NC is a means by which distribution connected wind generation can be utilised to provide reactive power support to the TSO at required times, whilst simultaneously ensuring that all relevant distribution system parameters are kept within secure limits [32].

5.3 IRELAND AND NORTHERN IRELAND- DYNAMIC VOLTAGE

Dynamic voltage control manages the reactive power imbalance during and after a large disturbance (e.g. for a transmission line fault). The primary sources of this control are the inherent response from the air gap of synchronous machines, the voltage sensitivity of demand, the control systems of power electronic interfaced generation and the automatic voltage regulators of synchronous machines. The inherent response of synchronous machines is one of the fastest and most significant sources of dynamic voltage control and the loss of this response, due to displacement of synchronous machines in the transition to higher levels of renewables, leads to concerns over the emergence of a scarcity in dynamic voltage control either due to the overall volume of response or the geographical distribution of this resource, due to the relatively localised impact of reactive power [1].

In order to address this scarcity, fast dynamic reactive power support will be essential for a successful voltage recovery and avoiding instability scenarios or voltage/reactive power issues cascading into frequency stability/balancing issues due to phenomena such as voltage dip induced frequency delay. The DS3 programme [33] introduced the Dynamic Reactive Response (DRR) system service to incentivise and enable provision of fast reactive power support in weak areas of the system and in high SNSP scenarios. DRR is defined as MVAr capability during large (>30%) voltage dips [34]. The following sections present the mitigation of the dynamic voltage scarcities identified in Deliverable 2.4 [1] using the DRR system service which is provided by a number of different technologies.

5.3.1 METHODOLOGY: DYNAMIC VOLTAGE SCARCITIES

The main objective of EU-SysFlex Task 2.6 is to mitigate the scarcities identified in Task 2.4. The dynamic voltage scarcities for Ireland and Northern Ireland are classified in two main forms in Deliverable 2.4 [1]:

1) A **global scarcity** that results in voltage stability issues for almost all contingencies regardless of location,
2) A **localised scarcity** that only results in voltage stability issues for contingencies in a specific location or region of the system [1].

Task 2.4 identified localised scarcities in the Ireland and Northern Ireland power system and these localised scarcities are separated into systematic localised scarcities, which occur for effectively all hours, and specific localised scarcities, which occur for a small subset of hours. To mitigate these systematic localised scarcities, DRR providing technologies are proposed as a potential solution. The DRR providing technologies considered in this analysis are Synchronous Condensers, static Synchronous Compensators (STATCOM) and Static Var Compensators (SVC).

Synchronous Condenser is a DC-excited Synchronous Motor, whose shaft is not connected to anything but spin freely [35]. Its field is controlled by a voltage regulator to either generate or absorb reactive power instantaneously similar to conventional generators.

STATCOM and SVC are power electronics devices which provide dynamic reactive power through its voltage controllers, hence these devices provide ramping reactive power and the speed or the ramp rate depends on the power electronics switches used. STATCOM uses fast acting Insulated Gate Bipolar Transistors (IGBTs) and SVC uses thyristors, hence the response time of STATCOM is shorter than SVC [36].

Look Ahead Security Assessment Tool (LSAT) is the online dynamic security assessment tool used in the control room of EirGrid and SONI. LSAT is the updated version of Wind Security Assessment Tool (WSAT) with look-ahead capability. The studies conducted, and reported in this section, for Ireland and Northern Ireland power system are performed in the Transient Security Assessment Tool (TSAT) which is a module in LSAT used for offline studies.

The dynamic models of DRR technologies used in this analysis are presented in detail in Deliverable 2.3. Task 2.4 selected 36 snapshots of low Carbon living (LCL) scenario based on SNSP level, System Inertia and Number of large units online. These 36 snapshots are modified with the addition of DRR technologies for Task 2.6 studies.

The metric used in Task 2.4 to assess dynamic voltage control known as dynamic voltage profile index. During Task 2.6 studies, this index was found to have a limitation which favours only technologies providing instantaneous reactive power. This limitation is explained in detail in the following section. Subsequently, a new improved metric is proposed and discussed. This metric is used to access dynamic voltage control which also includes the effectiveness of both instantaneous and ramping based reactive power injection. The simulation setup used in Task 2.4 such as 306 bolted three phase line fault contingencies and dynamic models of the generators, load, interconnectors and others are used in this analysis without any change.

In Task 2.6, numerous simulations are performed with the dynamic models of the different technologies and with a different combination of locations (substations) with DRR installations and the combination with least dynamic voltage violations were selected. The results of this will be presented in Section 5.3.6.

5.3.2 LIMITATIONS OF METRIC USED IN TASK 2.4

As mentioned above, the metric used in EU-SysFlex Task 2.4 to assess the dynamic voltage performance is an index termed **dynamic voltage profile index**. This index quantifies the number of buses where the corresponding dynamic voltage performance does not exhibit the desired voltage response during a fault. An illustrative example of the application of this metric is provided in Figure 5-16. The response is illustrated in the figure below (Figure 5-16) for Bus 1, Bus 2 and Bus 3 where the post-fault voltage recovery above the 0.5 p.u. threshold is achieved within fault clearance time or the post-fault voltage does not drop below 0.5 p.u threshold. This example presents three unique violations (Bus 1, 2 and 3), two of which exhibited early recovery (Bus 2 and 3). Note, the second violation by Bus 3 is not counted as a unique violation and is classed as a repeated violation.

It should be noted that the count of unique violations can be skewed by the ‘density’ of the network in the vicinity of the fault, i.e. the number of buses in close proximity to the fault. As such, it is not a perfect measure of the propagation of the fault and small differences (e.g. on the order of 25 buses) should not be given too much emphasis however large differences (e.g. on the order of several hundred buses) should not be ignored.

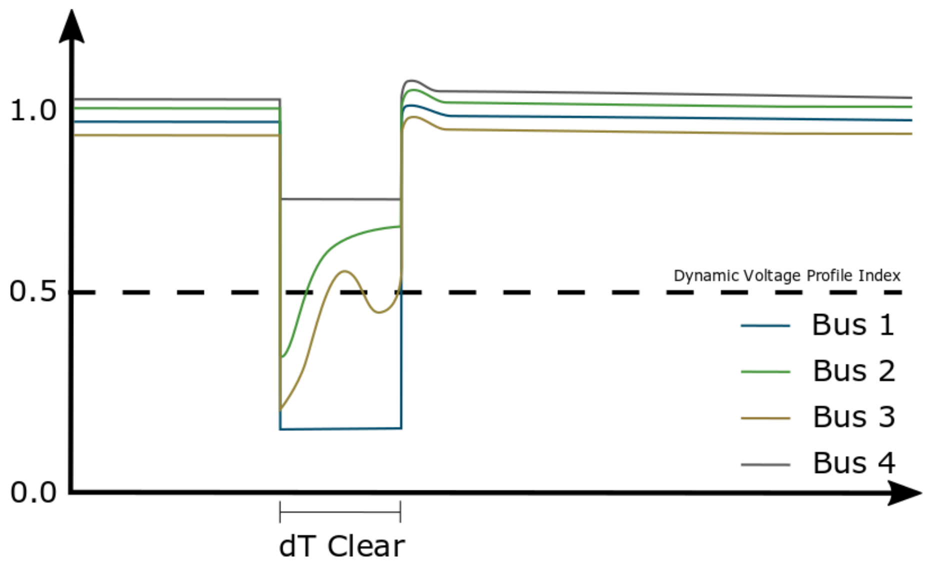


FIGURE 5-16: ILLUSTRATIVE EXAMPLE OF THE DYNAMIC VOLTAGE PROFILE INDEX [1].

Another indicator used in Task 2.4 is the early recovery index which is the percentage of buses whose voltage traces violated the 0.5 p.u. threshold but recovered to above this value during the fault clearance. This measure of early recovery is imperfect, e.g. it is heavily influenced by the depth of the voltage drop (i.e. a fault that causes many buses to drop to just below 0.5 will likely have a high percentage of early recoveries regardless of the volume of additional reactive power rejection during the fault).

Figure 5-17 shows typical post-fault responses for these technologies after a 3-phase to earth fault is applied at a 220 kV line in the vicinity of the substation where we considered different technologies (one at the time). Synchronous Condenser (yellow trace) is capable of providing instantaneous reactive power, whereas STATCOM (red trace) and SVC (green trace) are capable of providing ramping reactive power.

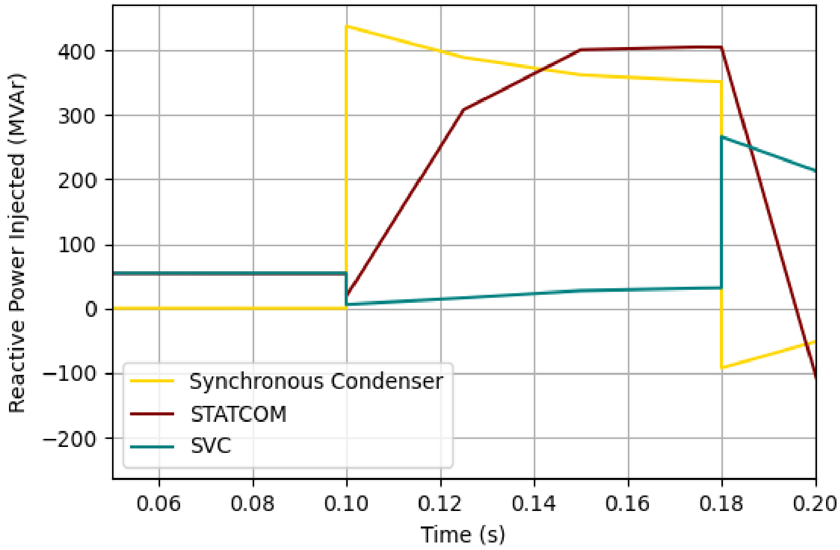


FIGURE 5-17: REACTIVE POWER INJECTION FROM DIFFERENT TECHNOLOGIES

Figure 5-18 shows the effect of installation of different technologies on its adjacent bus voltage magnitude. The size of reactive power support is the same across different technologies used in this example. The bus voltage magnitude in base case (black trace- without any additional reactive support considered) drops below 0.5 threshold p.u. and the voltage recovers only after the fault is cleared. The bus voltage magnitude when the Synchronous Condenser is installed (yellow trace) does not drop below 0.5 p.u. threshold due to the instantaneous reactive power injection from the Synchronous Condenser. The bus voltage magnitude, when a STATCOM (red trace) or an SVC (green trace) is installed drops below 0.5 p.u on account of the fact that these technologies cannot provide reactive power instantaneously, rather a more ramping driven response.

However, detailed analysis utilising a STATCOM installation has shown that the bus voltage magnitude recovers above the 0.5 p.u. threshold before the fault is cleared simply because the STATCOM can provide adequate reactive support even during low voltage conditions. This is not, however, the case with the SVC where investigations shows it which provides adequate reactive support only after the fault clearance (green trace at t = 0.18 s) when the voltage is recovered to near its pre-fault values.

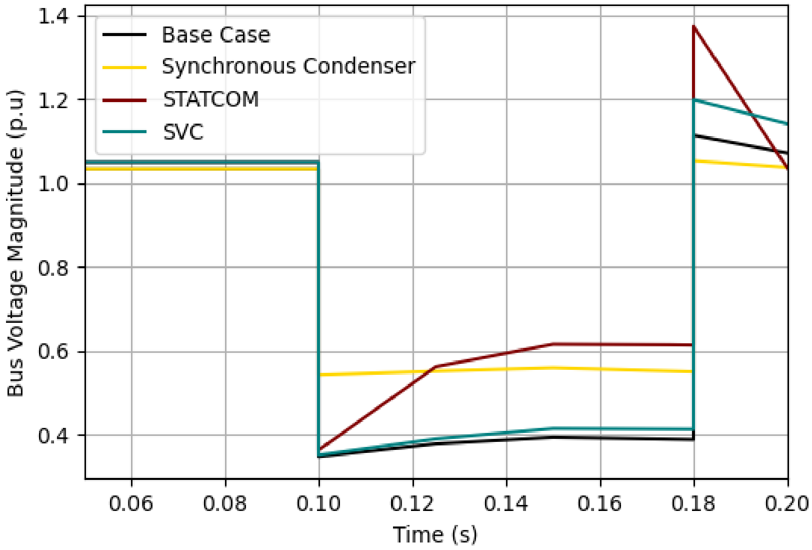


FIGURE 5-18: EFFECT OF INSTALLATION OF DIFFERENT TECHNOLOGIES ON BUS VOLTAGE MAGNITUDE

Figure 5-19 shows the unique violations reported (metric used in Task 2.4) for a 3-phase to earth fault on a 220 kV line close to the proposed mitigation technologies. If this metric is used for Task 2.6, Synchronous Condensers appear to be the more favourable option simply because they can provide instantaneous reactive power and consequently would be considered as the only option to mitigate this dynamic voltage scarcity identified in Task 2.4.

The main limitation using this metric is that it devalues the effectiveness of a STATCOM installation as outlined above where the bus voltage magnitude recovers above the 0.5 p.u. threshold before the fault clearance due to a non-instantaneous recovery response. An improved metric that ensures a more level playing field when it comes to the proposed mitigation technologies is discussed in detail in the following section.

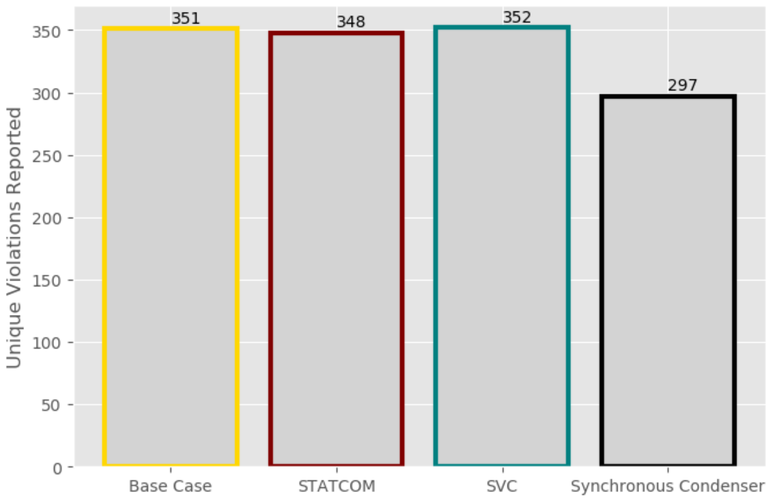


FIGURE 5-19: UNIQUE VIOLATIONS REPORTED FOR DIFFERENT TECHNOLOGIES INSTALLATION.

5.3.3 IMPROVED METRICS IN TASK 2.6

A new improved metric has been developed in Task 2.6 to focus on assessing the networks shortcomings with respect to voltage recovery. For the sake of simplicity and brevity, buses like Bus 2 in Figure 5-16 with almost immediate post-fault crossing of the 0.5 p.u. threshold should not be taken into account simply because those traces will definitely favour instantaneous reactive power support over ramping based support associated with SVC and STATCOMs. The only difference between the old and the new improved metric involves the removal of buses where the voltage magnitude drops below the 0.5 p.u. threshold and recovers above the 0.5 p.u. threshold within the fault clearance time (for example: Bus 2 and Bus 3 in Figure 5-16 are not counted in the proposed new metric while they are counted in the old metric used in Task 2.4).

Figure 5-20 shows the non-recoverable unique violations reported (new metric) for a 3-phase to earth fault on a 220 kV line near to the location of the technology installation. If this new metric is used for Task 2.6 then STATCOM and Synchronous Condenser will be both given equal consideration as mitigation options for dynamic voltage scarcity since this new metric account for effectiveness of both instantaneous and ramping based reactive power injection.

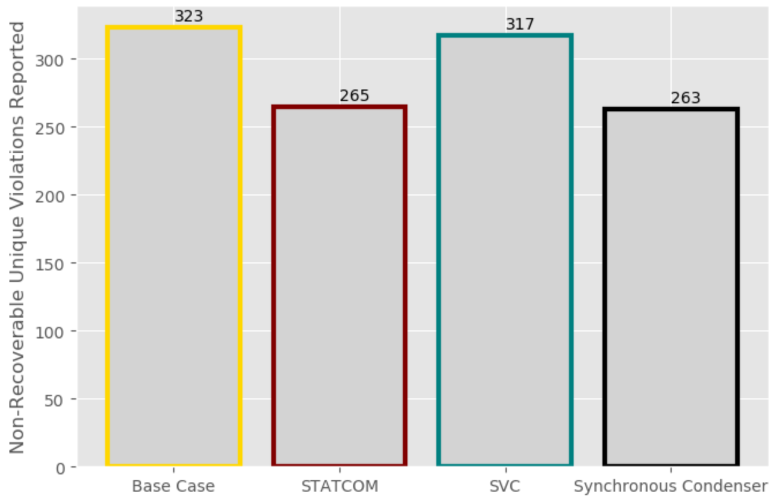


FIGURE 5-20: NON-RECOVERABLE UNIQUE VIOLATIONS REPORTED FOR DIFFERENT TECHNOLOGIES INSTALLATION

A case study of the Ireland and Northern Ireland power system is presented for better understanding of the old and improved new metrics. Figure 5-21 shows an example of the dynamic voltage profile of few buses in Ireland and Northern Ireland power system, while Figure 5-22 shows the corresponding excerpt from a TSAT output report. A 3-phase to earth fault is applied to a line at simulation time 0.1 s and the fault is cleared after 80ms at 0.18s. The results are summarised in the table below in terms of violations counted with old and new improved metrics:

TABLE 5-3: BUSES COUNTED IN TERMS OF VIOLATIONS

Old Metrics	New Improved Metrics
BUS C2	BUS C2
BUS B0	BUS B0
BUS A2	BUS A2
BUS RB	
BUS A1	
BUS S0	

The bus voltage magnitude of all buses listed in Table 5-3 drops below the 0.5 p.u. threshold when the 3-phase to earth fault is applied. The buses such as BUS C2, BUS B0 and BUS A2 are those where bus voltage magnitude do not recover above the 0.5 p.u. threshold during the fault clearance. The bus voltage magnitude of BUS A1 and BUS S0 recovers above the 0.5 p.u. threshold before the fault is cleared. The BUS RB bus voltage magnitude exhibits early recovery at 120ms and the bus voltage magnitude again drops below 0.5 p.u. threshold at 165ms. In the TSAT output file, two violations are reported for BUS RB bus and the remaining buses are reported once. The old metric used in Task 2.4 for this case would report 6 unique voltage violations (not counting the second violation of BUS RB). The improved metric will only count BUS C2, BUS B0 and BUS A2 buses and report these as 3 non-recoverable unique voltage violations. The BUS A1, BUS S0 and BUS RB buses are not counted in new metric.

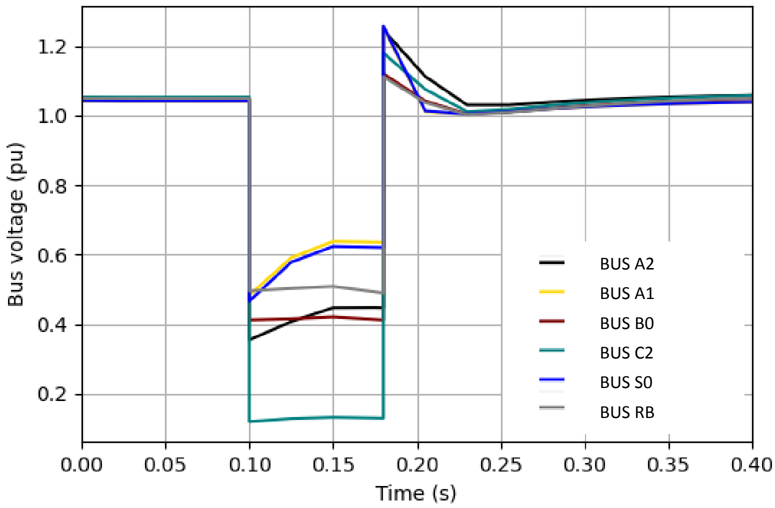


FIGURE 5-21: ILLUSTRATIVE EXAMPLE OF DYNAMIC VOLTAGE PROFILE INDEX.

*** CONTINGENCY - 78 -- IRISHT20 - SHELYB20 MIDDLE

Voltage Drop Violations

Bus			Vmin	Tstart	Tend	Vthr	Tthr	Criteria	Status
11220	BUS A2	220.	0.3419	0.100	0.180	0.5000	0.000	Voltage	Warning
11810	BUS A1	110.	0.4829	0.100	0.105	0.5000	0.000	Voltage	Warning
13200	BUS B0	38.0	0.4014	0.100	0.180	0.5000	0.000	Voltage	Warning
17420	BUS C2	220.	0.1130	0.100	0.180	0.5000	0.000	Voltage	Warning
6708	BUS RB	110.	0.4898	0.165	0.180	0.5000	0.000	Voltage	Warning
6708	BUS RB	110.	0.4833	0.100	0.120	0.5000	0.000	Voltage	Warning
49600	BUS S0	38.0	0.4659	0.100	0.110	0.5000	0.000	Voltage	Warning

FIGURE 5-22: ILLUSTRATIVE EXAMPLE OF TSAT OUTPUT REPORT

5.3.4 PROPOSED THRESHOLD FOR CONTINGENCIES GROUPING

The corresponding threshold of 150 was selected arbitrarily in Task 2.4 for the purposes of scarcities identification and categorisation only. The dynamic voltage profile index is the number of unique violations of the 0.5 p.u. threshold. For some of the Task 2.4 snapshots that we analysed through our dynamic security analyses, a typical contingency would have unique violations in excess of 350 for this index. Different contingencies would have different values depending on how weak the system is in the vicinity of contingency and the closeness of reactive power support available. The more buses are accounted for the wider is spread of the impact of the fault and the more additional and fast reactive power support is required.

Further analyses on the LSAT snapshots has been performed and confirmed that a typical contingency today would show, on average, more than 350 of buses being impacted. This, it is believed, would be overly optimistic, with increased level of renewables for the 2030 scenarios, to expect that a situation can be improved significantly comparing to today's levels. It would not be realistic and economically justified to provide better stability than what currently exists today. Hence for Task 2.6 the line of separation is selected as 250 for the new improved metrics instead of 150. To achieve non- recoverable unique violation less than 150 threshold, hundreds of technologies providing DRR would be required whereas for threshold of 250, less than ten DRR technologies are required.

5.3.5 SUMMARY OF INDICES AND THRESHOLD USED

The metric used in Task 2.4 to assess the availability of dynamic voltage control would favour technology able to provide an instantaneous reactive power support. The new improved metrics ensure a level playing field for different technologies and ensure that both instantaneous and ramping based reactive power support are equally treated. Hence the proposed metric is recommended to be used in Task 2.6.

5.3.6 RESULTS: MITIGATION OF DYNAMIC VOLTAGE CONTROL SCARCITIES USING DYNAMIC REACTIVE POWER PRODUCT

Figure 5-23 presents the results of applying the new dynamic voltage profile metric to the 36 snapshots selected for the Low Carbon Living scenario base case. Box plots are used to present the distribution of the unique violation count for each hour (each box plot represents 306 data points, one for each contingency) and the dots on the upper leg of each box plot marks the 95th percentile. From the non-recoverable violations reported, it can be seen that for many hours only the outliners (top 5 percentile) are above the current threshold 250.

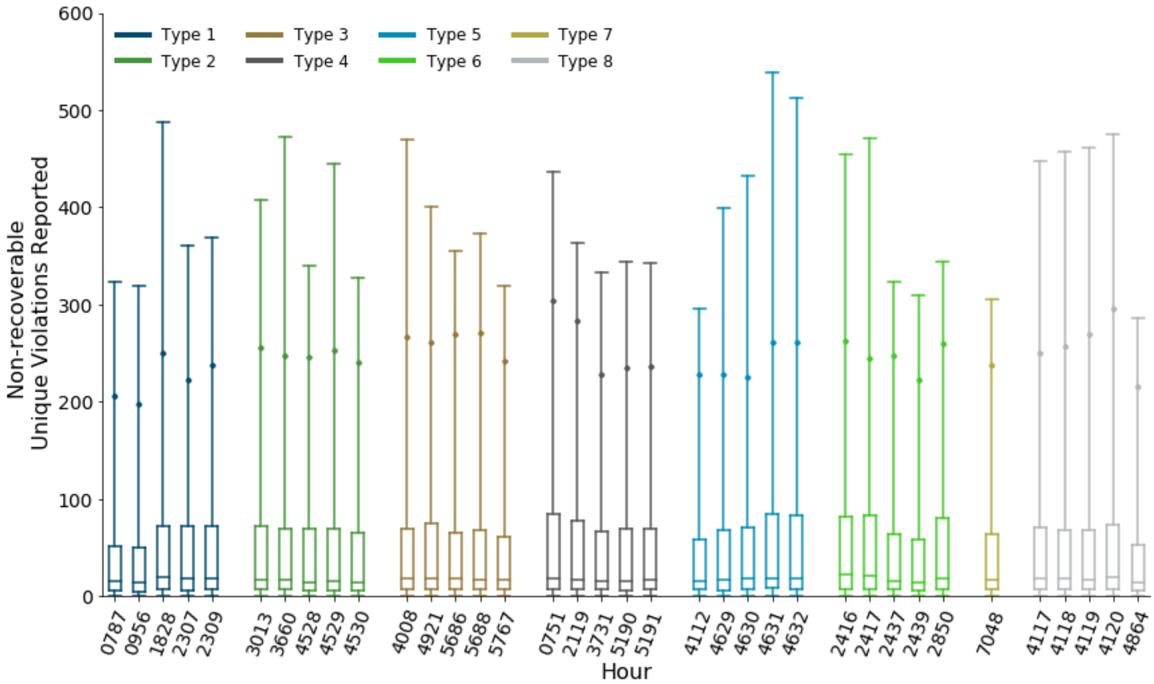


FIGURE 5-23: DISTRIBUTION OF NON-RECOVERABLE VIOLATIONS REPORTED FOR EACH CONTINGENCY GROUPED BY SNAPSHOT FOR THE LOW CARBON LIVING SCENARIO BASE CASE.

Figure 5-24 presents the results of applying the new dynamic voltage profile metric for each snapshot grouped by contingency. It can be seen that certain contingencies have universally low violation counts (coloured blue), universally high counts (coloured orange) and others have high counts for few hours (coloured green). These groups are separated by having a maximum count of less than 250 and a minimum count of greater than 250. This line of separation serves to demonstrate that for some contingencies a localised scarcity of dynamic voltage control is a systematic issue that occurs for all hours for some areas of the system.

Numerous simulations are performed with a different combination of location (substations) with DRR providing technology installed and the combination with least dynamic voltage violations was selected. Table 5-4 presents the list of bus numbers and kV level of the technology installed to mitigate the dynamic voltage control scarcity.

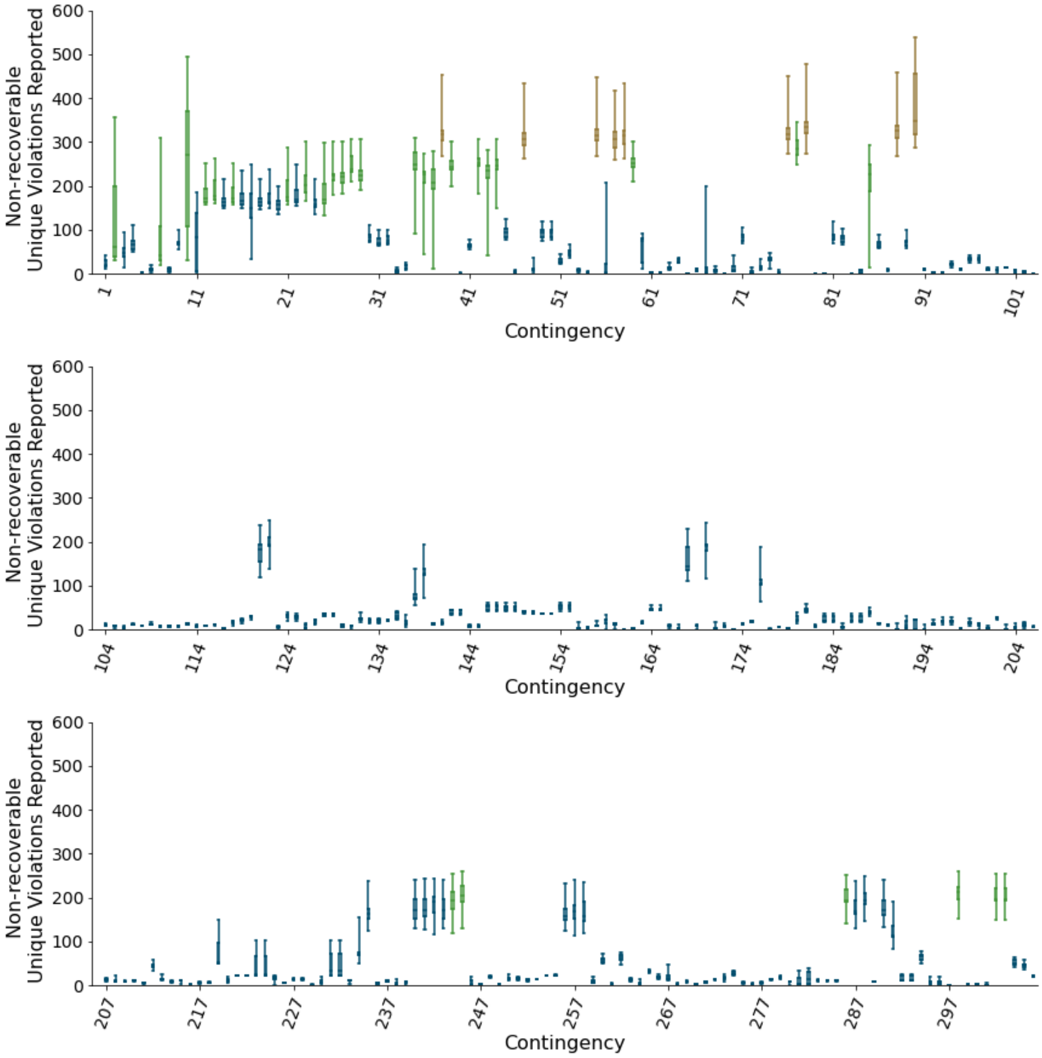


FIGURE 5-24: DISTRIBUTION OF NON-RECOVERABLE VIOLATIONS REPORTED FOR EACH SNAPSHOT GROUPED BY CONTINGENCY. RED BARS DENOTE THOSE CONTINGENCIES WITH ALL VALUES ABOVE 250 AND BLUE BARS THOSE WITH ALL VALUES BELOW 250 FOR THE LOW CARBON LIVING SCENARIO BASE CASE.

TABLE 5-4: LOCATION OF STATCOMS OR SYNCHRONOUS CONDENSERS

Bus Number	kV level	Technology
81530	275	STATCOM
35265	110	Synchronous Condenser
38210	110	STATCOM
30810	110	Synchronous Condenser
12710	110	Synchronous Condenser
13510	110	STATCOM
47410	110	Synchronous Condenser
11610	110	STATCOM

Figure 5-25 presents the results of applying the new dynamic voltage profile metric to the 36 snapshots selected for the Low Carbon Living scenario with the proposed mitigations. From the non-recoverable violations reported, it can be seen that, for only a few hours, the top 5 percentile outliners (black circles) are above the current threshold of 250.

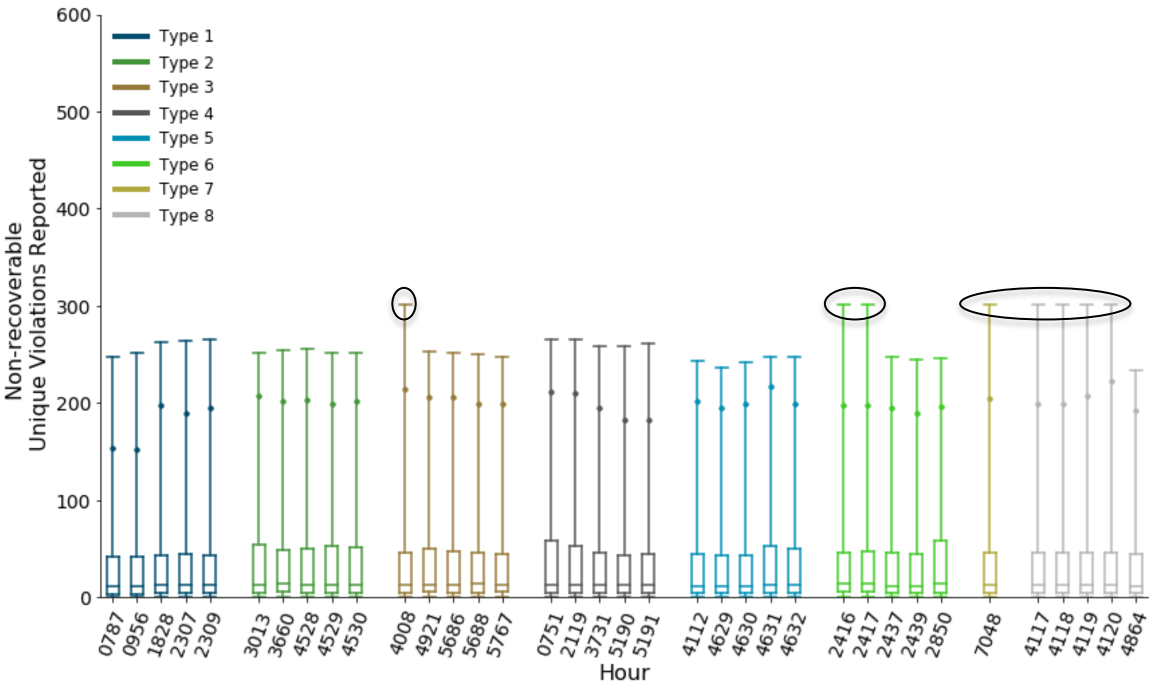


FIGURE 5-25: DISTRIBUTION OF NON-RECOVERABLE VIOLATIONS REPORTED FOR EACH CONTINGENCY GROUPED BY SNAPSHOT FOR THE LOW CARBON LIVING SCENARIO WITH MITIGATION.

Figure 5-26 presents the results of applying the new dynamic voltage profile metric for each snapshot grouped by contingency for modified case with mitigations. It can be seen that the dynamic voltage control localised scarcities have been mitigated as no universally high counts are observed (these would be coloured orange if observed).

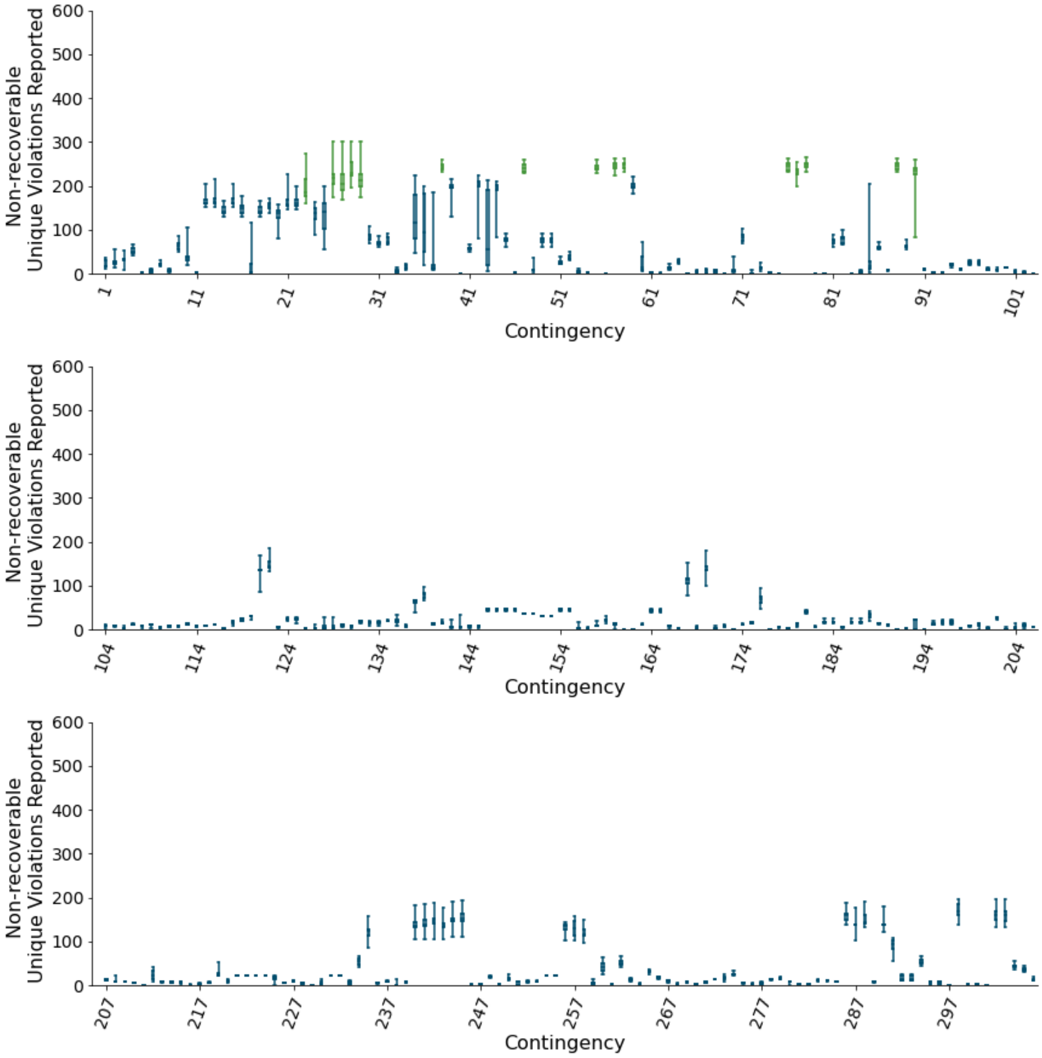


FIGURE 5-26: DISTRIBUTION OF NON-RECOVERABLE VIOLATIONS REPORTED FOR EACH SNAPSHOT GROUPED BY CONTINGENCY. RED BARS DENOTE THOSE CONTINGENCIES WITH ALL VALUES ABOVE 250 AND BLUE BARS THOSE WITH ALL VALUES BELOW 250 FOR THE LOW CARBON LIVING SCENARIO WITH MITIGATION.

5.3.7 KEY MESSAGES

The dynamic voltage scarcities identified in Deliverable 2.4 are mitigated using the **DRR system service which is provided by a number of different technologies**. These technologies either provide instantaneous reactive power support from Synchronous Condensers and ramping reactive power support from STATCOMs and SVCs. The metric used in Task 2.4 to assess the availability of dynamic voltage control would favour technology with the ability to provide an instantaneous reactive power response. The new metric proposed in Task 2.6 ensures a level playing field for different technologies and ensures that both instantaneous and ramping based reactive power supports are equally treated. The key messages from the identified measures related to the mitigation of dynamic voltage control scarcities for the Ireland and Northern Ireland power system are as follows:

1. The **technologies capable of providing a DRR system service such as Synchronous Condensers and STATCOMs are the best suitable technologies** for mitigating the dynamic voltage control scarcities identified in Task 2.4.
2. The **location of the placement of a DRR providing technology is vital** to mitigate the dynamic voltage control scarcity. The approach and methodology applied here is sufficient for demonstration of the capability of DRR providing technologies to mitigate the dynamic voltage issues previous identified, which is the primary objective. However, the approach is not suitable for identifying the crucial locations for placement of DRR providing technology. This is a result of the fact that the metrics used are influenced by the number of busses in an area, not necessarily by the scale of the voltage scarcity. Further work on the optimal placement of DRR capability is required and will be conducted in EirGrid Group.
3. **The fast provision of DRR is key** to mitigating dynamic voltage control scarcities.
4. Eight DRR providing technologies each with 400 MVA capacity (based on assumptions in this analysis) are required to mitigate the dynamic voltage control scarcities identified in Task 2.4. It is important to remember that this analysis was performed in isolation of consideration of other mitigation measures. Thus, measures to mitigate frequency issues, for example, may also support the mitigation of dynamic voltage issues. Future work will need to conduct holistic analysis to explore the optimal mix of mitigations for the system as a whole, acknowledging the synergies between mitigation measures.

5.4 LINK TO DEMONSTRATIONS AND THE QUALIFICATION TRIAL PROCESS: VOLTAGE

The material discussed earlier in this chapter is vital for the demonstration via simulation of the capability of various technologies for mitigating the technical scarcities related to voltage stability. However, while this is important, it is equally as important to test these technologies in real-life field tests and technology trials. EU-SysFlex has a range of different demonstrations and field test that are on-going at the time of writing this report. The voltage services being tested in the demonstrations are summarised in Table 5-5. A short description of each trial is then provided.

TABLE 5-5: SUMMARY OF VOLTAGE SERVICES BEING TESTED IN EU-SYSFLEX

Demonstration	Services Being Tested
Finnish demonstration	Provision of reactive power at TSO-DSO interfaces
French Demonstration	Reactive power support from aggregated resources (wind turbines, …)
German Demonstration	Provision of reactive power at TSO-DSO connection points
Italian Demonstration	Reactive power provision from distributed resources (PVs), STATCOM and battery storage system
Portuguese demonstrations: FlexHub (PV + storage)	Provision of reactive power from DSO owned resources (capacitor banks, OLTC).
QTP – Nodal Controller and PV	Provision of steady state reactive power from distributed connected wind generation (nodal controller) and from PV.

In the Finnish demonstration, the demonstrator explores management of reactive power flexibility to assist in voltage control at TSO/DSO interfaces. This is aimed at varying reactive power at TSO/DSO connection sites. In order to determine what level of reactive power demand is required for balancing, a PQ-window forecasting tool was developed. This forecasting tool was used for day, week and month ahead forecasting, the shorter term sets, i.e. day or week, can be used to decide the needs for reactive power consumption.

The French demonstration in WP8 is looking at the provision of a dynamic voltage service by investigating dynamic symmetrical injection of reactive current during low voltage [2]. In the French demonstration, a wind farm which consists of type 4 fully converted wind turbines provides operational benefits including its ability to provide reactive power services without the need for active power being produced (does not rely on available wind). Thus the units are more proficient and suited to provide local voltage support than older units such as type 3 DFIG wind turbines.

The German demonstration project will investigate reactive power management by the DSO for the TSO, while the Italian demonstration will look at voltage support in the MV network as well as voltage control in HV/MV substations.

5.5 SUMMARY OF VOLTAGE MITIGATIONS

Voltage control mitigation, both in terms of steady state and dynamic aspects, has been successfully demonstrated in this chapter via specific technologies representing a capability for a **range of system services to support voltage stability**. These services include:

- Steady State Reactive Power (SSRP)
- Dynamic Reactive Response (DRR)

As SNSP levels increase and conventional generation is displaced there will be a significant lack of steady state reactive capability if not replaced by other sources due to RES reactive power capability being limited by the rating of the power electronic converters. This lack of steady state reactive capability can lead to larger deviations in steady state voltage as well as increased instances of low voltage deviations. As reactive power is a local phenomenon, weaker parts of the network, with high levels of RES, are prone to requiring significant increases in reactive power services.

Mitigation of the steady state voltage scarcity will require the provision of steady state reactive power support (SSRP) from non-conventional technologies deployed in specific geographical locations. **Steady State Reactive Power (SSRP)[5] capability from static and dynamic reactive resources** was demonstrated in both the Continental European system and the Ireland and Northern Ireland power system. In the Continental European system, the

[5] SSRP is the steady state voltage product in Ireland and Northern Ireland. Other jurisdictions have similar products, with slightly different names. More information on this is provided in EU-SysFlex Deliverable 3.1 [2].

reactive power reserve activation from wind generation, capacitors and shunts were shown to be good alternatives to conventional synchronous generating plants for reactive power provision. While, in Ireland and Northern Ireland, mitigation to the steady state reactive power scarcity is established by the results of QV analysis whereby, an increased reactive requirement is identified for weak buses in order to maintain acceptable levels at all nodes under normal operating conditions and following a system disturbance. Static and dynamic reactive resources were found to be effective in mitigating this scarcity. The additional resources may include, but are not limited to Capacitor Banks, STATCOMS, Static VAr Compensators (SVCs), Synchronous Condensers and potentially the reactive capability from some DSO connected wind farms.

As the number of synchronous generators decreases to enable more shares of RES on the system, a reduction in system reactive power also leads to degradation in dynamic voltage performance resulting in the emergence of a dynamic voltage scarcity during fault recovery. Results in Task 2.4 also revealed the magnitude of the post-fault voltage oscillations will become more significant in a future 2030 power system, driving the need for more reactive compensation from a range of service providers.

Dynamic Reactive Response (DRR) capability from Synchronous Condensers, Statcoms and SVC's was demonstrated in the Ireland and Northern Ireland power system. Synchronous Condensers provide instantaneous reactive power support while ramping reactive power support is obtained from STATCOMs and SVCs. Results in Task 2.6 for the Ireland and Northern power system show that **the fast provision of DRR is key** in mitigating a dynamic voltage scarcity. Analysis also reveals that the **location of a DRR provision resource is vital** in mitigating the dynamic voltage scarcity. Additional future studies would be required in determining the optimal placement of DRR resources.

As discussed previously there are a range of system services to support the voltage stability scarcity. One other innovative service is the **Fast Post Fault Active Power Recovery (FPFAPR)** [2]**.** This is designed to mitigate the fall in frequency which can be induced by voltage disturbance or voltage dip induced frequency deviation (VDIFD) and is needed at very high levels of wind generation [2]. EirGrid and SONI define this product as the recovery of a providing unit's MW output to at least 90% of its pre-fault value within 250ms of the voltage at the providing unit's connection point recovering to at least 90% of its pre-fault disturbance value for any fault disturbance that is cleared within 900ms. The providing unit must be exporting active power to the power system and must remain connected to the Power System for at least 15 minutes following the fault disturbance [37].

6. ROTOR ANGLE STABILITY MITIGATIONS

Rotor angle stability refers to the ability of synchronous machines directly coupled to the grid to remain in synchronism after being subjected to a disturbance. This requires that each synchronous machine must maintain the existing equilibrium or reach a new equilibrium between its electromagnetic and mechanical torque whenever a disturbance in a power system occurs. Failure to do so will cause a synchronous machine to experience a loss of synchronism and that synchronous generator will be disconnected from the system [38].

The change of the electromagnetic torque of a synchronous machine after a disturbance consists of two components which affect the damping of oscillations:

- Damping torque component (in phase with speed deviation)
- Synchronising torque component (in phase with rotor angle deviation)

This section explores a number of possible mitigation measures that can be adopted in Task 2.6, first in the Continental, or pan European power system, followed by the Ireland and Northern Ireland power system.

6.1 CONTINENTAL EUROPE

Rotor angle stability analysis carried out within Task 2.4 has identified several issues with oscillatory stability in the Continental Europe Power System. As presented in Figure 6-1 - Figure 6-5 below, high penetrations of renewables and decreased synchronous generation capacity can cause significant issues with insufficient oscillation damping, which may cause problems with power system instability.

For the purposes of the oscillation damping assessment, settling and halving times have been calculated in order to assess the damping of inter-area and inter-plant oscillations. Regulation time indices that are illustrated in Figure 6-1 can be calculated as time after which the observed rotor angle signal does not extend beyond an assumed control band. The width of the reference control band is defined as a percent of the first amplitude value, which is 15% for settling time and 50% for halving time, respectively [1].

Three generation capacity scenarios have been considered in the voltage and transient stability studies. In conjunction with EU-SysFlex Energy Transition, two Network Sensitivities have been taken into account – Going Green and Distributed Renewables [7].

The operational snapshots on national level have been found with the use of EDF CONTINENTAL model and consider the following three criteria:

- Minimum inertia in the power system (abbreviations “Min_Inertia” or “MiH” are used in further part of report)

- Maximum power demand (abbreviations "Max_Load" or "MaL" are used in further part of report)
- Minimum power reactive margins for the synchronous generation (abbreviations "Min_Reactive" or "MiQ" are used in further part of report).

The following sets (perimeters) of countries have been considered in order to find particular operation snapshots:

- Poland (abbreviation "/1" used in further part of report);
- Poland and Germany (abbreviation "/2" used in further part of report);
- Poland, Germany, Austria, Czech Republic, Slovakia and Hungary (abbreviation "/3" used in further part of report);
- All countries in CE, only for "Min_Inertia" and Max_Load (abbreviation "/4" used in further part of report).

Detailed description of the operation scenarios and also selected and aggregated data obtained from EDF's Unit Commitment Model for Energy Transition capacity scenario are presented in [1].

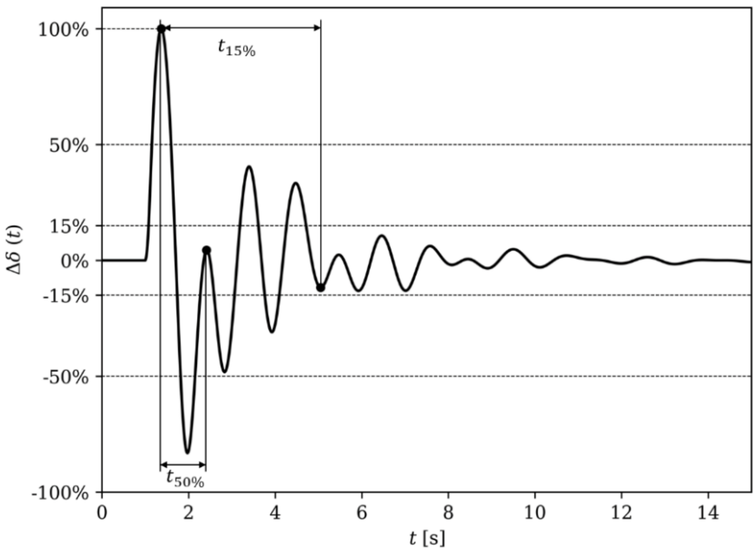


FIGURE 6-1: HALVING AND SETTLING TIMES DEFINITION.

Oscillation damping presents a global scarcity with poor settling and halving times for all snapshots and scenarios. Time-domain simulations have identified the poor oscillation damping during severe system disturbances such as the three-phase short-circuit events. It was found that only the *Maximum Load (MaL)* snapshots having any significant number of acceptable settling and halving times.

For each of the analysed capacity scenarios, both halving and settling time median values tend to be higher for the operational snapshots representing *Minimum Inertia* (*MiH*) and *Minimum Reactive* power generation (*MiQ*) level, which corresponds to the deterioration of oscillation damping. Also, the overall power system's' inertia is being reduced for the *Minimum Inertia* and *Minimum Reactive* scenarios, due to the higher renewables penetration, which displaces synchronous generation. The lower the reactive power generation is, the lower the voltages of generators connected at the power plant are, which causes reduced damping. This explains why the median values for *Minimum Reactive* and *Minimum Inertia* snapshots are comparable and apparently lower than for the *Maximum Load* ones.

As presented in the histograms in Figure 6-3 and Figure 6-5, a lot more fault events in the *Minimum Inertia* and *Minimum Reactive* snapshots have been identified in which both regulation time's requirements for oscillations damping are not met. This is showing that snapshots with high penetration of renewables connected with the power electronic converters have poor oscillation damping. There are numerous disturbance events, in which regulation time values have been larger than the maximum admissible value of 20 seconds, even for halving time requirements (in Going Green with Minimum Reactive power, GGMiQ 1), which is less strict than settling time, according to the width of control band.

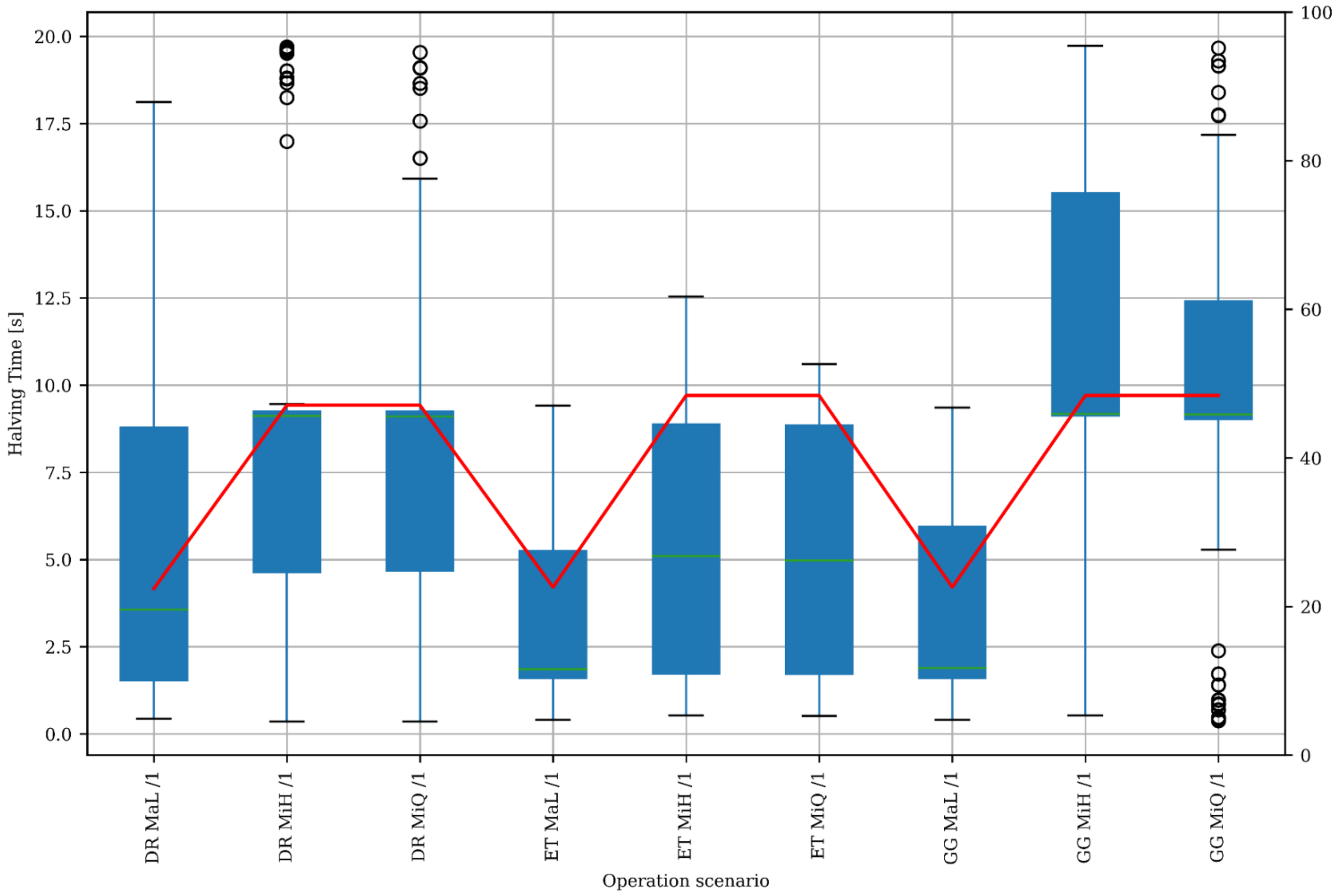


FIGURE 6-2: SCARCITIES IDENTIFIED IN OSCILLATION DAMPING WITHIN T.2.4 ANALYSIS – BOX PLOT OF HALVING TIMES.

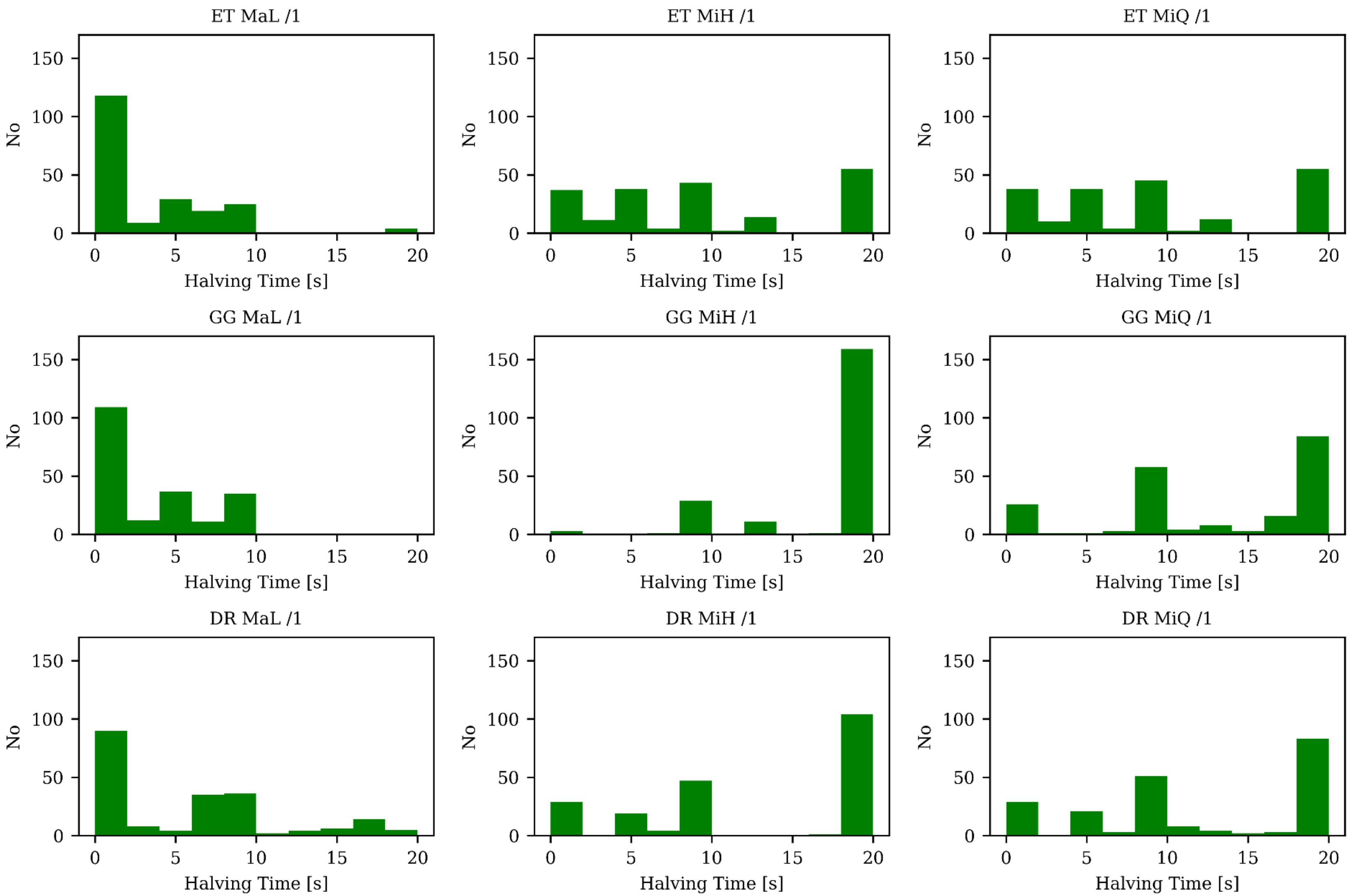


FIGURE 6-3: SCARCITIES IDENTIFIED FOR THE OSCILLATION DAMPING WITHIN T.2.4 ANALYSIS – HISTOGRAM OF HALVING TIMES.

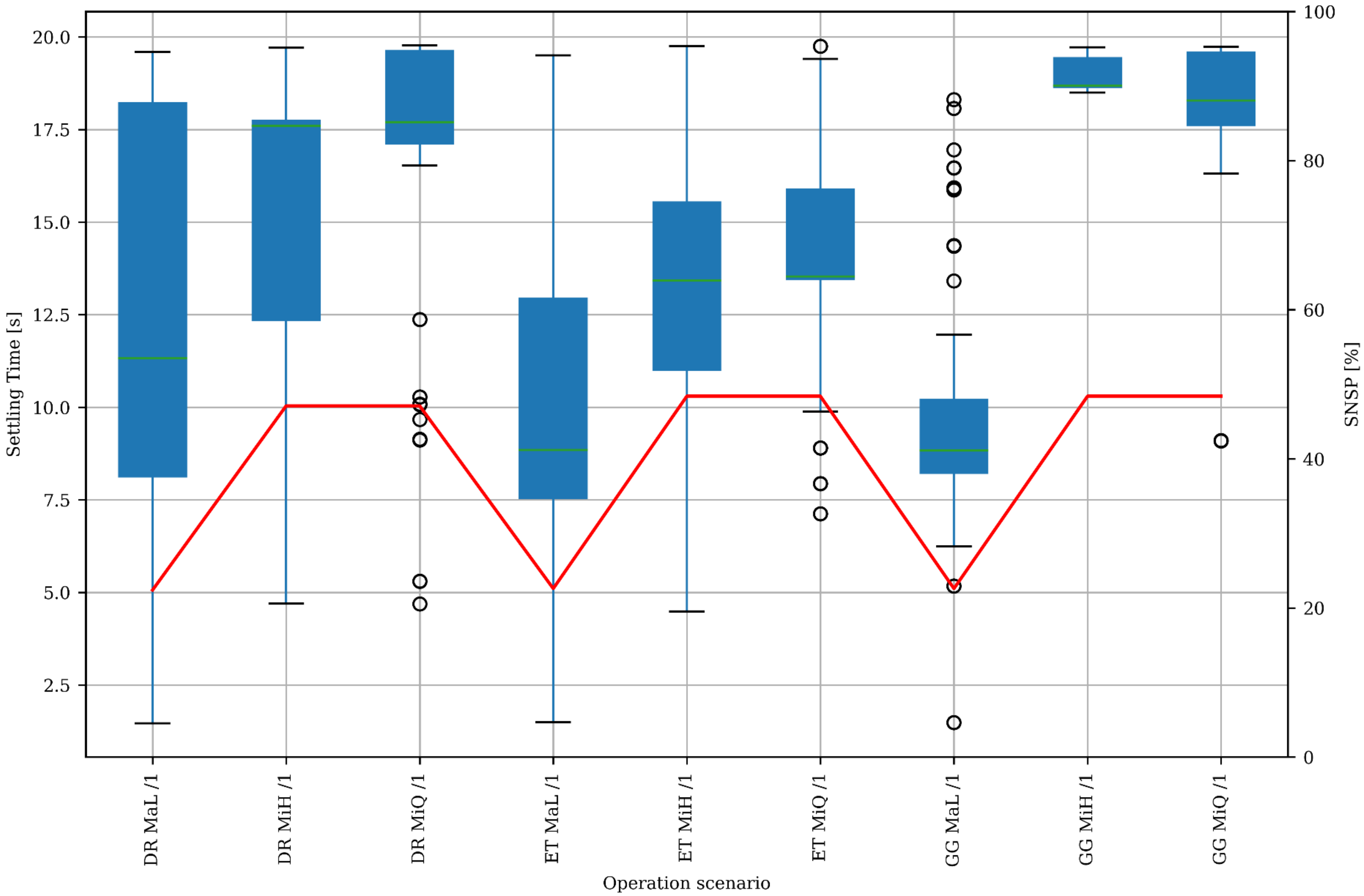


FIGURE 6-4: SCARCITIES IDENTIFIED FOR THE OSCILLATION DAMPING FROM TASK 2.4 ANALYSIS – BOX PLOT OF SETTLING TIMES.

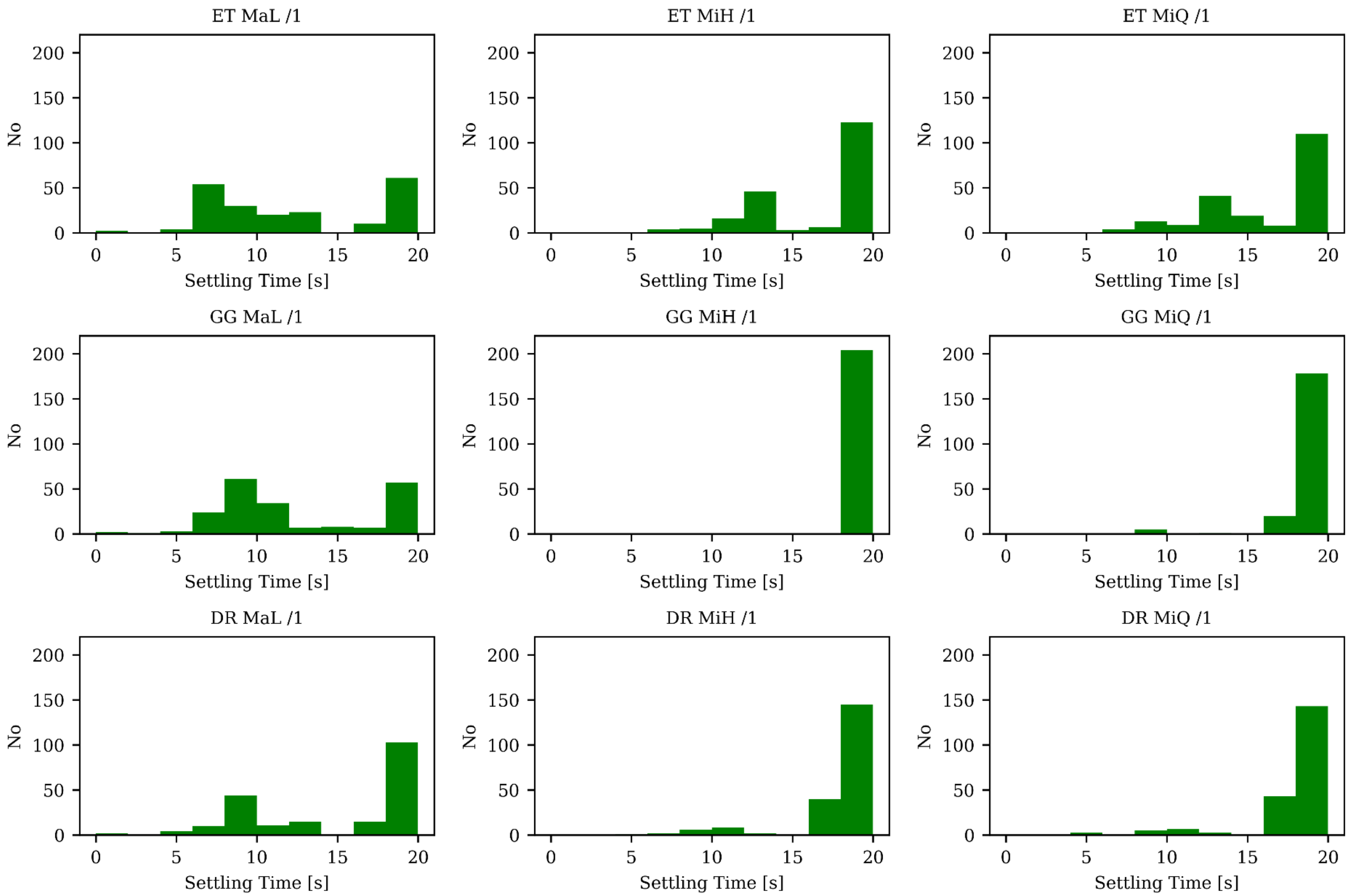


FIGURE 6-5: SCARCITIES IDENTIFIED FOR THE OSCILLATION DAMPING FROM TASK 2.4 ANALYSIS – BOX PLOT OF SETTLING TIMES.

6.1.1 RESULTS: EVIDENCE OF MITIGATIONS

In order to mitigate the technical scarcities identified within Task 2.4, and summarised in the previous section (Section 6.1) PSEI propose a countermeasure based on tuning controllers of relevant conventional synchronous generators in Continental Europe Power System, focusing on Power System Stabilisers (PSS) alongside Automatic Voltage Regulators (AVR) in order to mitigate oscillatory problems with electro-mechanical oscillations.

The dynamic response of the power system is strongly affected by the network structure and its configuration, parameters of generators, and also AVR and PSS controllers [39]. Automatic Voltage Regulator regulates the generator terminal voltage by controlling the amount of current supplied to the generator field winding by the exciter. A power system stabiliser is installed with AVR to dampen the low-frequency oscillations in the power system by providing a supplementary signal to the excitation system, which should lead to the generation of additional damping torque [38].

Optimal design of synchronous machine controllers, putting emphasis on voltage regulators and power system stabilisers, is a broad issue due to various aspects of power system operation, including a variety of generator operation conditions, different fault events which need to considered, and the overall complexity of the power system. The important issue in the parallel tuning of PSS and AVR controllers is the contrary impact of excitation control on voltage control and damping of the power system electromechanical oscillations. Generally, fast and accurate generator voltage control does not contribute to sufficient damping of the low-frequency active power oscillations. On the other hand, tuning of PSSs and AVRs towards a better quality of the generator rotor angle swings damping leads to an evident deterioration of the voltage control response. Therefore, it is important to simultaneously tune AVR and PSS in order to obtain better oscillation damping in the system while minimizing the negative impact on voltage regulation.

Proposed mitigation of oscillation damping scarcity has been done by the expert-based adjustment of parameters of PSSs and AVR of the synchronous generators. Regulator types implemented in the Continental Europe Power System model have been presented in the Deliverable 2.3 of EU-SysFlex [8]. The presented study was particularly focused on the most relevant power plants in Polish Power System due to the complex representation of the considered power system for this area.

A typical model of the power system stabiliser type PSS2A, which is commonly used in the Continental Europe Power System is presented in Figure 6-6. In the most representative case for the countermeasures analysis, the process of PSS tuning is focused on several aspects, including adjustment of the following parameters:

- gains and time constants for input signals and washout filters : $K_{s2}, K_{s3}, T_6 - T_9, T_{w1} - T_{w4}$;
- time constants for correction terms $T_{s1} - T_{s4}$;
- main stabiliser gain K_{s1};
- limiters for the output PSS signal $V_{st\,min}$,$V_{st\,max}$.

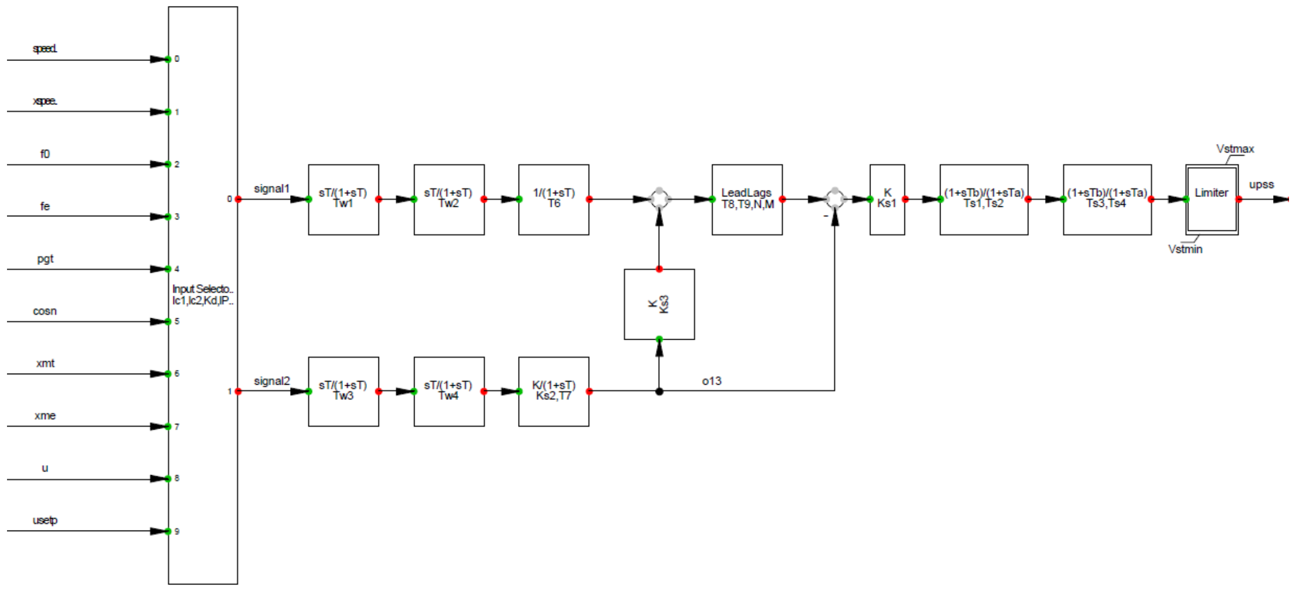


FIGURE 6-6: POWER SYSTEM STABILISER PSS2A MODEL DIAGRAM [40]

For the purposes of the analysis of the oscillatory stability countermeasures applied to the Continental European power system, the same three capacity scenarios (**Energy Transition**, **Going Green** and **Distributed Renewables**) have been investigated as for the initial Task 2.4 studies. Dynamic time-domain simulations representing electromechanical phenomena have been performed in order to calculate oscillation damping assessment indices. The analysis also has been carried out for the same selected operational snapshots, including the following scenarios: *Maximum Load* demand, *Minimum Inertia* in the power system and *Minimum Reactive* power margins for the synchronous generation. The settling and halving times have been calculated for disturbances in which clearing times are assumed to be 100 ms. For the purposes of the oscillation damping assessment, the same set of close 3-phase short circuit fault events have been assumed as for the initial Task 2.4 studies.

Presented box plots (Figure 6-7 and Figure 6-9) of the regulation time indices results prove that tuning of PSSs alongside AVRs contribute to a significant reduction of both halving and settling times, which describe oscillation damping in the power system. As has been observed also in the Task 2.4 studies, for each of the analysed capacity scenarios, both halving and settling time values are the lowest for the *Maximum Load* operational snapshots. On the other hand, median values for all the analysed snapshots tend to be significantly lower than in the initial Task 2.4. Scarcity analysis, even for the most problematic operational snapshots representing *Minimum Inertia* and *Minimum Reactive* power system's conditions, demonstrating that that countermeasure has been successful in mitigating the issue.

As can be observed in the histograms of the regulation time indices distribution (Figure 6-8 and Figure 6-10), the proposed mitigations apparently reduce the number of cases for which halving and settling times do not exceed the acceptable limit, while maintaining the steady trend of changes towards improving the oscillation damping. For several operation snapshots analysed, the applied countermeasures can even contribute to reducing the total number of such cases for which oscillation damping requirements are not met to zero. On the other hand, the proposed solution of oscillation damping augmentation has been not sufficient in several cases, which needs to be examined individually and other countermeasures may need to be considered, for example the increase of the power systems synchronous inertia or application of the FACTS devices.

Rotor angle plots presented in Figure 6-11 represents the influence of the proposed countermeasures on oscillation damping for a selected 100 ms close 3-phase short circuit disturbance, applied at the transmission line leading out of one of the largest power plants station in Poland. In order to present the differences between damping in the initial and modified models with mitigations applied, rotor angle plots have been presented for the same groups of selected power plants synchronous generators and capacity scenarios as in Task 2.4 study. The presented example case is also representative of the rest of disturbance events analysed within the scope of this study.

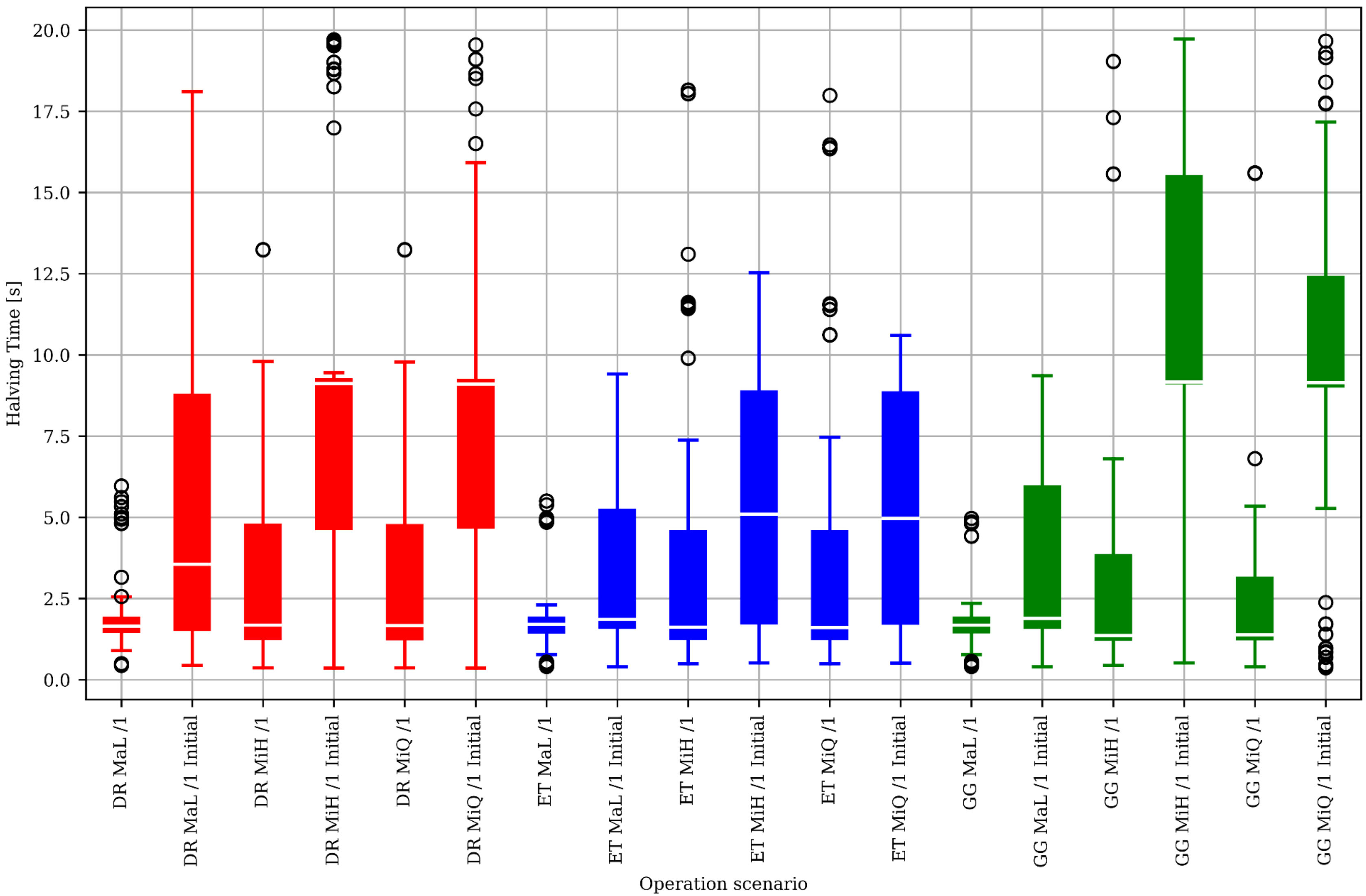


FIGURE 6-7: OSCILLATION DAMPING SCARCITY MITIGATION RESULTS – BOX PLOT OF HALVING TIMES.

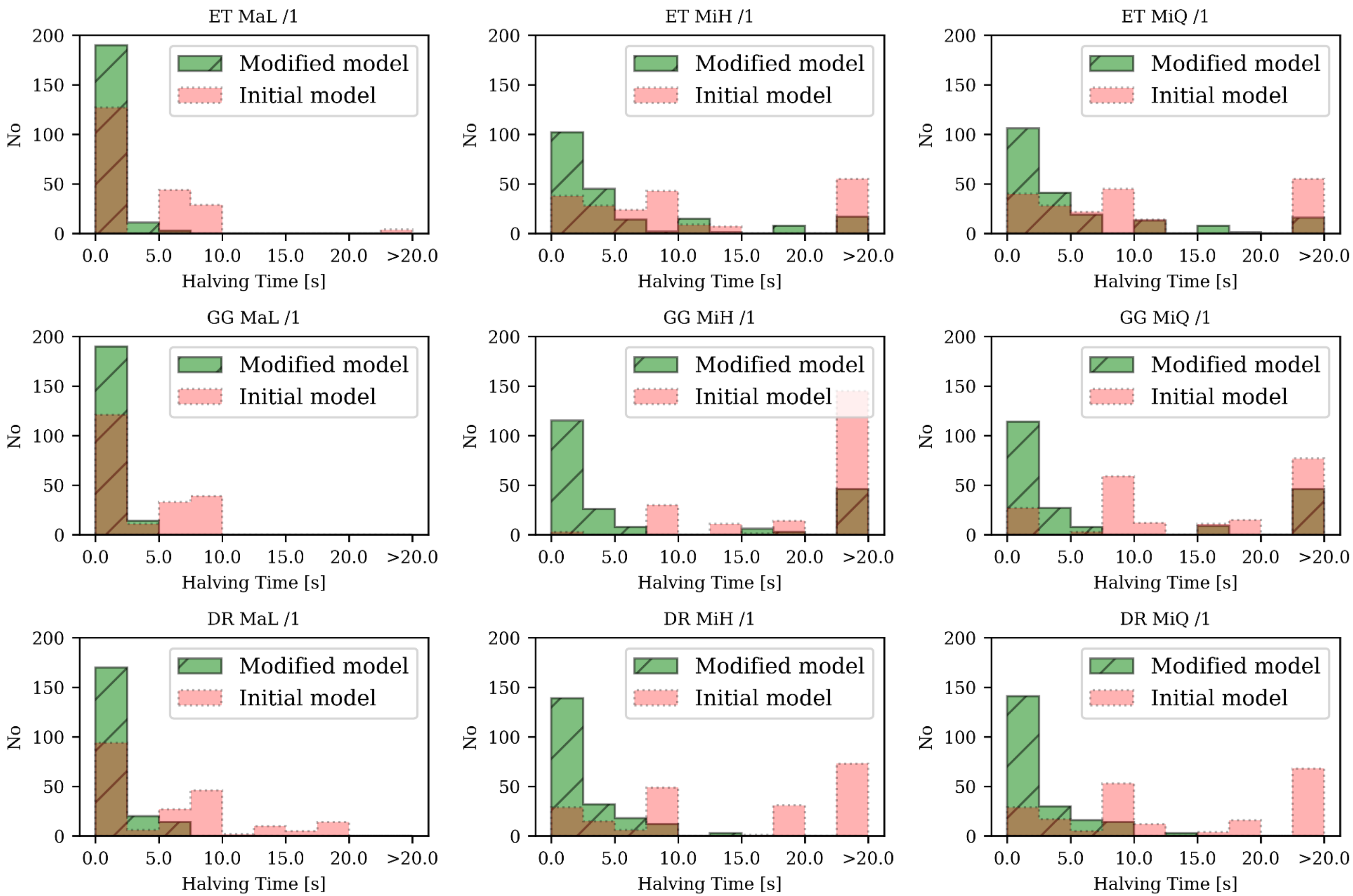


FIGURE 6-8: OSCILLATION DAMPING SCARCITY MITIGATION RESULTS – HISTOGRAM OF HALVING TIMES.

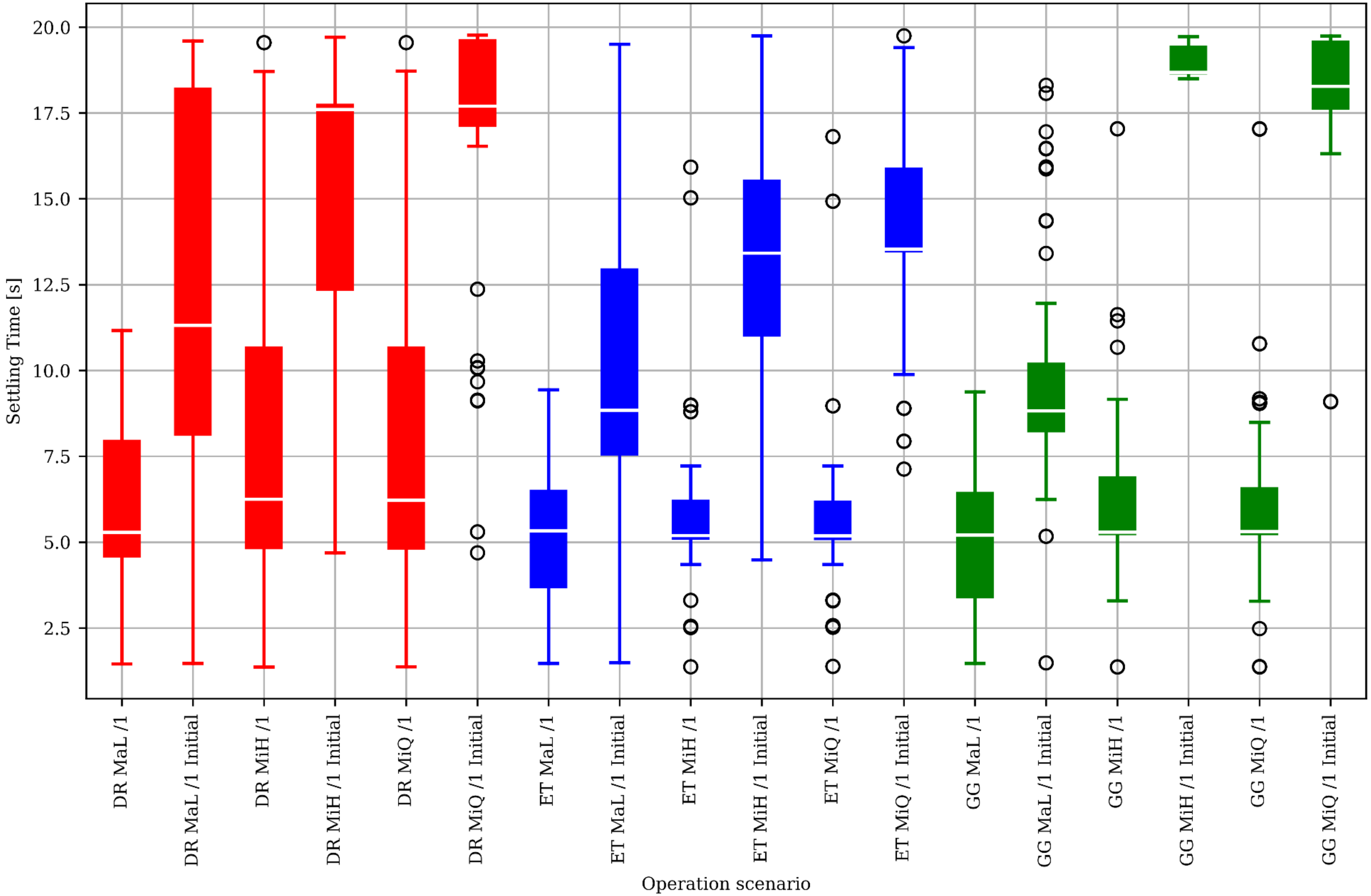


FIGURE 6-9: OSCILLATION DAMPING SCARCITY MITIGATION RESULTS – BOX PLOT OF SETTLING TIMES

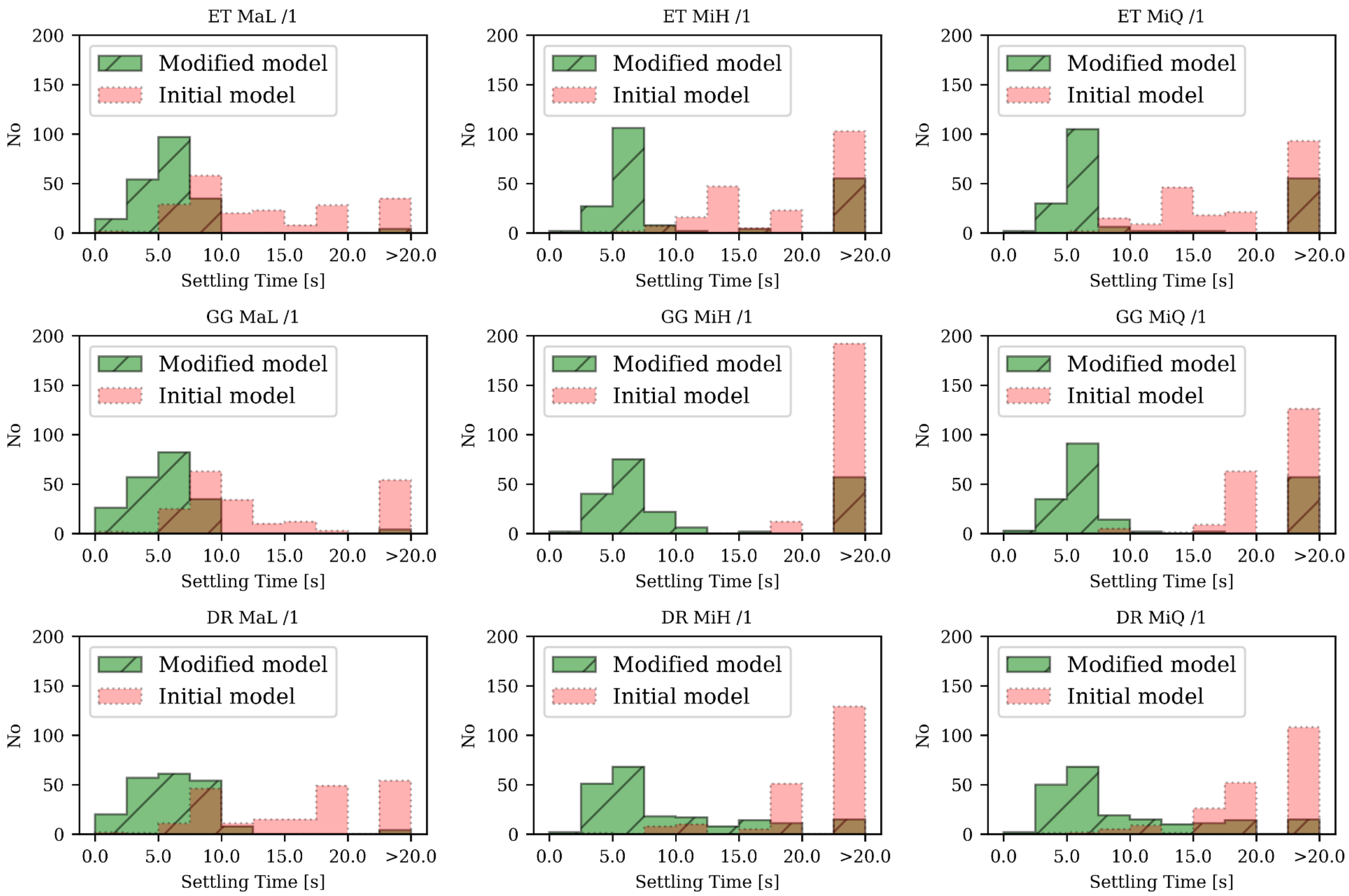


FIGURE 6-10: OSCILLATION DAMPING SCARCITY MITIGATION RESULTS – HISTOGRAM OF SETTLING TIMES.

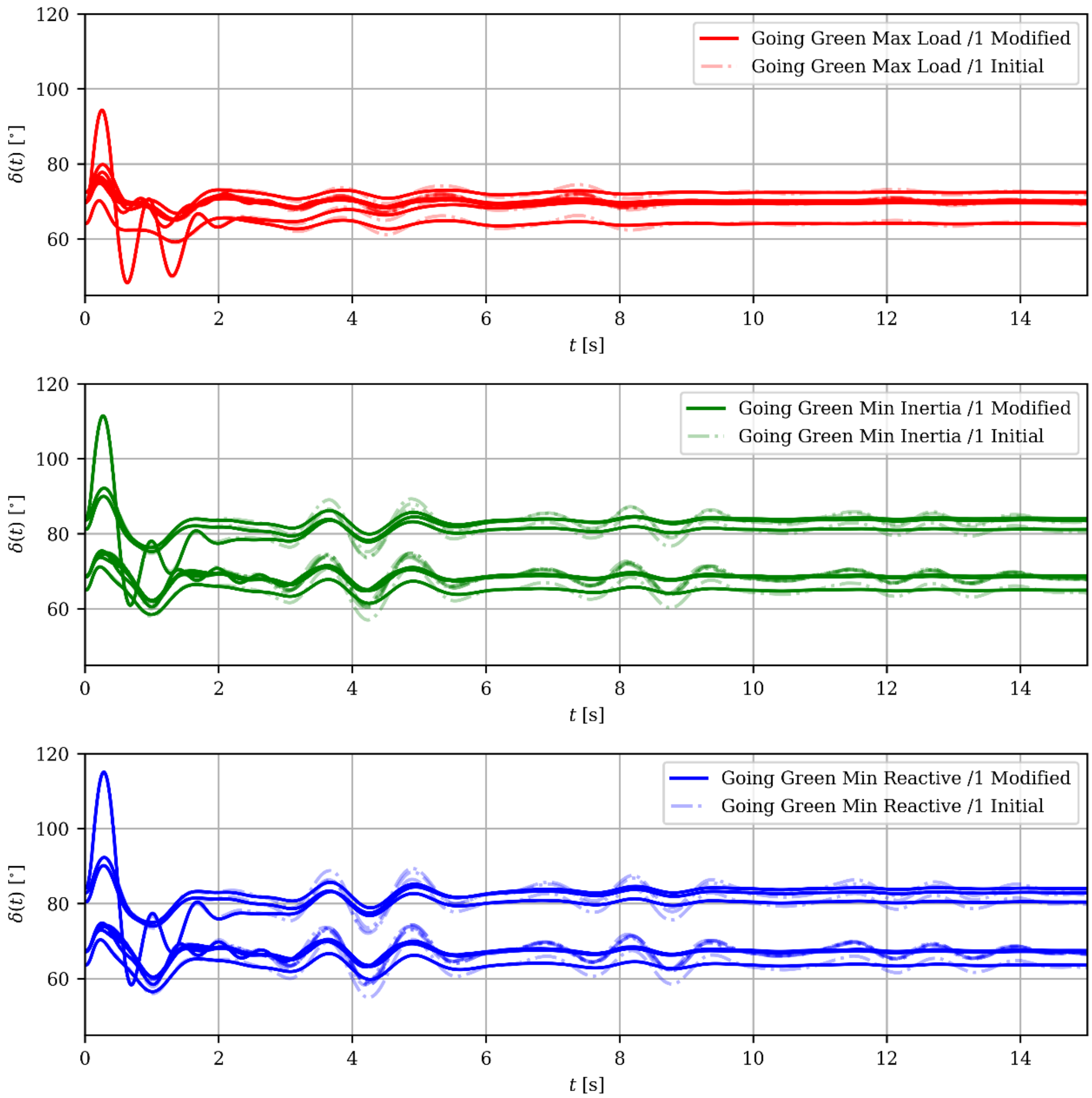


FIGURE 6-11: OSCILLATIONS DAMPING – ROTOR ANGLE PLOTS FOR VARIOUS OPERATION SNAPSHOTS.

The main conclusion from the considered figure is that proposed modifications contributed to better damping of power system oscillations for each of the operation snapshots analysed. It can be also observed, that high penetration of synchronous generation due to the higher active power demand helps to better damp power systems oscillations, as for *Minimum Inertia* and *Minimum Reactive* operational snapshot oscillation damping is still apparently worse, caused by higher penetration of renewables and less reactive power generation. However, implemented mitigations helped to decrease the power system oscillations to the acceptable level also in these operational conditions in a sufficient time.

6.1.2 KEY MESSAGES: CONTINENTAL EUROPE

Presented results prove that **optimal tuning of power system stabilisers alongside automatic voltage regulators of the conventional synchronous machines may contribute to the improvement of the oscillation damping** in the power system.

6.2 IRELAND AND NORTHERN IRELAND

In EU-SysFlex Task 2.4, rotor angle stability analysis has been carried out for the Ireland & Northern Ireland power systems. The analysis focussed on time domain simulations following a system short circuit event. The levels of stability have been categorised using multiple indicators such as rotor angle deviations, critical clearing times & oscillation damping quantification indices. The following sections present the methodology and the results for the mitigation of the rotor angle stability identified in Deliverable 2.4.

6.2.1 METHODOLOGY: DAMPING TORQUE SCARCITIES

The rotor angle oscillations are a natural part of the behaviour of any dynamic system and are not a concern, provided they are sufficiently well damped [38]. An important pre-requisite for assessing oscillation is the settling time which can be defined as the time required for a quantity to get to its steady-state with potentially some negligible variations in its output. An approximate steady state is defined as the peak to peak magnitude of the oscillation remaining below 15 % of its maximum peak to peak magnitude (i.e. the first cycle peak to peak magnitude) [8]. Depending on how long it might take for different dynamic phenomena to settle down one should be careful when selecting the corresponding simulation time. In EU-SysFlex Task 2.3, a settling time of 20 seconds was defined as appropriate, where the settling time is defined here as the time required reaching an approximate steady state.

To quantify oscillation damping as already proposed in EU-SysFlex Task 2.4 a decay time is used as the metric for these purposes. The decay time constant of an oscillation is a function of its natural frequency and damping ratio and it is equivalent to the time constant of the exponential decay. Therefore, the oscillation reaches 36.8 % of its initial value after this time. As such, requiring the decay time to be less than a third of the target settling time would seem an effective index for assessing the stability of each oscillatory mode. The decay time is calculated within TSAT using Prony analysis. Prony analysis method decomposes a time domain signal into a sum of a number of damped oscillatory components. The method can be applied to the time domain response of the system to a disturbance and then the stability of each component can be assessed independently for assessing small signal stability. Figure 6-12 shows how an oscillatory response can be decomposed into two dominant oscillatory components. A detailed narrative on Prony analysis is provided in deliverable D2.3 [8].

Based on these definitions and requirements, the criteria applied here is that the decay time must be less than approximately 7 seconds. Failure to abide by this limit would indicate a scarcity in damping. In Task 2.4, it was found that damping had significantly reduced for all 36 snapshots in LCL scenario and at times was outside of acceptable limits.

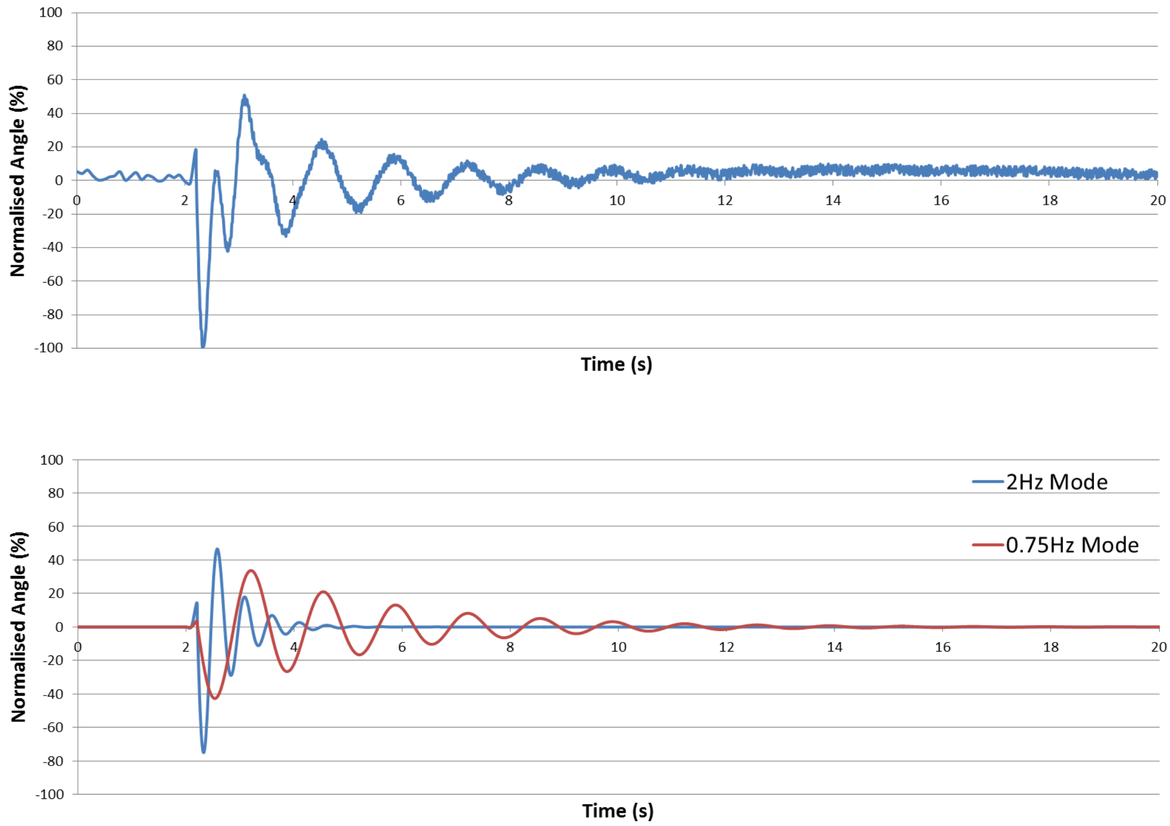


FIGURE 6-12: DECOMPOSITION OF A SIGNAL INTO ITS DOMINANT OSCILLATORY MODES

In this report, technologies providing additional electromechanical torque or damping are considered as potential mitigation options. The potential mitigation options for rotor angle stability considered are:

- Synchronous Condensers;
- STATCOM;
- SVC and
- Power system stabiliser (PSS). The PSS is an additional control unit that stabilises the synchronous machine excitation system. The basic function of PSS is to add damping to the generator rotor oscillations by controlling the synchronous machine excitation using auxiliary stabilising signals. To provide damping, the stabiliser must produce a component of electrical torque in phase with the rotor speed deviations [38].

The studies for the Ireland and Northern Ireland power system are performed in Transient Security Assessment Tool (TSAT) which is a module in LSAT used for offline studies. The metric, dynamic models and simulation setup used in Task 2.4 are again used in this analysis. Task 2.4 selected 36 snapshots of low Carbon living (LCL) scenario based on SNSP level, System Inertia and Number of large units online. These 36 snapshots are modified with the addition of potential mitigation options for Task 2.6 studies.

6.2.2 METHODOLOGY: SYNCHRONIZING TORQUE SCARCITIES

The objective of the synchronizing torque scarcities presented here is to study credible faults, events such as loss of infeed/outfeed and system separation events to investigate potential loss of synchronism. The studied faults are compiled using the known protection settings and driven by our extensive operational experience. Obviously, the longer it takes to clear a fault the more severe the impact that fault will have on the system. Furthermore, the longer a fault takes to clear the more likely it is that a generator might lose synchronism and become unstable, as the accelerating torque encountered through the fault might cause that it exceed its critical angle. The synchronizing torque scarcities are identified using two metrics, **angle margin** and **critical clearing time** (CCT).

Angle Margin:

The transient rotor angle stability index presented here is angle margin which compares the relative rotor angles of various generators to evaluate the current level of synchronism in the system and the margin to loss of synchronism. The index is defined as follows [41]:

$$\eta = \frac{360 - \delta_{\max}}{360 + \delta_{\max}} X\, 100 \qquad \text{(Eq. 6-1)}$$

where δmax is the maximum difference between the relative rotor angles across all generators within the simulation timeframe. The proposed index value can vary between -100 to 100. For index values of greater than zero the system is stable and higher values indicate the system is more secure. For index values of less than or equal to zero, the system is unstable i.e. at least one generator loses synchronism following a contingency. However, larger negative values do not indicate if the system is more or less unstable.

Critical Clearing Time (CCT):

The critical clearing time (CCT) is driven by the first generator becoming unstable when a fault/event is imposed and it is the longest fault clearing time required that ensure generator remain in synchronism. It is typically expressed in cycles. The CCT is the longest clearing time for which the system will remain stable for the imposed credible faults. The CCT is obtained through a binary search method, whereby, a fault clearance range and set threshold levels are pre-specified. The stability margin and the threshold applied to check for instability are based on the angle margin index as described above. The binary search applied here was for between 4 cycles and 70 cycles to 1 cycle precision. This means that the maximum CCT result will be 70 cycles and the minimum result will be 4 cycles (even if the case is unstable for a 4 cycle CCT). Given the current protection design in the All-Island system most of the credible faults are expected to be cleared within 4 to 8 cycles. The worst case fault clearance time, allowing for a complete failure of primary and redundant communications, the failure of any accelerate tripping schemes and a zone 2 fault, is 25 cycles. This is an extreme worst case that is unlikely to occur but provides a useful reference point for when CCTs may potentially require further study [1].

1. The synchronising torque scarcities are classified in two ways in Deliverable 2.4 [1]:a **global scarcity** that results in several groups of generators separating from one another but remaining synchronised to one another, or
2. a **localised scarcity** that results in one generator or a small group of generators separating from the rest of the system.

In Task 2.4, the studies for the Ireland and Northern Ireland power system, revealed a clear localised scarcity in synchronising torque regardless of scenario that manifested through angle margin and CCT of certain generators for certain N-1 contingencies in all scenarios studied. No global scarcity was observed in the study (which would manifest as inter area oscillations and in the worst case system separation) and the current power system has no particular recent history of exhibiting such behaviour.

The rotor angle dynamics of the synchronous machine is present Equation 6-2 which is the swing equation of a synchronous machine.

$$M\,\frac{d^2\delta}{dt^2} = P_a = P_m - P_e = P_m - \frac{EV}{X}\sin(\delta) \qquad \text{(Eq. 6-2)}$$

Where M is the inertia constant, δ is the rotor angle, P_m, P_e, P_a is the mechanical, electrical and accelerating power respectively. E and V are the generator internal EMF and terminal voltage respectively and X is the generator reactance. Generators are more likely to remain stable if they continue to transfer electrical power to the network during the fault, as the imbalance between mechanical and electrical power will be reduced and thereby the accelerating power applied to the machine will be reduced. When a fault is remote from a generator it will have very little impact on the electromagnetic torque of the machine, as it has little impact on the impedance between the machine and the load it is serving. As such, many faults will have long critical clearing times as they are remote from generators and it is unlikely that such faults might be designated of having short CCT. However, there is no doubt that CCT is driven by the pre-fault loading of a machine and the proximity of the fault.

From Equation 6-2, it is inferred that the accelerating power for a fault can be reduced by increasing the generator terminal voltage during fault. Hence, technologies such as STATCOM and synchronous condenser are considered as mitigation options for increasing the synchronising torque scarcities. Also from Equation 6-2, it is inferred that reducing mechanical power can reduce accelerating power, hence, an operational policy under specific circumstances that would reduce the dispatch of the generator that loses synchronism and increasing output from anothergenerator is considered as a potential mitigation.

6.2.3 RESULTS: DAMPING TORQUE SCARCITIES

6.2.3.1 INTRODUCTION

Figure 6-13 shows the box plot of decay time for the LCL base case. From the analysis of 36 snapshots in the LCL scenario, EU-SysFlex Task 2.4 identified a localised scarcity of damping for two hours and an emerging trend of a localised scarcity in other hours.

For better insight on the root cause of these oscillations, further investigation was performed. The outliners (95% percentile) are hours 2307, 2309, 5190, and 5191 (black circles) as per Figure 6-13 are investigated. The corresponding box plots for these four hours demonstrate occurrence of oscillations with higher decay time and these cases are therefore analysed in more detail. Figure 6-14 shows the rotor angles for these four hours and the existence of the oscillations (red trace). For all four hours, it is observed that the same generator units oscillate. These oscillations exist for type 1 hour which is classified as low SNSP, high inertia and high number of units online. Hence, these oscillations are not related to any other operational metrics such as SNSP, inertia or number of units online.

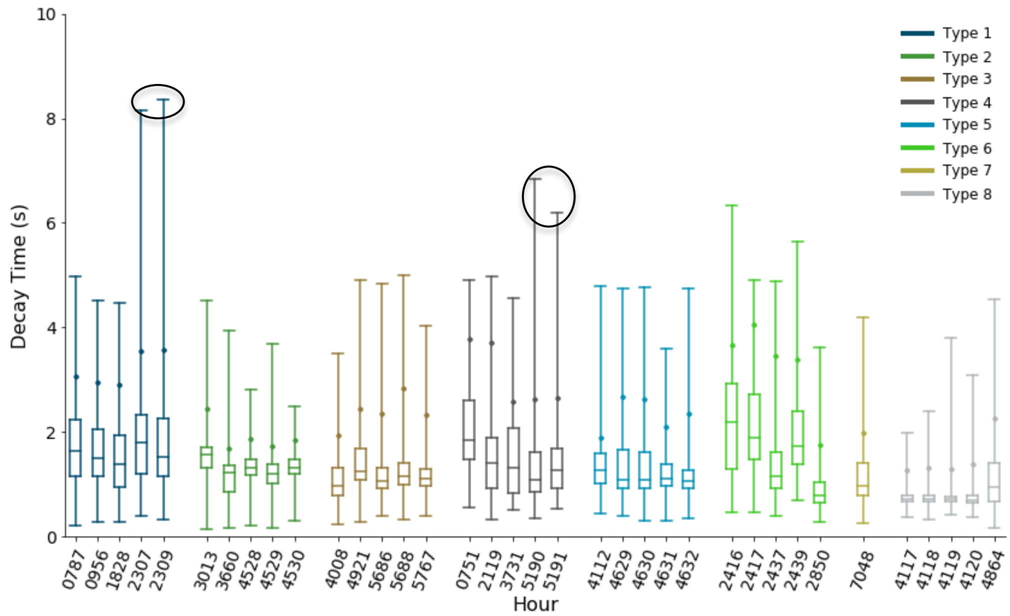


FIGURE 6-13: BOX PLOT OF DECAY TIME FOR LOW CARBON LIVING SNAPSHOTS (BASE CASE).

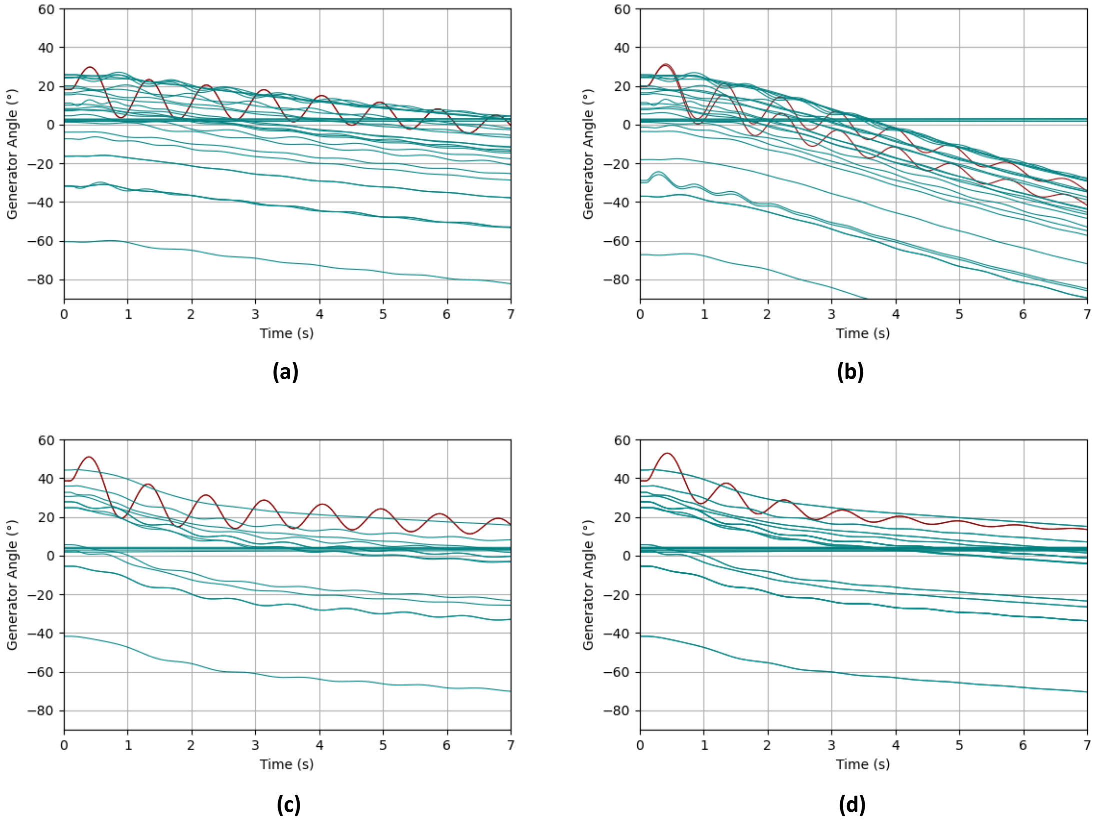


FIGURE 6-14: TIME DOMAIN EXAMPLES FOR OSCILLATION CASES.
(A) HOUR 2307 (B) HOUR 2309 (C) HOUR 5190 (D) HOUR 5191

Figure 6-15 shows the active power output from one of these the oscillating units for Hour 2307 for a fault with voltage dip of 0.5 p.u. There is significant overshoot in post-fault recovery with the first and the second overshoot being almost identical which might point in the direction of possible modelling issue in the generator unit's governor for the given circumstances.

To investigate this further we researched on the Phasor Measuring Unit (PMU is a device that measures the phasor values of current and voltage) data as illustrated in Figure 6-16 with PMU data presented for the same unit followed a fault with retained voltage 0f 0.87 p.u. The overshoots and oscillations are also seen in the PMU data, which demonstrate that the oscillations are not driven by just a modelling issue.

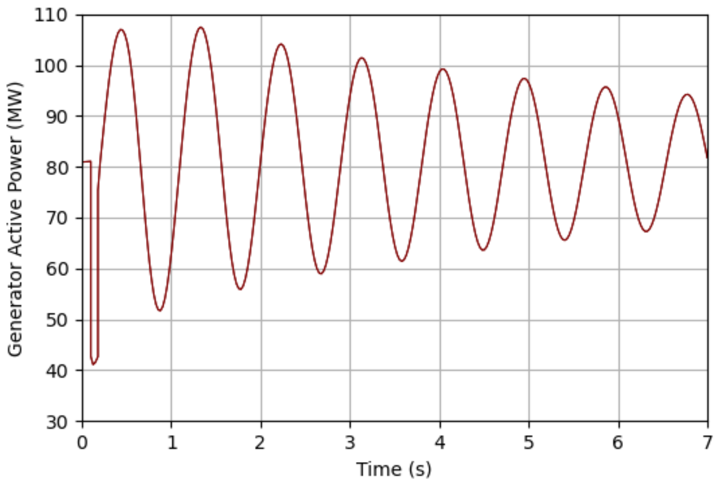


FIGURE 6-15: ACTIVE POWER OUTPUT FROM THE OSCILLATING UNITS FOR OSCILLATION CASE (HOUR 2307).

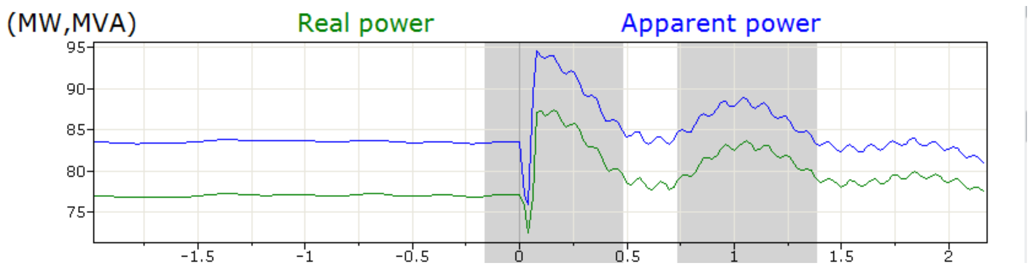


FIGURE 6-16: EXAMPLE OF PMU DATA OF THE OSCILLATING UNIT.

6.2.3.2 MITIGATION MEASURES FOR DAMPING TORQUE SCARCITIES

A number of options are considered here focusing on potential technical solutions and their capabilities and ignoring cost implications. Adding a Power System Stabiliser (PSS) to the oscillating units, Synchronous Condenser and STATCOM are all considered as mitigation options for the damping oscillation scarcities:

- PSS emulates a damping on the synchronous machine generator mechanical shaft through the regulation of the rotor field voltage, which damp electromechanical oscillations following a disturbance in the power system.
- Synchronous Condensers are able to modulate its reactive power output using its automatic voltage regulator (AVR), which help in damping the oscillations.
- STATCOM is a power electronics device which provides damping through its reactive power controller. In essence, all of these devices provide some additional voltage injection.

A case study is performed for the case with the highest decay time (Hour 2307 and contingency 274).Table 6-1, presents the decay time for different mitigations proposed. All three mitigation options reduce the decay time to less than 7s. PSS and STATCOM provide significant reduction in decay time. The recommendation proposed for mitigation of the damping oscillation scarcity is based on reduction of decay time as well as reduction in peak overshoot.

TABLE 6-1: DECAY TIME FOR DIFFERENT MITIGATIONS.

Mitigations	Decay Time (s)
BASE CASE	8.16
With PSS	4.39
With Synchronous Condensers (400 MVA size)	6.42
With STATCOM (400 MVA size)	3.63

Figure 6-17 shows the rotor angles of all generators for Hour 2307 for base case and with mitigations. The oscillating unit's generator angles are presented with the red trace, Synchronous Condenser rotor angle is presented in yellow trace (in Figure 6-17 (c)) and other synchronous generating units are presented with the green traces.

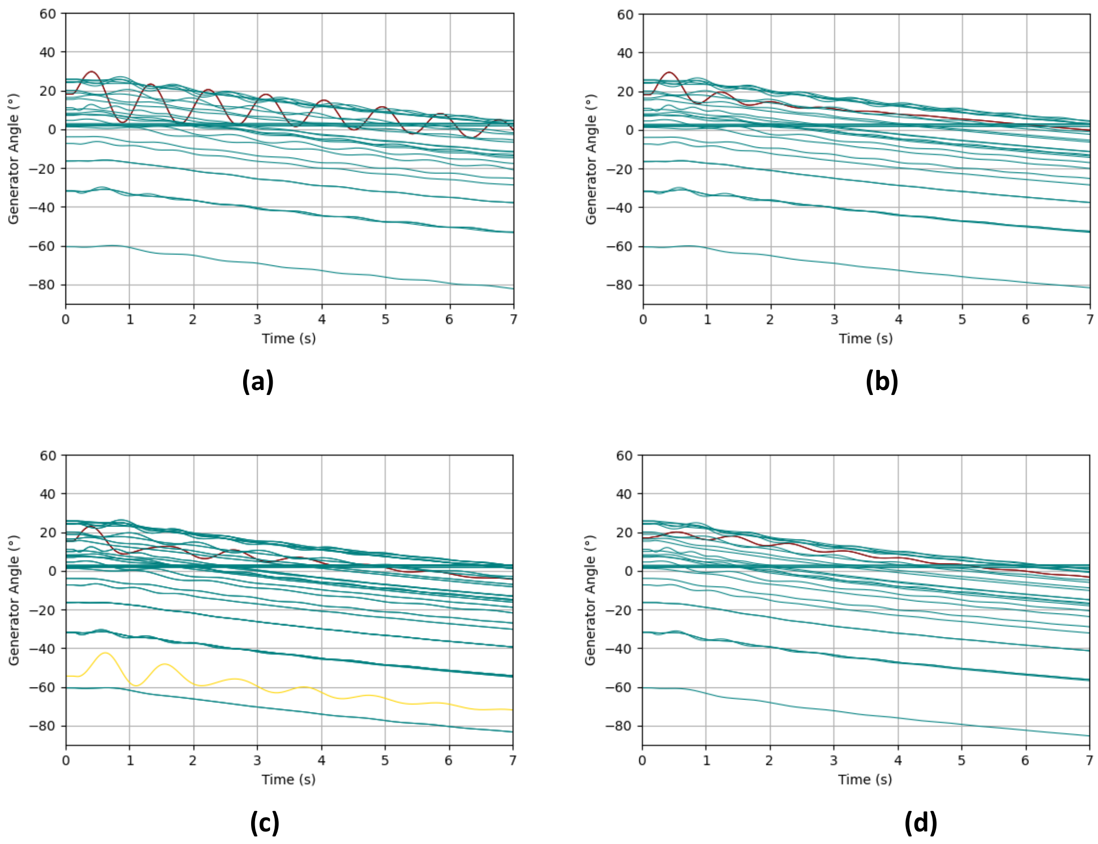


FIGURE 6-17: TIME DOMAIN EXAMPLES FOR MITIGATION MEASURES FOR HOUR 2307.
(A) BASE CASE, (B) ADDING PSS, (C) ADDING SYNCHRONOUS CONDENSER, AND (D) ADDING STATCOM.

Figure 6-18 presents the active power of the oscillating unit for different mitigations options. Comparing Figure 6-17 (a) and Figure 6-17 (b), Figure 6-18 (a) and Figure 6-18 (b) indicates that PSS provides significant damping. However during the first half cycle of the oscillation (i.e. 0.1s-0.9s), the generator angle and active power traces are identical for the base case and with PSS. Thus, the response speed from PSS is not sufficient to reduce the first swing in generator angle and overshoot in generator active power. Figure 6-17 (c) and Figure 6-18(c) indicates that the damping provided by synchronous condenser is not significant, in comparison with the PSS. Hence, synchronous condenser is not recommended as a mitigation option based on the decay time presented in Table 6-1. Figure 6-17 (d) and Figure 6-18 (d) suggests that the STATCOM provides sufficient damping and a significant reduction in first swing in generator angle and overshoot in generator active power. Since the STATCOM can provide a faster response and sufficient damping, it is recommended, out of the three options investigated here, as the more appropriate mitigation option for the damping oscillation scarcities.

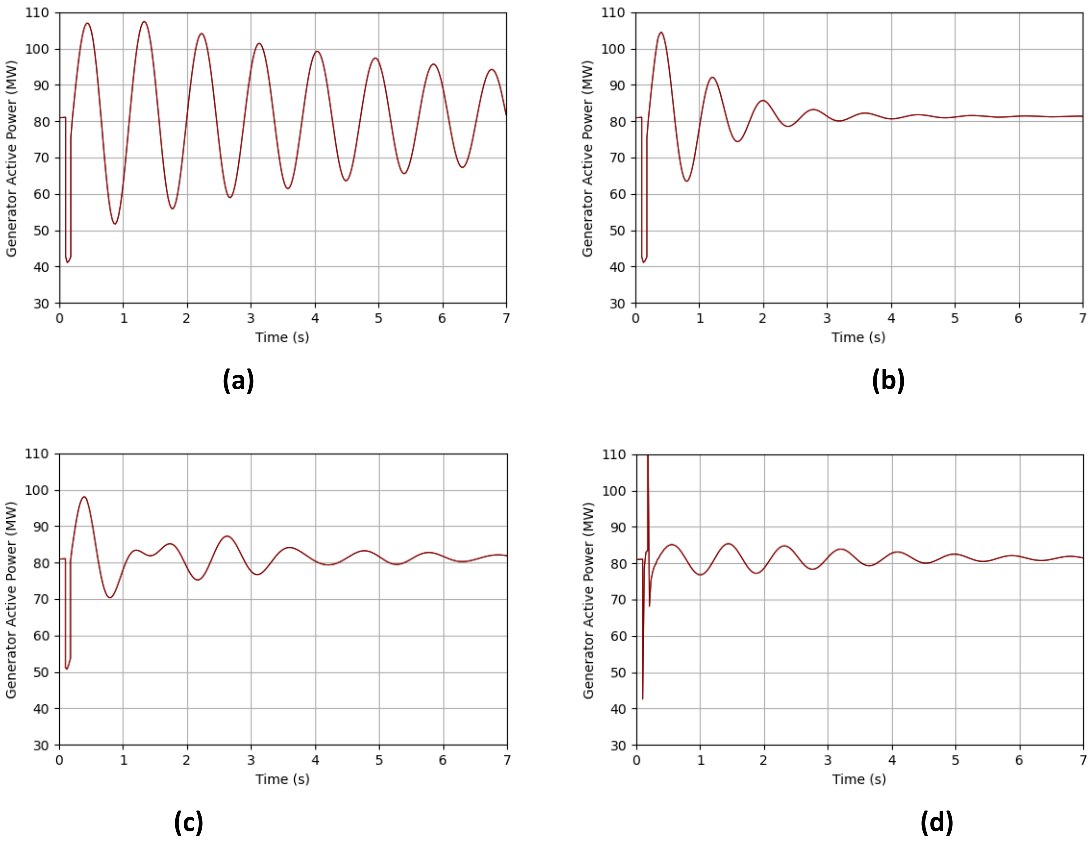


FIGURE 6-18: ACTIVE POWER OUTPUT OF OSCILLATING UNITS WITH MITIGATION MEASURES FOR HOUR 2307. (A) BASE CASE, (B) ADDING PSS, (C) ADDING SYNCHRONOS CONDENSER (D) ADDING STATCOM.

Figure 6-19 presents results of the decay time for each of the 36 snapshots under investigation for each of the 306 contingencies for the modified case which includes all the technologies used to mitigate of dynamic voltage control scarcities (synchronous condensers and STATCOMs – see Table 5-4 for locations) and damping oscillations (i.e. STATCOMs). From Figure 6-19, it is evident that the damping oscillation localised scarcities are mitigated, which is an important finding.

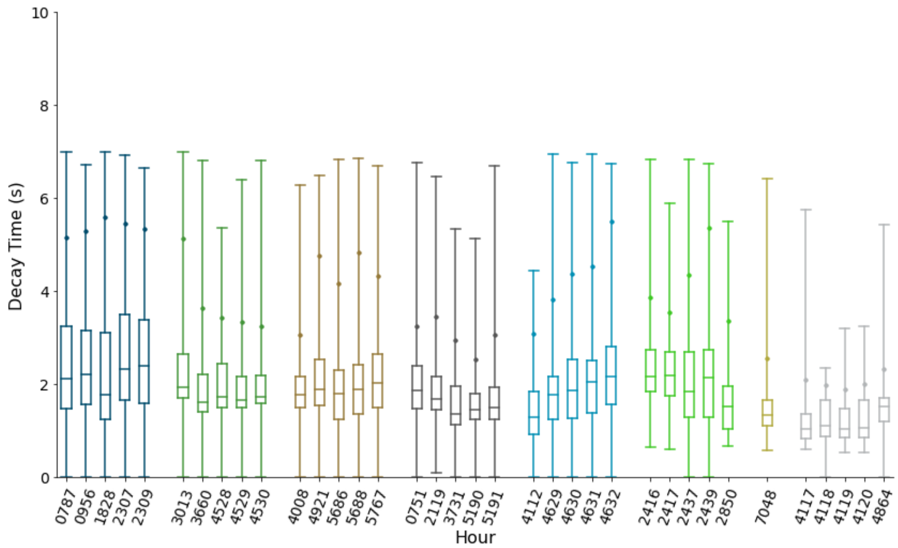


FIGURE 6-19: BOX PLOT OF DECAY TIME FOR LOW CARBON LIVING SNAPSHOTS (WITH MITIGATIONS).

6.2.4 RESULTS: SYNCHRONISING TORQUE SCARCITIES (ANGLE MARGIN)

6.2.4.1 INTRODUCTION

Figure 6-20 presents the Task 2.4 results of the angle margin index for each of the 36 snapshots studied for each of the 306 contingencies considered for the LCL scenario. Each box plot represents the distribution of the angle margin results for each hour except for unstable results that are excluded from these distributions and plotted as dots.

Task 2.4 did not find any global scarcities of synchronising torque, as there is no hour of operation with particularly poor angle margin. However, a localised scarcity has been identified that caused a generator to lose synchronism when it was heavily loaded and exposed to a large loss of infeed close to its point of connection, shown in Figure 6-20 (black circle in Hour 4629, Hour 4630, Hour 4631 and Hour 4632). These localised scarcities were investigated in detail in Task 2.4 and it was found that these localised scarcities will likely emerge for specific combinations of unit commitment and contingency. Note, similar scarcities can emerge for different combination of unit commitments and contingencies that were not identified in Task 2.4.

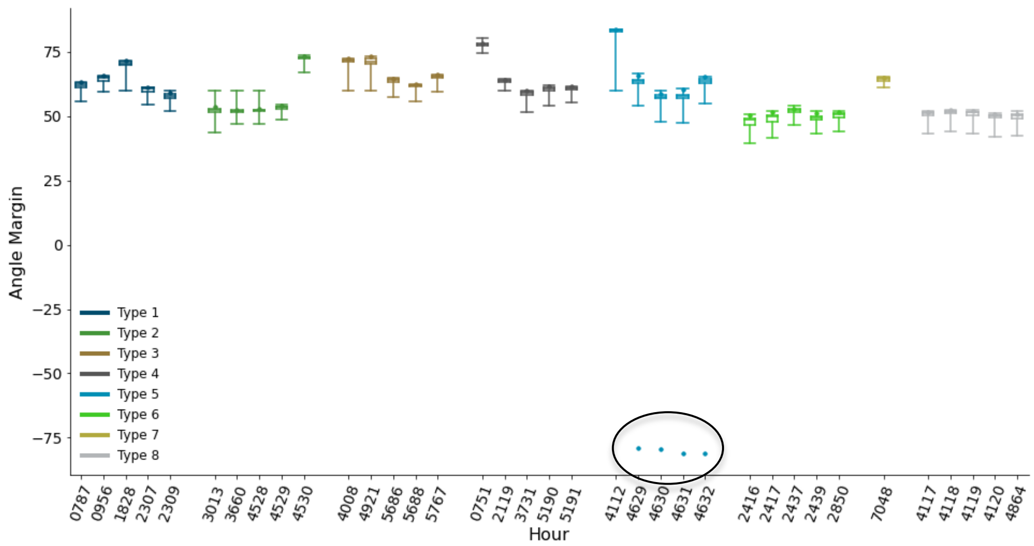


FIGURE 6-20: BOX PLOT OF ANGLE MARGIN FOR EACH HOUR FOR LOW CARBON LIVING (BASE CASE).

6.2.4.2 MITIGATIONS MEASURES FOR SYNCHRONISING TORQUE SCARCITIES (ANGLE MARGIN)

Technologies such as Synchronous Condenser, SVC and STATCOM are analysed as potential mitigation measures for synchronising torque scarcities. Focus on Hour 4629, Hour 4630, Hour 4631 and Hour 4632 demonstrates that the generator that loses synchronism is electrically near to the fault. The generator that loses synchronism and a nearby large generator are operating at maximum dispatch and the nearby interconnector is at maximum import. In order to avoid this generator losing synchronism, Synchronous Condensers, SVCs and STATCOMs are required in large quantities; quantities that would be unfeasible from a cost perspective in reality. Thus, the best mitigation option appears to be consideration of an operational policy under specific circumstances and system conditions that would result in the modification of the considered unit commitment by dispatching down the unit that loses synchronism and increasing the output of another generator to accommodate the shortfall in generation from the dispatch down process.

Figure 6-21 presents results of the angle margin index for each of the 36 snapshots for each of the 306 contingencies for the modified case which includes the technology used to mitigate the other scarcities discussed above such as a lack of dynamic reactive power and oscillations. From Figure 6-21, it is evident that the synchronous torque localised scarcities are mitigated (comparing Figure 6-20 and Figure 6-21 there is clear evidence of improvement as it can be seen that the negative angle margin case in Figure 6-20 have been avoided in Figure 6-21). Also the distribution of angle margin index are between 45 to 65 which indicate that the technologies used to mitigate other scarcities (synchronous condenser and STATCOM) did not deteriorate the transient rotor angle stability.

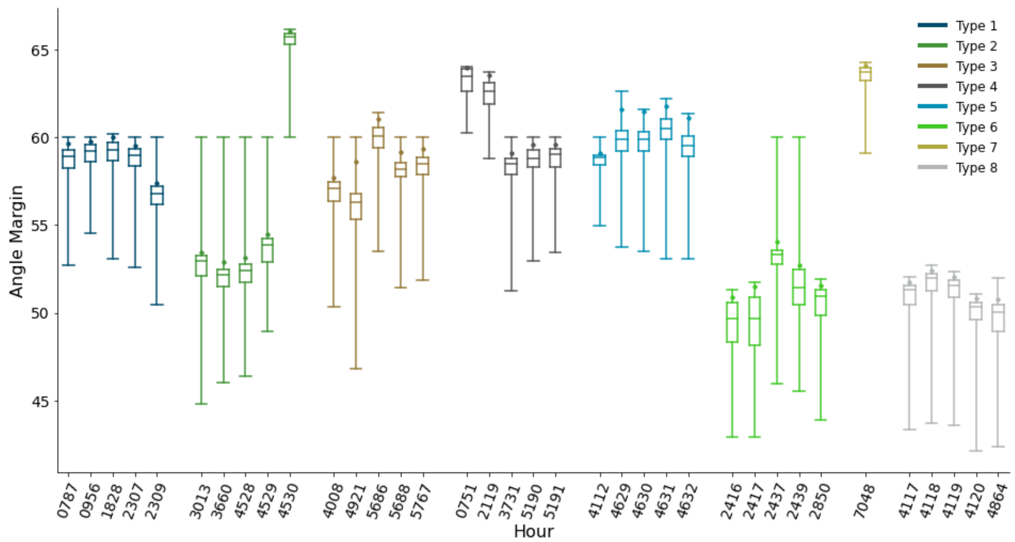


FIGURE 6-21: BOX PLOT OF THE ANGLE MARGIN FOR EACH HOUR FOR LOW CARBON LIVING (WITH MITIGATIONS).

6.2.5 RESULTS: SYNCHRONISING TORQUE SCARCITIES (CRITICAL CLEARANCE TIME)

Figure 6-22 presents the EU-SysFlex Task 2.4 results of the CCT index for each of the 36 snapshots under study for each of the 306 contingencies for the LCL scenario. The 4 cycle CCTs recorded for hours 4629, 4630, 4631 and 4632 (black circle) relate to a single contingency that was unstable in the base case. This is dealt with in detail in the section on transient rotor angle stability above. The box plots show that no hours of operation have a 5 percentile of faults for which the CCT is approaching the 4 cycle expected clearing time. This implies there is no global CCT scarcity, however, for most hours, the outliner are below 10 cycles.

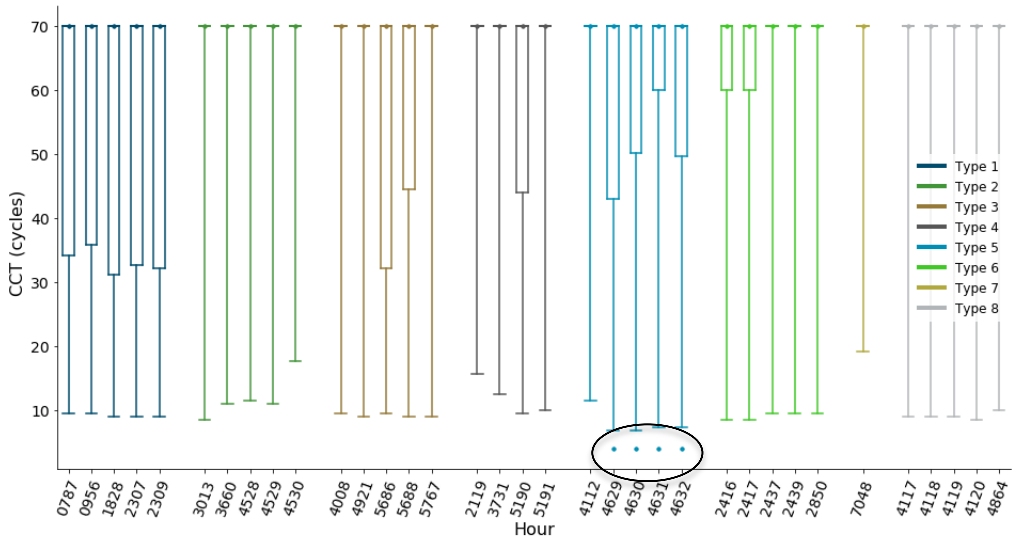


FIGURE 6-22: BOX PLOT OF THE CRITICAL CLEARING TIMES FOR EACH HOUR FOR LOW CARBON LIVING (BASE CASE).

Table 6-2 presents further insight of the overall distribution of CCT for the base case. In the overall analysis, 77 cases (0.7%) have CCTs below 10 cycles and there are 1239 cases (11.4%) with CCT above 10 cycles and below the absolute worst case clearing time of 25 cycles. As such these results do appear to indicate that a localised CCT scarcity is the main concern here supporting the findings for EU-SysFlex Task 2.4.

TABLE 6-2: THE DISTRIBUTION OF CCT FOR LOW CARBON LIVING (BASE CASE).

CCT(Cycles)	Base case
70	8447(77.71%)
25-70	1107(10.18%)
10-25	1239(11.4%)
0-10	77(0.71%)

6.2.5.1 MITIGATIONS FOR SYNCHRONISING TORQUE SCARCITIES (CRITICAL CLEARANCE TIME)

A case study is performed for the case with the lowest CCT (Hour 1828 and Contingency 30). In this case, two large generators which are in proximity to the fault are operating at maximum power. Both the generators experience loss of synchronism. STATCOMs or Synchronous Condensers of size 400 MVA connected close to the generators are explored as potential mitigation options to increase the CCT. Also, modifying the power flow by reducing the output of both generators by 100 MW is also explored. Table 6-3 presents the impact on CCT for adding Synchronous Condensers or STATCOMs in proximity of the fault or reducing generator output.

TABLE 6-3: CASE STUDY: CCT FOR DIFFERENT MITIGATION.

Mitigations	CCT (cycles)
Base Case	8.817
With 1 Synchronous condenser (400 MVA size)	11.719
With 2 Synchronous Condensers (400 MVA size)	10.906
With 1 STATCOM (400 MVA size)	11.125
With 2 STATCOMs (400 MVA size)	12.625
With 3 STATCOMs (400 MVA size)	15.785
Reducing generation by 100 MW	14.712

The improvement in the CCT by adding STATCOMs and Synchronous Condensers is not significant considering the cost implications. However, these technologies are used for mitigations of other scarcities such as dynamic reactive power and damping oscillation, and so their impact on CCT for all snapshots is considered.

Figure 6-23 presents the distribution of CCT index for each 36 snapshots with mitigations. The box plots show that there are no hours of operation which have a 5 percentile of contingencies for which the CCT is approaching the 4 cycle expected clearing time. The outliner of most hours is below the absolute worst case clearing time of 25 cycles. Table 6-4 presents comparisons between the overall distribution of CCT for the base case and with mitigations. There is significant reduction in number of cases below 10 cycles and 25 cycles. Also there is no deterioration of CCT and stability issues due to the mitigation of dynamic reactive power and damping oscillation. If any transient instability arises, reducing generator output or modifying the power flow (as explained in Section 6.2.4) are the cost effective mitigation options.

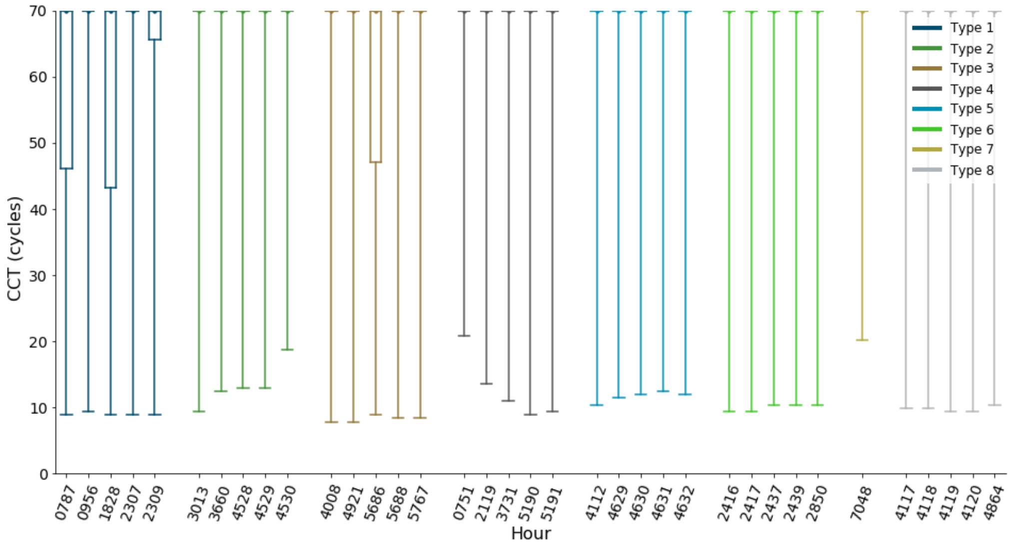


FIGURE 6-23: BOX PLOT OF THE CRITICAL CLEARING TIMES FOR EACH HOUR FOR LOW CARBON LIVING (WITH MITIGATIONS).

TABLE 6-4: THE DISTRIBUTION OF CCT FOR LOW CARBON LIVING (BASE CASE).

CCT(Cycles)	Base Case	With Mitigations
70	8447(77.71%)	9316(84.59%)
25-70	1107(10.18%)	867(7.87%)
10-25	1239(11.4%)	820(7.44%)
0-10	77(0.71%)	10(0.09%)

6.2.6 KEY MESSAGES: IRELAND AND NORTHERN IRELAND

Rotor angle stability requires that each synchronous machine must maintain the existing equilibrium or reach a new equilibrium between its electromagnetic and mechanical torque whenever a disturbance in a power system occurs [38]. The change of the electromagnetic torque of a synchronous machine after a disturbance consists of two components which affect the damping of oscillations:

- Damping torque component (in phase with speed deviation)
- Synchronising torque component (in phase with rotor angle deviation)

A number of options are considered here focusing on potential technical solutions and their capabilities and ignoring cost implications. **Adding a Power System Stabiliser (PSS) to the oscillating units, Synchronous Condenser and STATCOM are all considered as mitigation options** for the damping oscillation scarcities. The key messages from the identified measures related to mitigation of damping oscillation scarcities for Ireland and Northern Ireland power system are as follows:

1. STATCOM provides sufficient damping and a significant reduction in first swing in generator angle and overshoot in generator active power.
2. PSS provides significant damping. However there is no reduction in first swing in generator angle and overshoot in generator active power.
3. Damping provided by synchronous condenser is not significant.

Task 2.4 identified localised scarcity in synchronising torque that caused a generator to lose synchronism when it was heavily loaded and exposed to a large loss of infeed close to its point of connection. **Technologies such as Synchronous Condenser, SVC and STATCOM are analysed as potential mitigation measures for synchronising torque scarcities**. The key messages from the identified measures related to mitigation of synchronising torque scarcities for Ireland and Northern Ireland power system are as follows:

1. Synchronous Condensers, SVCs and STATCOMs are required in large quantities to avoid the generator losing synchronism.
2. The best mitigation option appears to be consideration of an operational policy under specific circumstances and system conditions that would result in the modification of the considered unit commitment by dispatching down the unit that loses synchronism and increasing the output of another generator to accommodate the shortfall in generation from the dispatch down process.

6.3 SUMMARY OF ROTOR ANGLE MITIGATIONS

This chapter has successfully demonstrated, through simulations, and utilisation of specific technologies as a means of representing capability, a range of system services to support rotor angle stability. These services include:

- Dynamic Reactive Response (DRR)
- Synchronous Inertial Response (SIR)

As conventional generation is displaced with variable renewable generation, synchronising torque on the system also decreases. While a system-wide scarcity was not identified in Task 2.4, localised scarcities were noted, including a localised scarcity of oscillation damping. These scarcities could be addressed by Power System Stabilisers, Synchronous Compensators, and STATCOMS for example [42].

The tuning of **Power System Stabilisers (PSS)** of relevant conventional synchronous generators was demonstrated in the Continental Europe power system in order to mitigate **damping oscillation scarcities,** while a number of options are considered in the Ireland and Northern Ireland power system focusing on potential technical solutions and their capabilities including the addition of **Power System Stabiliser (PSS)** [43] to the oscillating units and the addition of **Synchronous Condenser and STATCOMS to provide the need capabilities**.

Results from the Continental Europe power system show that **optimal tuning of power system stabilisers alongside automatic voltage regulators** of the conventional synchronous machines may contribute to the augmentation of the oscillation damping in the power system. Investigations on the Ireland and Northern Ireland Power system show that the **addition of PSS** on the offending units or **STATCOM provides significant damping**, while no substantial mitigation was observed for the Synchronous Condenser.

Dynamic Reactive Response (DRR) capability from Synchronous Condensers, STATCOMS and SVCs was demonstrated in the Ireland and Northern Ireland power system for mitigating **synchronising torque scarcities**. Analyses showed large quantities of these technologies are required in mitigating this localised issue. The most appropriate mitigation option appears to be the **modification of the considered units commitment**, therefore development of a new **damping product** may be necessary to incentivise sufficient capability and behaviour to deal with this scarcity. System services have shown that they can incentivise investment in new technologies that can provide a needed capability.

7. CONGESTION MITIGATIONS

There is strong evidence across Europe that transmission network congestions will be one of the most difficult challenges to deal with for the further advancement of the integration of Renewable Energy Sources (RES). Societal and environmental pressures often result in either an inability to build new network or significant delays in doing so. Futhermore, the respective cost-benefit analyses demonstrate that it may not be economically viable to develop transmission networks that would guarantee compliance with the traditional security/planning criteria under all conditions/scenarios. Both magnitude and frequency of the congestions will play important role when deciding how to tackle them. It seems that congestion drivers are of a stochastic nature (variable RES outputs, demand variations, outages of both transmission network and generation) which makes the congestion problem particularly challenging mainly due to a vast space of potential congestions scenarios required to deal with. The time dimension becomes increasingly important in all this considering different RES generation targets imposed by a number of governments and/or related protocols as well as planning permissions and portfolio management limitations.

The experience of the countries dealing with a high level of RES integration undoubtedly shows that the pace of transmission network development cannot not follow the required pace of the RES integration which often leads to imposing constraints on the renewable generation output. Thus, the congestion problem that is traditionally dealt with through planning departments tends to shift to the operation departments within a TSO business. New and innovative options are also being explored both in academia and in industry. It is therefore very important to find a right balance in terms of a coordinated approach to tackle congestions problems across both the planning and operation domains.

7.1 IRELAND AND NORTHERN IRELAND

As discussed in deliverable D2.3 [8], the Ireland and Northern Ireland power system is operated at 400 kV, 275kV, 220 kV and 110 kV and the network is generally comprised of over-head lines with the exceptions of the city centres of Belfast, Dublin and Cork where underground cables are used. The 400 kV, 275 kV and 220 kV network forms the backbone of the power system as they have higher power capacity than the 110 kV networks. However the 110kV circuits are the most extensive element of the transmission system providing parallel paths to these circuits and are generally comprised of single circuit lines which are interconnected to cover the wider geographical distances between nodes.

Steady state analysis was carried out in Task 2.4 to assess the impact of increasing high levels of RES on the All-Island transmission system in order to investigate potential congestion issues. As SNSP increases, analysis indicated that there will be a significant rise in the frequency of transmission line overloading above 100% of thermal capability.

Figure 7-1 from Deliverable 2.4 [1] shows the results of the 2030 LCL transmission network thermal over loading analysis for N-1 system conditions. The results shown are for both the summer (red) and winter (blue) seasons with each dot representing a transmission line overload above 100%. Analysis showed that the areas of the network most affected by the loss of a single circuit are in the west of Ireland and Northern Ireland. These are the regions with high geographically distributed RES densities and electrically distant from load centres.

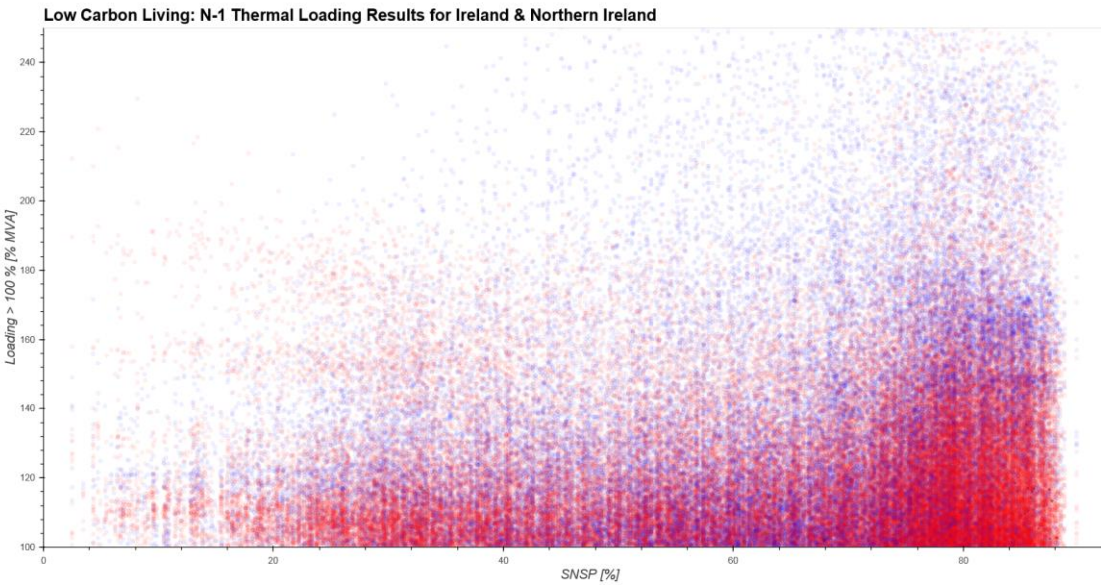


FIGURE 7-1: COMPARISON OF 2030 LOW CARBON LIVING TRANSMISSION NETWORK THERMAL OVER LOADING AGAINST SNSP

Analysis from EU-SysFlex Task 2.4 concurs with analysis from the Shaping Our Electricity Future report [23]. Figure 7-2 from the Shaping Our Electricity Future report [23] clearly demonstrates that the greatest overloading of lines are around the Dublin region and in the North-West of the island of Ireland.

Investigations also revealed that the Dublin region, despite having high local load which will increase over the coming decade as a result of the connection of large energy users (LEU’s), can experience thermal overloads at both low and high SNSP levels due to the large numbers of conventional generators and offshore wind farms.

The following sections focus on a range of solutions and potential mitigations for the congestion scarcities identified in Deliverable 2.4 [1].

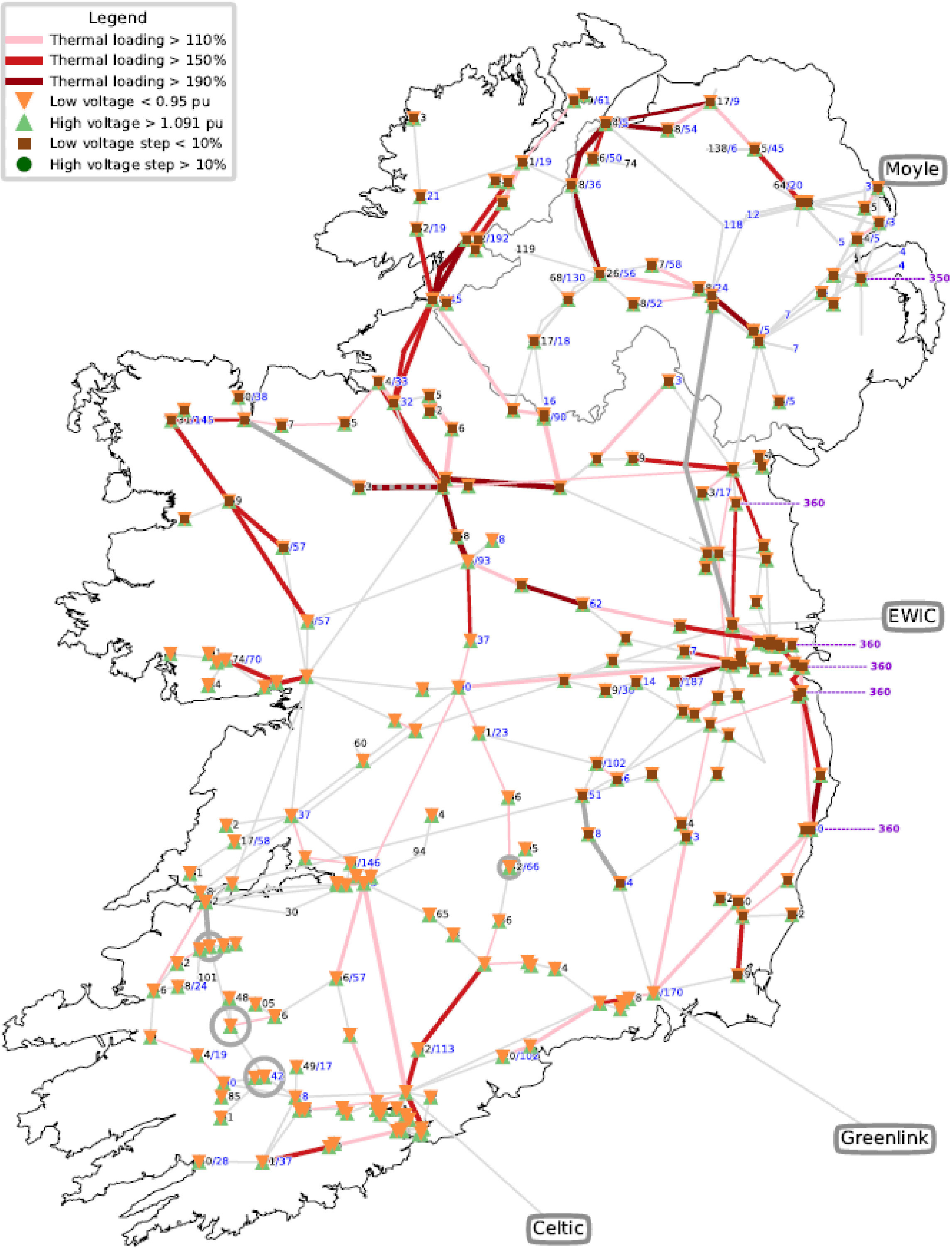


FIGURE 7-2: ILLUSTRATION OF TRANSMISSION NETWORK NEEDS IN 2030 [23]

7.1.1 METHODOLOGY: IRELAND AND NORTHERN IRELAND

The methodology presented in these sections focuses on a spectrum of solutions and potential mitigations for the identified congestion problems in Deliverable 2.4 [1]. As such, the outlined methodology is of a qualitative nature and not a quantitative comprehensive assessment that would result from cost-benefit studies following traditional analyses that would be exercised in both planning and operation domains. As with the other sections of this report, the aim is to demonstrate potential solutions or mitigations for the challenge of congestion and to illustrate the capability of certain measures or specific technologies. It should be noted from the outset that, whilst EirGrid Group's strategy in relation to the network is to maximise the use of the existing transmission networks and to minimise new build, in many cases there is no alternative except to invest in new reinforcements, while making every effort to minimise new additional infrastructure. Uprating existing lines or cables could be seen to be an alternative to investing in new additional circuits. Additionally, it should be noted that in the case that no new network can be built for social and/or environmental reasons, or indeed if the built out would take a considerable amount of time, alternative and novel mitigations would need to be considered for managing congestion.

The methodology related to resolving congestions identified in the Task 2.4 is focused on the following potential solutions and mitigations:

i. **Network reinforcements.** This involves identification of the top priority network corridors to reinforce and to determine the support requirements. A new identical line/cable is added in parallel to the existing circuit thus minimising new infrastructure requirements.
ii. **Operational mitigation measures** that are related to the following options:
    - Use of phase-shifters and traditional transformer voltage control
    - Demand shifting that utilises flexible demand that is capable of shifting consumption away from congested hours to other hours within a 24H period
    - Constraining generation
    - Use of smart power flow controllers.
    - Use of dynamic line rating: This is discussed in section 12.1.1.

The methodology implemented for the network reinforcements is discussed in Section 7.1.1.1 and the results provided in Section 7.1.2 for the Dublin region and Section 7.1.4 for the North-West region. The methodology related to these operational mitigation measures is outlined in Section 7.1.1.2 and the results are presented in Section 7.1.3 for the Dublin region and Section 7.1.5 for the North-West region.

An illustrative example is given below in Figure 7-3 for two different snapshots A and B where the former is more onerous with a more complex congestions problem ‘space’. The congestion problem for snapshot B is solvable either through imposing a number of reinforcements or by applying the operational mitigations measures discussed in ii) above. This is not the case with the snapshot A. Resolving congestion issues for the snapshot A by applying only the operational mitigation measures outlined in ii) would not be successful and it would result in an infeasible solution. Alternatively, the required number of reinforcements to resolve this congestion issue would not be economically viable, due to the significant number of reinforcements that would be needed. Therefore, a potential feasible and economical solution could involve application of a selected number of reinforcements in conjunction with a number of operational mitigation measures. Novel innovative mechanisms in conjunction with i) and ii) could also be considered. The most important messages around the challenges associated with congestions are:

- Congestions problems cannot be solved exclusively by reinforcements (planning) alone or by operational mitigation measures alone. A combination of mitigations is required.
- Due to the economic cost of reinforcement work, reinforcements are applied here such that any remaining congestion problems are manageable by day-to-day operations. It should be noted, that subsequent sections will also explore more innovative options as it must be acknowledged that there may be situations were reinforcement is simply not possible due to environmental and/or societal pressures, or indeed considerable lead times for completion of reinforcements would lead to adverse outcomes, for example, missing renewables targets.

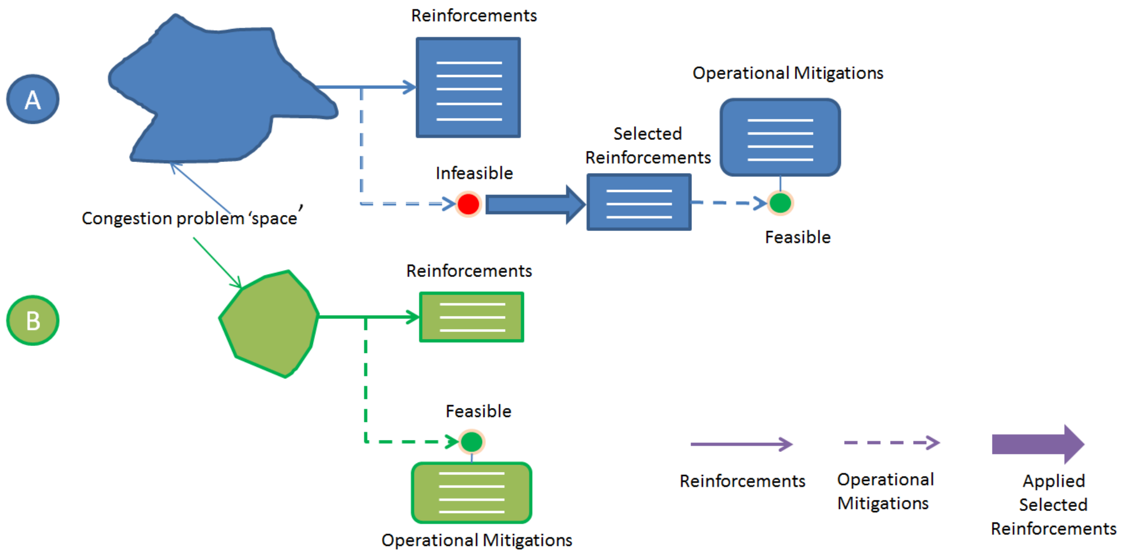


FIGURE 7-3: ILLUSTRATION OF MITIGATION OPTIONS

7.1.1.1 METHODOLOGY: NETWORK REINFORCEMENTS

Network congestions drive the transmission network development and have been traditionally dealt with by the respective planning departments in Ireland and Northern Ireland. While, it needs to be acknowledged that societal and environmental pressures often result in either an inability to develop new network or considerable time delays in doing so, there is still significant merit in considering the process for network development, as network development could continue to have a role to play in the future.

The corresponding planning process is quite comprehensive and includes a number of major steps as outlined in [27]:

I. Scenario selection
II. Generation scheduling
III. Identification of network bottlenecks
IV. Proposing most effective network reinforcement options
V. Cost-benefit analyses of the proposed options

This is a complex process typically requiring a number of iterations. Some of the steps in this procedure (i.e. scenario selection and generation scheduling) have already been carried out through the work reported in Deliverable 2.4 [1]. The focus of Task 2.4 involved comprehensive contingency analyses of hourly snapshots (8760) carried out in accordance with Eirgrid and SONI transmission planning criteria [27]. The main conclusions observed with respect to transmission network congestions is that the Dublin, North-West regions were identified as the most impacted regions in terms of system congestions.

Results from Task 2.4 are utilised in order to identify the most effective network reinforcements and the extent to which they can mitigate the congestion issues. A cost-benefit analysis of the proposed options is omitted in Task 2.6 as the focus of these investigations is to identify, largely irrespective of cost, the mitigation options that can help deal with the challenges associated with the integration of high levels of RES on a power system. A techno-economic evaluation of the reinforcements would need to be performed as part of the decision making process for network reinforcements. Although, not in scope in Task 2.6, the importance of this type of analysis is acknowledged by EirGrid and SONI and, in fact, significant work of this nature is being carried out as part of the "Shaping Our Electricity Future" analysis [23].

The first part of the congestion analysis in Task 2.6 involves the identification of the network bottlenecks and identifying the most promising reinforcement options based on the calculation of different overload indices. There are two types of indices used in this investigation:

- **Overload Index (OI)** –this is a metric associated with each overloaded/congested circuit representing both the severity and frequency of the overload caused by different contingencies. This metric can be calculated for each hour and summed over all hours to calculate a Total Overload Index (**TOI**).
- **Impact Overload Index (IOI) -** this metric is similar to OI but focuses only on the contingency causing the highest overload of the considered circuit. Similarly to TOI the corresponding Total Impact Overload Index (**TIOI**) can be calculated for a circuit by tallying IOI of the respective circuit over all hours.

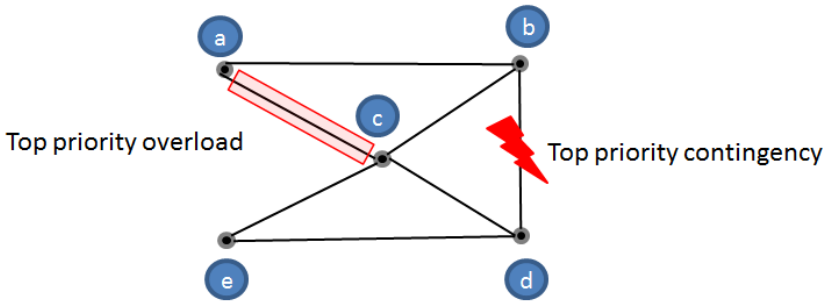
These indices are the main drivers for selecting the best reinforcement candidates through a complex staggered procedure involving the ranking of reinforcement options. This iterative contingency analysis contains a stopping criteria to ensure that only contingencies contributing to the reduction of the OverLoad Index (OI) are considered for the next stage.

All of these metrics OI, IOI, TOI and TIOI can be calculated for each contingency causing these overloads. The benefit of these metrics is that they target both the severity and frequency of overloads including contingencies causing overloads. The same overload can be identified in a number of hourly snapshots instigated by different contingencies. A simple example is given in Figure 7-4 where three overloads are identified for a single hour *h*:

- The line a-c is overloaded due to a number of outages:
  - the line a-b causing the loading of the line a-c of 120%,
  - the line e-d causing the loading of the line a-c of 140%,
  - the line b-d causing the loading of the line a-c of 140%.
- The line c-d is overloaded only for the outage of the line b-d that causes the line c-d loading of 140%
- The line b-d is overloaded only for the outage of the line e-f that causes the line b-d loading of 140%.

The Total Overload Index (TOI) for the considered hour *h* would be 6.8 as per Figure 7-4 with the line a-c having the highest overload index of 4.0 and the outage (contingency) line b-d being the most taxing contingency as illustrated in Figure 7-4 . There are two good candidates in terms of the top reinforcement choice:

- The line a-c with overload index (OI) of 4.0.
- The line b-d that has its OI of 1.4 but contributes to other lines OI - lines a-c and line c-d. When combined the OI for this contingency is 4.2. Hence reinforcements for line b-d might potentially be more rewarding than reinforcing the line a-c.



Hour *h* load summary	Contingencies	Overload Index (OI)	Impact Overload Index(IOI)
a-c	a-b->(120%) e-d->(140%) b-d->(140%)	1.2+1.4+1.4=4.0	1.4
c-d	b-d->(140%)	1.4	1.4
b-d	e-f->(140%)	1.4	1.4
Total for hour *h*		TOI=6.8	TIOI=4.2

FIGURE 7-4: SIMPLE EXAMPLE TO ILLUSTRATE THE CALCULATION OF OVERLOAD INDICES

The simplified overload index approach example summarised above confirms that the best reinforcement would be to add a circuit in parallel to line b-d. The implemented approach for the purposes of the reinforcement analysis is driven by the premises outlined above, however it is significantly more complex with computation/logic that extends beyond these premises especially for the procedures focusing on (i) ranking of the candidates, (ii) iterative contingency analyses performed for each candidate and (iii) staggered approach with a careful cautious selection of the reinforcement candidate to be brought forward to the next stage. Some of the major blocks of this complex approach are illustrated in Figure 7-5.

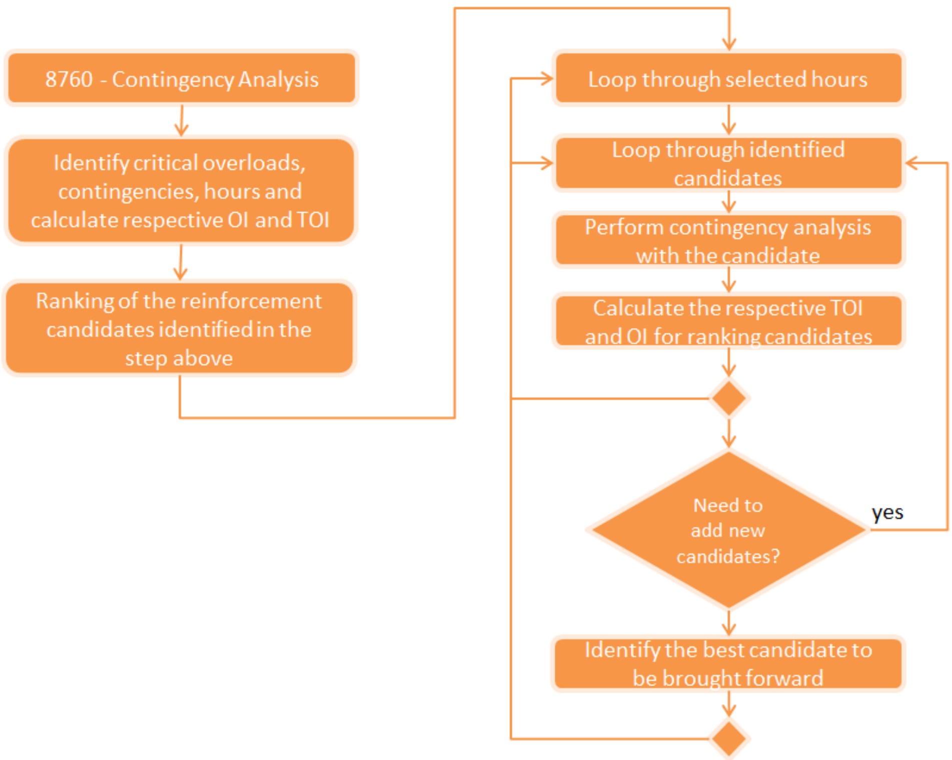


FIGURE 7-5: REINFORCEMENT ALGORITHM MAIN BLOCKS

7.1.1.2 METHODOLOGY: OPERATIONAL MITIGATION MEASURES

Building new network infrastructure is a traditional way to tackle transmission network congestion as pointed out in Section 7.1.1.1 would not be economically viable or practical in resolving all congestions issues for a future power system with very high RES penetrations. When the economic viability of new infrastructure is combined with the potential challenges from societal and environmental pressures, it is evident that alternative mitigations need to be explored. Consequently, and in order to deal with infrequent system congestions, TSOs might consider imposing a number of operational mitigation measures.

For the purposes of this project the predictive logic outlined earlier was utilised using a Preventive Security Constrained Optimal Power Flow (PSCOPF) to identify load shifting, generation adjustments, phase shifter angle and tap changes to eliminate the identified hourly overloads. The optimisation tool employed is PSS®E PSCOPF [44].

The security constrained optimal power flow is a special class of Optimal Power Flow (OPF) problems which takes into consideration the system constraints derived from a base case and a set of predefined contingencies. System security is the ability to withstand contingencies, in other words, to remain intact even after equipment outages or failures. Security plays a crucial role in the planning and operation of a power system. To ensure a secure system operation, system planners and operators conduct analyses to identify the necessary adjustments required to avoid limit violations for both an intact case (pre-contingency) condition and following any known contingency [44].

The objective function of PSCOPF is to minimise the adjustments of the following types of control [44]:

- On-line and off-line generator MW generation control
- Phase shifter adjustments
- Load controls
- Tap setting adjustments
- Switched shunt adjustments

subject to the following types of constraints:

- Power balance equations of base case and contingencies cases
- Limits on controls
- Operation limits under base case and contingency cases.

While constraining RES in regions with high geographically distributed RES densities that are electrically distant from load centres can be an effective operational mitigation measure, other measures have to be considered in order to acknowledge and support the goals of operating a power system with high RES penetration levels. Demand shifting, for example, might be an option to ensure that demand is shifted away from hours of high marginal price and moved to hours of low marginal price of electricity. Generation adjustments might also be required for conventional generation to mitigate congestions. There are obviously many dependencies between these operational measures where for example conventional generation might be affected by the level of RES constraints or demand shifting or phase shifter angle adjustments as well.

As outlined in Section 7.1.1.1 and Section 7.1.1.2 the reinforcement methodology remains within a planning domain while the PSCOPF optimisation is an operational tool and therefore lies within an operational domain. It is expected that the PSCOPF optimisation success rate in terms of reaching feasible optimal solutions might be low for the complex constraints space shown in Figure 7-3 .

Use of optimisation offers many advantages but has a number of disadvantages, particularly in the operational domain where the number of preventive measures that can be considered is limited in terms of time and capabilities. Thus, it is important to find the right balance and a high degree of coordination between planning and operation departments. The performed optimisation runs confirm that a significant number of mitigation measures will be required by 2030.

A significant PSCOPF challenge in relation to significant number of contingencies causing overload issues can result in a large-scale optimisation problem. Trying to solve this issue for a large power system by simultaneously imposing all the post-contingency constraints could lead to prohibitive computer memory requirements and CPU time. Benders decomposition [45] is an appropriate solution method in dealing with large-scale optimisation issues. Benders method decomposes the initial problem into several sub-problems shown in Figure 7-6 allowing for each to be solved separately and iteratively. In using the Benders decomposition method in the PSCOPF function, the master problem is set up with the base case condition and cuts from the contingency cases, and a sub-optimisation problem is modelled for each contingency to ensure the feasibility of the solution.

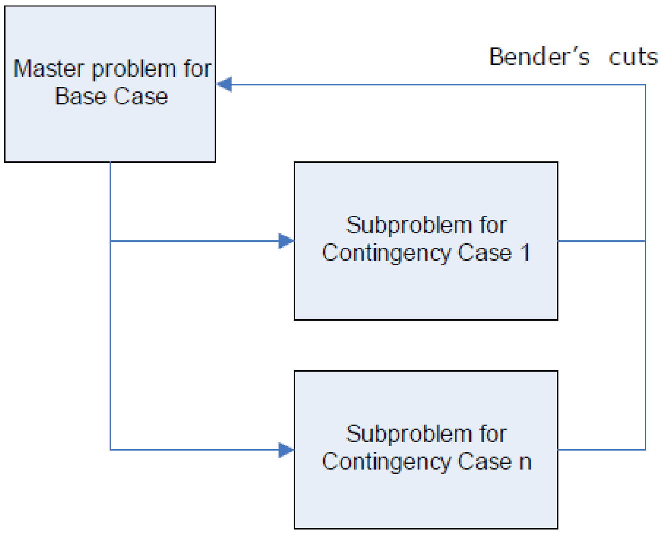


FIGURE 7-6: BENDERS DECOMPOSITION OF COMPLEX OPTIMISATION PROBLEMS [44]

The results section is structured as follows:

- The Dublin region mitigations are discussed first demonstrating:
  - Reinforcements
  - Operational Mitigation Measures.
- The Dublin North-West region mitigations are then discussed demonstrating:
  - Reinforcements
  - Operational Mitigation Measures.
- Two novel studies or proofs-of-concept are then introduced. These include the:
  - Use of Smart Power Flow Control devices

- Use of flexible loads or demand-side management.

7.1.2 RESULTS: NETWORK REINFORCEMENT - DUBLIN REGION

This section summarises the results related to only the network reinforcements for the Dublin region. A significant number of overload issues were observed for the 220 kV network in the Dublin region in Deliverable 2.4 [1]. The number of contingencies causing these overloads and the frequency of occurrence is significantly higher compared to congestion challenges experienced in the North-West region in Section 7.1.4. The characteristics of the 220 kV network in the Dublin region and its topology is very different when compared to the North-West 110 kV network as despite having high local load, the region can experience thermal overloads at both low and high SNSP levels due to the large numbers of conventional generators and offshore wind farms in this region.

Thus, while the mitigation method applied for determining the best approach in reinforcing the Dublin region is similar to the one applied for the North-West, a few modifications are required to address the differences between the two regions. The results for the Dublin reinforcements are summarised into the following three sections:

1. Top ten critical hours with respect to the Total Overload Index (TOI) calculated for all hours
2. The selection of the best reinforcement candidates for the top ten critical hours
3. The impact of the selected reinforcements on the less critical hours.

7.1.2.1 TOP TEN CRITICAL HOURS FOR THE DUBLIN REGION

A full contingency analysis for the entire year shows that the Dublin region has significant congestion issues for the 2030 scenario studied. There are a number of specific phenomena driving very high TOI values for these hours (Figure 7-7). These phenomena include the fact that:

- The magnitude of overloads is quite high in the Dublin region.
- There are high numbers of different contingencies causing the overloading of the same lines or transformers in the Dublin region.

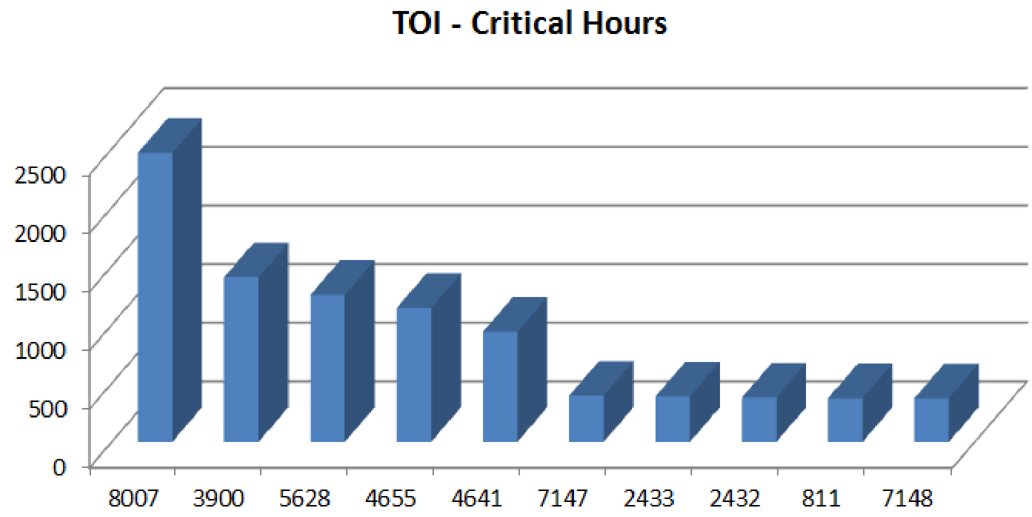


FIGURE 7-7: TOP TEN CRITICAL HOURS DUBLIN

7.1.2.2 SELECTION OF THE BEST REINFORCEMENT CANDIDATES FOR THE DUBLIN REGION

The method applied for determining the best reinforcements for the Dublin region to mitigate congestion issues is outlined in Section 7.1.1.1. The specific details of the methodology for the Dublin region are as follows:

- Based on the ranking of overloads and contingencies for the Dublin region using the contingency analysis snapshot results across an entire year, an initial set of 21 potential reinforcements is established. As previously explained (Section 7.1.1.1), the contingencies and the resulting overloads are ranked based on both magnitude and frequency of occurrence from the full year analysis.
- A new contingency analysis is then performed through the iterative based approach; one reinforcement from the set of 21 potential reinforcements is added at a time and the total overload index is calculated for each of these potential reinforcements. The reinforcement that reduces the total overload index most significantly is taken as the first choice to be applied.
- A similar procedure has been applied further in subsequent steps leading, for example, to the selection of the second reinforcement. The stopping criteria for the iterations is based on the TOI that is achieved; if the potential reinforcement's contribution to lower than TOI is less than a 20% reduction, or the magnitude of the TOI is smaller than 20, the reinforcement is not added and the iteration is stopped. This value of a 20% reduction (or TOI less than 20) was chosen due to the fact that there are a number of barriers related to the re-development of the Dublin 220 kV network and the fact that the Dublin 220 kV network is meshed with significant generation and load. Consequently, it has been deemed more appropriate to minimise the number of reinforcements, only investing in those which offer the greatest contribution to reducing overloads, and to focus on the use of operational mitigation measures to resolve the remaining congestion.

A list of the proposed circuits requiring reinforcement (see Table 7-1) to mitigate the congestions for the top ten critical hours are either circuits in the Dublin region or circuits that are directly impacting it. The list of reinforcements is given in Table 7-2 and all of the reinforcements proposed are related to the 220 kV network.

Table 7-1 illustrates that around 56 km of additional 220 kV circuits would be required to mitigate the congestions identified for the top ten critical hours. It should be pointed out that the proposed reinforcements will not eliminate all congestions and that remaining congestions would need to be mitigated through operational measures or innovative mitigation options, which will be discussed in a later section. While it is evident that these reinforcements have a positive impact on network congestion in the Dublin region, the planning process must have cognisance of the potential risks associated with relying on network reinforcements (cost, societal and environmental pressures and build times).

The effect of adding the proposed reinforcements is illustrated in Table 7-1 with the TOI calculated for the cases with:

- No reinforcements.
- With the top five reinforcements.
- With all seven proposed reinforcements.

The impact of these reinforcements on the TOI calculated for the critical hour 2432 is elaborated in the last two columns of Table 7-1 and shown in Figure 7-8.

TABLE 7-1: NETWORK REINFORCEMENTS IN DUBLIN PROPOSED FOR TOP CRITICAL HOURS

					Hour 2432	
STAGE	ID	Bus 1	Bus 2	Length[km]	TOI-before	TOI-After
FIRST	x1	1742	3122	11.5	379	254
SECOND	x3	3122	5122	1.3	254	134
THIRD	z3	4242	4462	4.5	134	91
FOURTH	c2	3522	66121	14.5	91	71
FIFTH	a1	4462	5022	0.12	71	56
SIXTH	z2	2563	4242	11.9	56	16.5
SEVENTH	x2	3082	3122	12.1	N/A	
…						

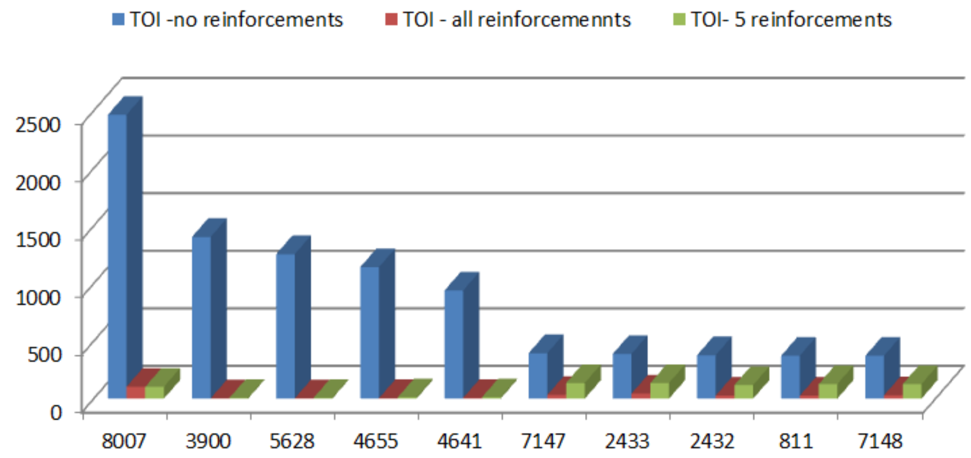


FIGURE 7-8: EFFECT OF PROPOSED REINFORCEMENTS ON TOI

TABLE 7-2: REINFORCEMENT MATRIX FOR THE DUBLIN REGION

Bus			Hours									
ID	Bus1	BUs2	8007	3900	5628	4655	4641	7147	2433	2432	811	7148
x1	1742	3122	x	x	x	x	x	x	x	x	x	x
x2	3082	3122										
x3	3122	5122	x	x	x	x	x	x	x	x	x	x
y1	2202	5202										
y2	1661	1821										
y3	2041	2042										
z1	1401	1661	x	x	x	x	x	x	x	x	x	x
z2	2563	4242	x	x	x	x	x	x	x	x	x	x
z3	4242	4462	x	x	x	x	x	x	x	x	x	x
t1	1641	2281										
t2	1742	5082										
t3	4041	4371										
c1	4472	17431										
c2	3522	66121	x	x	x	x	x	x	x	x	x	x
c3	2521	4981										
g1	1871	2571										
g2	4472	30820										
g3	1871	20411										
g4	5462	66121										
g5	1401	4041										
a1	4462	5022	x	x	x	x	x	x	x	x	x	x

7.1.2.3 LESS CRITICAL HOURS DUBLIN REGION

In terms of the less critical hours, a range of hour clusters has been selected to investigate the impact of the reinforcements given in Table 7-1. The clusters considered include:

- Upper mid-range cluster where the corresponding TOI before the reinforcements is between 350 and 300,
- Lower mid-range clusters with TOI before the reinforcements below 200.
- Lower range cluster with TOI before the reinforcements between 160 and 40.

The selected clusters are different sizes, with a different number of hours in each cluster.

The following conclusions can be drawn based on the results obtained for the upper mid-range cluster:

- A large majority of the hours from the upper mid-range cluster show a significant overload index reduction following the introduction of the 7 reinforcements identified in the previous section:
    - Inclusion of the first 5 reinforcements results in a 66% reduction in overload index.
    - Inclusion of all 7 reinforcements results in an 85% reduction in overload index. .
- There are a very small percentage of hours where the issue driving the overload is not located in the Dublin region. Thus, the addition of reinforcements in Dublin does not directly target the issue. Thus the proposed reinforcements have a smaller overall effect on those hours, achieving a reduction in the TOI of only 40% or less.

The following conclusions can be made for the lower mid-range cluster:

- For most of the hours in the lower mid-range cluster there is almost no difference between introducing 7 reinforcements and 5 reinforcements in terms of the overload index reduction.
- There are a small percentage of hours where the TOI is less than 20 which reveals that the Dublin area reinforcements alone may not be sufficient for the lower mid-range cluster and some other areas/overloads required further investigation.

The following conclusions can be made for the lower range cluster:

- The reinforcements have a significant impact on the most critical hours but the resulting shift of power flows might not be beneficial for the less critical hours and may actually amplify the severity of overloads if measured by the total overload index.

- The reinforcements appear to be very effective for approximately 30% of the lower range cluster hours, with modest improvement for all other hours.

The main conclusion is that using 7 of the proposed reinforcements in the 220 kV Dublin area would be quite effective for most of the hours in the upper mid-range cluster. However, operational mitigation measures are required based on analysis on the lower mid-range and lower range clusters where significant number of hours have a corresponding high TOI. Indeed, in situations where the lead times for network upgrades are excessive, or in areas where network upgrades are simply not possible for societal or environmental reasons, alternative operational measures or innovative mechanisms need to be considered. Some of these operational mitigation measures are now discussed. Other more innovative options are introduced in later sections.

7.1.3 RESULTS: OPERATIONAL MITIGATION MEASURES - DUBLIN REGION

This section presents results pertaining to investigation of the efficacy of the operational mitigation measures (outlined in section 7.1.1.2) in eliminating system overloads using PSCOPF. Simulations are performed for the different hour clusters defined in Section 7.1.2.3 for the intact network as well as for the contingencies causing overloads.

Similarly, for investigating the impacts of incorporating reinforcements, simulations are performed on the original network as well as with the 7 Dublin-area reinforcements (see Table 7-1) added.

7.1.3.1 OPERATIONAL MITIGATION MEASURES FOR CRITICAL HOURS – DUBLIN REGION, INTACT CASE

For this section, PSCOPF simulations are run to identify the operational mitigations required to eliminate system overloads for the intact case.

Both the original and reinforced versions of the network are considered for these simulations. For the reinforced version, the 7 reinforcements listed in Table 7-1 are considered. The results are presented in Table 7-3. The table lists the optimal number of load shifting locations, the minimum MW load shifting and number of PST angle adjustments required by the PSCOPF algorithm for removing violations for the intact case.

The resources used as part of the operational mitigation measures that are considered in the PSCOPF for addressing the issues encountered in Dublin are not only located in Dublin, but the algorithm makes use of other resources across the entire network. Additionally, in the case with reinforcements, it is important to note that these reinforcements are only those identified for the Dublin region. Thus, while the algorithm looks at the entire network, not all the network has been analysed for reinforcement requirements. This can lead to some unusual results, which will be highlighted and caveated.

The following are the main conclusions of the PSCOPF runs on the intact case for the critical hours cluster:

- A combination of load shifting and optimal adjustments of the PST angle are sufficient to remove all overloading violations for all critical hours under consideration without the need for any reinforcement. In fact, for hours 5628, 4655 and 4641, it can be observed from Table 7-3 that optimal adjustment of a single PST angle alone is sufficient to remove all overloading violations without resorting to load shifting/curtailment.
- With the seven reinforcements (as listed in Table 7-1) added to the intact case, it can be observed from Table 7-3 that the degree of control actions required by the PSCOPF algorithm to remove system violations decreases as compared to the no reinforcement results.

TABLE 7-3: PSCOPF RESULTS FOR CRITICAL HOURS CLUSTER – DUBLIN REGION, INTACT CASE

Hour	Without reinforcements			With 7 reinforcements		
	No. of load shifting locations	Total MW load shifted	No. of PST adjustments	No. of load shifting locations	Total MW load shifted	No. of PST adjustments
3900	5	278.7	1	0	0	0
5628	0	0	1	0	0	0
4655	0	0	1	0	0	0
4641	0	0	1	0	0	0
7147	8	519.2	1	0	0	1
2433	8	416.6	1	5	163.2	1
2432	7	393.9	1	1	48.2	1
811	8	319.3	1	0	0	1
7148	8	319.3	1	0	0	1

7.1.3.2 OPERATIONAL MITIGATION MEASURES FOR LESS CRTICIAL HOURS – DUBLIN REGION, INTACT CASE

This section investigates how successful the operational mitigation measures, and demonstrated using the PSCOPF tool, are in removing overloading violations associated with the upper mid-range, lower mid-range and lower range hour clusters (defined in Section 7.1.2.3). Both the original and reinforced versions of the power system are considered for these simulations. The focus is on the intact case.

Similar to the results for the critical hour cluster, simulations show that **a combination of load shifting and PST angle adjustment is sufficient for removing all overloading violations in the Dublin region for all clusters under consideration without the need for reinforcements**.

The minimum volume (MW) of load shifting[6] required for removing all overloading violations associated with the upper-mid, lower-mid and lower range hour clusters are presented in Figure 7-9, Figure 7-10 and Figure 7-11, respectively. The following are some important conclusions drawn from the figures:

- While the addition of the 7 reinforcements (refer to Table 7-10) helps to significantly reduce the MW load shifting associated with most hours from the upper-mid and lower range clusters, they do not offer much benefit when it comes to the lower-mid range cluster. This is in line with the findings from Section 7.1.2.3 where it was observed that the incorporation of the reinforcements does not significantly help in reducing the overload indices associated with the lower mid-range hours.

It is evident from Figure 7-9, Figure 7-10 and Figure 7-11 that power evacuation and consequently loading of the network components might be significantly different from one hour to the next. As mentioned in Section 7.1.1, this shows that both power system operation and planning departments will have to work closely together to determine the most efficient way in tackling overloads in a cost effective manner.

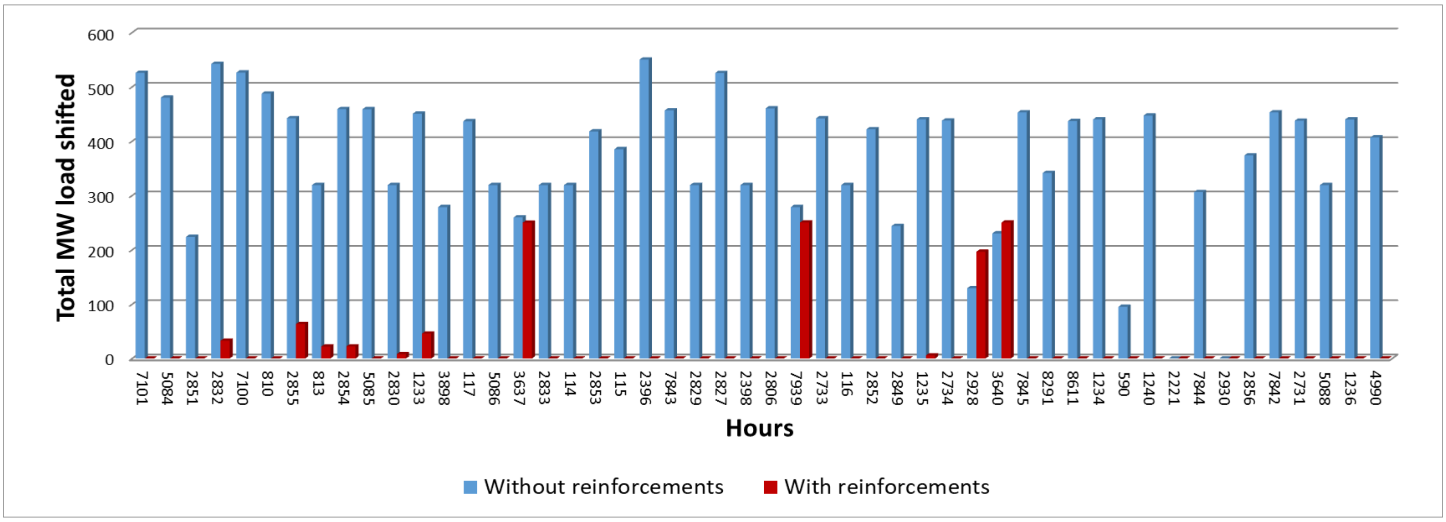


FIGURE 7-9: TOTAL MW LOAD SHIFTING UNDER THE UPPER-MID RANGE HOUR CLUSTER – DUBLIN REGION, INTACT CASE

[6] In this context, as a result of the fact that the approach focuses on individual hours, strictly speaking this is load-shedding. However, in reality, and as will be demonstrated in later sections, load-shifting across the day is the preferred mechanism.

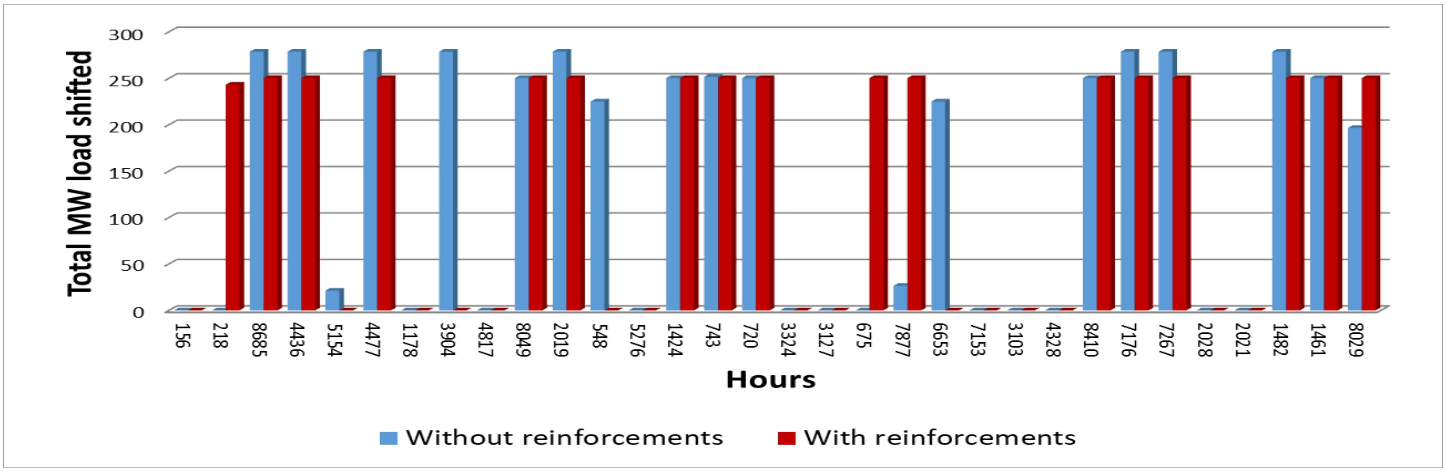


FIGURE 7-10: TOTAL MW LOAD SHIFTING UNDER THE LOWER-MID RANGE HOUR CLUSTER – DUBLIN REGION, INTACT CASE

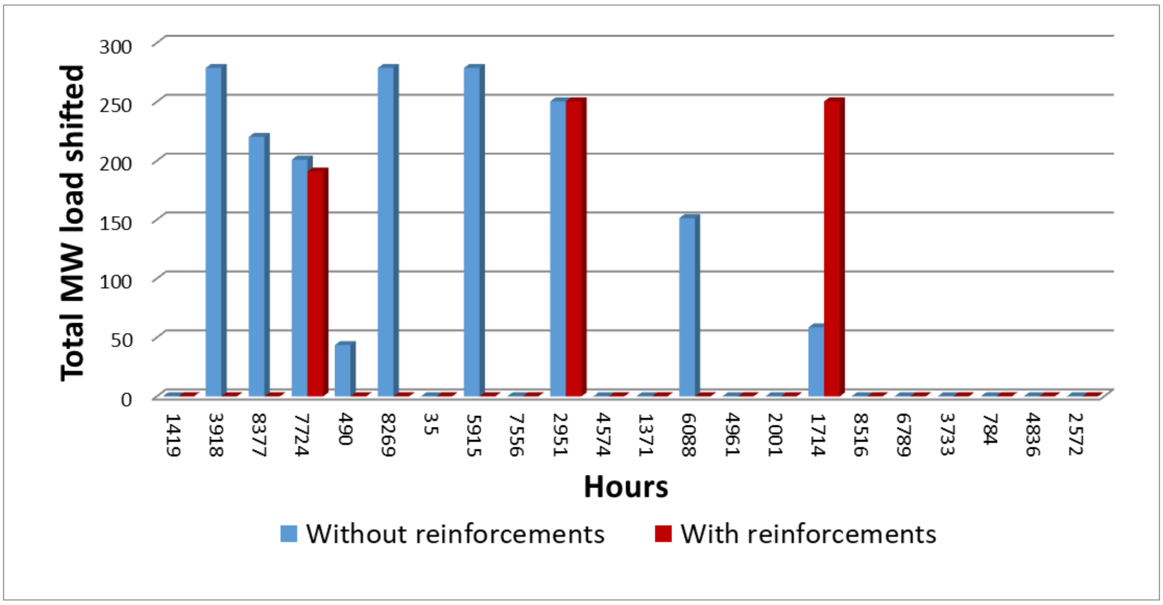


FIGURE 7-11: TOTAL MW LOAD SHIFTING UNDER THE LOWER RANGE HOUR CLUSTER – DUBLIN REGION, INTACT CASE

7.1.3.3 OPERATIONAL MITIGATION MEASURES FOR CRITICAL HOURS – DUBLIN REGION, CONTINGENCY CASE

This section presents the results related to the implementation of operational mitigation using PSCOPF simulations conducted for the critical hours cluster (refer to Section 7.1.2.1) but with contingencies considered. For each overloaded line in the network, the worst contingencies contributing to the overloads are determined and included in the list of active contingencies to be simulated in the PSCOPF run for the particular hour under consideration.

Comparing this to the intact case discussed in the preceding sections, the corresponding constraint optimisation space here is significantly larger and more complex and the use of master-slave optimisation based on the Bender's decomposition (refer to Section 7.1.1.2) is required [44].

With reference to the results presented in this section, a combination of the following 6 control actions are utilised by the optimisation tool for removing line overloading violations in the system:

- Load shifting
- Generation re-dispatch
- PST angle adjustments
- Tap changer adjustments
- Switching on offline generators
- Switched shunt controls.

The PSCOPF outputs associated with the system without and with 7 reinforcements (refer to Table 7-1) incorporated are summarised in Table 7-4 and Table 7-5, respectively. The following quantities are reported in the tables:

- Total MW load shifted (Load-shifting)
- Total positive and negative generation re-dispatches (MW) (Generation re-dispatch)
- Total wind generation constrained (MW) (Generation re-dispatch)
- Optimal number of PST angle adjustments carried out by PSCOPF for removing overloading violations (PST angle adjustments).

In the event that the optimisation algorithm is able to successfully remove all overloading violations using the six control actions listed above, the same is recorded in the column titled 'Feasible?'[7] in Table 7-4 and Table 7-5.

As observed from Table 7-4 the PSCOPF optimisation tool is successful in removing all overloading violations for 6 out of 10 hours considered in the critical cluster through a combination of the control actions listed above[8]. In other words, for hours when PSCOPF is successful, the solution facilitates the removal of all overloading issues for the intact case as well as for any contingency occurring from the list of contingencies considered for the

[7] If there is no feasible solution, the results related to load shifting, wind generation constrained and generation adjustments would need to be taken with caution. They can be only interpreted in terms of how difficult it was for the optimisation tool to get to the optimal solution –other conclusions should not be drawn from these tables for the infeasible cases.

[8] Note that only three operational mitigations – load shifting, generation re-dispatch and PST adjustments – are listed in the table for the sake of brevity.

simulations. The 'success rate' of PSCOPF is therefore defined as the ratio of hours where the algorithm is successful in removing all system violations to the total number of hours associated with the particular cluster. The success rate for the critical hours cluster without reinforcements is therefore calculated at 60% from Table 7-4.

TABLE 7-4: PSCOPF RESULTS FOR CRITICAL HOURS WITHOUT REINFORCEMENTS – DUBLIN REGION, CONTINGENCY CASE

Hour	Total MW load shifted	Total positive generation adjustment (MW)	Total negative generation adjustment (MW)	Total wind generation constrained (MW)	No. of PST angle adjustments	Feasible?
8007	0	642.6	-691.7	691.7	1	YES
3900	0	696.4	-704.6	704.6	1	YES
5628	0	248	-283.7	283.7	1	YES
4655	0	945	-1000.9	149	1	YES
4641	19.9	775	-924.5	114.5	1	YES
7147	16.5	1268.7	-1275	1033.3	1	NO
2433	459.4	1212.5	-1704.2	1565.2	1	NO
2432	339	1114.3	-1482.9	1383.5	1	NO
811	299.2	1383.2	-1658	1475.5	1	YES
7148	205.3	1232.3	-1410.1	1183.6	1	NO

The addition of 7 reinforcements to the critical hours cluster helps to improve the success rate of PSCOPF from 60% to 80% as observed from Table 7-5. It can also be seen from the table that the addition of reinforcements for hour 5628 eliminates all overloading violations under both intact as well as contingency cases without the need of any control action to be implemented by the optimisation tool. Finally, it can be seen from Table 7-5 that the different control quantities presented are mostly lower than the corresponding values in Table 7-4 without reinforcements. There are still hours however where wind generation is required to be constrained and this could be in excess of 900 MW. The load that needs to be shifted is not higher than 100 MW for any of the hours shown in Table 7-5 which shows that the wind generation is the main driver for these overloads and that demand shifting, which is rather efficient for the intact case, might not be that efficient when it comes to the consideration of the contingencies. It should be noted that the levels of wind constrained in Table 7-4 and Table 7-5 are quite high and this is one of the unusual results that needs to be caveated here. These high values are due to the fact that no reinforcements have been applied in the North West region (NW) for this scenario, as the focus is the Dublin region, and the fact that the PSCOPF algorithm looks at the entire transmission network. The NW region has significantly high geographically distributed RES densities and is electrically distant from load centres. Results which will be presented in section 7.1.5.1 will show that the levels of wind constrained in the system is substantially lower with the additional reinforcements in the NW included.

TABLE 7-5: PSCOPF RESULTS FOR CRITICAL HOURS WITH REINFORCEMENTS – DUBLIN REGION, CONTINGENCY CASE

Hour	Total MW load shifted	Total positive generation adjustment (MW)	Total negative generation adjustment (MW)	Total wind generation constrained (MW)	No. of PST angle adjustments	Feasible?
8007	0	683.6	-758.1	758.1	1	YES
3900	0	217.1	-238.2	238.2	1	YES
5628	0	0	0	0	0	YES
4655	0	305.3	-287.5	2.4	1	YES
4641	16.3	847.1	-964	30.9	1	YES
7147	137	1216.2	-1319.8	1102.7	1	NO
2433	79.1	1126.9	-1246.4	1155.7	1	YES
2432	96.4	985.4	-990.8	951.2	1	YES
811	85.7	943.4	-929.4	929.4	1	YES
7148	61	1209.9	-1275.4	1018.8	1	NO

7.1.3.4 OPERATIONAL MITIGATION MEASURES FOR LESS CRITICAL HOURS – DUBLIN REGION, CONTINGENCY CASE

This section presents the results of the implementation of operational measures in relation to PSCOPF simulations conducted for the remaining less critical hour clusters (i.e. upper-mid, lower-mid and lower ranges, refer to Section 7.1.2.3) and with contingencies considered. Similar to the results for contingencies for the critical hour cluster simulations, only the worst contingencies contributing to the overload on a given line and for a given hour are determined and included in the list of active contingencies to be simulated in the PSCOPF for this section. The PSCOPF algorithm has (as before) 6 control options – load shifting, generation re-dispatch, PST angle and tap changer adjustments, off-line generators and switched shunt controls – that can be used for removing system overloading violations.

The total MW wind generation constrained for the different hour clusters and for the system without and with the 7 reinforcements (refer to Table 7-1) added are presented in:

- Figure 7-12– for upper mid-range cluster
- Figure 7-13- for lower mid-range cluster
- Figure 7-14 - for lower range cluster

Again it needs to be recognised that these high wind constraint values are due to the fact that reinforcements in the NW region are not considered in this part of the analysis.

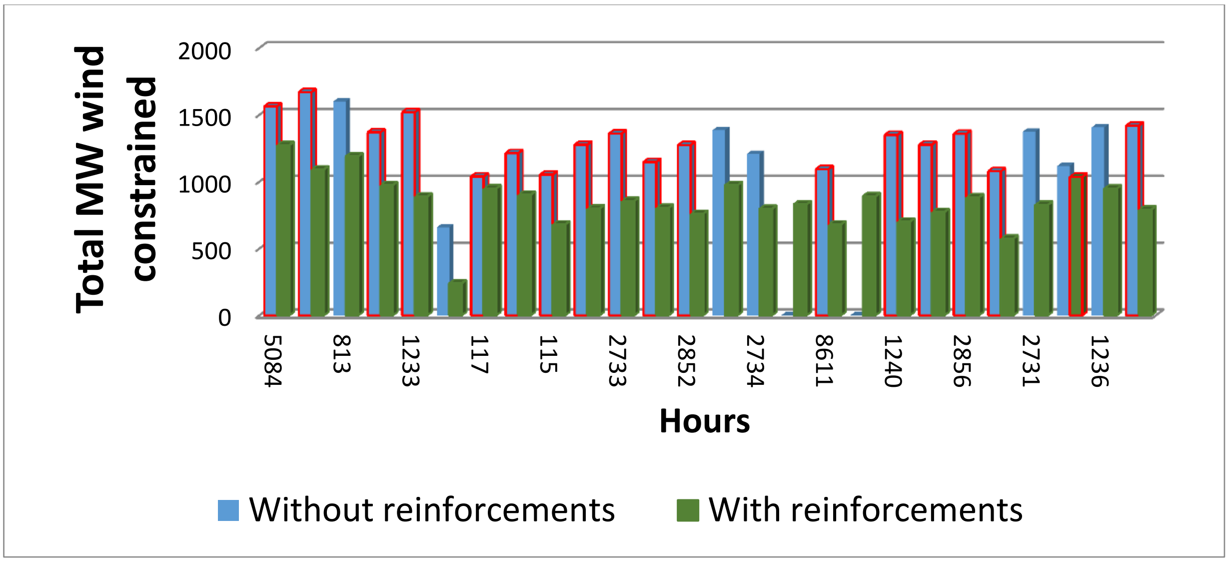


FIGURE 7-12: TOTAL MW WIND ACROSS THE ENTIRE POWER SYSTEM CONSTRAINED UNDER THE UPPER-MID RANGE HOUR CLUSTER – DUBLIN REGION, CONTINGENCY CASE

Similar to the results presented in the previous section, there are several hours under the upper-mid, lower-mid and lower range clusters when the PSCOPF output is infeasible, i.e., the optimisation algorithm is unsuccessful in eliminating all overloading violations even after using all 6 control actions at its disposal. The results presented in Figure 7-12- Figure 7-14 pertain to only those hours where at least one of the two PSCOPF solutions (i.e., for the system without or with reinforcements added) is feasible. For hours when one of the two PSCOPF solutions is infeasible, the corresponding bar in the figures is outlined in red. **The first observation from the figures is that the incorporation of reinforcements leads to a marked reduction in the number of hours associated with infeasible PSCOPF outputs across all clusters** (and particularly for the upper-mid range cluster) under consideration.

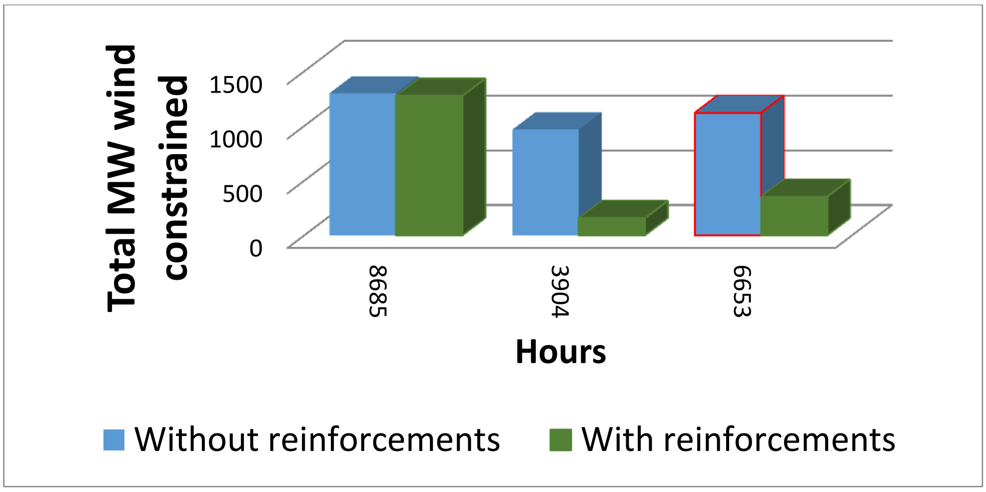


FIGURE 7-13: TOTAL MW WIND CONSTRAINED ACROSS THE ENTIRE POWER SYSTEM UNDER THE LOWER-MID RANGE HOUR CLUSTER – DUBLIN REGION, CONTINGENCY CASE

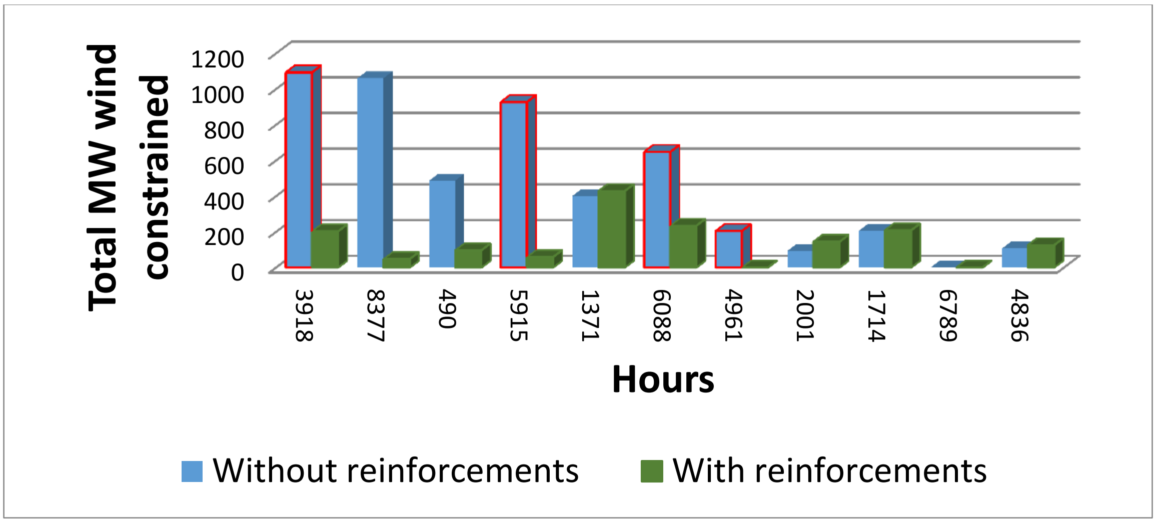


FIGURE 7-14: TOTAL MW WIND CONSTRAINED ACROSS THE ENTIRE POWER SYSTEM UNDER THE LOWER RANGE HOUR CLUSTER – DUBLIN REGION, CONTINGENCY CASE

It can be observed from Figure 7-12- Figure 7-14 that the average MW wind constrained steadily decreases from the upper-mid to the lower-mid and then to the lower range hour cluster. Considering only those hours where the PSCOPF solutions both without and with reinforcements added are feasible, it can be seen that the incorporation of reinforcements helps to significantly reduce the total MW wind constrained for all concerned hours under the upper-mid range cluster. However, for the lower-mid (Figure 7-13 and lower Figure 7-14) range clusters, there is not much reduction in the total MW wind constrained after the implementation of reinforcements. In fact, it can be seen from Figure 7-14 that the wind constrained with reinforcements added is higher than the corresponding value without reinforcements for several hours under the lower range cluster. This is in line with the observations from Section 7.1.2.3 where it was noted that the incorporation of reinforcements do not cause any significant reduction in the overload indices for the lower-mid and lower range hour clusters. Thus, it can clearly be seen that reinforcements are not the solution to all congestion related issues, and alternative mitigation mechanisms also need to be seriously considered.

Additionally, in terms of load shifting required by the PSCOPF algorithm for removing overloading violations, it was observed from the simulations that the introduction of reinforcements helps to significantly reduce the MW load shifted for all three clusters under consideration.

7.1.4 RESULTS: NETWORK REINFORCEMENTS – NORTH-WEST REGION

The results presented in this section focus on the overload index that is calculated for the North-West region of Ireland. Only the overloads identified in the North-West region are accounted for through the respective contingency analyses below.

This section is split into three segments focusing on:

- The top ten critical hours with respect to the Total Overload Index (TOI) calculated for all 8760 hours.
- The selection of the best reinforcement candidates for the top ten critical hours.
- The impact of the selected reinforcements on the less critical hours.

7.1.4.1 TOP TEN CRICIAL HOURS FOR THE NORTH-WEST REGION

The most critical hours for the North-West region in terms of the congestions that are identified from the contingency analysis of the full year (8760 hours) are shown in Figure 7-15 below. It can be seen that the top 10 critical hours have an overload index between 70 and 90.

The impact of reinforcing the North-West region is minor compared to the Dublin region based on the influence it has on the total overload index. Congestions in the North-West region are mainly observed on the 110 kV network used specifically for wind power evacuation, while the Dublin region network is more meshed and congestions are mainly witnessed on the 220 kV network.

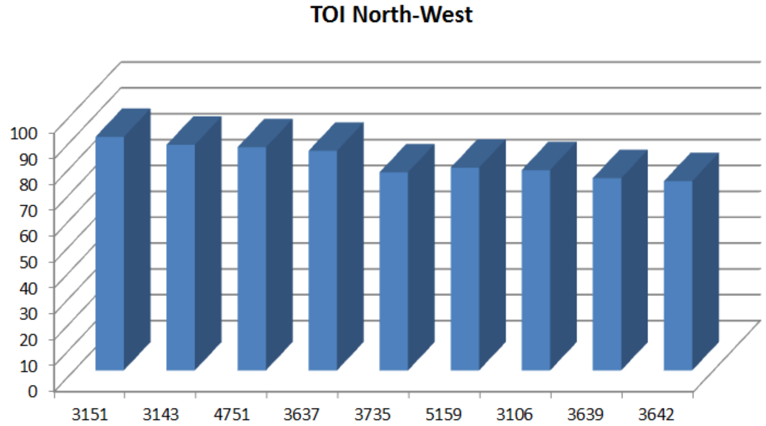


FIGURE 7-15: TOTAL OVERLOAD INDEX CALCULATED FOR THE NORTH WEST REGION -CRITICAL HOURS

7.1.4.2 SELECTION OF THE BEST REINFORCEMENT CANDIDATES FOR THE NORTH WEST REGION

The approach for reinforcement selection, which was previously illustrated in Figure 7-5, is applied here for the North-West region:

- Based on the ranking of overloads and contingencies for the North West region using the contingency analysis snapshot results across an entire year, an initial set of 20 potential reinforcements is established. As previously explained, the contingencies and the resulting overloads are ranked based on both magnitude and frequency of occurrence from the full year analysis.

- A new contingency analysis is then performed through the iterative based approach; by one reinforcement from the set of 20 potential reinforcements is added at a time and the total overload index is calculated for each of these potential reinforcements. The reinforcement that reduces the total overload index most significantly is taken as the first choice to be applied. For example, Table 7-6 indicates that the reinforcement n1 (between bus 1661 and 1821) reduces the total overload index for hour 3151 from 87 to 66.5 (a 23.7% reduction). None of the other potential reinforcements were as successful as reinforcement n1 in terms of the total overload index reduction.
- A similar procedure has been applied further in subsequent steps leading, for example, to the selection of the second reinforcement (n2) with an achieved reduction of 31.8%, while a third reinforcement (n16) leads to a cumulative reduction of 21.5%. The stopping criteria for the iterations is based on the TOI that is achieved; if the potential reinforcement's contribution to lower than TOI is less than a 10% reduction, the reinforcement is not added and the iteration is stopped.

To illustrate the result of the approach for the selection of the reinforcements for the North-West, the most critical hour 3151 is chosen, with a TOI of 87, and the results are shown in Table 7-6 below.

TABLE 7-6: SUMMARISED REINFORCEMENTS FOR THE MOST CRITICAL HOUR 3151

Stage	Reinforcement ID	Bus1	Bus2	Initial Index	Improved Index	Improvement % Total Index
FIRST	n1	1661	1821	87	66.5	23.7
SECOND	n2	1401	1661	66.5	45.4	31.8
THIRD	n16	3581	28019	45.4	35.6	21.5
FORTH	n5	2521	4981	35.6	29	18.53
FIFTH	n20	1701	5041	29	24	17
…						

The reinforcement methodology outlined above is applied to all 10 critical hours identified for the North -West region. The reinforcement results are summarised in Table 7-7 below. The approach demonstrates that for most of the 10 critical hours the TOI can be reduced to below 10. The approach was not successful for the hour 4751 and less successful for the hours 5159 and 3639. This is a result of the application of the stopping criteria, which dictates that only reinforcements that are having a positive contribution to the reduction in the total overload index (i.e. more than a 10% reduction) are considered.

The reinforcement matrix that outlines the results of the applied reinforcement approach to all critical hours is given in Table 7-7 and shown in Figure 7-16.

TABLE 7-7: REINFORCEMENT MATRIX FOR THE NORTH-WEST REGION

	Bus		Hours									
ID	Bus1	BUs2	3151	3143	4751	3637	3735	5159	3106	3639	3642	3141
n1	1661	1821	x	x	x	x	x	x	x	x	x	x
n2	1401	1661	x	x		x	x	x	x	x	x	x
n3	1641	2281					x					
n4	4041	4371					x					
n5	2521	4981	x	x		x	x	x	x	x	x	x
n6	1401	4041										
n7	1661	2281					x					
n8	1931	4371					x					
n9	1931	4981										
n10	3501	4001	x	x		x	x		x		x	x
n11	2321	28710			x							
n12	2870	17010										
n13	1701	28712	x	x		x	x		x	x	x	x
n14	3501	66094	x	x		x			x		x	x
n15	1861	10619										
n16	3581	28019	x	x		x		x	x	x	x	x
n17	1631	10619										
n18	2521	66094	x	x							x	x
n19	5041	17010							x	x	x	x
n20	1701	5041	x	x		x						

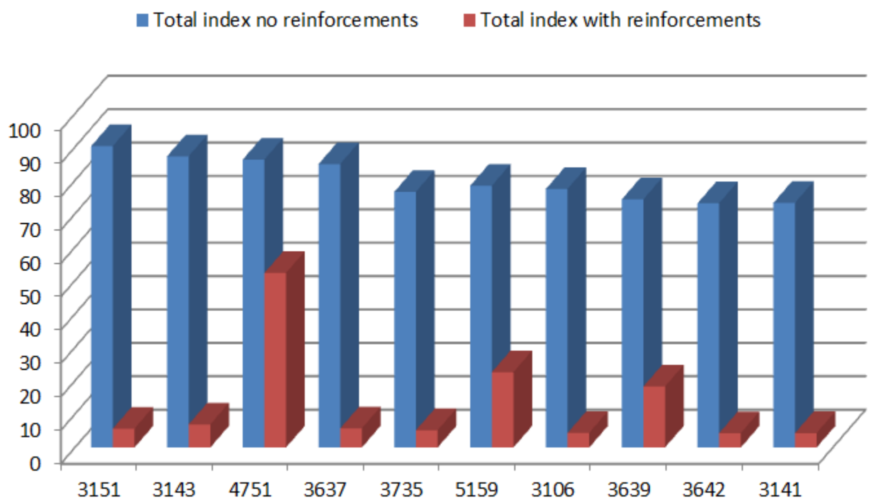


FIGURE 7-16: REINFORCEMENT APPROACH APPLIED TO ALL CRITICAL HOURS FOR THE NORTH-WEST REGION

The following conclusions can be drawn:

- The rows in the matrix related to the reinforcements n1, n2, n5, n10, n13, n14 and n16 are densely populated which means that these reinforcements work well for most of the critical hours.
- The reinforcements n6, n9, n12, n15 and n17 should not be further considered in the reinforcement approach due to the fact that their contribution in terms of reducing the total overload index was less than 10%. .
- It is expected that 9 reinforcements might be required in the North-West region to deal with the congestions issues there.
- If the 9 reinforcements applied to the most critical hour 3151 were applied as per Table 7-8 with a total length of almost 340 km of additional 110 kV circuits to all of the critical hours, the congestion issues would be resolved for all but one of the critical hours.
- While it is evident that these reinforcements can have a positive impact on network congestion in the North West region, the planning process must have cognisance of the significant potential risks associated with relying on network reinforcements (cost, societal and environmental pressures and build times), particularly given the significant length of additional circuits that is being proposed here.

TABLE 7-8: NINE SELECTED REINFORCMENTS FOR THE CRITICAL HOUR 3151

ID	Bus1	BUs2	Circuit length[km]
n1	1661	1821	57
n2	1401	1661	37
n5	2521	4981	50
n10	3501	4001	46
n13	1701	28712	26
n14	3501	66094	9
n16	3581	28019	38
n18	2521	66094	22
n20	1701	5041	53

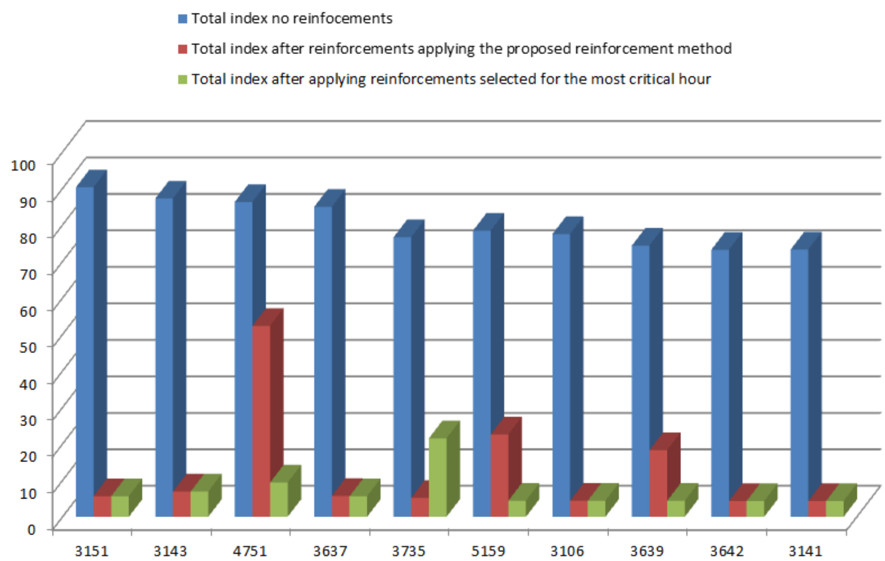


FIGURE 7-17: IMPACT OF REINFORCEMENTS

7.1.4.3 LESS CRITICAL HOURS NORTH-WEST REGION

The mitigations options that appear to be efficient for the critical hours may not be as effective for the less critical hours). To investigate this further a number of these less critical hours for the North-West region were selected. These hours had a TOI varying between 72 and 10. To assess the impact of the proposed reinforcements, the 9 reinforcements identified for the most critical hour 3151 are included. The results presented in Figure 7-18 demonstrate that:

- The proposed reinforcements for the most critical hours works exceptionally well on the selected less critical hours. This is indicated by the significant decrease in the Total Overload Index with (green bars in the histogram) and without reinforcements (blue bars in the histogram)
- There are 5 hours out the 10 hours where the overloads are completely eliminated. For the remaining hours, operational mitigations measures would need to be adopted. Thus, it can be seen that reinforcements are not the solution to every congestion related issue, and alternative mitigation mechanisms also need to be seriously considered. The potential for utilising operational mitigation measures are demonstrated for the North-West region in the next section.

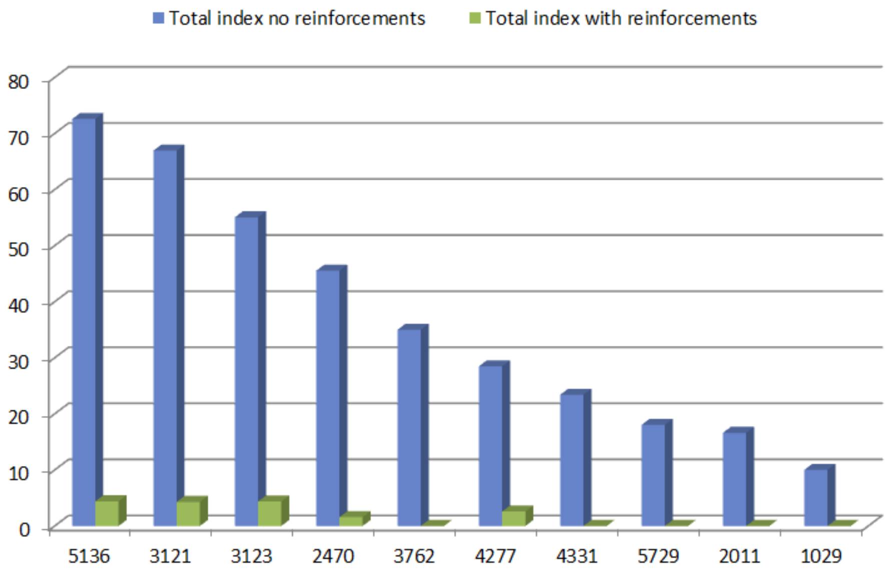


FIGURE 7-18: LESS CRITICAL HOURS ANALYSIS

7.1.5 RESULTS: OPERATIONAL MITIGATION MEASURES - NORTH WEST REGION

This section presents the results related to the investigation of using the operational mitigation measures discussed in Section 7.1.1.2 to eliminate hourly network congestions occurring in the North-West region of Ireland. This section builds upon the analyses carried out on the network reinforcements for the critical hours in the North West region.

7.1.5.1 OPERATIONAL MITIGATION MEASURES FOR CRITICAL HOURS FOR THE NORTH-WEST REGION

For this section, 2 sets of PSCOPF simulations are performed on the network with and without the selected 9 proposed reinforcements for the critical hour for the North-West region of Ireland. The following are considered for the PSCOPF simulations:

- Only lines from the North-West region are monitored for potential overloads;
- PSCOPF has the following control actions available for use for removing potential network congestions: load shifting, generation re-dispatch, bringing off-line generators online, and using a combination of phase shifting transformers (PST), switched shunts and tap changers.

As was the case with the Dublin region, it is important to remember that the resources used as part of the operational mitigation measures that are considered in the PSCOPF for addressing the issues in the NW region are not only located in the NW, but the algorithm makes use of other resources across the entire network. Thus, while the algorithm looks at the entire network, not all the network has been analysed for reinforcement requirements.

A preliminary set of simulations are run for the intact case (i.e., with no contingencies being considered) and it is observed that most critical hours do not experience any overloading violations as a result of the investments in reinforcements, hence no corrective actions are required from PSCOPF for such hours. For critical hours which do encounter congestions for the intact case, the congestion can be successfully removed using PST adjustments only.

The simulations are repeated for all contingencies causing one or more overloads in the North-West region being considered (over and above the intact case). The total wind generation constrained (with and without the corresponding 9 reinforcements – see Table 7-8) as the result of the optimisation procedure is presented in Figure 7-19. As can be seen the levels of wind constrained are significantly lower when the North-West region is considered in isolation, in comparison to when the Dublin region is considered in isolation.

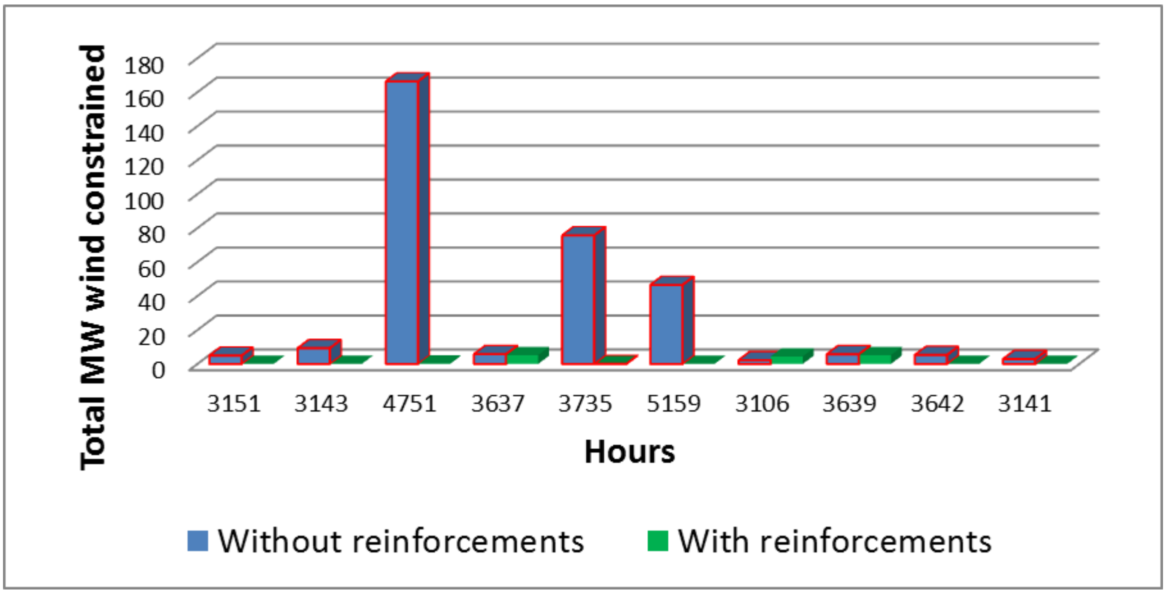


FIGURE 7-19: TOTAL RES CONSTRAINED ACROSS THE ENTIRE POWER SYSTEM UNDER CRITICAL HOUR CLUSTER (NORTH-WEST REGION, CONTINGENCY CASE)

It is indicated in Figure 7-19 (by the bar edge in red) that PSCOPF would not be successful in terms of eliminating all congestions for these critical hours without the proposed 9 reinforcements. The success rate of the PSCOPF tool (i.e., the percentage of hours when the optimisation algorithm can completely remove all congestions with respect to the total number of hours associated with the concerned cluster) is practically zero for the critical hours in the absence of reinforcements. It has been shown that a number of overloads can be removed using wind constraints alone. However, constraining wind alone is not capable of removing all the overloads for even a single critical hour. This indicates that, given the mitigations available in this analysis, the only option for successfully eliminating (or at the very least reducing) overloads for the North-West region is to invest in network reinforcement. However, with the 9 reinforcements added as per Table 7-8, the success rate increases to 90%. This means that PSCOPF can remove all network overloads using the control actions at its disposal for 9 out of 10 critical hours under consideration.

The optimisation studies indicate that in the presence of contingencies, load shifting might not be supportive in eliminating constraints for the North-West region of Ireland simply because power evacuation of the RES generation is the key driver for the 110 kV line loadings in this region. Similarly, the incorporation of the proposed reinforcements causes a significant reduction in the total MW RES (wind) constrained for most critical hours under consideration. As mentioned earlier, the right balance between the reinforcements and operational measures needs to be considered through the respective cost-benefit analyses and societal acceptable that are out of context of this project. For example, having just five instead of the proposed nine reinforcements would significantly reduce the network development costs however the need to reduce the output of wind generation to mitigate the congestion would be greater than presented in Figure 7-19.

7.1.5.2 OPERATIONAL MITIGATION MEASURES FOR LESS CRITICAL HOURS FOR THE NORTH-WEST REGION

Similar PSCOPF simulations are performed for 10 additional non-critical hours. These hours have been already identified for the purposes of the reinforcement work in Section 7.1.4.3.

Similarly to the preceding section, a preliminary set of simulations are run for the intact case. No corrective actions from PSCOPF are required for nine out of ten hours without reinforcements and all ten hours with reinforcements incorporated owing to the base case network being lightly-loaded. Only one hour without reinforcements needs some PST adjustments for removing associated network congestions.

Figure 7-20 presents the total MW RES constrained with contingencies incorporated for the ten non-critical hours with and without considering reinforcements. Hours when the optimisation algorithm is infeasible are outlined in red (bar edges in red) in the figure. It can be seen from Figure 7-20 that the incorporation of reinforcements facilitates the improvement of the PSCOPF success rate from 0% (all less critical hours are infeasible – congestions are not completely eliminated) to 100%. Similar to the critical hour simulations in the presence of contingencies, load shifting appears to have very limited effect on the north-west congestions. Finally, the incorporation of the reinforcements shown Table 7-8 reduces significantly the total RES constrained to zero for all 10 non-critical hours under consideration.

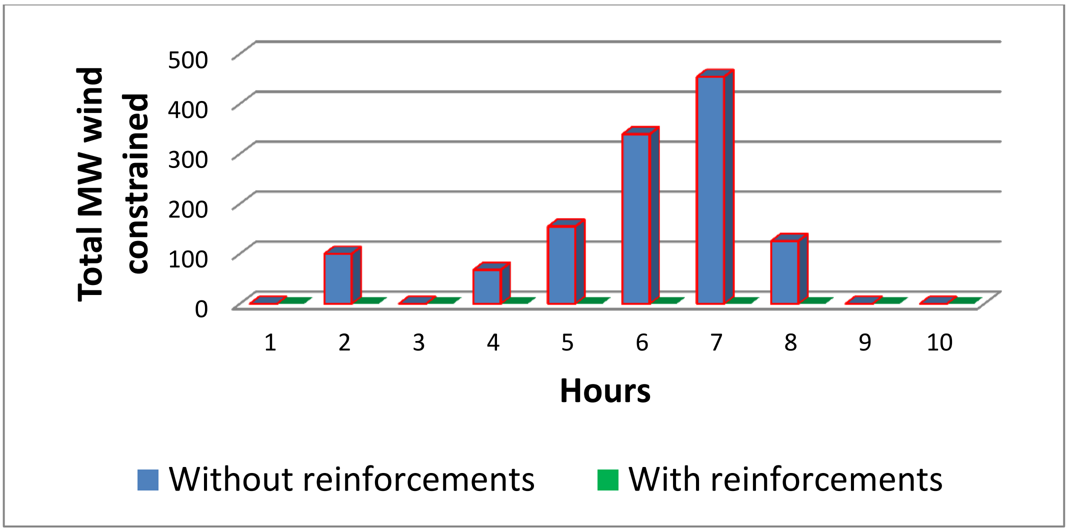


FIGURE 7-20: TOTAL MW WIND CONSTRAINED ACROSS THE ENTIRE POWER SYSTEM UNDER NON-CRITICAL HOUR CLUSTER (NORTH-WEST REGION, CONTINGENCY CASE)

7.1.6 RESULTS: INVESTIGATING IMPACTS OF INCORPORATING SMART POWER FLOW CONTROL DEVICES FOR MANAGING CONGESTION

As an alternative to using PSCOPF optimisation as an operational mitigation measure this section presents results from a 'proof-of-concept' study conducted for investigating the use of smart power flow control devices that can change the flows through a line (thereby potentially removing overloading violations). The focus here is on the active power flows that can be decreased by decreasing the angle shift between the adjacent ends or increasing the line reactance.

It is well known that the reactance of the line is inversely proportional to the active power flows on it. Determining the impacts of changing line reactances (using smart power flow control devices) on the resulting overload index values associated with the different hour clusters (refer to Section7.1.2.1) is the main objective of this section. The following considerations were used for performing the simulations:

- Maximum line loading thresholds are assumed to be 100% of their nominal ratings,
- Only lines from the Dublin area are being monitored for potential overloads and all 7 reinforcements (refer to Table 7-1) are being considered.

Contingency analysis was run on the 'base case network' associated with the above considerations, and all lines experiencing overloading were selected as candidates for having their reactance values adjusted. As already outlined above, an approximate formula for computing line active power flows can be expressed as:

$$P_{ij} = (\delta_i - \delta_j)/X_{ij} \quad \text{(Eq. 7-1)}$$

For line i-j between buses *i* and *j*, variables P_{ij}, δ_i, δ_j and X_{ij} in Equation (1) respectively represent the active power flow (pu) through line i-j, the voltage angle (radians) for bus i, the voltage angle (radians) for bus j, and the reactance (pu) for line i-j. It can therefore be appreciated from Equation (1) that reactance X_{ij} needs to be incrementally increased to reduce P_{ij}, i.e., for alleviating the overload in line i-j.

A simplified algorithm was applied here focusing on changing line reactances to mitigate overloads. It should be pointed that this is not the optimal placement methodology for determining where/how the smart power flow control devices should be integrated in the network. For all lines experiencing overloading in the base case network, their reactances were increased in the following range: 5%, 10%, 15% and 20% over and above their base case values.

Contingency simulations were repeated with the networks with adjusted reactance values and the highest overloads encountered for each hour under all clusters were recorded. The average reduction (in % terms) in the highest overload values by increasing reactances from 0%-5%, 5%-10%, 10%-15% and 15%-20% are reported in Table 7-9 for the different hour clusters under consideration. It can be observed from the table that for every 5% increase in the reactance values, a very nominal reduction (ranging from 1.11% - 2.52%) in the highest overload is recorded on an average across all 4 hour clusters. It can also be observed that for any given cluster, the higher the increase in the reactance, the lower the corresponding benefit (in terms of reduction of highest overload) obtained.

TABLE 7-9: IMPACTS OF LINE REACTANCE ON HIGHEST OVERLOAD UNDER DIFFERENT CLUSTERS

Hour clusters	Average reduction in highest overload (%)			
	5% higher X	10% higher X	15% higher X	20% higher X
Critical	2.13	2.08	1.91	1.51
Upper medium	2.52	2.15	2.05	1.9
Lower medium	1.65	1.41	1.36	1.33
Lower	1.24	1.15	1.13	1.11

The average overload indices (pu) recorded from the contingency analysis runs conducted on the base case network as well as with line reactances adjusted according to the previously defined ranges are presented in Figure 7-21 for all four hour clusters under consideration. It can be observed from the figure that while the increase in reactances produces a noticeable reduction in the overload indices for the critical (from 55.45 for the base case to 39.37 for the 20% higher reactance setting) and upper medium cluster (from 84.77 for the base case to 60.08 for the 20% higher reactance setting), the reduction is much more modest for the lower medium and lower clusters. This is because for the lower medium and lower clusters, while the number of overloads are lower than the critical and upper medium clusters, the degree to which each line is overloaded (in %) is much higher than 100%. With reference to the conclusions arrived at from Table 7-9 it can therefore be concluded that while increasing reactances for the lower medium and lower clusters helps to nominally reduce the degree of overloads, it cannot completely remove the overloads and in turn bring about a substantial reduction in the overload indices.

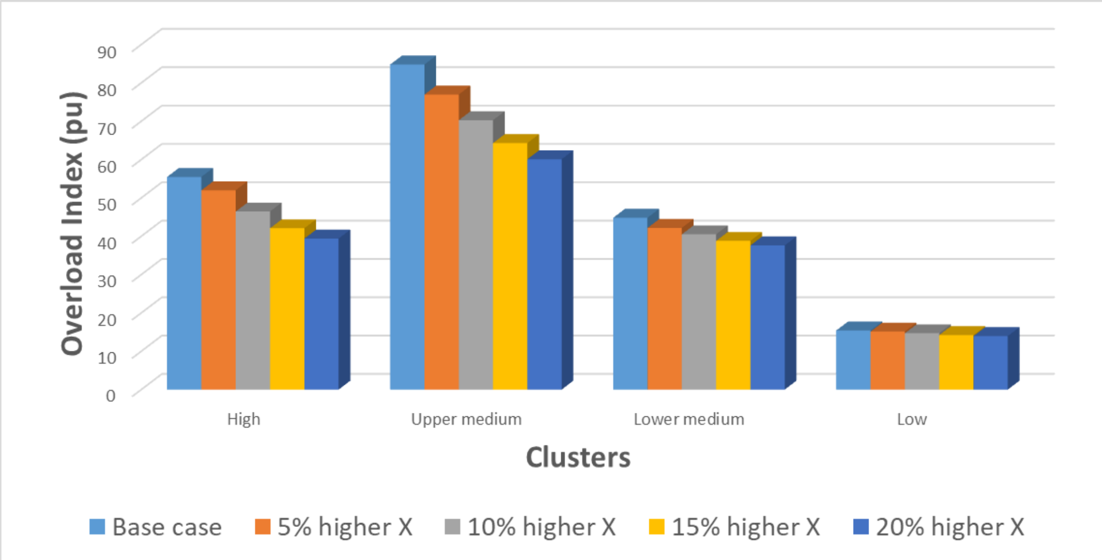


FIGURE 7-21: IMPACTS OF LINE REACTANCE ON OVERLOAD INDICES UNDER DIFFERENT CLUSTERS

In comparison, for the critical and upper medium clusters, while the number of overloads is higher than the other two clusters, there are some lines associated with overloads of just 101% - 103% which can be completely removed by increasing the corresponding reactances. This therefore brings about a noticeable reduction in the overload indices for the critical and upper medium clusters.

The overarching conclusion from the studies presented in this section is that while increasing line reactances (using smart power flow control devices) to up to 20% of their nominal values can bring about a modest reduction in the degree of overloads, power flow control devices alone are not sufficient to completely remove overloading violations for lines. However, it is noted that power flow control devices can be used as a single mitigation for modestly overloaded lines.

Another important thing to note is that increasing reactances of selected lines changes the resultant power flow, which can in turn cause new overloads due to a change of network reactances and consequently power shift. Increasing line reactances alone is therefore not a robust mitigation strategy that should be solely relied on in terms of completely removing overloading violations. However, in conjunction with other mechanisms, it could be a useful option for supporting the mitigation of congestion.

The results presented in this section correspond to only the selected hours from the four clusters under consideration. A complete yearly (i.e., 8760 hourly) contingency analysis run would need to be performed to get a better picture of the extent to which increasing line reactances can help in mitigating overloading violations. Also, as mentioned before, only those lines that were overloaded under the base case contingency analysis were selected as potential sites for installing the smart power flow control devices. Using more robust optimisation packages which can quickly compute the optimal siting of these smart devices for maximising the reduction of overloading violations may need to be considered in the future.

Reinforcing critical network segments, where economically feasible, and incorporating operational mitigations therefore still remain reliable mitigation strategies for removing overloading violations. However, in many instances it may not be environmentally and/or socially acceptable to do so, or the lead times for upgrading the network may be considerable. Therefore, alternative options need to be seriously considered. Increasing line reactances can be used for removing modest overloading issues, but it needs to be appreciated that increasing reactance values also leads to higher reactive power losses, which will in turn lead to the artificial creation of additional reactive power support in the network and adversely affect bus voltage profiles. It was indeed observed from the simulations that the PSCOPF algorithm was unsuccessful in converging for several hours associated with line reactances being increased to more than 10% of their nominal values mainly due to voltage/reactive power issues observed. However, it should be noted that is unlikely that smart power flow controllers will be deployed as the only mitigation against congestion and thus any positive benefit they can have on network loading is to be considered and explored.
Another potential mitigation that should be considered in the use of flexible load (or demand-side management).

7.1.7 DEMONSTRATION OF FLEXIBLE LOAD

With reference to the operational mitigation results presented for the Dublin region and the North-West region, it may be recalled that load shifting is used by the PSCOPF optimisation tool as one of the control actions for removing overloading violations associated with critical hours. To further elaborate on the implications of load shifting, this section provides a simple demonstration of potential use of demand flexibility where load at a given bus is flexible to be shifted from onerous peak hours to less critical hours within the same day to avoid congestions. The flexible load considerations here are focused on the following two constraints:

1. Daily energy demand MWh of a flexible load has to be met
2. Within a day, a flexible load is able to move its hourly MW demand

7.1.7.1 FLEXIBLE LOAD DEMONSTRATION CONFIGURATION

To perform this demonstration, 24 consecutive hours – 2425 to 2448 (corresponding to 12th April 2030) – were randomly chosen and operational mitigation measures were implemented using the PSCOPF optimisation tool for investigating the feasibility of removing network congestions

Once load curtailment was identified by PSCOPF as one of the control actions for removing overloading violations for certain onerous hours, it was assumed that those curtailed MW loads might be shifted to some 'adjacent' hours (i.e., within ± 24 hours of the actual load curtailment) without causing any new violation or load curtailment in the hour where the load is shifted to. The rationale behind selecting only adjacent hours for potential load shifting was designed considering the convenience of affected customers as well as for satisfying the daily energy demand constraint listed above.

For each affected hour associated with load curtailment, the total MW load was shifted to one adjacent hour at a time, and a new PSCOPF run was conducted for the new hour to check if the algorithm needs to curtail any new load for removing potential network congestions in that hour. The hour that was the closest to the affected hour and which did not require any additional load curtailment from the PSCOPF run was selected as the 'target hour' for load shifting. Finally, contingency analysis was run for each target hour to verify that no more overloading violations remain in the network after implementing the PSCOPF control actions.

7.1.7.2 FLEXIBLE LOAD DEMONSTRATION RESULTS

As mentioned in the preceding section on the flexible load demonstration setup, PSCOPF runs were performed for 24 consecutive hours for investigating the feasibility of using operational mitigation measures for removing network congestions. The total MW load curtailed for each hourly PSCOPF run is presented in Figure 7-22 It can be observed from Figure 7-22 that only 3 out of 24 hours (i.e., hours 7, 9 and 13) require some degree of load curtailment for removing corresponding network congestions.

The target hours (refer to preceding section on demo setup) for shifting loads curtailed from hours 7, 9 and 13 were determined as hours 5, 6 and 15, respectively. As per Figure 7-22, 54.7 MW, 22.3 MW and 80.5 MW of load are therefore shifted from hours 7, 9 and 13 to hours 5, 6 and 15, respectively. Finally, contingency analysis was run for each target hour and it was verified that the network is able to successfully accommodate the increased load without causing any additional overloading violations.

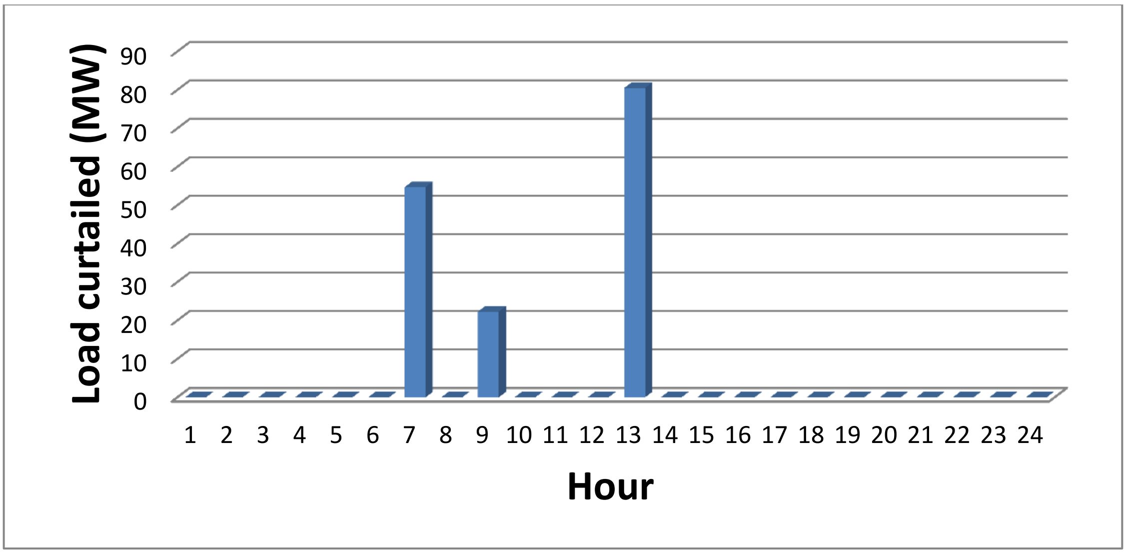


FIGURE 7-22: TOTAL MW LOAD CURTAILED FOR ALL 24 HOURS USING PSCOPF

The key finding from the flexible load demonstration study is on similar lines to the conclusions drawn from the study incorporating smart power flow control devices presented in Section 7.1.6, i.e., the sole use of load shifting may have limited benefits for removing all network congestions. In essence, load shifting needs to be used in conjunction with other mechanisms for efficient removal of every overloading issue in the network. However, load-shifting is unlikely to be deployed as the only mitigation against congestion and thus any positive benefit load-shifting can have on network loading is to be considered and explored.

It is to be also noted that a very simple methodology is used in this section for demonstrating the load shifting capabilities in the network. If a similar study was to be conducted in detail in the future, one way could be to incorporate energy storage devices at affected load buses for facilitating demand side management through energy arbitrage. Such a study would, however, not be able to be performed using PSCOPF, rather a different hourly optimisation tool with look-ahead functionality would need to be utilised in such a situation. The next section presents a proof-of-concept for such a potential study.

7.1.8 DEMAND-SIDE MANAGEMENT IN UCED MODEL

To further assess the proof-of-concept of utilising DSM for congestion mitigation, demand-side management (DSM) is modelled in the Ireland and Northern Ireland PLEXOS UCED model. Modelling DSM in a UCED model permits the time-varying nature of DSM to be considered. The benefit of utilising the PLEXOS platform is that it can combine an optimal power flow (OPF) with unit commitment and economic dispatch. Please note however that the OPF in PLEXOS is a linearised DC load flow algorithm. All operating constraints, such as SNSP, RoCoF, minimum number of units constraint and reserve requirements are included in the UCED model and are aligned with those discussed in Task 2.4 [1]. However, in addition to the operating constraints, the transmission network anticipated for 2030 is also included, which was not considered in the UCED analysis in Task 2.4 as this was investigated using a separate power flow analysis tool with preventative security constraints applied [8]. A set of network contingencies is also considered in some situations, the results of which will be discussed in section 7.1.8.4. These contingencies include the loss of major lines, both 440kV, 220 kV and 110 kV in Ireland and 275 kV and 110 kV in Northern Ireland, the loss of major transformers and the loss of large power plants.

The transmission network considered in the PLEXOS model for 2030 does not include any of the reinforcements identified earlier in this chapter as the intention is to determine the extent to which DSM alone can help to mitigate congestion issues. However, some network developments such an uprating and upgrading of transmission lines which are already in the planning pipeline have been incorporated.

7.1.8.1 REPRESENTING DEMAND-SIDE MANAGEMENT

A number of assumptions have been made as part of this analysis in order to represent DSM. These include the fact that aggregation of demand is assumed to be possible and that the correct monetary incentive is in place for end-consumers to participate in demand-side management programs. It is anticipated that this monetary incentive would come in the form of perhaps a congestion management system service product, the value of which would likely be in addition to the value that was identified in Task 2.5 as being attributable to system services. However, this particular aspect of the analysis is out of scope in this preliminary study.

Furthermore, it is assumed that any enabling infrastructure such as control systems on individual appliances/homes and mechanisms for sending and receiving signals from TSO to aggregator and aggregator to the individual demand-sites/homes is in place where need. Additionally, a range of assumptions have been made relating consumer willingness to participate. This is done by assuming typical technology adoption rates (Figure 7-23). As this work here is a scoping study to see if there is potential for DSM, a range of adoption rates are being considered, rather than specifying one rate.

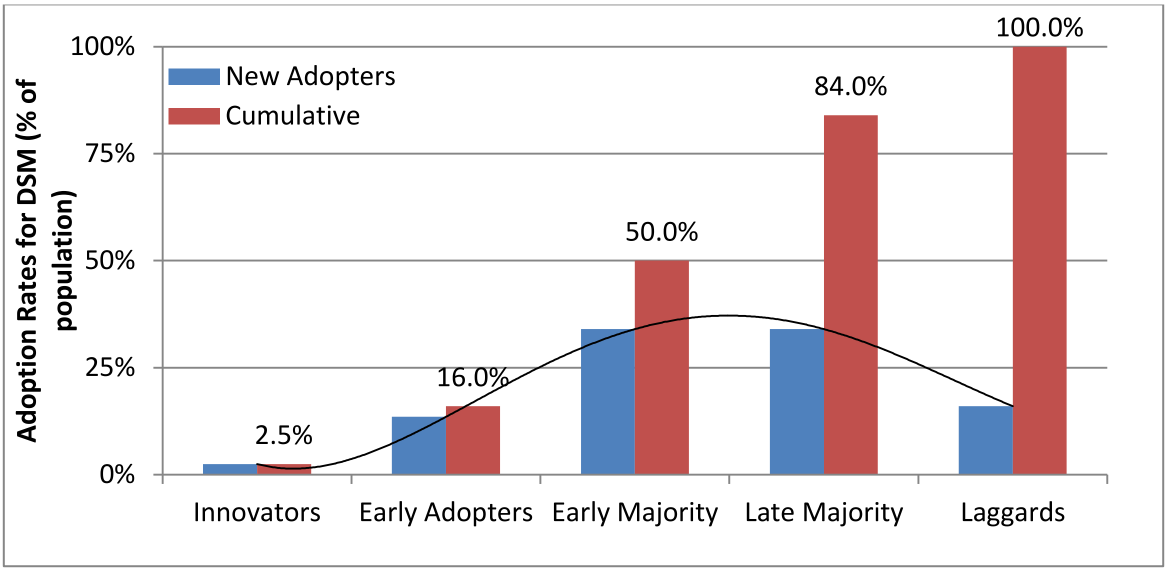


FIGURE 7-23: ADOPTION RATES FOR DEMAND SIDE MANAGEMENT

It must also be noted that it is acknowledged that not all load is capable of participating in DSM and not all load is capable of load-shifting or energy-shifting. This is due to the inherent characteristics of various appliances. Preliminary analysis, based on work previously conducted on behalf of EirGrid, was performed to determine what this percentage breakdown might be. The analysis suggests that about 50% of residential and commercial demand is capable of energy-shifting and providing reserve, with a further 25% capable of providing reserve only. It should be noted that what is being considered in this section is residential and commercial DSM, not large demand-side units (DSUs), which concern one or more individual demand sites that can be dispatched by the TSO as if it was a generator. These large DSU's are modelled separately in the model and are typically utilised to provide reserve services.

Currently, DSUs in Ireland and Northern Ireland are typically large commercial and industrial-scale demand sites and are proven to be able to provide FFR through to TOR2, Replacement Reserve and all three ramping services. Demand side response from residential and small commercial customers (Residential DSM or RDSM), which is considered in this section, on the other hand, is not yet proven. However, DSM has potential to not only provide significant levels of reserve services over multiple-time scales (FFR to TOR2), but to also contribute to congestion management and energy arbitrage.

It should be recognised that the adoption rates and the percentage breakdown of the demand, in terms of capability, are distinct but related. For example, for the "innovators" case, where 2.5% of the population is willing to participate in DSM, the resultant breakdown would then be 1.25% of the demand being capable of providing energy shifting and reserve (i.e. 50% of the demand that is willing to participate), with 0.625% capable of providing reserve only (i.e. 25% of the demand that is willing to participate). The remaining 0.625% of the demand is unavailable for DSM. These values are thus scaled according to the adoption rates (see Figure 7-24).

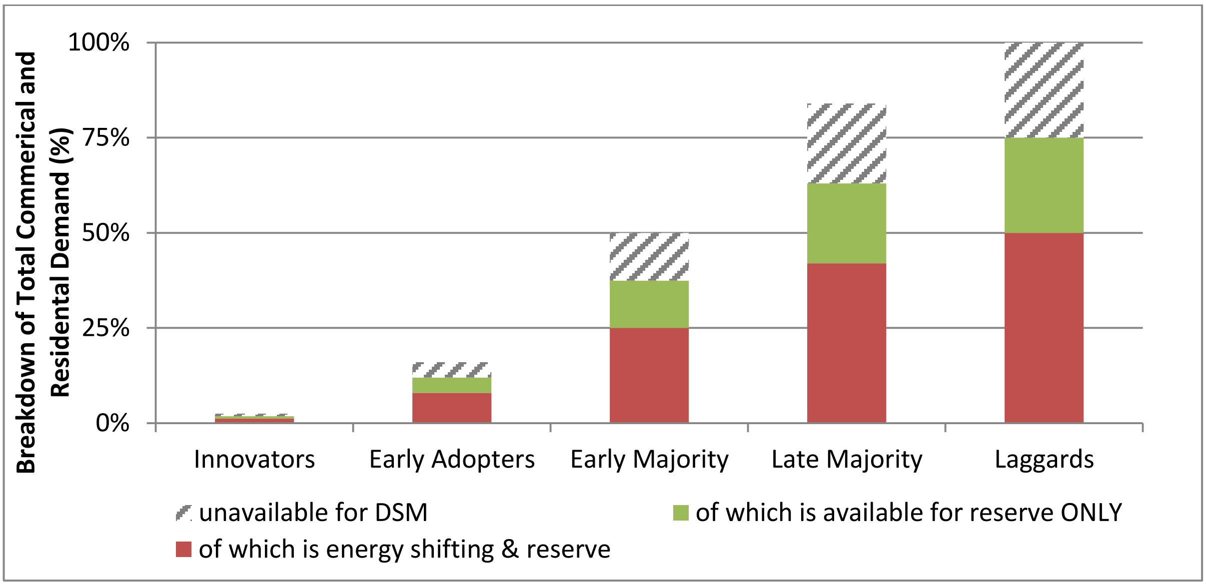


FIGURE 7-24: BREAKDOWN OF THE DEMAND CAPABILITIY ASSUMED FOR EACH CASE

In general, DSM can be considered similar to energy storage devices in that they can provide some system services and can shift energy use over time. Also, DSM is similar to energy storage devices in that DSM is energy-limited. However, DSM is different to energy storage because the operation of DSM is inherently tied to specific end-users. In this study, one DSM unit is created in the model at load node in Ireland (industrial load is modelling separately). This results in the creation of 130 individual DSM models. Future work will look at also extending the DSM modelling for Northern Ireland. However, it is deemed that the current study is sufficient for proof-of-concept and for scoping work for future analysis.

DSM is modelled here in such as way so as to consider it's ability to provide a) energy shifting only (DSM**e**), b) reserves only (DSM**r**) or c) both energy and reserve services (DSM**er**). Focus here for this report is on energy shifting only (DSMe) as energy shifting only is most likely to have the biggest impact on congestion. Future work, however, will look at performing more sensitivities.

The DSM at each node is modelling as follows:

The maximum amount of demand that can be reduced in an hour at each load node is limited to a user defined percentage (x) of the demand at that node that would normally be consumed in that hour:

$$x\%\ Demand_t \qquad \text{(Eq. 7-2)}$$

There is a limit placed on the amount of energy that can be shifted at each load node in any one day. It is limited to a user defined percentage (y) of the total energy consumed in each 24 hour period:

$$y\% \sum_{t=1}^{t=24} Demand_t \qquad \text{(Eq. 7-3)}$$

The maximum amount demand can be increased by at each load node is limited by a user defined percentage (z) of the peak demand for each 24 hour period:

$$z\% \, max(Demand_t) \; \forall \; t \; \in \{1,2, \ldots.,24\} \qquad \text{(Eq. 7-4)}$$

To account for a certain level of losses that will be inherent in energy shifting/energy storage devices, an efficient of 90% is assumed:

$$\eta = 90\% \qquad \text{(Eq. 7-5)}$$

In order to ensure that any that is shifted is recovered in the same day, to avoid inconveniencing end-users, energy balance constraints are enforced over each 24 hour period at each load node:

$$\sum_{t=1}^{t=24} Decrease_t = \eta \sum_{t=1}^{t=24} Increase_t \qquad \text{(Eq. 7-6)}$$

x, y and z are user defined quantities as previously mentioned, but they are directly related to the technology adoption rates and the assumed breakdown of demand capability (i.e. energy shifting and reserve provision–v-reserve provision only) and so vary from case to case.

The PLEXOS algorithm can then utilise each of the individual DSM models to co-optimise the, scheduling of generation and provision of reserves (i.e. minimise system operating costs) and the flow of electricity on the network taking into account all the operating and network constraints.

The metrics that are considered to assess the potential for DSM mitigation of congestion include total system generation costs, total economic rent on the transmission lines, total number of hours lines are congested and the loading level on the network.

7.1.8.2 DEMAND-SIDE MANAGEMENT RESULTS

The addition of DSM for load-shifting has been found to have a number of positive implications for the power system in general [46] [47] [48]. A key benefit is that DSM, when used primarily for load-shifting as it is here, alters the shape the of the system load profile. This has the effect of reducing overall system costs due to a portion of load being shifted away from peak load times when system costs are typically high [49]. As can be seen from Figure 7-25 below, load-shifting DSM from residential and commercial consumers results in a change to the overall system load profile, with increased demand occurring during the night time period, and reductions in demand occurring around peak times or with peak times being shifted slightly.

The addition of DSM results in a significant reduction in overall system costs as will be illustrated in the next sections for selected sensitivities. It should be noted that due to inherent round-trip inefficiencies assumed for the DSM, there is a small overall increase in the total annual system demand. Crucially, however, much of this additional demand is occurring during off-peak periods, when wind levels are high and thus system costs are low. It can be noted from the example in Figure 7-26, that during the period between hours 85 and 90 where the wind is low in comparison to demand levels, there is very little load-shifting occurring, while the period between hours 36 and 43 where the wind generation exceeds demand, there seems to be load increase, indicating that the DSM is taking advantage of the lower system prices.

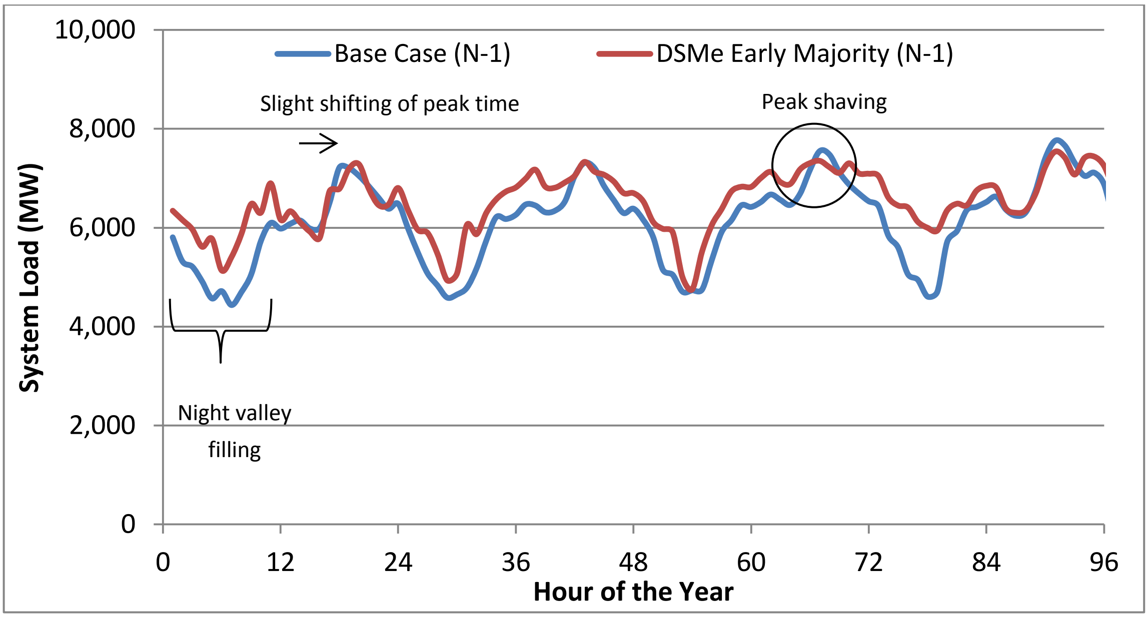


FIGURE 7-25: ILLUSTRATIVE COMPARISON OF SYSTEM LOAD WITH AND WITHOUT LOAD-SHIFTING DSM (EARLY MAJORITY ADOPTION RATE) INCLUDED IN THE MODEL (N-1 CASE)

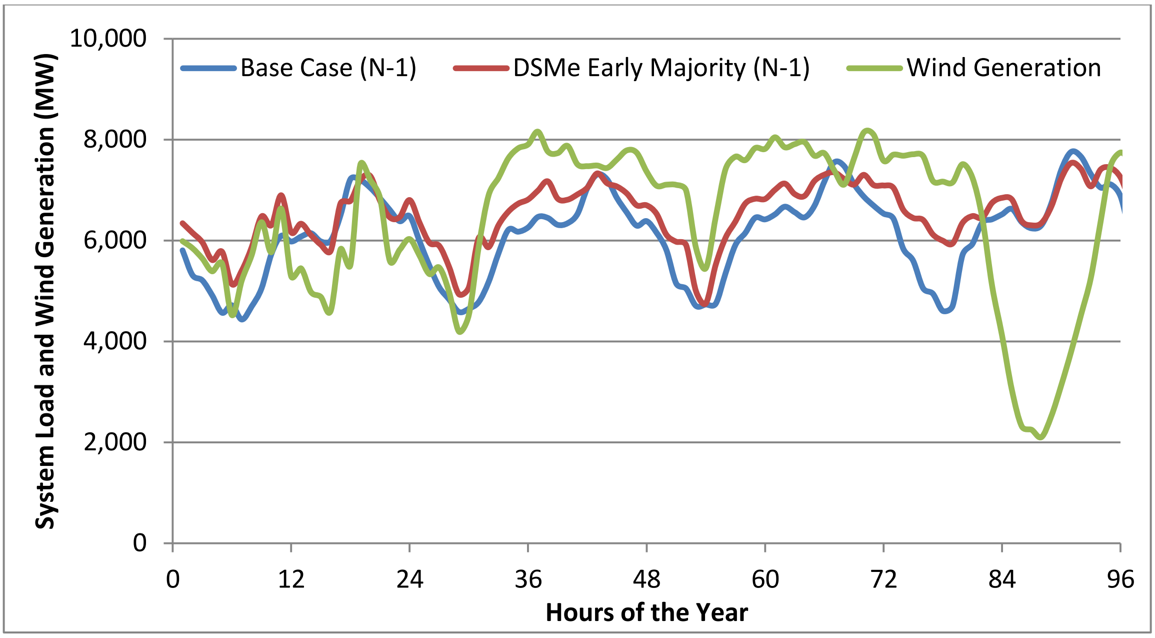


FIGURE 7-26: ILLUSTRATIVE COMPARISON OF SYSTEM LOAD WITH AND WITHOUT LOAD-SHIFTING DSM (EARLY MAJORITY) INCLUDED IN THE MODEL AND WIND GENERATION PROFILE (N-1 CASE)

7.1.8.3 INTACT NETWORK RESULTS

As mentioned in the previous section, DSM can have a profound impact on total generation costs and for the intact network case this is illustrated in Table 7-10. As can be seen, with increasing DSM adoption rates, there is a greater reduction in total generation costs. It does appear that the benefit of DSM begins to saturate as the highest adoption rates are reached, as illustrated in Figure 7-27.

TABLE 7-10: INDICATIVE CHANGES IN TOTAL GENERATION COSTS DUE TO THE ADDITION OF LOAD-SHIFTING DSM (INTACT NETWORK)

Case	Total Generation Costs	% Change in Generation Costs
Base case	€1.045 billion	-
DSMe_Innovators	€1.033 billion	1.13% decrease
DSMe_EarlyAdopters	€1.006 billion	3.71% decrease
DSMe_EarlyMajority	€ 0.967 billion	7.39% decrease
DSMe_LateMajority	€0.955 billion	8.59% decrease
DSMe_Laggards	€0.953 billion	8.77% decrease

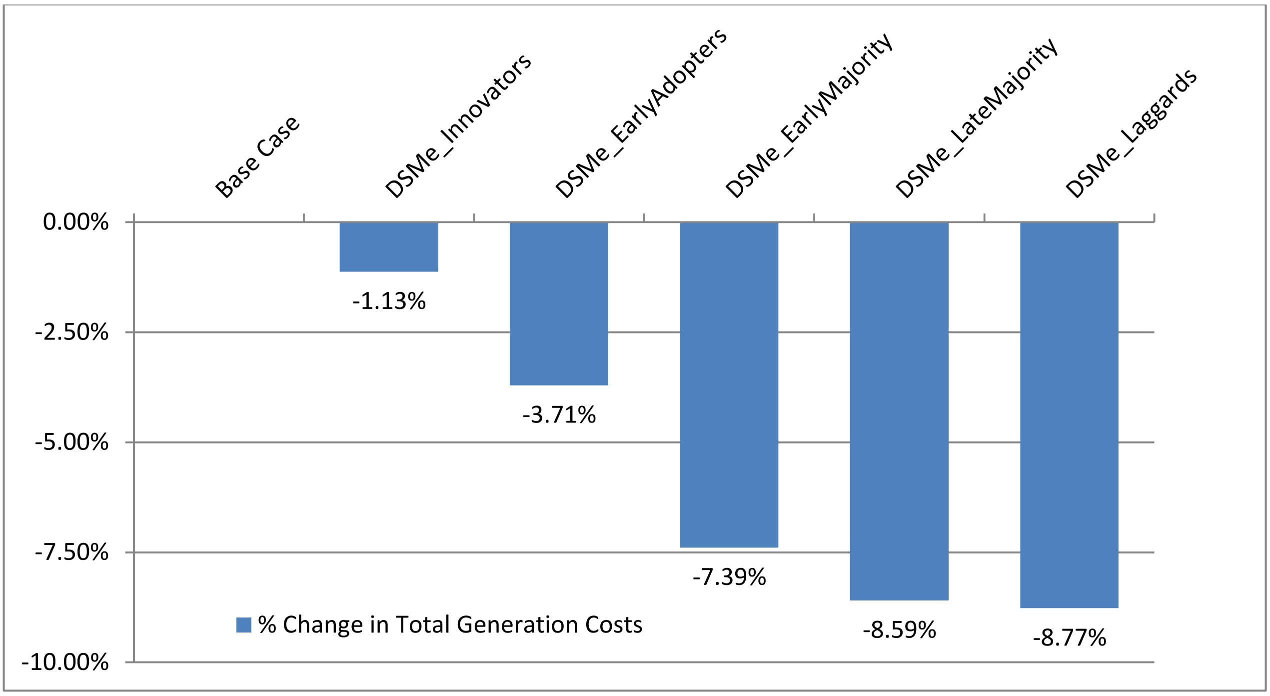


FIGURE 7-27: PERCENTAGE CHANGE IN TOTAL GENERATION COSTS WITH INCREASING DSM ADOPTION RATES (INTACT CASE)

In relation to line loading results, the potential for DSM is less clear and obvious. Focussing on only the top 15 congested lines in Ireland based on the PLEXOS analysis, there are certain lines which experience congestion, in the intact network case, which do not benefit from DSM alone. For these lines, the average line loading either remains static or in even increases slightly, with greater adoption of DSM. On the other hand however, there are some of the top 15 congested lines which do indeed see an overall reduction in their average loading as a result of the addition of DSM, as illustrated in Figure 7-28. However, average loading does not tell the complete picture as these lines do experience an increase in the number of hours during the year where they are congested (see Figure 7-29 - same lines as in Figure 7-28). Thus, focusing on number of hours of congestion only also does not tell the complete picture.

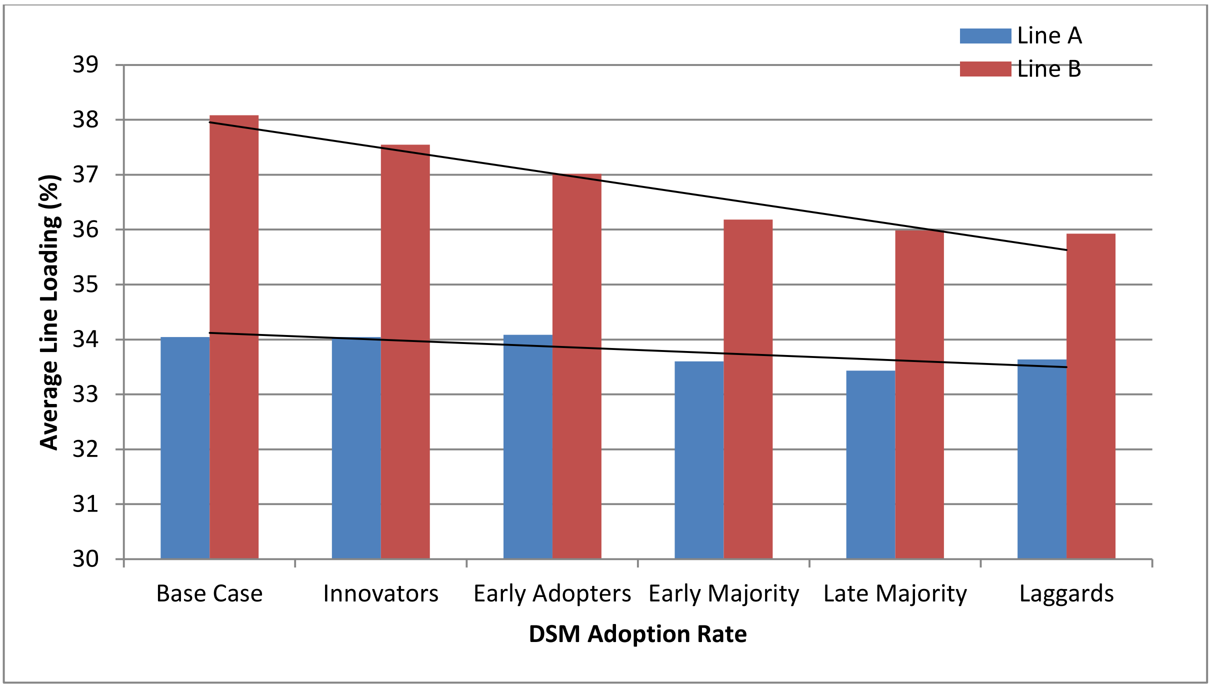


FIGURE 7-28: EXAMPLE OF DECREASE IN AVERAGE LINE LOADING WITH INCREASING DSM ADOPTION RATES FOR TWO SPECIFIC LINES WHICH EXPERIENCE OVERLOADING DURING THE YEAR

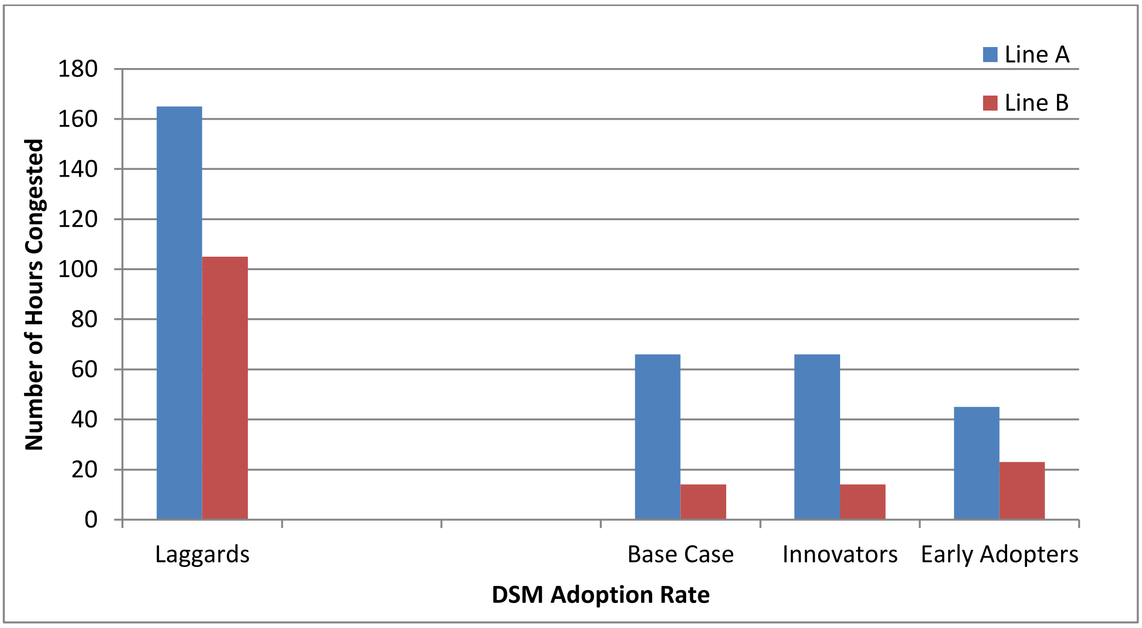


FIGURE 7-29: EXAMPLE OF CHANGE IN THE NUMBERS OF HOURS CONGESTED WITH INCREASING DSM ADOPTION RATES FOR TWO SPECIFIC LINES

The top 15 congested lines, particularly those which do not experience a significant improvement in loading, or numbers of hours congested, with increasing levels of DSM are often lines which do not have any DSM, or limited DSM capacity even at high DSM adoption rates, at the two connecting nodes. In fact, of the 15 lines considered here, only 8 of them have a DSM resource at one or both of the connected nodes, and of those 8 lines, the maximum total DSM capacity (both connected nodes) that is available for shifting, is less than 25 MW, on average across the 8 lines. Thus, it is unrealistic to expect DSM to be in a position to have an impact on such parts of the network, particularly for lines where ratings greater of 200MW or even 500 MW are exceed, and the maximum DSM capacity is less than 25 MW. For such cases, alternative mechanisms to manage congestion would need to be investigated.

On the other end of the spectrum, the line which has the greatest capacity of DSM at the connecting nodes (Line C) does see a downward trend in the max loading it records with increasing DSM adoption rates, as illustrated in Figure 7-30. As this line is never overloaded during the course of the year, there is no real necessity for congestion mitigation to take place at the connecting loads. However, nevertheless, DSM is showing that it has potential to reduce loading on lines when there is sufficient DSM capacity available, when there is a financial incentive (i.e. minimisation of costs in this case).

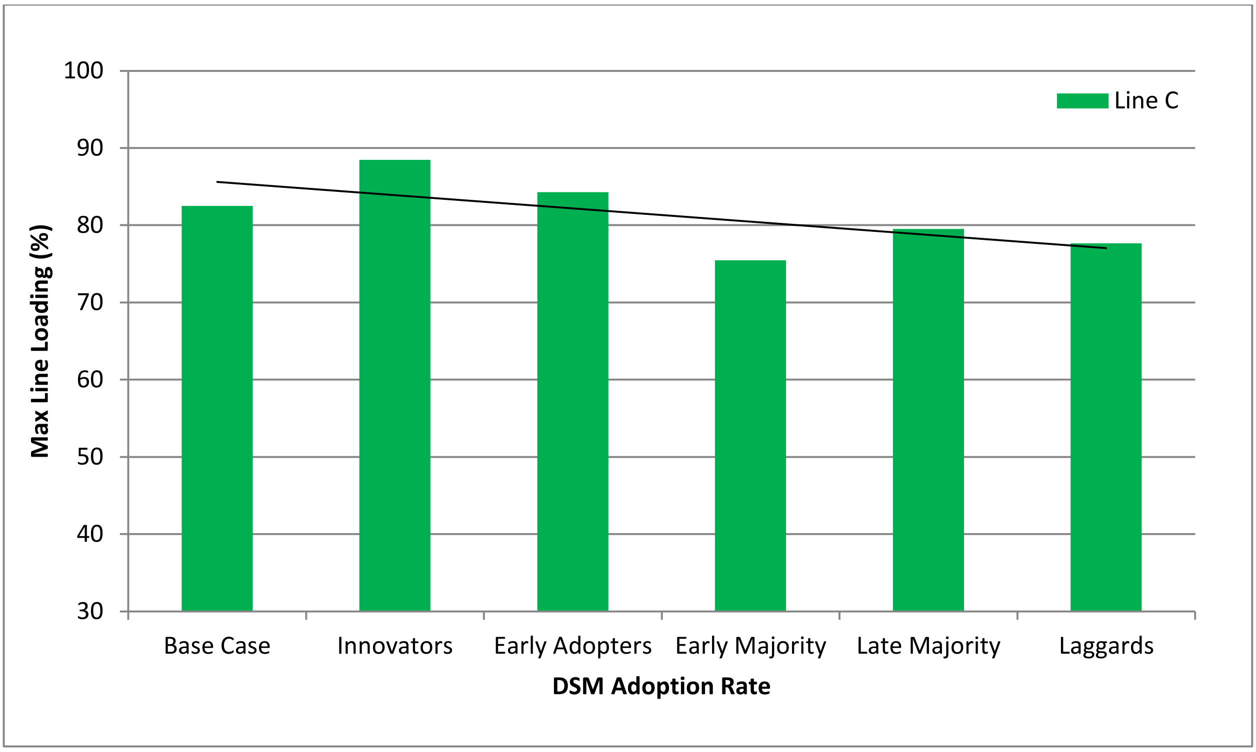


FIGURE 7-30: EXAMPLE OF DECREASE IN MAX LINE LOADING WITH INCREASING DSM ADOPTION RATES FOR A SPECIFIC LINE WHICH HAS HIGH DSM CAPACITY AT EACH CONNECTING NODE

While, it is difficult to ascertain the potential of utilising DSM for congestion management from line loading and number of hours of congestion alone, the economic rent can give a much clearer picture. Economic rent is a useful metric for indicating the level of congestion on the entire transmission system [50]. The economic rent calculated by PLEXOS for each of the different intact network cases is shown in Table 7-11, below. As can be seen, DSM has a very significant impact on the economic rent, with reducing rent as the level of DSM increases. This indicates that DSM is effectively reducing the level of congestion on the transmission network.

It needs to be pointed out that the calculation of economic rent is based on the price differential at each node multiplied by the flow on the line between the nodes. So some of these significant decreases in economic rent could be attributable to a reduction in loading/congestion and some is attributable to the falling system prices due to DSM. Future work should investigate what is the key driver.

TABLE 7-11: INDICATIVE CHANGES IN TOTAL ECONOMIC RENT DUE TO THE ADDITION OF LOAD-SHIFTING DSM (INTACT NETWORK)

Case	Total Economic Rent	% Change in Economic Rent
Base case	€66.2 million	
DSMe_Innovators	€64.4 million	2.77% decrease
DSMe_EarlyAdopters	€60.0 million	9.30% decrease
DSMe_EarlyMajority	€52.5 million	20.73% decrease
DSMe_LateMajority	€46.4 million	29.98% decrease
DSMe_Laggards	€46.0 million	30.52% decrease

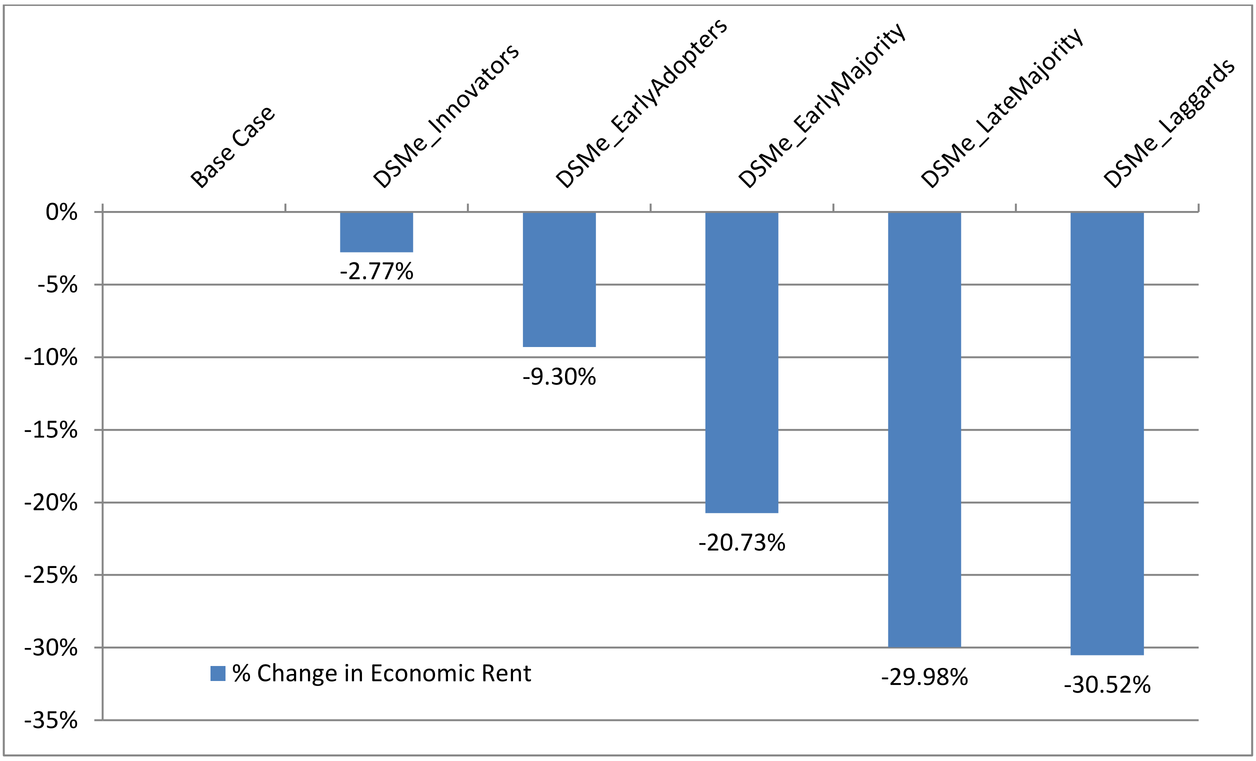


FIGURE 7-31: PERCENTAGE CHANGE IN TOTAL ECONOMIC RENT WITH INCREASING DSM ADOPTION RATES (INTACT CASE)

7.1.8.4 N-1 CONTINGENCIES RESULTS

Whilst the previous section explored the potential for DSM for an intact transmission network, it is useful to also consider the potential of DSM for congestion mitigation when the transmission network is subjected to a number of contingencies (N-1). This can help to understand some of the limitations of DSM for congestion management.

The first observation is that the impact of DSM on the total generation costs relative to the base case is largely unchanged from the intact network sensitivity. However, the impact of DSM on economic rent of the lines is much more muted.

TABLE 7-12: INDICATIVE CHANGES IN TOTAL GENERATION COSTS DUE TO THE ADDITION OF LOAD-SHIFTING DSM (N-1 CONTINGENCIES)

Case	Total Generation Costs	% Change in Generation Costs
Base case	€1.112 billion	-
DSMe_Innovators	€1.097 billion	1.28% decrease
DSMe_EarlyAdopters	€1.067 billion	4.00% decrease
DSMe_EarlyMajority	€ 1.027 billion	7.61% decrease
DSMe_LateMajority	€1.015 billion	8.73% decrease
DSMe_Laggards	€1.010 billion	9.19% decrease

TABLE 7-13: INDICATIVE CHANGES IN TOTAL ECONOMIC RENT DUE TO THE ADDITION OF LOAD-SHIFTING DSM (N-1 CONTINGENCIES)

Case	Total Economic Rent	% Change in Economic Rent
Base case	€512.6 million	-
DSMe_Innovators	€493.9 million	3.65% decrease
DSMe_EarlyAdopters	€491.6 million	4.11% decrease
DSMe_EarlyMajority	€478.0 million	6.75% decrease
DSMe_LateMajority	€448.5 million	12.51% decrease
DSMe_Laggards	€455.4 million	11.17% decrease

For the case with N-1 contingencies included, as with the intact network, DSM has limited effect on the heavily loaded lines. It appears that DSM does have some potential to reduce overall transmission congestion levels for the N-1 contingencies cases, as indicated by the reducing economic rent, however, it is limited in comparison with the intact case.

Part of the reason for this is, as already mentioned, that in some areas where congestion management is most needed during contingencies, there are limited load centres (i.e. North-West region of the island of Ireland) and thus, limited DSM capacity or perhaps no DSM capacity. The ability of DSM to provide congestion mitigation is therefore severely restricted in these areas. However, a decrease in network loading on other lines near load nodes is recorded with the addition of DSM, an indication of some mitigation of congestion taking place with N-1 contingencies being considered.

The other reason is that the occurrence of an N-1 contingency is usually a very onerous situation for transmission system management anyway, and a small DSM resource in some locations is not going to be sufficient to mitigate congestions associated with the loss of an important line. However, future work should explore if there is potential for DSM and other mechanisms, such as power flow controls, or FACTS devices to work in conjunction with DSM to mitigate congestion issues during N-1 contingencies.

7.2 LINK TO DEMONSTRATIONS AND THE QUALIFICATION TRIAL PROCESS: CONGESTION

Many of the demonstration projects in EU-SysFlex investigate congestion management services [2]:

Demonstration	Services Being Tested
German Demonstration	Active and reactive power management by DSO for TSO for congestion management
Italian Demonstration	Congestion management and balancing

7.2.1 CONGESTION MANAGEMENT – GERMANY

In Germany, it is expected that by 2030 the share of RES will have increased by up to 65%. Already today there is a high RES share (~40% RES in Germany and ~100% in one of the German regions since 2017), especially wind power in north eastern Germany. These high levels of wind require substantial re-dispatch measures to avoid overloading transmission and distribution assets. As per current regulatory framework, only conventional power plants with an installed capacity of more than 10 MW are integrated in a schedule-based congestion management (re-dispatch). Due to these limitations, the re-dispatch potential in the transmission grid is reaching its limits due to the minimal capacity of conventional power plants and decreasing level of installed capacity in conventional plants. Therefore, emergency measures are used to curtail RES in the distribution grid, which is leading to increasing costs. Taking this into consideration, in 2021, a new regulatory framework for congestion management will come into force in Germany.

7.2.2 CONGESTION MANAGEMENT – ITALY

Due to the increasing share of RES together with the corresponding decrease in conventional generation capacity, there is a scarcity of resources to provide ancillary services in transmission network. This inconvenience is faced by the TSO, which started to install compensator devices (e.g. STATCOM). In addition, in the ancillary services market, the TSO requires conventional generators to modify profiles scheduled in previous markets. The modification of the scheduled profile is a costly operation that has to be covered by TSO. The improvement of the coordination between distribution and transmission allows the distributed resources to participate to the ancillary services, reducing the need of conventional measures.

The continuous increase of distributed generation affects directly and indirectly the operation of transmission network. Directly, because the nodes of transmission network that traditionally behaved as loads, now are also injecting power. Indirectly, because the increase of distributed generation reduces the conventional generation directly connected to the transmission network. This evolving scenario is leading to a decrease of the TSO possibilities to regulate the frequency and the voltage within the transmission network and the increase of the probability to have current congestions. These issues have already been encountered in the last years by the Italian TSO (Terna) and the Authority. Terna, in order to avoid congestion and increase the available resources portfolio, planned to add new lines. In particular, new connections are planned between the north, where the load is concentrated, and the south, where the generation is higher. Besides, it installed some static compensators, in order to manage the network voltages better.

The possibility of distributed resources to offer services to the transmission network represent an external challenge (and opportunity) for the DSOs, who have to manage a distribution network where the resources can behave in new and unexpected ways. In this new scenario, DSOs have to facilitate the participation of local resources to different ancillary services to the transmission network. This can be achieved thanks to different functionalities. Firstly, DSOs can help increasing the observability of the power system aggregating the information (e.g. forecast) of the connected resources. Secondly, they can adopt advanced control systems so it is guaranteed that the effects, due to the power modulation of local resource for the ancillary services, do not create problems to the distribution network operations. The renewable resources have also an impact on distribution networks. They can introduce voltage violations and overloading of lines and transformers. Thus, to improve the operations of distribution networks, the Italian Authority started to incentivise the adoption of smart grid solutions by DSOs.

The Italian Authority also acted to support the transmission operation in two ways: for the variable renewable generators connected to the Transmission, it started to align the specifications to the ones of the conventional generators. As for the resources connected to the distribution network (renewable generation, but also conventional, loads and storages), the Italian Authority supported, by means of pilot projects, the possibility of aggregating distributed energy resources to participate in the ancillary service market. For this reason, the DSOs could also use their own assets in order to contribute to the regulation of power flows at DSO/TSO interface.

7.3 SUMMARY OF CONGESTION MITIGATIONS

As SNSP increases, analysis in Task 2.4 indicated that there will be a significant rise in the frequency of transmission line overloading above 100% of thermal capability. This chapter demonstrates the mitigation of this congestion scarcity through simulations and through utilisation of a number of potential solutions, including network reinforcement and other more novel mechanisms.

A number of different approaches were established to reinforce the transmission network to address the congestion scarcity:

i. **Network reinforcements.** This involves identification of the top priority network corridors to reinforce and to determine the support requirements. A new identical line/cable is added in parallel to the existing circuit thus minimising new infrastructure requirements. However costs and social acceptance limit this reinforcement, and it cannot follow the deployment pace of RES.
ii. **Operational mitigation measures** related to:
    - Use of phase-shifters and traditional transformer voltage control
    - Constraining generation
    - Use of smart power flow controllers
    - Demand shifting from flexible demand and storage that is capable of shifting consumption away from congested hours to other hours within a 24hr period.

The aim of this methodology is to demonstrate potential mitigations for the challenge of congestion and to illustrate the capability of certain measures, mechanisms or specific technologies. **Results from the Ireland and Northern Ireland power system show that a number of reinforcements (addition of 110kV & 220kV Circuits) required** in terms of reducing the total overload index (TOI) and mitigating the congestion scarcity for most of the upper range cluster of hours, if no other mitigation measures are available. The PSCOPF optimisation results indicate that **a combination of load shifting/DSM, generation redispatch and optimal adjustments of the PST angle can be sufficient to remove overloading violations for critical hours without the need for any further reinforcements.** This is a critical result as societal and environmental pressures often results in either an inability to build new network or result in significant delays in doing so. Thus, the existence of other mechanisms for resolving or at least mitigating the congestion issues is very welcomed. Indeed, it should be noted that, whilst in some cases there is no alternative except to invest in new infrastructure, EirGrid Group's strategy in relation to the network is to maximise the use of the existing transmission networks and to minimise new build. Additionally, ENTSO-Es TYNDP acknowledges that a multitude of different solutions will be needed from across the industry, including storage and demand-side management, not just network development, to enable the transition to a decarbonised power system.

EirGrid and SONI are currently, at the time of writing, undertaking a comprehensive public consultation on the future of Ireland and Northern Ireland's power system entitled "Shaping Our Electricity Future" (SOEF) [23]. In this consultation document a number of different approaches were developed to reinforce the transmission network to address the identified congestion issues. The purpose is to identify the relative merits of each approach and provide meaningful information on what is the most advantageous pathway to follow when developing the transmission network of the future. The approaches in the SOEF report represent the strategic view of how to develop the grid and relies heavily on uprating the capacity of existing 110 kV circuits and the construction of a minimum number of new circuits at a minimum voltage level of 220 kV in Ireland and 275 kV in Northern Ireland. In addition, the SOEF report acknowledges the potential role residential demand-side management has to play in mitigation of congestion.

A key benefit of DSM for congestion mitigation is that at high levels of renewables demand will still be available and "online" to some extent and also due to the fact that loads are dispersed throughout the system. However, one limitation is that it is inherently tied to specific end-users and the inconvenience to them needs to be minimised or avoided. In addition, in some areas where congestion management is most needed, there are limited load centres (i.e. North-West region of the island of Ireland) and thus, the ability of DSM to provide congestion mitigation is limited. However, the proof of concept study demonstrated that there is some potential for DSM, as modelled here, to provide decreases in overall system costs plus a decrease in network loading on certain lines, an indication of some mitigation of congestion. Further additional work on exploring the potential of DSM for the mitigation of congestion will need to be conducted. As acknowledged in this report, there is a need to better utilise the existing grid infrastructure and to minimise the build of new lines. DSM, in conjunction with other mechanisms has the potential to enable system operators to better utilise the existing grid.

As previously alluded to, **congestion can be mitigated in a number of ways, including infrastructural investment, network reconfiguration and re-dispatching as well more novel concepts such as power flow controllers and demand-side management.** As the transition to a power system with increasing levels of variable renewables continues, it is easy to see how the need for a congestion product increases and how events that once used to be considered infrequent become part of normal operation. The framework of a congestion product could be essentially the same as those used for frequency control with the only differences being the activation of product is driven by or triggered by congestion and the requirements would be locational in nature.

This locational aspect, if leading to subsequent congestions and generation constraints, could also be taken into account when planning new RES capacities. It also opens the field of energy coupling (power to X) studies, which were not in the perimeter of 2030 scenarios of EU-SysFlex, but could unlock a number of issues.

8. USE OF DISTRIBUTED TECHNOLOGIES TO MAINTAIN GENERATION ADEQUACY AND SUPPORT RENEWABLES INTEGRATION

In addition to the suite of technical challenges and instabilities associated with transition to high levels of renewables, a potential reduction in system adequacy has also been identified as a challenge associated with displacement of conventional generation. As power systems transition to having portfolios with higher levels of vRES, the capacity of vRES that is required to displace conventional capacity, and still maintain the same level of generation adequacy, increases dramatically. This is a result of the variable nature of these resources and the fact that renewable generation availability may not coincide with peak demand times. Uncertainty of generation capacity and system interdependencies were also identified in the state of the art review in D2.1 as scarcities to achieve a capacity-adequate European power system [5].

It should be noted that although a portfolio may be sufficient from the point of view of generation adequacy and having sufficient capacity to meet peak demand, there is no guarantee that the portfolio also has the requisite fast responding capability that has been shown in Task 2.1 and confirmed in T2.4 to be vital for secure power system operation.

In modelling, adequacy can be secured, i.e. respecting the 3 hour loss of load criteria that applies in the Continental European Power System[9], by adding a large amount of interconnections and peaking plants, as was first done for the base-case of the EU-SysFlex core scenarios. While this results in a generation adequate portfolio, it was pointed out in Task 2.5 [4] that a generation adequate portfolio may not necessarily have the right level of capability needed on the system. Indeed analysis in Task 2.4 demonstrated that despite the scenarios being generation adequate, there were still significant scarcities materialising with high shares of vRES. In addition, Task 2.5 showed that there are financial challenges for RES and other technologies and low load factors for peaking units even while the portfolio is generation adequate.

This chapter will investigate the effects of deploying certain technologies, which were identified in Task 2.1 as effective mitigations for managing system adequacy whilst also accommodating vRES integration and supporting the reduction of curtailment and the use of CO_2-emitting peaking units. In particular, this chapter will investigate the effect of interconnections on system interdependencies, the use of vRES to provide reserves and the impact of adding storage (in the form of batteries (BESS) and by Electric Vehicles (EV)) on limiting the need for more expensive and CO_2-emitting peaking capacities in generation portfolios. Some of these technologies are tested in demonstrators across the EU-SysFlex project. Through simulations, this chapter shows how the impacts of these technologies could scale-up at the European level and contribute to supporting large-scale deployment of vRES

[9] It should be noted, that different power systems will have dfferent loss of load criteria.

and reducing CO_2 emissions through maximising the use of low-carbon solutions, whilst mitigating scarcities and challenges.

8.1 SUMMARY OF ISSUES

This section continues the analysis from Task 2.1, which identified from literature, a number of scarcities appearing in a high RES power system, and Task 2.5, which provided a techno-economic analysis to assess the levels of revenues available to fund large scale deployment of renewables.

With regards to system adequacy, the studies reviewed in Task 2.1 indicate that as a result of the penetration of renewable generation, thermal plants are being decommissioned, and hence the capacity margins become tighter. Uncertainty of generation capacity and system interdependencies appear to be areas that may affect the target to achieve a capacity-adequate European power system.

A way to deal with system inadequacy relates to planning new transmission corridors within and between countries (i.e. interconnections). Indeed, as we move towards a unified energy market characterising the pan-European system, interconnections would enable countries to share capacity leading to a pro-EU approach rather than a member state centric one. Therefore, as indicated in D2.1, interconnections are considered as a key factor in supporting adequacy in a large-scale system such as the European one [5]. Additionally, it was shown in Task 2.5 [4] that, for the Continental power system, increasing the level of RES also increases the installed capacity of peaking plants to ensure adequacy and balancing, albeit with low load factors and high RES curtailment.

It is useful to note that generation adequacy was not explored in Task 2.4 as it was determined that the generation portfolios in the scenarios were adequate. However, based on the results from Task 2.5, it is useful to re-examine generation adequacy and to determine ways adequacy could be supported via low-carbon technologies, whilst also supporting the goal of integration higher shares of renewables. In this context, this chapter seeks to demonstrate alternative options for maintaining system adequacy, by optimising the use of distributed technologies such as VRES themselves, storage and Electric Vehicles (EVs) to support the integration of high levels of renewables.

The first mitigation that will be analysed in this chapter is the option for **vRES to provide frequency reserves** (primary and secondary). If vRES provide reserves, and it has been shown in section 4.2.2.3 that it is capable of doing so and can support the mitigation of the frequency stability scarcity, it reduces the need for conventional dispatchable plants to meeting the reserve requirements. Thus, this section builds upon the work in section 4 in that while the previous work sought to demonstrate the capability of certain technologies to mitigate frequency stability issues, this section seeks to demonstrate the positive effect vRES provision of reserves can have on the overall system commitment and dispatch, and therefore on system adequacy.

Two additional technologies will be also be demonstrated: **4h stationary batteries and electric vehicles (EV) smart charging.** The volume of Net Transfer Capacities (NTC) in the European power system is also discussed as we looked at system interdependencies. Market potentials linked to system services, intra-day markets and capacity mechanisms are not evaluated in this study. A nodal approach is not taken into account, i.e. flexibility needs linked to local congestion on distribution networks are not considered. Furthermore, only energy-only markets are considered. In Task 2.5 it was identified that energy-only markets will not be sufficient in the future as high levels of RES will result in suppression of energy prices and thus participant revenue. Consequently, it should be acknowledged that in the future additional revenue streams, such as system services markets for example, will be required [4], not only for making up revenue shortfalls, but also for incentivising the capabilities for mitigating scarcities, as demonstrated in the previous chapter. Thus, the operation and participation of the technologies being explored in this chapter could be very different in the future where compared to the energy-only market context in this chapter as the addition of system services markets could provide the potential for increased revenues for the technologies under consideration here. Consequently, the aim of this chapter is not to provide a full economic assessment of these storage technologies, but rather to provide a first order of the magnitude and global tendencies linked to the integration of stationary batteries and EV smart charging and demonstrate that they have a positive impact on overall system commitment and dispatch, and therefore on system adequacy, and thus can support the goal of integrating high shares of renewables and maintaining generation adequacy.

The methodology employed in this chapter is explained in section 8.2. It includes scenario design, hypothesis and modelling approach. Results are then presented in section 8.3. We examine and discuss the technical and economic implications of the different technologies for the European power system with a high vRES share.

8.2 METHODOLOGY

8.2.1 SUB-SCENARIO DESIGN FOR SENSITIVITY STUDY

To assess the impact of the various technologies for mitigating issues with system adequacy, several sensitivities based on the core scenario Renewable Ambition [7] were developed. The different sensitivities are shown in Figure 8-1. Two different sensitivities were developed to explore the effects of the technologies under consideration in this chapter to contribute to system adequacy:

- Sensitivity 1: vRES provides reserves
- Sensitivity 2: The technologies under investigation are integrated.

For a better understanding of system integration and capacity sharing at Pan-European level, sensitivities were also performed on the assumed level of interconnections.

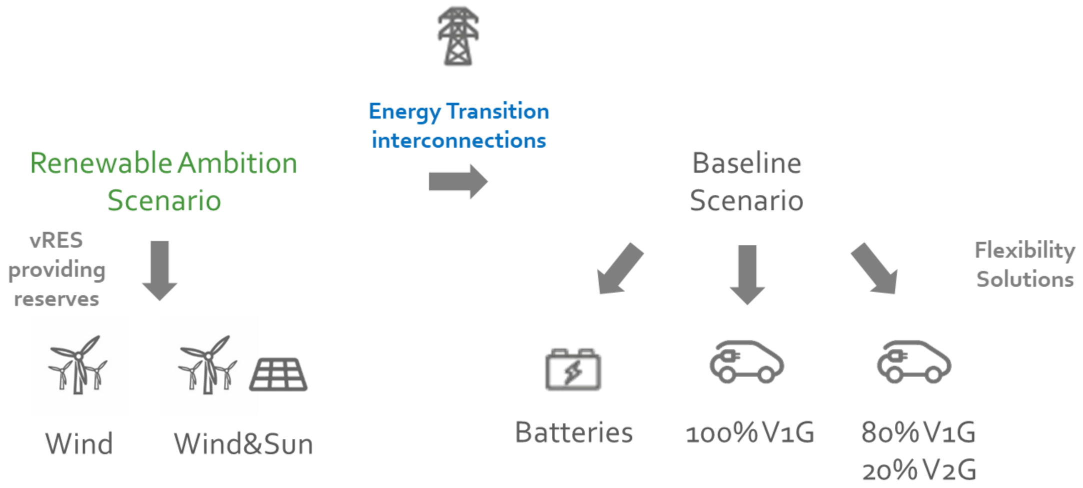


FIGURE 8-1 : SENSITIVITIES USED FOR EXPLORING THE DIFFERENT TECHNOLOGY OPTIONS

8.2.1.1 VRES PROVIDING RESERVES: SCENARIOS AND ISSUES

In Task T2.5, reserves were provided by thermal plants (gas, coal and biomass) as well as nuclear and hydro in the Continental European system. With these hypotheses, when vRES represents the major share of generation, some thermal plants need to be started only to provide reserves. This leads to significant vRES curtailment to make room for these plants as thermal plants typically have a minimum generation level below which they cannot be operated. Allowing wind and solar to provide reserves can help mitigate these situations and prevent the requirement to start fossil fuel plants, thereby supporting the integration of vRES in the system. It can also help reduce system service (in this case frequency reserve) shortfall in countries with only few thermal power plants. Since renewables will be the last technologies to be called to provide reserves, as they have zero variable cost and thus will be prioritised for energy provision, provision of reserves from vRES should have only little impact on their production and could be seen as an additional revenue stream if the correct market designs and incentives are in place.

The simulations will evaluate the role that vRES can play in providing reserves, and the impact on CO_2 emissions and curtailment compared with the base-case scenario. This analysis scales up the insights provided by the Virtual Power Plants in the WP6, 7 and 8 of the EU-SysFlex project, in which vRES demonstrate their technical capabilities to provide reserves.

The reference scenario is Renewable Ambition where 33% of the total annual demand on the Pan-European power system is met by variable renewables. This reference scenario respects system adequacy criteria which are achieved by adapting CCGT and OCGT capacities in various countries.

Two sensitivities will be studied:

1. A "Wind" sensitivity where primary and secondary reserves can be provided by 30% of the installed wind capacity;
2. A "Wind&Sun" sensitivity where primary and secondary reserves can be provided by 30% of the installed wind capacity and 30% of the installed solar capacity.

The European generation mix is identical in the baseline scenario as well as in the sensitivities. The European power system is simulated using CONTINENTAL model, a state-of-the-Art Unit Commitment (UC) Model developed by EDF R&D. The two sensitivities are compared, thereby enabling an assessment of the impact of solar providing additional reserves. The model gives priority to wind providing reserves when solar is added. This priority helps in comparing both sensitivities, and makes sense in the way that wind has the potential to be available throughout the day, which is not the case for solar, which has a much more diurnal pattern.

8.2.1.2 FLEXIBILITY SOLUTIONS: SCENARIOS AND ISSUES

In Task 2.2 [7], the core scenario Renewable Ambition was designed to meet system adequacy criteria with a 3h loss of load limit and assumed a very high level of cross-border interconnections. Therefore, Renewable Ambition does not require the capability from the additional technologies being considered in this chapter strictly from an adequacy point of view. However, a financial gap was shown in T2.5 [4] which calls in to question the portfolio mix and the capability of that portfolio mix to support the integration of renewable generation. In addition, challenges appeared in Task 2.5 in terms of CO_2 emissions for peaking plants, and there is also a question around social acceptance for network development, particular for very high levels of cross-border interconnections. Consequently, to look at the impact of the technologies being considered in this chapter in a high-RES scenario, the level of interconnections are lowered to a more "realistic" one based on recent developments by taking the lower interconnections level from the core scenario Energy Transition. This allows for assessment of the impact that interconnections have in mitigating system adequacy issues as well as enables a closer look at the impact stationary batteries and EV smart charging have on system balancing, and therefore in contributing to system adequacy.

In order to evaluate the potential of cross-border interconnections with high shares of vRES, a comparison has been done between Renewable Ambition with e-Highway Net Transfer Capacity (NTC) level [51] and the same scenario but with the NTC assumptions from Energy Transition, called Baseline Scenario.

Both scenarios, Renewable Ambition and the Baseline Scenario, have the same baseload plant capacities but different CCGT and OCGT so that they meet the reliability target level of 3 hours loss of load per year for each country. Costs are available in Annex II. The baseline scenario includes more than 430 GW of dispatchable units including Nuclear, CCS, OCGT and CCGT units, which support the integration of vRES, in conjunction with the relatively high level of interconnections.

As an intermediary result, a comparison of the renewable curtailment levels in both scenarios is shown in Table 8-1. Reducing the NTC assumptions induces a nearly doubling volume of curtailment over Europe. This highlights the high impact that NTC scenarios have on curtailment and the benefit in reassessing the generation portfolio mix with updated NTC assumptions. The curtailed energy mainly happens in Spain but also appears in other European countries.

TABLE 8-1: ENERGY CURTAILED IN THE RENEWABLE AMBITION AND IN THE BASELINE SCENARIO

Curtailment (TWh)	Renewable Ambition	Baseline Scenario (Renewable Ambition with NTC vision 2030)
Europe	23.0	39.2
Spain	21.6	31.1
Europe without Spain	1.4	8.1

The different technologies are then introduced to demonstrate their ability to support the integration of vRES and reduce curtailment in this new and more realistic scenario.

Stationary batteries are first installed in several countries in Europe in the baseline scenario in order to provide multi-hour flexibility to balance the system and mitigate the net load variability induced by vRES. Only one 4h battery (BESS) technology type is considered which is rather well calibrated to compliment and cover the duration of mid-day solar PV production. Battery capacities are dimensioned such that they can recover their costs through an iterative process in which an economic equilibrium is reached in the energy only market (revenues coming from arbitrage on the market are equal to equalising annualised costs). As explained earlier, revenues from the intraday, system services markets and capacity mechanisms have not been taken into account here, thus leading to some extent to an under-estimation of the batteries capacity potential. Batteries costs are computed using O&M and investment costs assumptions coming from [52], [53], and assumptions are displayed in Table 8-2.

TABLE 8-2: TECHNO-ECONOMIC ASSUMPTIONS FOR BATTERIES 4H [52]

	Overnight cost	Lifetime (years)	Discount rate	Investment annuity (€/kW.an)	O&M cost (€/kW.y)	Efficiency
4h stationary battery	120 €/kW 120 €/kWh	20	7%	47.2	7	0.85

In the sensitivity with the batteries, the economic integration of batteries for mitigation of curtailment due to RES variability results in important deployment of batteries in the peninsulas of Europe where interconnections, despite several fold development, are not sufficient to avoid high amounts of energy curtailment. Out of the 33.8 GW batteries developed in Europe, economic integration intermediate results show that 75% of these are located in Spain (25.3 GW) and another 4.5 GW is spread between Italy and Portugal. This intermediate result from dimensioning will permit analysis of its effect on RES integration and capacity-adequacy of the system in future work. Thus, it can be concluded that even in a well-interconnected European power mix with a vRES share of circa. 34%, 4h stationary batteries find an economic place especially in peninsulas.

Two additional sensitivities utilising EVs where different smart charging regimes are then considered:

a. **100% of the EV fleet are operated through V1G, first generation of EVs which cannot provide system services**: 100% of the EV fleet demand is managed through smart charging, thus economically adapted to the variations of supply and demand.
b. **80% of the EV fleet operated through V1G and 20% through V2G, second generation of EVs that can inject into the grid and provide system services**. This 20% assumption is in line with the most optimistic scenario (Opera scenario) released by RTE when it comes to V2G deployment [54]. This capped penetration rate is explained by a rapid cannibalisation of V2G value when being deployed into an EV fleet (without considering any other revenues coming from system services or capacity mechanisms).

In these scenarios, EV charging (and discharging) profiles are the results of a European-wide optimisation. EVs are modelled as storage assets with constraints for mobility and availability at the charging station. In the baseline scenario, the charging profile of EV is predetermined and added to the demand. In the baseline scenario and the two sensitivities, the energy consumption level for each country EV fleet is kept equal. Detailed data for EVs is available in section 8.2.2.

Additional costs linked to the deployment of EV are not taken into account. The EV fleet deployment is assumed to occur irrespective of the revenue available from the energy market. This is because it is believed that the main motivation for buying an EV is for mobility, not for receiving energy payments, and so the energy revenue is an upside that does not become part of the investment decision. Thus, there is no cost associated with its ability to provide smart charging services. Given their limited level and high associated uncertainties, no additional costs have indeed been taken into account for V1G and V2G integration. This differs from the case of the batteries, as the battery investment decision relies on the revenues from the energy markets, and in this case the energy-only market, and so consideration needs to be given to the costs.

These two EV smart charging sensitivities are not meant to be realistic but represent higher bounds to highlight global tendencies on long-term techno-economic indicators. In a more realistic scenario, less development of smart EV charging may be more likely, depending on the structure of tariffs at this time horizon. However, the scenarios here are compared to a baseline scenario that already includes some sort of smart charging driven by current tariffs, displacing an important part of EV charging at night. In the end, this exercise can provide insight on the positive impact of EV to mitigate curtailment and to contribute to balancing, and guidance for the definition of future tariff to incentivise smart charging.

Compared to the batteries sensitivities, demand-side management potential by EV is well spread over European countries for the two EV smart charging scenarios. As seen in Table 8-3, given assumptions on EV development, EV average smart charging capacity potential is 5 times higher than the battery capacity in Europe for the same underlying scenario. This global tendency is opposite for Spain, however, which sees a 50% decrease in total storage capacity (EVs and batteries) in the EV smart charging scenarios when compared to the storage capacity in the batteries only sensitivities, as it is capped by the size of the fleet. As a reminder, this analysis does not take into consideration intra-day services, system services or capacity revenues in the economic development of batteries.

TABLE 8-3: EV SMART CHARGING CAPACITY POTENTIAL AND BATTERIES INSTALLED CAPACITY IN SPAIN AND EUROPE

	Batteries installed capacity (based on an economic optimisation) (GW)	Average potential charging capacity by EV (GW)
Spain	25.29	12.53
Europe	**33.83**	**166.68**

EV smart charging average potential capacity, with fleets deployed over Europe, is generally higher and better spread over countries than batteries, which are only installed when it is techno-economically viable to do so.

8.2.2 MODELLING OF THE EUROPEAN POWER SYSTEM

The European power system is simulated using CONTINENTAL model, a state-of-the-Art Unit Commitment (UC) Model developed by EDF R&D used to perform an extensive publicly available study on integrating 60% RES into the European power system [55]. CONTINENTAL model optimises the hourly dispatch of power plants available in the European power system (exogenous data) to address both power consumption and reserve provisions while minimizing total cost given a range of economic and technical constraints.

For a given scenario, the power units are defined for each country. Thermal power plants can be coal-fired, gas-fired, oil-fired or nuclear. Hydroelectric facilities include weekly and seasonal reservoirs as well as pumped hydro storage (PHS). One of the main strengths of CONTINENTAL model is that it computes the optimal use of hydraulic reservoirs in a refined way. In addition, the model represents run-of-river, CHP, wind and solar power, decentralised biomass and other kind of RES technologies (tidal, geothermal). This generation can be dispatched down (or curtailed) if it turns out to be cost-effective for the system.

Technical and economic input data have to be entered into the model, such as technical characteristics for thermal units (efficiency rate, variable cost, forced outage rate and maintenance schedules (which optionally can be optimised)) and for hydro units. Dynamic constraints and constraints related to system services procurement were also implemented for each country and units involved. VRES generation, batteries storage or EVs can contribute to these reserve requirements and a maximum rate of reserve participation for each type of plant is specified without differentiating between primary and secondary reserves. For Renewable Ambition and the Baseline Scenario, reserves are only allocated to thermal plants and hydro. For sensitivities where vRES provide reserves, reserves can also be allocated to wind or wind and solar. As the model does not differentiate between zero variable cost technologies, priority is given in the model to wind providing reserves when solar is added to compare sensitivities, as wind is generating more often. The modelling does not allow for sharing reserve requirements between countries and reserves are supposed to be symmetrical.

Once the power system of each country is described in the model, the different countries are then linked though interconnections to form the European power system.

A system demand requirement and a reserve requirement are prescribed for each country. The consumption will include the demand coming from the different technologies being considered in this chapter such as EVs and the batteries where applicable. Two ways of modelling electric vehicle (EV) charging are possible within the CONTINENTAL Model. Either their charging profile is pre-determined and included directly in the demand curve or it can be optimised like any other storage asset to minimise overall system costs. In the case where EV charging profiles are integrated in the demand curve, the charging profile can be determined on an as-needed-basis or by a tariff signal to model an incentive for charging at a favourable moment for the power system. In the second case, CONTINENTAL Model optimises the charging profile of the EV fleet over time for V1G, or both EV charging and discharging profiles for V2G. In the V2G case, the EV fleet represents a decentralised way of storage to provide additional flexibility to the power system. This implies the use of a bidirectional charging station. The modelling of V1G and V2G in CONTINENTAL takes into account technical characteristics associated to EV types and mobility constraints given the typology of uses. The EV fleet is divided into 3 categories: battery EV; plug-in hybrid EV and light-duty EV with different storage size (refer to Table 8-4).

TABLE 8-4: BATTERY SIZE DEPENDING ON EV TYPE [54]

EV type	Battery size (kWh)
Battery EV	70
Plug-in hybrid EV	16
Light duty EV	80

A refined segmentation of the EV fleet is modelled homogeneously over Europe in order to take into account mobility and parking habits. Additional parameters are also considered, not only whether the EV is being used or not, but consideration is also given to whether there is access to a charging station at home and/or at work and also to the type of service vehicle. Different charging station capacities are applied at work, home and in public places. The definition of these different EV segments result in the setting of the following constraints:

1. Mobility profiles which are different depending on whether the vehicle is used or not.
2. Availability power profiles at the charging points per country, such a profile depending on a certain time of presence at the charging station, a certain level of frequency of connection to the station, as well as differentiated capacities of charging stations.
3. A minimum level of charge for the battery storage imposed at some point of time (in the morning for instance) to ensure that enough energy is available to use the EV during the day and the week. This charge level is differentiated from one EV segment to the other.

In our dataset, around 40% of the fleet is available during the day at a charging station (unused, charging at home or charging at work); and 95% of the EV fleet is available for charging at night (charging of private individuals EV at home or services EV at work).

Once the global framework for the power system has been modelled, an important feature for prospective high RES scenarios is to include the uncertainty coming from weather patterns. This uncertainty will impact vRES generation, and is modelled through time series. Having enough representative weather patterns is essential to get an accurate dimensioning of the European power system. For each country, 55 years of historical data for wind speeds, temperature and solar radiation are used to compute the vRES generation and demand. It is to be noted that the temporal correlation between vRES and demand is maintained, which highly influences needs for flexibility.

During the simulation, generation units are scheduled in increasing order of variable costs for providing energy and decreasing order of variable cost for providing reserves. This allows the lowest total cost for the power system by ensuring with technologies that are cheapest (vRES for example) are utilised primarily for energy provision while using the most expensive technologies, such as fossil plants, for reserves that might not be called.

The outputs of CONTINENTAL model include the hourly commitment status, generation output and the scheduled participation to reserves for all groups of units. Marginal prices for energy and reserves (FCR & aFRR) are also outputs for all zones. This set of tools allows carrying out detailed technical and economic studies of a system with a large amount of vRES. The overall CONTINENTAL methodology is summarised in Figure 8-2.

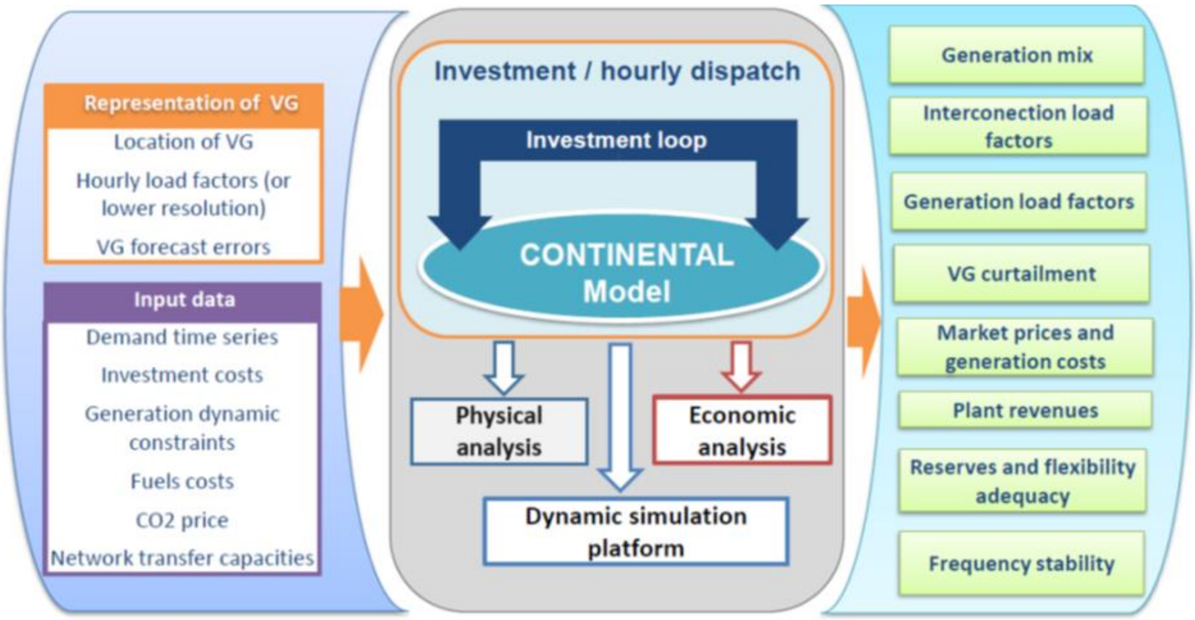


FIGURE 8-2 : CONTINENTAL METHODOLOGY (VG: VARIABLE GENERATION)

8.3 RESULTS AND EVIDENCE OF MAINTAINING SYSTEM ADEQUACY AND SUPPORTING RES INTEGRATION

In this section, the impact of vRES providing reserves on the need for peaking units is first discussed. The technical and economic implications of the integration of batteries and EV smart charging the European power system and their impact on improving VRES integration, and the use of their capacities, are then considered.

8.3.1 IMPACT OF VRES PROVIDING RESERVES

Figure 8-3 shows the annual share of reserves for each technology that is capable of contributing to reserves in the CONTINENTAL model. When wind provides reserves, it contributes to 8% of the total reserve requirement at a European level. When solar can also provide reserve, the impact on the European power system reserve requirement is small with solar contributing to 0.5% of the requirement. However, for some countries, the share provided by solar is higher. It reaches 8% in Switzerland and 2.4% in Portugal. This is explained by the mix in these two countries. In Switzerland, the installed capacity of solar is much higher than the installed capacity of wind whereas in Portugal, very few thermal plants are installed and therefore available for reserves. Thus, in Portugal a significant portion of the reserve requirement must be met by renewables.

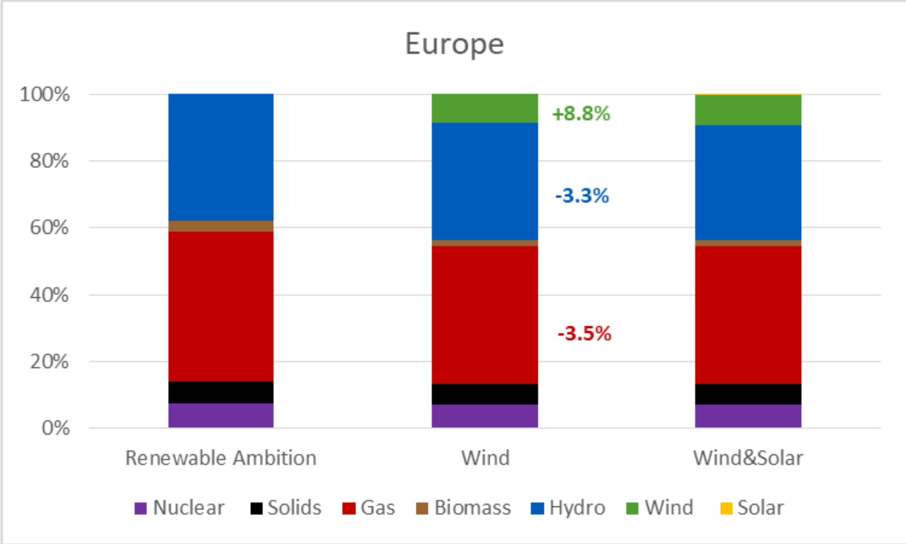


FIGURE 8-3 : EVOLUTION OF RESERVES ALLOCATION BY TECHNOLOGY (%)

The contribution to reserves provided by vRES varies highly by country as shown in Figure 8-4. It is higher in countries with very high shares of vRES and fewer thermal plants. vRES provide 72% of the total reserve in Portugal and 41% in Denmark. For countries like Germany, France, the UK or Italy, wind provides only a small share of reserves in this particular model despite representing a larger share of vRES in energy generation. Hours when vRES generation exceeds demand is limited in these countries in the model results, because vRES generation in the model is prioritised to provide energy, and reserves are therefore not allocated to vRES, but to other technologies.

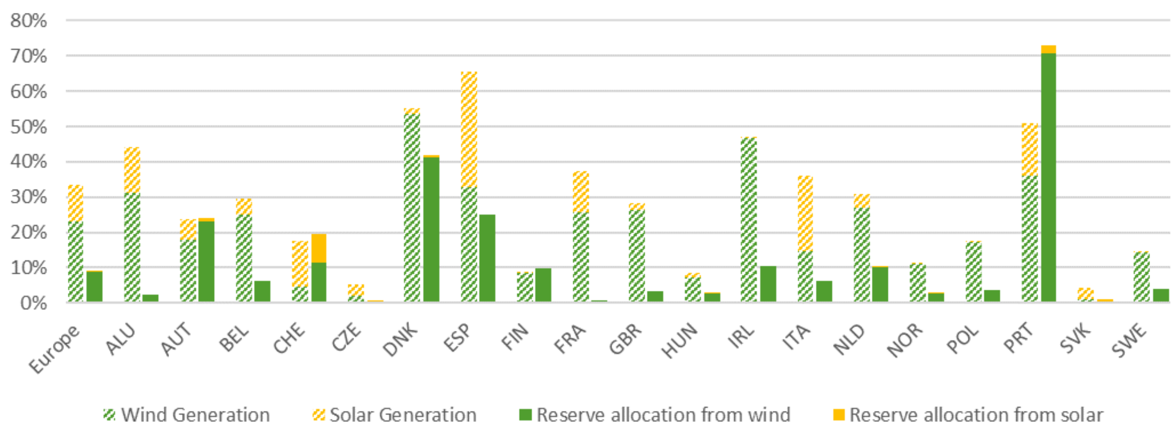


FIGURE 8-4 : SHARE OF WIND AND SOLAR IN GENERATION AND IN RESERVE ALLOCATION BY COUNTRY

The reserves provided by each technology type are shown in Figure 8-5 for Europe. For the baseline scenario, gas provides the majority of reserves (45%) followed by hydro (38%), nuclear (7%), coal (7%) and biomass (3%). When wind provides reserves, the reserves provided by gas plants and hydro generation are displaced. The replacement of gas reserves by wind and solar reserves leads to a 8.3TWh decrease in gas production for Europe and, therefore, a drop of 3.5 Mtons of CO_2 at European level. It also leads to a 1.3TWh decrease in curtailment at the European level, and in Spain curtailment it drops by 21% compared to the case without reserve provision from vRES, as vRES capacities are used for reserves as well vRES provision of reserves decreases the need to resort to fossil peaking units to do so, supporting vRES integration and providing option to address system adequacy.

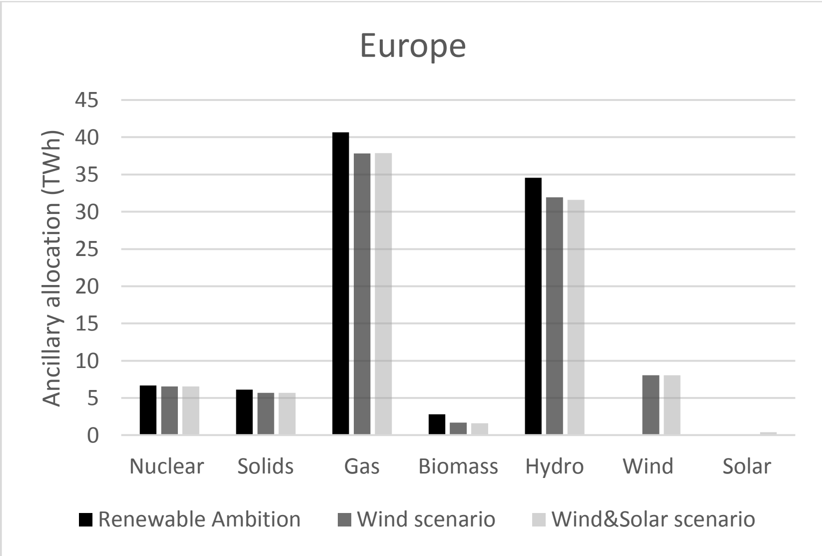


FIGURE 8-5 : EVOLUTION OF ANCILLARY ALLOCATION BY TECHNOLOGY (TWH) FOR DIFFERENT SCENARIOS

The case of Spain is detailed in Figure 8-6. It shows that reserves from wind replace reserves provided by gas and hydro. For Germany, results show that reserves from wind are replacing reserves provided by coal CCS.

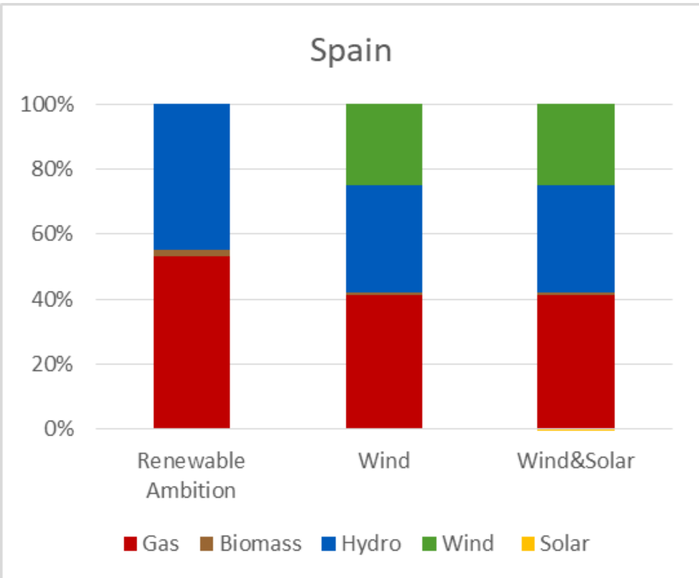


FIGURE 8-6 : COMPARISON OF RESERVE ALLOCATION FOR SPAIN

An example of a generation and reserves schedule in Spain for a six-day period in July 2030 is shown in Figure 8-7. The reader is reminded that the modelling assumes that wind reserves are called upon before solar reserve provision. The graph shows that reserves are provided by wind (green), at midday when vRES represents almost all of the generation. Generation at these times covers not only consumption but also allows for exports and hydro pumping. In the baseline scenario (Renewable Ambition) , if gas plants are used to supply reserves, vRES curtailment is high. If the modelling did not give priority to wind for reserves, the graph would have shown that solar could have provided reserves at that time. It should be noted that wind does not provide reserves at night because there is no excess variable generation and reserves are provided by technologies with a higher cost.

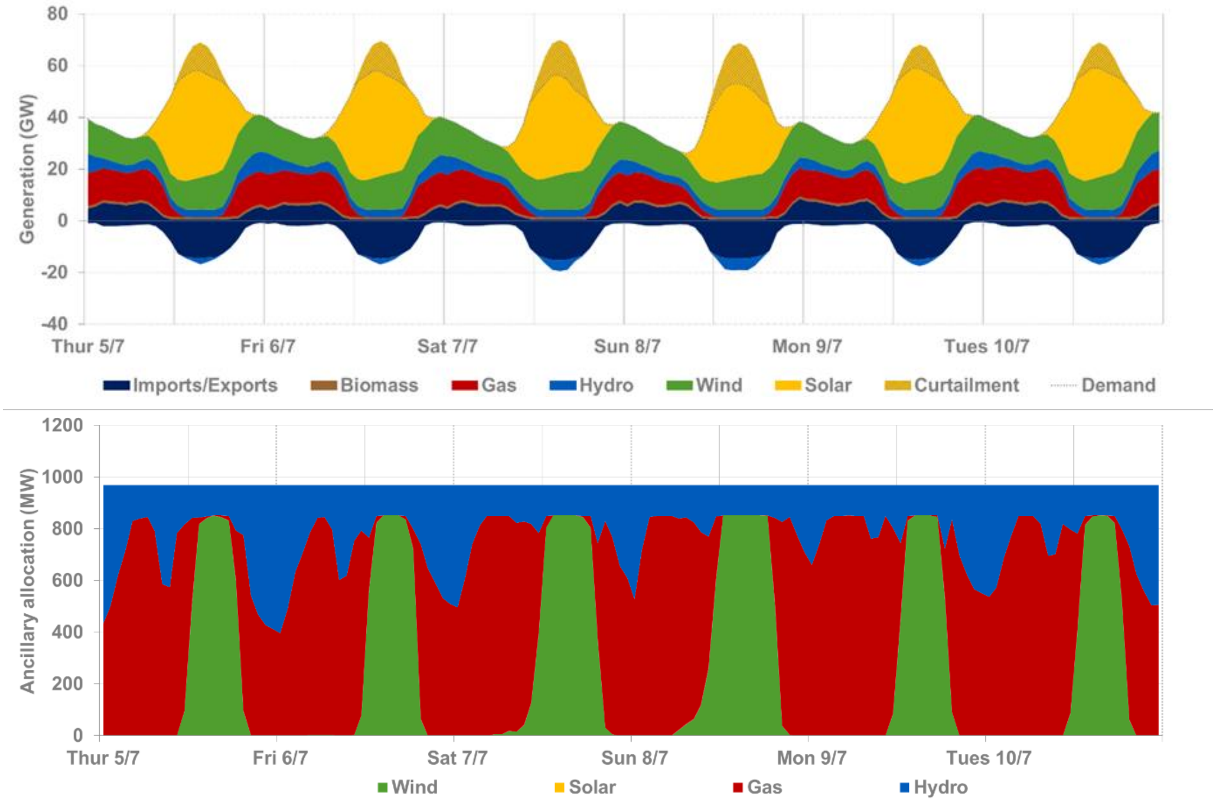


FIGURE 8-7 : SIX-DAY PERIOD OF GENERATION AND ANCILLARY ALLOCATION IN SPAIN WHEN WIND HAS PRIORITY OVER SOLAR FOR PROVIDING RESERVES

The main conclusions that can be drawn include the fact that when wind provides reserve, it replaces reserves provided by other technologies, in particular gas plants, and thus helps to lower curtailment, as well as CO_2 emissions. Additionally, in countries with very high shares of vRES, vRES has to provide reserve, to meet the reserves requirements. If wind provides reserve, adding reserve from solar has little impact for most European countries. Finally, by lowering the use of fossil peaking plants and thus lowering vRES curtailment, system adequacy is achieved at a lower cost, RES integration is supported and there is a reduction in CO_2 emissions.

8.3.2 IMPACT OF CROSS-BORDER INTERCONNECTIONS ON SYSTEM ADEQUACY

Figure 8-8 shows that increasing interconnections allows a significant reduction of the gas installed capacity in Europe and by consequence a drop of CO_2 emissions by almost 6%.

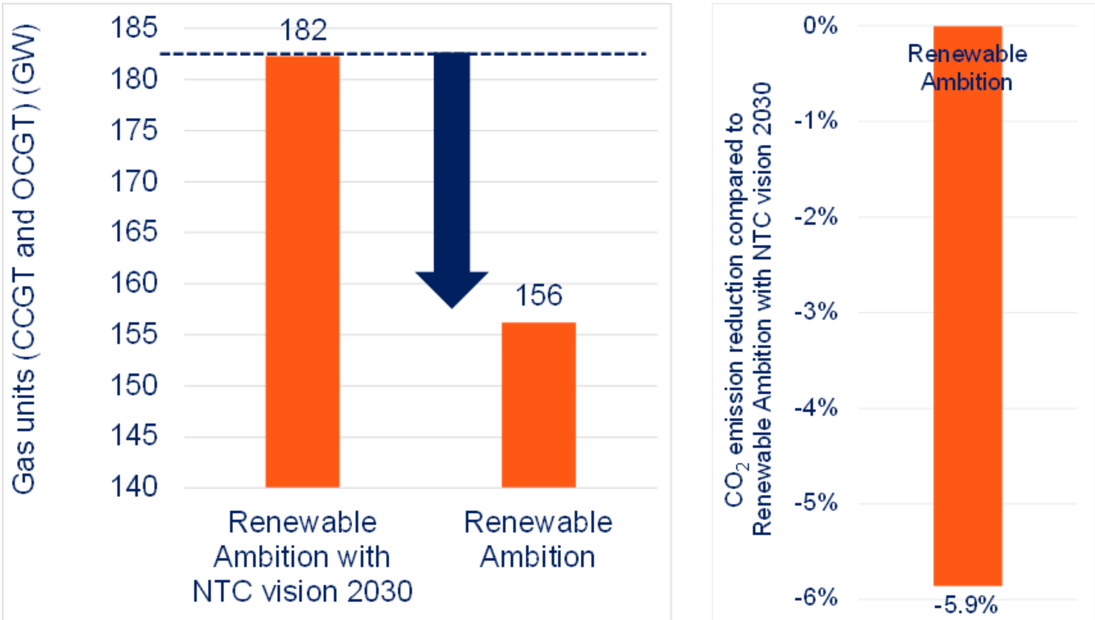


FIGURE 8-8 : GAS UNITS INSTALLED CAPACITY IN EUROPE IN THE RENEWABLE AMBITION SCENARIO WITH NTC VISION 2030 AND THE RENEWABLE AMBITION (ON THE LEFT); CO_2 EMISSION REDUCTION IN THE RENEWABLE AMBITION COMPARED TO THE RENEWABLE AMBITION NTC VISION 2030 (ON THE RIGHT)

An optimistic NTC development across Europe largely contributes to the integration of vRES and supports system adequacy by providing a route to additional demand in neighbouring countries for surplus vRES. NTC is considered as a potential option for countries to share vRES production, reduce curtailment and reduce the need for load-shifting, in particular in peninsulas like Spain. Interconnections consequently reduce the need for gas-fired peaking plants.

8.3.3 IMPACT OF DEPLOYING BATTERIES AND EV SMART CHARGING ON GENERATION CAPACITIES

As shown on Figure 8-9, total gas (CCGT + OCGT) installed capacity is reduced at European level with the deployment of the technologies that are being considered in this chapter. From section 8.2.1.2, EV smart charging deployment over Europe in the model, and based on the modelling assumptions, results in 5 times more EV capacity installed than when batteries are deployed in the model, thus reducing the need for back-up capacities to support the integration of vRES. An additional, although small, capacity is installed whenEV adoption of V2G is considered.

Installing 33.8 GW of batteries in Europe (25.3 GW in Spain) replaces 12 GW of gas capacity, of which 10 GW is decommissioned in Spain. This result comes from the fact that 4h-batteries help support the integration of vRES, especially in peninsulas with high shares of VRES and limited interconnection capacity. Their integration reduces the need for vRES back-up capacity. The capacity credit is defined as the capacity of dispatchable power plants that a given unit or technology can replace to meet the system demand without compromising system reliability [56]. In this scenario, in Europe, the capacity credit of batteries is 35% (40% in Spain). With the assumption of V1G EV charging, twice as many gas units are displaced than the amount displaced when batteries are deployed, and this reduction is well spread over countries. Proportionally, EV contribution to peak demand is however lower and amounts to 15% in the V1G scenario (16% with additional V2G deployment). This can be explained by the fact that in the baseline scenario, EV charging occurs mainly at night and is not concentrated during the evening peak (thus there is little potential for the share of the EV charging power to be displaced from the annual peak hour as this hour is already being avoided).

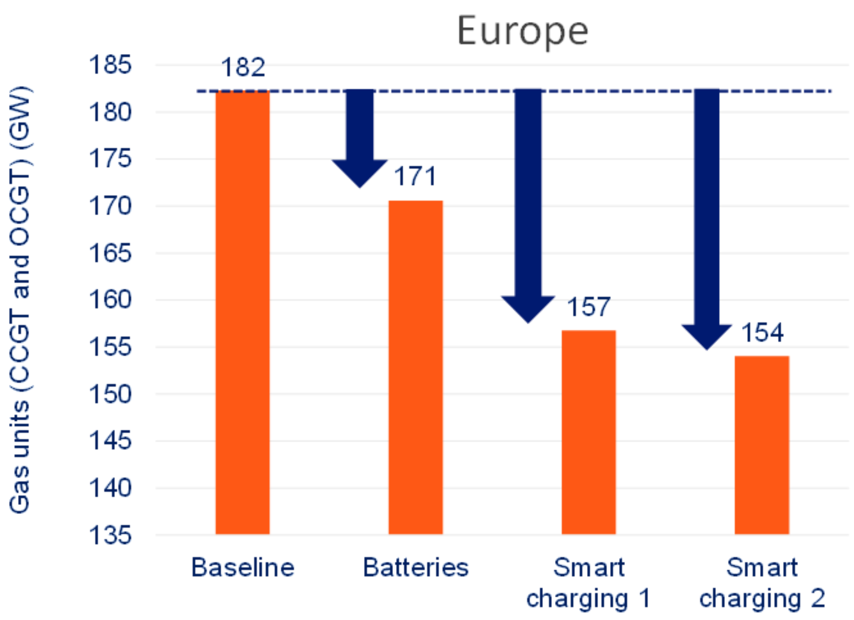


FIGURE 8-9 : GAS UNITS INSTALLED CAPACITY IN EUROPE DEPENDING ON THE TECHNOLOGY DEPLOYED

The share of CCGTs and OCGTs in the optimal European power mix including the technologies under investigation in this chapter is shown on Figure 8-10. The introduction of stationary batteries mainly displaces gas units in Spain however the ratio of CCGT to OCGT remains the same. The introduction of EV smart charging results in a shift towards more OCGT peaking units compared to baseload CCGT in the European power mix. This effect is slightly more pronounced with the presence of V2G. Indeed, smart charging flattens the residual demand curve thus the CONTINENTAL model favours baseload generation over peaking units. Even if the total gas capacity is decreased, the model favours investment in less CAPEX intensive and more flexible power plants. In that sense, the CO_2 price considered would have a key influence on the resulting composition of the power mix. The higher the CO_2 price is, the fewer OCGT units will be installed and this will directly influence the direct CO_2 emissions.

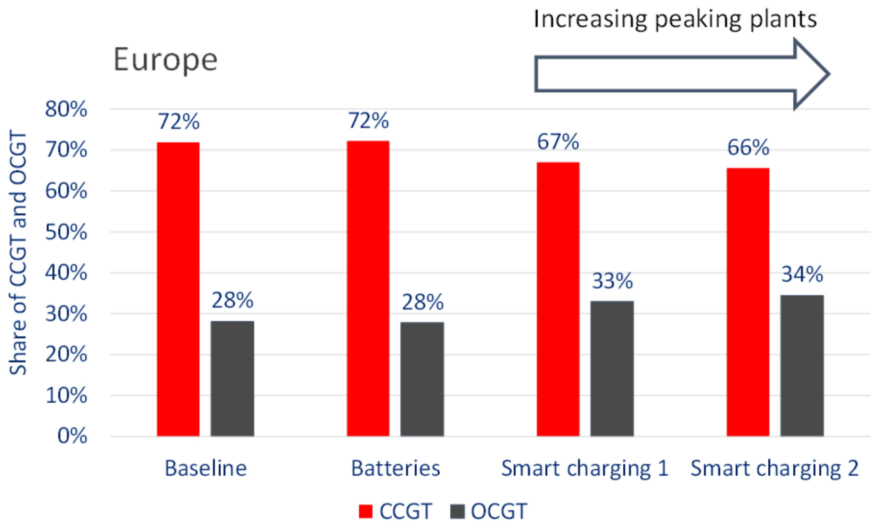


FIGURE 8-10 : SHARE OF CCGT AND OCGT IN EUROPE DEPENDING ON THE TECHNOLOGY DEPLOYED

In summary, the need for gas power plants is reduced with the integration of batteries, mainly in peninsulas like Spain. EV smart charging displaces twice as many gas units compared to batteries alone, and V2G integration slightly increases this effect. EV smart charging induces a shift from CCGT to more flexible but more CO_2-emitting OCGT peaking units, which is slightly amplified with the integration of V2G.

8.3.4 IMPACT OF INTEGRATION OF BATTERIES AND EV SMART CHARGING ON CURTAILMENT

Reduced curtailment in high vRES scenarios is indicative of better use of the installed capacities and a more efficient system. In this section, the definition of curtailment is used loosely to describe the number of hours when variable generation exceeds demand, and has to be either displaced (stored), exported, or effectively curtailed. It does not refer to curtailment as a preventive action to ensure balancing and stability. This share of vRES production in surplus is displayed for Europe and Spain in Figure 8-11.

With the deployment of batteries, Europe reduces vRES curtailment by 66%. The distribution is however not uniform. Spain reduces vRES curtailment by 77%, while curtailment is reduced, at most, by 35% in the other European countries. This leads to a mean value of 66% reduction over Europe. This figure of 35% shows that batteries are mainly charging outside the hours when RES generation exceeds demand in all countries except for Spain, where it highly contributes to the reduction of curtailment. Overall, it can also be observed that for a large part of the time, battery arbitrage is based on the differential between OCGT and CCGT variable cost.

With EV smart charging, curtailment reduction occurs in most countries, but to a lesser extent in Spain. This reduction is slightly increased with V2G integration. The Spanish curtailment increase with EV smart charging compared to batteries results in the slight curtailment increase in Europe between the batteries scenario and the EV smart charging scenarios. Given the EV deployment in Spain, curtailment still amounts to 15 to 20 TWh, thus giving economic space for stationary batteries development (10 to 15 GW as a first approximation for arbitrage on the energy-only market). In other European countries, batteries development is competing with the deployment of EV smart charging, and in an even more pronounced way with V2G development.

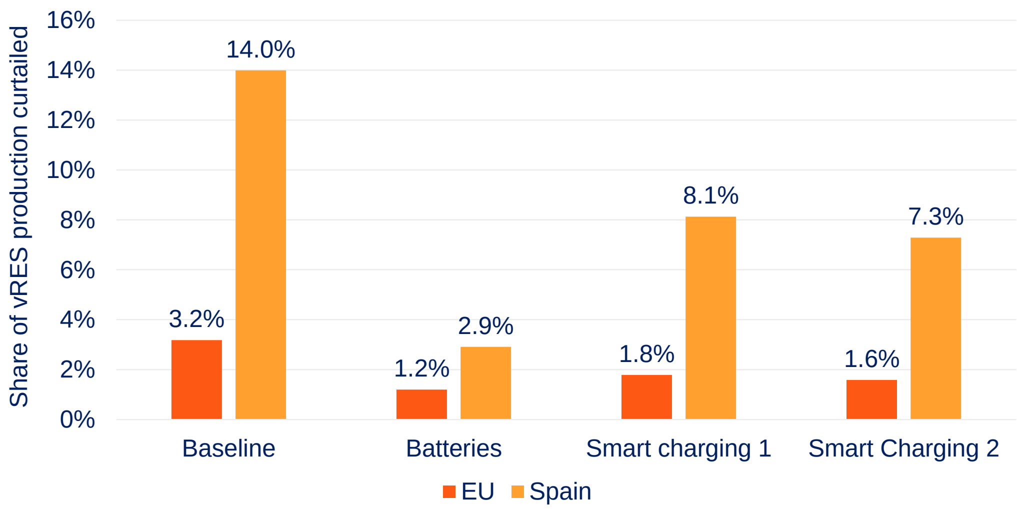


FIGURE 8-11 : SHARE OF VRES PRODUCTION THAT IS CURTAILED DEPENDING ON TECHNOLOGY DEPLOYMENT, IN EUROPE AND IN SPAIN

With battery integration, curtailment is greatly reduced in Spain. EV smart charging has an impact on curtailment for most countries, but to a lesser extent in Spain. Both technology options improve the use of RES capacities in Europe, and thereby can help contribute to the maintenance of system adequacy.

In summary, the potential for stationary batteries depends on other the technologies available in the European power system and batteries are competing with EV smart charging deployment. With EV smart charging deployed, the economic potential for batteries is mainly in peninsulas like Spain, where hours when RES generation exceeds demand are still numerous. These considerations do not include any additional possible revenues from systems services and intra-day markets

Hourly schedules are shown in Figure 8-12 to Figure 8-19 below for typical surplus situations in summer and for shortfall situations in winter with the different technologies integrated into the European power system. Schedules are presented for Spain which is very specific given its high shares of vRES and limited interconnections.

Hourly schedules for a representative week in summer in Spain are displayed in Figure 8-12 to Figure 8-15. It can be seen that curtailment is strongly reduced at mid-day with the introduction of batteries in Spain as well as in neighbouring countries (due to ability to export from Spain). In Spain, the EV deployment potential (V1G) is not as impactful as batteries and thus reduces curtailment to a lesser extent. This is specific to Spain. The case with V2G also has little impact. Furthermore, gas production is reduced, in a more pronounced way with batteries (specific to Spain, there is a more pronounced reduction of gas production in interconnected countries in the EV scenarios). Batteries are discharging surplus energy during the evening peak and night and exporting part of it to neighbouring countries.

Hourly schedules for a representative week in winter in Spain are displayed in Figure 8-16 to Figure 8-19. It can be seen that in winter batteries support the avoidance of curtailment as well as avoidance of loss of load hours. The duration of the storage from batteries and EVs is yet not sufficient to meet peak hours and thus gas production continues to be necessary. Batteries are frequently charging and discharging while gas units are producing and creating price differentials between CCGT and OCGT. EV smart charging is more efficient in reducing loss of load hours due to the high duration of the storage but gas production is less reduced than with batteries (specific to Spain). This situation is improved with V2G integration.

In summary, storage either through stationary batteries or EVs helps with integrating large volume of vRES in peninsulas such as Spain. Batteries are showing better results and a real potential in peninsulas compared with interconnected countries.

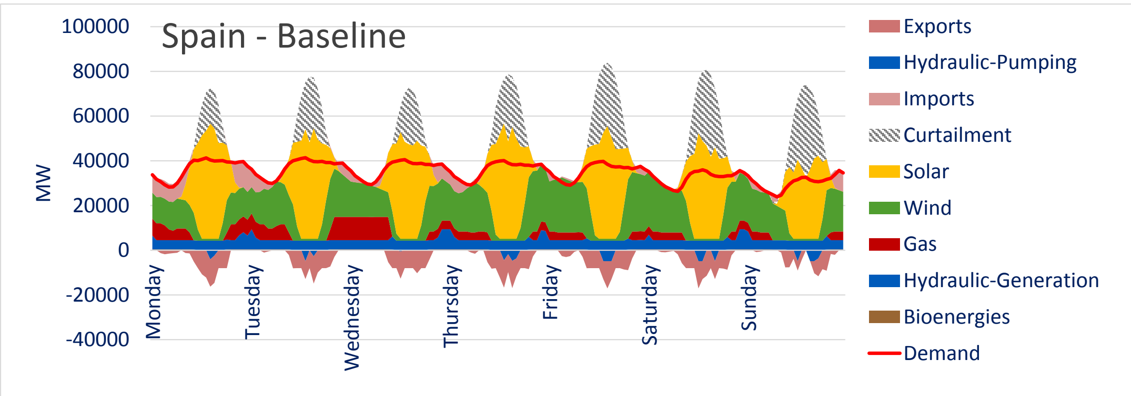


FIGURE 8-12 : HOURLY DYNAMICS FOR THE BASELINE SCENARIO IN SPAIN – JULY, WEATHER YEAR 1974

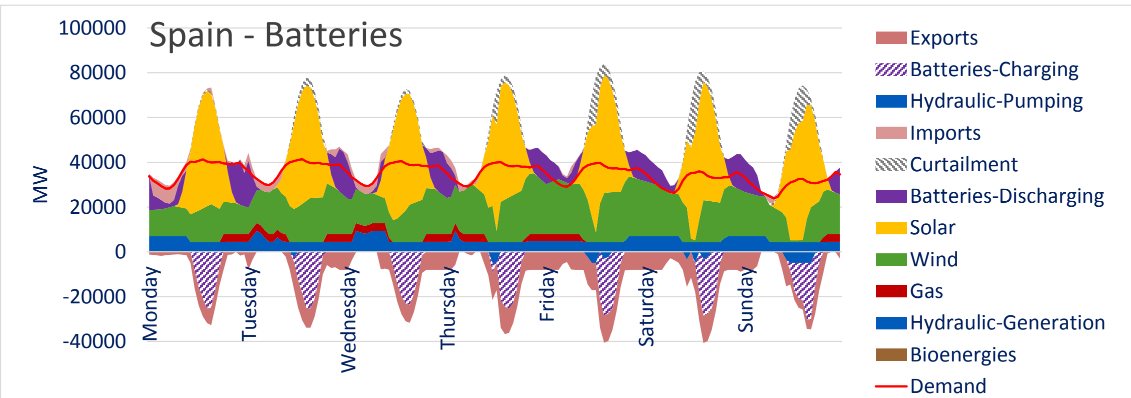


FIGURE 8-13 : HOURLY DYNAMICS FOR THE BATTERIES SCENARIO IN SPAIN – JULY, WEATHER YEAR 1974

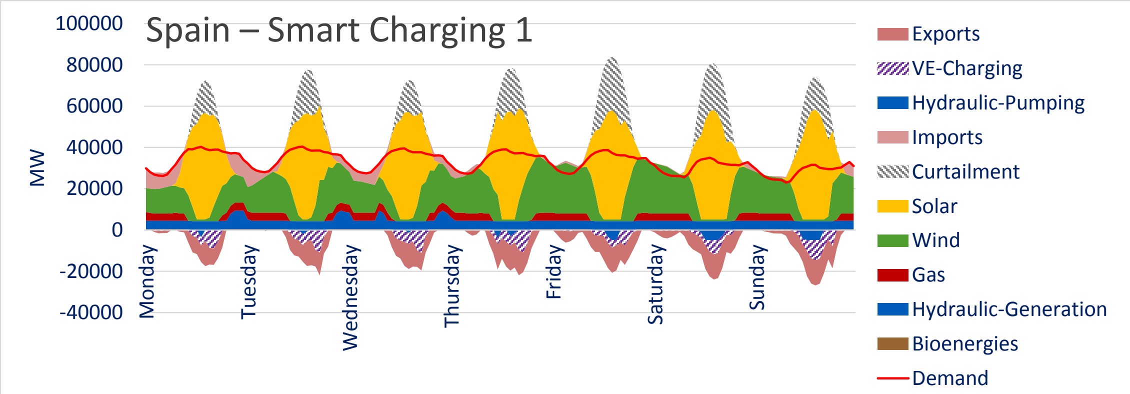


FIGURE 8-14 : HOURLY DYNAMICS FOR THE EV SMART CHARGING 1 SCENARIO (100% V1G) IN SPAIN – JULY, WEATHER YEAR 1974

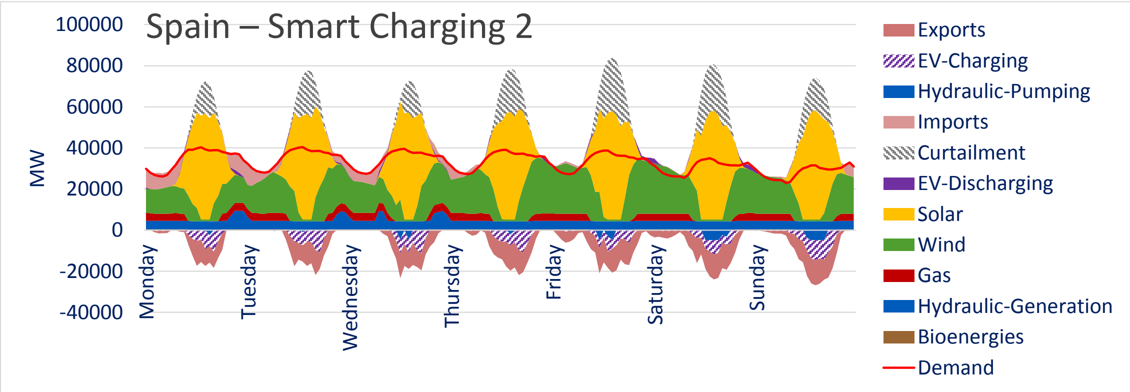


FIGURE 8-15 : HOURLY DYNAMICS FOR THE EV SMART CHARGING 2 SCENARIO (80% V1G, 20% V2G) IN SPAIN – JULY, WEATHER YEAR 1974

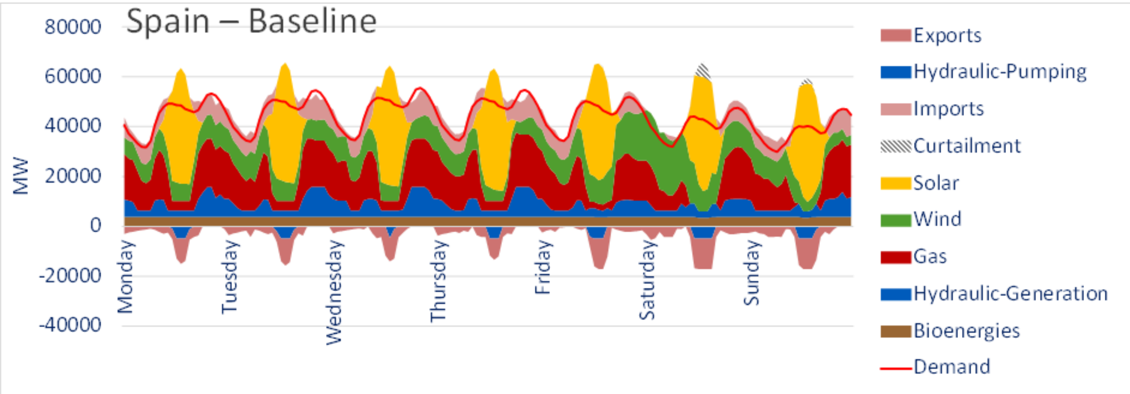


FIGURE 8-16 : HOURLY DYNAMICS FOR THE BASELINE SCENARIO IN SPAIN – JANUARY, WEATHER YEAR 1996

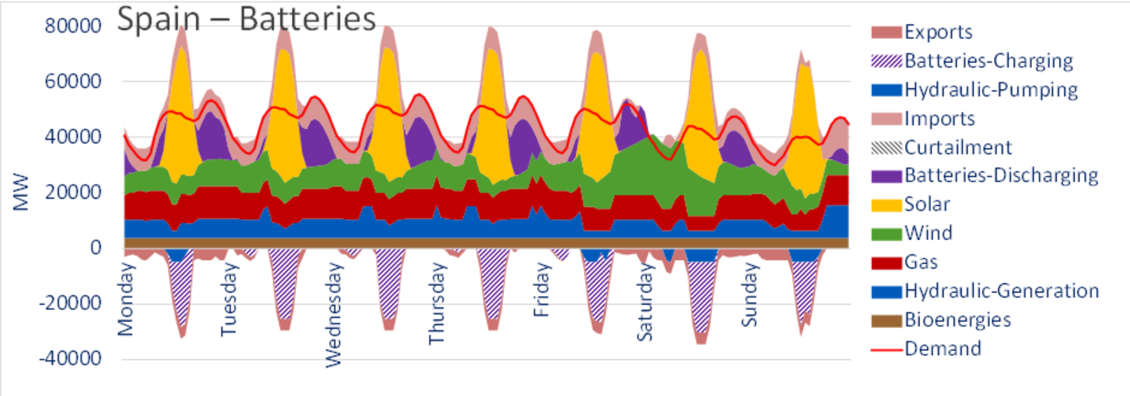


FIGURE 8-17 : HOURLY DYNAMICS FOR THE BATTERIES SCENARIO IN SPAIN – JANUARY, WEATHER YEAR 1996

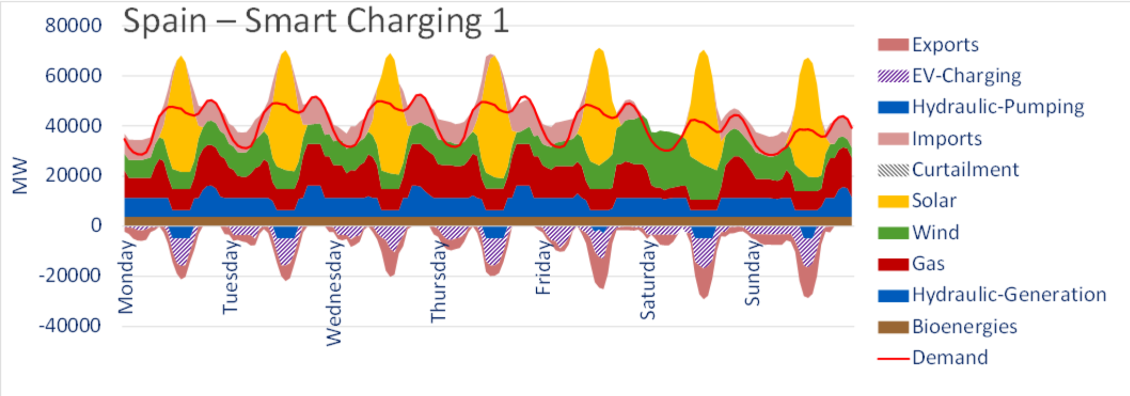


FIGURE 8-18 : HOURLY DYNAMICS FOR THE EV SMART CHARGING 1 SCENARIO (100% V1G) IN SPAIN – JANUARY, WEATHER YEAR 1996

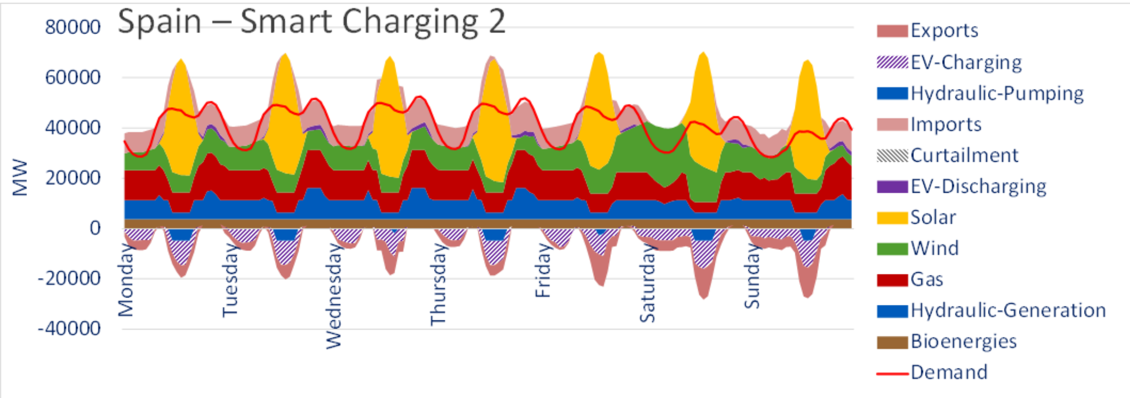


FIGURE 8-19 : HOURLY DYNAMICS FOR THE EV SMART CHARGING 2 SCENARIO (80% V1G 20% V2G) IN SPAIN – JANUARY, WEATHER YEAR 1996

8.3.5 IMPACT OF STORAGE FOR MITIGATING CO_2 EMISSIONS

An efficient integration of RES in the power system should translate in CO_2 reductions, the ultimate goal of the low-carbon energy and climate change policies. The improvement in CO_2 emissions thanks to the integration of storage (i.e. batteries and EVs) is illustrated in Figure 8-20, shown as the reduction in percentage compared with the Baseline scenario.

Introducing EV smart charging doubles the direct CO_2 emission reduction compared to an economic integration of batteries. This is directly linked with the reduction of gas production with EV smart charging compared to batteries in Europe. This effect is however the opposite of what is seen in Spain where EV smart charging offers less flexibility capacity and thus results in higher fossil production compared to the batteries scenario. In the meantime, the increase of baseload low carbon production (nuclear and other renewables) three times higher with EV smart charging compared to batteries and vRES production is less curtailed.

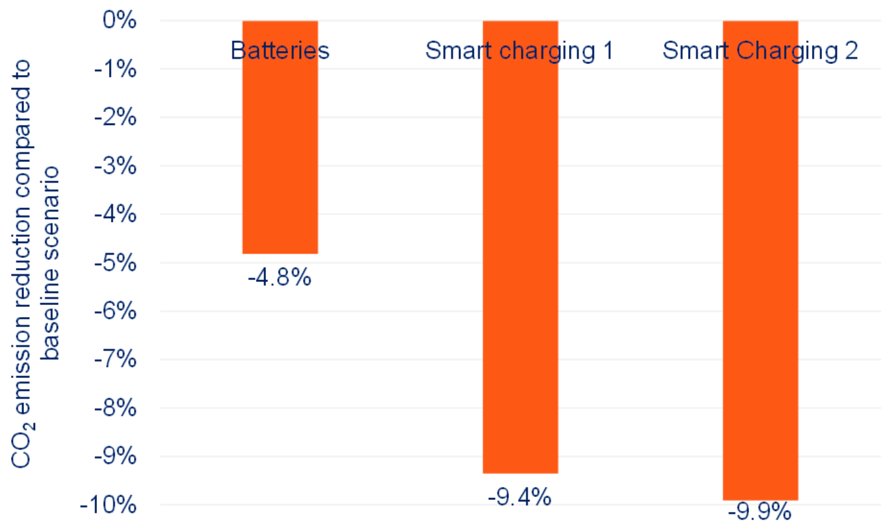


FIGURE 8-20 : DIRECT CO2 EMISSION REDUCTION WITH THE DIFFERENT TECHNOLOGIES CONSIDERED COMPARED TO THE BASELINE SCENARIO

In summary, the technologies considered have positive impacts on CO_2 emissions reduction. More evenly spread through Europe, and allowing for a larger volume of surplus variable generation stored, EV smart charging halves the CO_2 emissions compared to the scenario with an economic integration of batteries.

8.3.6 RESULTS ON ECONOMIC INDICATORS

Task 2.5 underlined the financial gap and investment risks associated with a high RES system with increasing hours of excess supply and lost generation. A more efficient integration of RES than that seen in the baseline scenario could be achieved through adoption of some of the technologies discussed in this chapter (batteries and EVs), and should show in the economic indicators.

8.3.6.1 IMPACT ON OVERALL SYSTEM PRODUCTION COST

This section focuses on the change of the European power system total production costs with the addition of the different technology options considered in this chapter. Production costs include fixed (O&M and investment costs) and variables costs (i.e. mostly fuel and CO2 costs). The costs are computed using O&M and investment costs assumptions coming from WEO (2018) and RTE (2017) as well as the different installed capacities and energy produced. Additional investment costs linked to network development are not taken into account, nor additional costs linked to the deployment of EVs, V1G and V2G charging/discharging modes.

The European power system total production cost is shown on Figure 8-21 for the three different technologies considered; batteries, EV smart charging 1 and EV smart charging 2.

Furthermore, EV smart charging deployment leads to a higher decrease in total production cost than batteries. The reduction in gas production is concentrated in the peninsulas in Continental Europe, and it also includes batteries additional investment costs. For EV smart charging, the impact is widespread in Europe and therefore enhances the decrease of variables costs by favouring baseload production and by displacing gas units investment and production. Moreover, EV batteries are present in the power system as a result of the reasonable assumption that they are financed via private investment, as discussed earlier. With V2G integration, the total system production cost is slightly decreased compared to the scenario with 100% V1G: better use of baseload units and CCGT instead of OCGT.

Introducing batteries has a small effect in decreasing total production cost since its effects are concentrated in peninsulas and investment costs are taken into account. With a widespread effect over Europe, EV smart charging has a bigger impact in reducing production cost, to a greater extent with V2G, considering that the EV charging installation cost is assumed to be already accounted for through the use of EVs for mobility use.

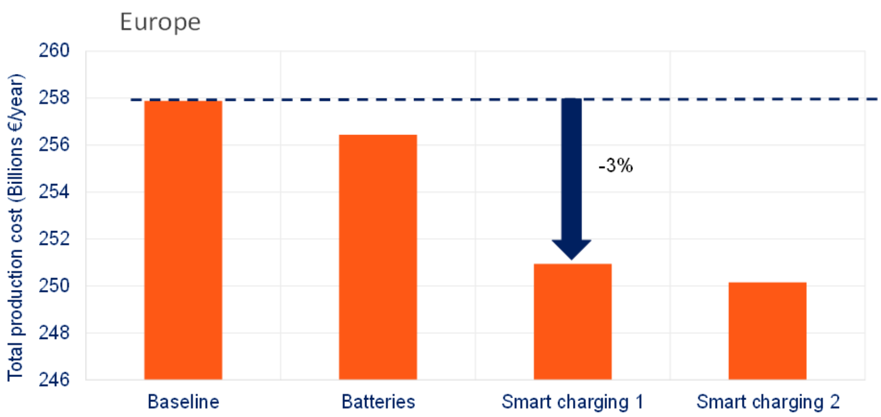


FIGURE 8-21 : EUROPEAN POWER SYSTEM TOTAL PRODUCTION COST DEPENDING ON THE TECHNOLOGY DEPLOYED IN EUROPE

8.3.6.2 IMPACT ON AVERAGE MARGINAL COST

This section looks at the impact of the different technologies on the marginal costs in the European power system. System marginal costs can be interpreted as electricity prices, under the assumption of perfect competition within an energy-only market, and thereby gives an overview of the trend of the revenues that can be expected by producers with this type of market design. For more discussion on different market design options being considered in EU-SysFlex, the reader is directed to Deliverable 3.2 [3].

Hourly system marginal costs are obtained with the detailed optimisation model described in Section 8.2. They are computed for each country in Europe, taking into account interconnection constraints, 165 annual combined climate years and outage scenarios and with a 3 hours of loss of load constraint. The CO_2 price is €90/tCO2.

In the graphs below (Figure 8-22 to Figure 8-25), average marginal cost profiles are displayed over a day in winter and in summer for Spain and France for the different sensitivities: baseline, batteries, EV smart charging 1 and EV smart charging 2. France is chosen to represent typical schedules observed in interconnected countries. Resulting average marginal costs in Spain are specific to its situation with high vRES development and limited interconnections.

Introducing the different technologies has the effect of smoothing marginal cost during the day. Globally, marginal costs are reduced during evening peaks and night in winter while increased during off-peak hours at mid-day, early morning as well as during week-ends.

In Spain, the economic introduction of batteries induces a higher smoothing effect than the introduction of EV smart charging, given the EV fleet deployment assumptions. Batteries capacity potential to absorb surplus at mid-day is indeed twice as high as the EV smart charging potential in the studied scenario. The displacement of EV consumption from peak to off-peak hours allows ta reduction of gas production at the evening peak but this is not sufficient for a switch to lower variable cost units. This reduction is however increased with V2G. Moreover, reduction of marginal cost appears also at night as there is more potential of EV charging displacement compared to the baseline scenario.

In other well interconnected countries like France, the impact of EV smart charging on smoothing average marginal costs is higher than with the economic introduction of batteries. We can see a significant reduction of the evening peak and a significant increase in the early-morning (a minimal charging level has to be met in the morning to answer mobility constraints) and at mid-day in winter. In summer, the increase is mainly concentrated at mid-day.

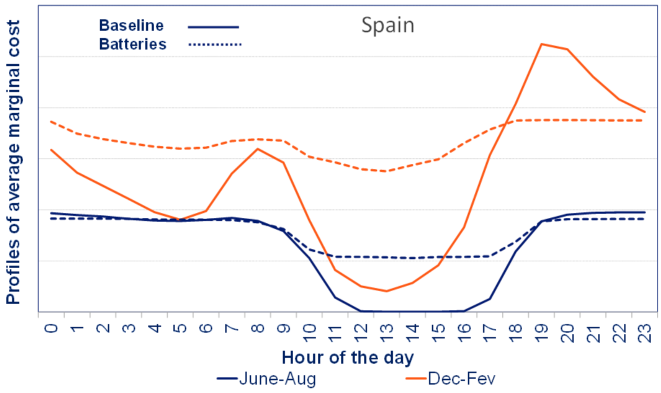


FIGURE 8-22 : AVERAGE MARGINAL COST FOR SPAIN IN THE BASELINE SCENARIO AND IN THE BATTERIES SCENARIO

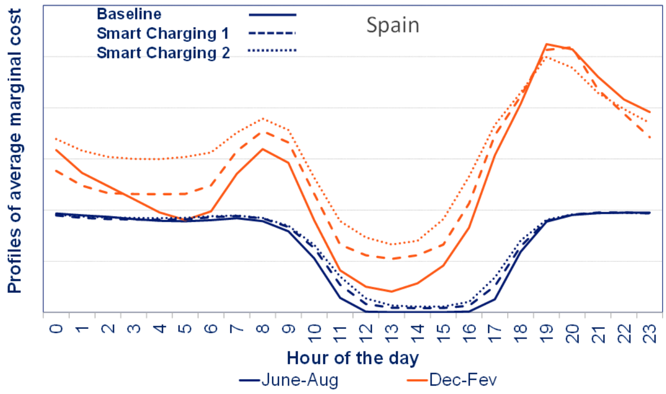


FIGURE 8-23 : AVERAGE MARGINAL COST FOR SPAIN IN THE BASELINE SCENARIO AND IN THE TWO EV SMART CHARGING SCENARIOS

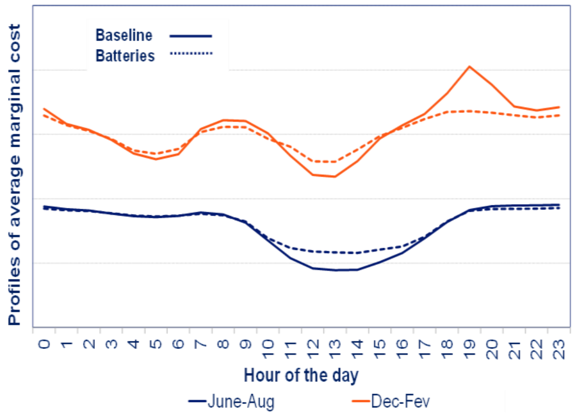


FIGURE 8-24 : AVERAGE MARGINAL COST FOR FRANCE IN THE BASELINE SCENARIO AND IN THE BATTERIES SCENARIO

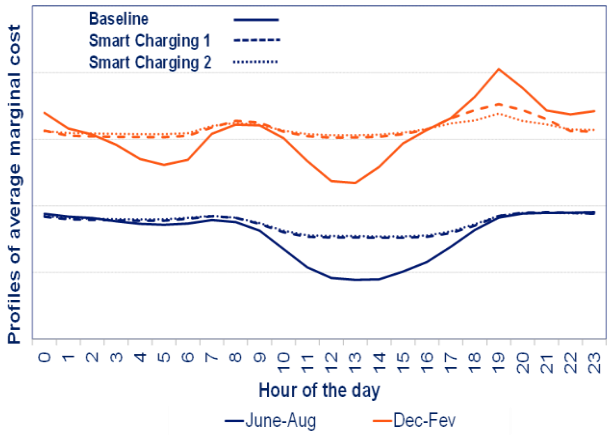


FIGURE 8-25 : AVERAGE MARGINAL COST FOR FRANCE IN THE BASELINE SCENARIO AND IN THE TWO EV SMART CHARGING SCENARIOS

To summarise, the change in marginal costs mainly happens at mid-day in summer but is more spread over a day during winter. V2G introduction results in a smoothing of average marginal costs. Introducing flexibility solutions has the tendency to smooth the average marginal cost along the day. While this effect is more pronounced with batteries in Peninsulas like Spain, it is more pronounced with EV smart charging in interconnected countries like France.

8.3.6.3 IMPACT ON VRES REVENUES FROM THE ENERGY MARKET

Having investigated projected marginal costs on the energy-only market, whether or not energy-only market revenue covers the costs for vRES generation is analysed. In EU-SysFlex Task 2.5, integration costs of vRES have been explored through their market value and the market value of vRES decreases with their penetration levels revealing the so-called self-cannibalisation effect [4]. Technologies such as those explored in this chapter could be key assets to decrease vRES integration costs. This is explored in this section thanks to the evaluation of vRES market revenues from the energy-only market, comparing them with projected costs at this time horizon.

Solar, onshore wind and offshore wind market revenues are displayed respectively on Figure 8-26, Figure 8-27 and Figure 8-28 for the baseline scenario and for batteries and EV smart charging sensitivities. Overall in Europe, vRES receives higher revenues with the deployment of storage. 4h Batteries integration increases the value of each vRES asset but with a more pronounced effect for solar. The battery storage duration complements the solar production concentrated at mid-day. EV smart charging with V1G and V2G also increases vRES revenues in the energy only market with a stronger effect for wind than for solar in comparison to batteries (EV storage duration has a better match with wind in comparison to 4h batteries). This result is in line with section 8.3.6.2 since EV smart charging has a more pronounced effect in smoothing marginal costs than batteries in European interconnected countries. Overall, the smoothing effect will have the effect of cannibalising arbitrage potential on the energy-market and revenues for storages assets like batteries, thus limiting to some extent the economic development of the technologies considered in this chapter.

To go further into the analysis, contrasted effects have been observed between countries. While solar revenues are highly benefiting from batteries integration in Spain and largely exceeding projected costs, EV smart charging induces however a much smaller benefit for solar for which revenues hardly reach equilibrium. This result confirms the need for other options such as batteries storage to complement EV smart charging development in Spain. In France, whereas solar revenues are highly benefiting from storage integration, the effect on wind is inverted. Even if onshore and offshore wind revenues are increasing with EV smart charging in comparison to the case with batteries, they are lower than in the baseline scenario and this in particular jeopardises the financial viability for offshore wind. In this case, the decrease of market prices during peak hours and at night in winter surpasses market marginal cost increase at midday and early morning.

The technologies considered in this chapter are complementary and could be encouraged jointly and incentivised via the right market design in order to reduce the integration cost of vRES, reduce their market risk exposure and decrease the need for carbon intensive back-up peaking units as much as possible. While their deployment increases the vRES share on the power system, it has to be noticed that the more vRES there is in the power system, the lower the marginal price in the energy-only market and thus there is a decreased market value with associated with their integration – this is the cannibilisation effect. On the other hand and as pointed out in previous section, economic integration of storage is capped given the assumptions made here and the self-cannibalisation effect as well as the reduced arbitrage potential with their increasing penetration level in an energy-only market. An equilibrium must then be found between both developments (i.e. between vRES and other technologies, such as those explored in this chapter) otherwise subsidies would still be needed, or an additional revenue stream, which could come from a system services market. If vRES penetration rate is too strong compared to deployment of complimentary technologies like storage or demand-side management, the self-cannibalisation effect could override flexibility solutions effects. Energy-only market design only works (i.e., ensure cost recovery) if the energy power mix (in particular the share of vRES) is freely defined by the market. If the share of vRES is imposed exogenously (for instance by political will), other long-term mechanisms should be added to the market design to ensure cost recovery. System services markets could provide a lucrative revenue stream for the types of technologies explored in this chapter as they have the capability (although not demonstrated in this chapter) to provide a wide range of system services. The benefit of a system services market is that it incentivises investment, through the provision of an additional revenue stream, in the technologies and capabilities that are need to support vRES integration and the continued operation of a safe secure and reliable power system.

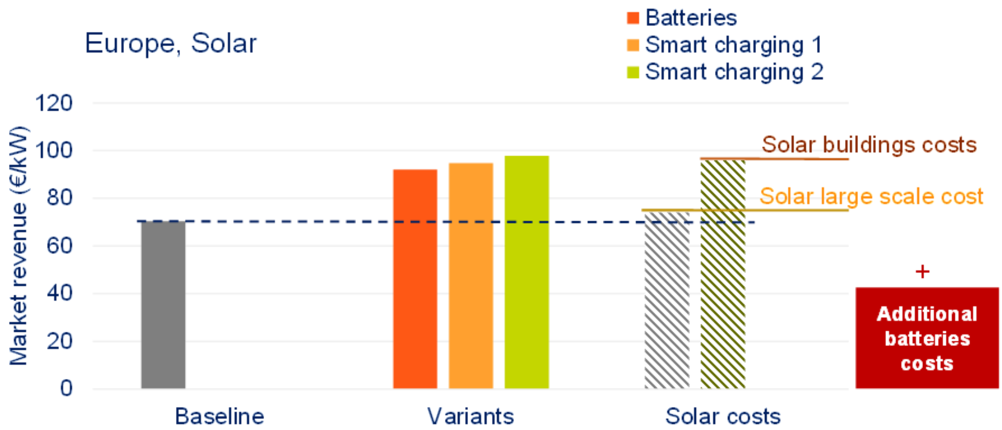


FIGURE 8-26 : AVERAGE ANNUAL MARKET REVENUE AND COSTS FOR SOLAR PV IN EUROPE DEPENDING ON THE TECHNOLOGIES DEPLOYED

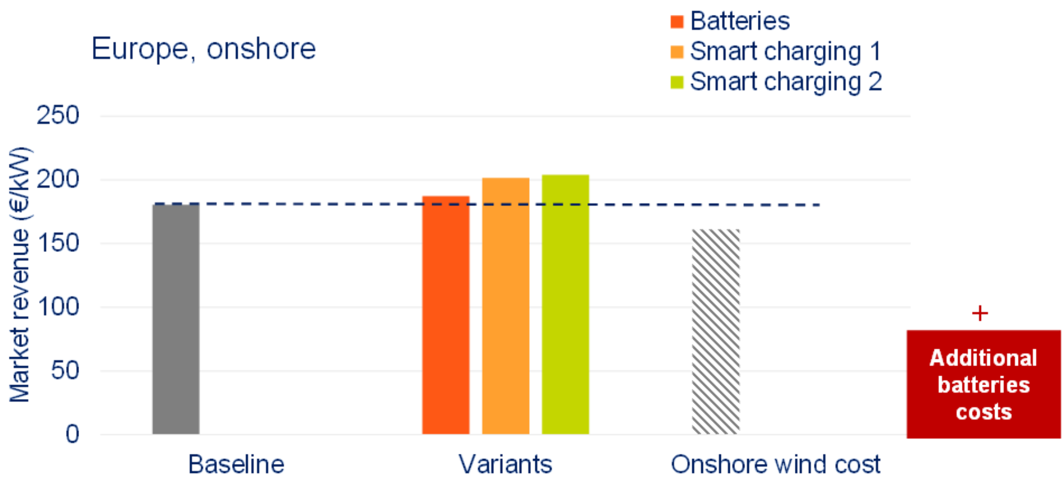


FIGURE 8-27 : AVERAGE ANNUAL MARKET REVENUE AND COSTS FOR WIND ONSHORE IN EUROPE DEPENDING ON THE TECHNOLOGIES DEPLOYED

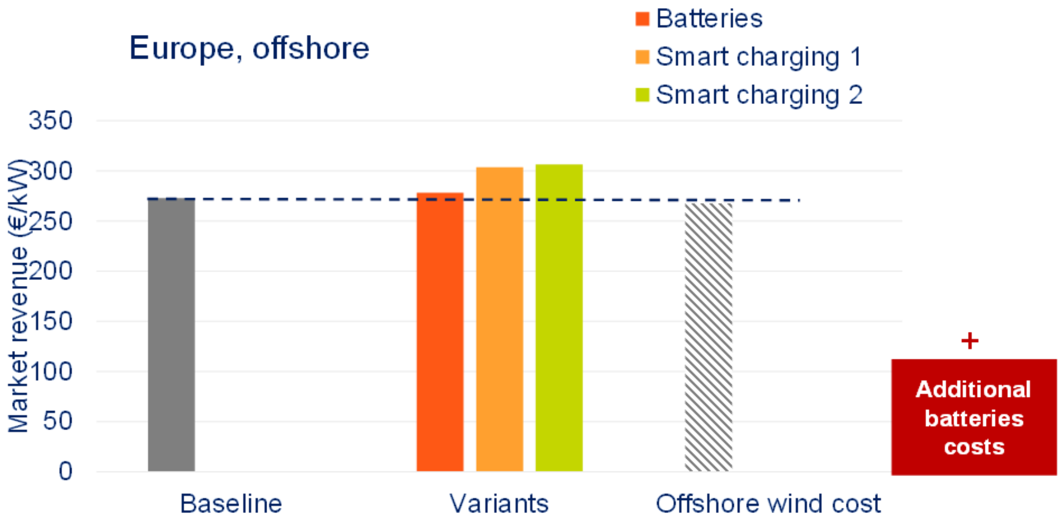


FIGURE 8-28 : AVERAGE ANNUAL MARKET REVENUE AND COSTS FOR WIND OFFSHORE IN EUROPE DEPENDING ON THE TECHNOLOGIES DEPLOYED

In summary, vRES revenues increase with the integration of the types of technologies considered in this chapter, and are highest with EV smart charging (V1G and V2G). Solar revenues are benefiting from batteries integration, especially in Spain, where there are very complimentary. On the other hand, it appears that EV smart charging is more favourable to wind production. The technologies considered here support the integration of vRES onto the power system. Support for the integration of VRES mitigates the risks on capacities and ultimately on system adequacy.

8.4 SUMMARY AND KEY MESSAGES

Uncertainty of generation capacity and system interdependencies are challenges to achieving a capacity-adequate European power system. Adding a large amount of interconnections and peaking plants will address the 3h loss of load criteria/adequacy standard, but leads to low load factors for peaking units and a share of RES production is curtailed, which although succeeds in meeting the generation adequacy requirements, does not result in a portfolio with the right level of capability to support the integration of variable renewables. **This chapter demonstrated the positive impacts of a range of different technologies, namely batteries and EVs, to satisfy the 3h loss of load criteria and to support vRES integration.** Less curtailment and less CO_2-emitting peaking units needed as a result.

As demonstrated in the EU-SysFlex Task 2.5 [4], enabling a deep decarbonisation of the European power system would require mobilisation of all options to facilitate the integration of vRES into power systems. As also pointed out by the IEA in several publications [57], [58], a range of technology options should be encouraged jointly in order to decrease the need for carbon intensive peaking units as much as possible. **The need to deploy a suite of technologies and a suite of mitigation options has been highlighted in other chapters of this report also.**

However, as explored throughout this report and by taking a close look at the different solutions, each technology option or mitigation has its own specific technical and economic implications that have different impacts depending on the characteristics of the power system in which they are integrated. This is an area that will required attention in future work.

When wind provides reserves, it reduces reserves required to be provided by other fossil fuel based technologies and therefore lowers CO_2 emissions. In countries with very high shares of vRES, wind providing reserves lowers the risk of not meeting reserve requirements as there is an addition reserve providing resource potentially available. Finally, if wind can provide reserve, it was found in this chapter that solar also providing reserve had little impact for most European countries.

It has been highlighted in this chapter that interconnections are a key option in integrating high shares of vRES. They allow countries to share vRES production, thus reducing curtailment as well as the need for load-shifting. Peninsulas, where interconnections are limited, required more diverse technology and mitigation options to reduce system costs linked to the integration of vRES.

Secondly, given the perimeter of the present study considering a well-interconnected European power system (and excluding any additional revenues from other electricity markets), 4h stationary batteries are economically viable especially in peninsulas like Spain (around 25 GW of batteries are installed in this study). This remains true, but with lower capacity, when a high level of interconnection is considered as well as EV smart charging within Spain. **Additional value could be provided for storage by considering its operational schedule in light of participation in the intra-day market and/or by providing system services or through long term capacity mechanisms**, which is out of the scope of the study in this chapter. This proves that the place of stationary batteries largely depends on the other technologies and mitigations available in the power system at different time scale and in different markets. The technical and economic implications of 4h stationary batteries mainly occur in Spain where curtailment is largely reduced, as are gas production and CO_2 emissions. Solar PV revenues largely benefit from the presence of batteries, as does wind, yet to a lesser extent.

The analysis of generic and optimistic scenarios for EV smart charging highlights key elements linked to this technology, which is likely to be deployed irrespective of the developments on the power system, and expecting a rapid growth in the years to come. At first, the flexibility capacity potential due to EV smart charging is large and well-spread over Europe. Batteries development on the energy-only market is competing with EV smart charging. EVs, given the capacities considered in this study, allow avoidance of the majority of curtailment situations for most European countries (except in Spain), as well as halving gas production and CO_2 emissions compared to the scenario with only batteries. Furthermore, it is significantly reducing the European power system total production cost. In comparison to an option with 100% V1G, the introduction of V2G has limited additional impact for the system, and the additional costs and constraints linked to V2G deployment must be factored in.

The technical and economic implications of the technologies considered in this chapter translate into a higher vRES market value than was seen in Task 2.5 where batteries and EVs were not considered in the pan-European portfolio. The more a solution helps the integration of a vRES technology, the more this technology is beneficial for the system leading to lower integration costs. EV development supports vRES integration onto the power system provided that smart charging is developed. EV smart charging development results in a higher volume of batteries in Europe than the addition of batteries alone, except in Spain and with a more pronounced way for wind than for solar.

Overall and given their specificities, all technology options, whether through appropriate market designs, production assets, interconnections or demand-side management are to be considered as complementary, with associated benefits and costs closely linked to the power system in which they are integrated (including the mix of vRES). To broaden the scope, it would be worth analysing optimal mixes of technologies and mitigations to decarbonise the European power system with varying shares of vRES. An optimal level and mix of technologies would allow balancing the self-cannibalisation effect with increasing shares of vRES thus orienting the decision-making process towards an economic and carbon-neutral integration of vRES into future power systems.

While it has been assumed in this chapter that investment in EVs will be a result of private investment for mobility reasons only, **in the future with the correct incentives and the correct market design, system services could be provided by vehicle to grid technologies and this could change the landscape, encouraging a greater uptake of EVs.** The same can be said for investment in batteries and other technologies that provide the needed capability to the power system. The reader is directed to the WP3 deliverables of EU-SysFlex for more information on potential system services products and on different market design concepts.

9. DISCUSSION AND CONCLUSIONS

9.1 DISCUSSION ON OTHER SCARCITIES

The following sections will discuss potential mitigations for some scarcities that were identified in Task 2.1 or Task 2.4, but which have not been studied via simulation in Task 2.6.

9.1.1 SYSTEM RESTORATION

In the case of a total or partial system black out, the restoration of the continuous supply of electricity as quickly and safely as possible to all generation, transmission, distribution and customers is required. Traditionally, power system operators develop an organised and considered procedure to ensure system restoration [1]. This procedure sets out guidelines and plans for utilising generation stations that can be restarted without an external power supply and to then energise other parts of the transmission system and other generators.

In Task 2.4, a review of the system restoration procedure was conducted for the Ireland and Northern Ireland Power System. It was found that as the transition is made to a power system with higher levels of variable renewables resources by 2030 there is a likely to be a) a decrease in the numbers of self-starting generating units and b) an increased likelihood that a self-staring synchronous generator will be offline which could impede timely system restoration. In addition, higher levels of renewables will result in an increase in the geographical dispersion of the generation resources [1], which can fundamentally change the system restoration paths to target generators or loads.

It will be crucial in the future to have black start capability coming both from technologies that are online and available during periods of high renewables and from other non-conventional technologies should a black out occur at times of low renewable availability. These technologies could include, but are not limited to wind, solar, batteries and interconnectors.

- Renewables with grid-forming technologies can provide black-start capabilities. Black start capabilities from a windfarm equipped with virtual synchronous machine[10] technology have been successfully demonstrated[11].
- Voltage Source Converter (VSC) HVDC interconnectors can be and have been used for black start and system restoration [59, 60]. The inherent controllability of a VSC means that the HVDC control can provide a stiff voltage and frequency on the ac side requiring black start. Early in the restoration process

[10] A Virtual Synchronous Machine is a type of grid forming technology that emulates some of the features of a synchronous generator.
[11] https://www.scottishpowerrenewables.com/news/pages/global_first_for_scottishpower_as_cop_countdown_starts.aspx

when much active power flow may not be required, the VSC has the capability to act as a STATCOM providing reactive support to the restoring grid, supporting circuit re-energisation and subsequent voltage containment [59]. Later in restoration, the HVDC interconnector has a large active power resource to support load pickup whilst continuing to regulate the voltage and frequency [59].

A recommendation here is, in conjunction with a review and updating of system restoration plans, to explore the potential for the development of a black-start system services product that incentivises the needed capability. As will be mentioned in the next section, a resource adequate portfolio is crucial for secure operation of the power system. However, a resource adequate portfolio does not guarantee that the resources in the portfolio have the requisite capabilities. Developing a black-start service and remunerating for service provision can help to incentivise either maintaining levels of synchronous black-start capable units or the upgrading of existing units to become self-starting. Such a product could also help to incentivise investment in new technologies.

9.1.2 ADEQUACY

In addition to the discussion on generation adequacy in Chapter 8, an additional area of concern related to adequacy pertains to the risk of a high renewable system having periods of very low renewable generation out for a prolonged period of time. This is often referred to in the industry as a "Dunkelflaute". Effectively, if a high pressure weather event occurs, there is a risk of consistently low wind output for a considerable numbers of days. From a power system operations perspective, it is important that there is enough capacity and system services capability available to ensure that a safe, secure and reliable system is maintained at all times, including during winter peaks (or summer peaks) and during Dunkelflaute events.

In general, **many technologies that are capable of reliably providing active power for prolonged periods of time could be considered to be able to contribution to system adequacy**. Traditionally, adequacy contribution has largely come from large conventional fossil fuel power plants. However, with the transition to a more decarbonised power system, there is a need to avail of the adequacy contribution provided by other resources such as renewable technologies, battery storage technologies and the demand-side.

The capability of the demand-side to contribute to generation adequacy fundamentally alters how generation adequacy is viewed and assessed. The same can be said for battery storage technology, as the energy limit characteritics of storage technologies necessitates careful consideration of their contributions. The European Resource Adequacy Assessment (ERRA) methodology [61] is reflective of the need to account for these changes.

9.1.3 RAMPING

A ramp event can be considered to be a large or rapid change in power in either direction [62]. It is also pointed out that increases in renewables cause an increase in the variability of the system net load [62]. This concurs with the results from analysis in EU-SysFlex Task 2.5 as considerable net load ramps, both upwards and downwards were observed. This net load variability creates challenges for system operation and requires sufficient flexibility and fast acting capability.

Whilst not studied in Task 2.4 and Task 2.6, it is acknowledged that both net load ramp events and variable generation forecast errors could create a significant challenge for future power systems with the transition to more weather dependent sources of electricity generation. An area of increasing concern relates to the challenge of dealing with weather patterns that materialise before or after they are forecasted [23] in a wind or solar dominated system.

In Ireland and Northern Ireland, currently, forecast error events can be managed as a result of ramping capability in the existing portfolio. However, with very ambitious renewable energy targets of the coming decade (70% RES-E by 2030) and only a potentially marginal improvement in forecast accuracy, there is significant potential for the magnitude of forecast errors to grow. **The current ramping services, which are utilised in Ireland and Northern Ireland to incentivise maintaining sufficient levels of ramping capability, both from existing conventional technologies but also from batteries, will be need to be extended to enable ramping capability from interconnectors, wind and solar generation and offline conventional plants.** There may also be a potential need for a longer-term ramping product to help manage the challenge associated with "Dunkelflaute", which was discussed in the previous section.

9.2 FUTURE WORK

Throughout the studies and analysis carried out in Task 2.6, a number of areas of future work have been identified. These are now discussed.

Future work will also be required to find the right suite of technologies to ensure the right mix of system services capability. What has been demonstrated in this report is the ability of mitigation measures, typically in isolation, to support the mitigation of a range of technical scarcities. In reality, however, no mitigation measures will be implemented in isolation and there would be complementarities and interactions between measures. This interaction would need to be assessed in future work. It is anticipated that the most efficient way to deliver the needed capability is to develop appropriate markets and to incentivise investment in the needed technological capability. In Task 2.5, it was shown that, for the Ireland and Northern Ireland power system, there is significant value to the power system in adopting system services. **The key benefit of system services is the fact that they**

can incentivise investment in the capability needed to mitigate the technical scarcities (as demonstrated in this report), but also provide a much needed additional revenue stream to all technologies (as demonstrated in Task 2.5). There may be a need for the development of new system services products to incentivise investment in technologies with the required capabilities to tackle the technical scarcities. New system services products could include an oscillation damping product, a network congestion product and a long-term ramping product. This would require detailed technical analysis in conjunction with market design considerations, which are discussed in WP3 of EU-SysFlex.

Future work on modelling inertia constraints in the CONTINENTAL model will be required to build upon the developments presented in this report. As discussed in Section 4.1.4, the approach applied was not able to capture every phenomenon experienced during system split events, which are very complex incidents. Split simulations with electromagnetic tools and with detailed grid modelling would be very useful to underpin this study and to reveal more precisely its limitations.

Futher work on exploring the full potential and ability of smart power flow controllers and demand-side management to mitigation of congestion will need to be conducted. As acknowledged in this report, there is a need to better utilise the existing grid infrastructure and to minimise the build of new infrastructure. Smart power flow controllers and demand-side management have the potential to enable system operators to better utilise the existing grid, in conjunction with other mechanisms. Future work would need to consider how such concepts could be incentivised, enabled via control centres and utilised as part of the suite of mitigations needed. Pilot trials would be required. Additionally, future work on ascertainting the economic benefit of utilised DSM for congestion management should be conducted.

9.3 CONCLUSIONS

As mentioned in the introductory text for this report, a scarcity can be loosely defined as a shortage of something that the power system has traditionally had in good supply. This report has successfully demonstrated, through simulations, the ability to mitigate some of the key technical scarcities identified in Task 2.4. The focus has been on the **capabilities** that are needed to solve these technical scarcities rather than specifically on the technologies themselves.

Crucially, it has been demonstrated throughout this report that renewables and non-conventional technologies are well positioned to provide a range of different system services capability which is needed to mitigate the technical scarcities. This is vital as these are the mitigation measures that would be available at times of high renewable generation, times when the scarcities are typically more severe due to the displacement of tradition service providers such as conventional synchronous plants.

In general, each technology, concept or mitigation has been demonstrated in isolation, but it should be acknowledged that in reality **a range of solutions will be needed**. The required mix of solutions will need to be assessed holistically in order to consider trade-offs and synergies. The reason is that some scarcities, as is shown in this report, can be mitigated by a range of different technologies and strategies, while some technologies can be effective in mitigating a selection of different issues. The key will be to identify the mix of technologies that will be needed to ensure safety and reliability of the system and to deliver value to consumers. Additionally, future markets will need to be designed such that they successfully both promote a choice for investors and incentivise investment in technologies which will ultimately have the right capability needed to support the power system. Work on future market design was conducted as part of EU-SysFlex Work Package 3. For more information the reader is directed to both the Task 3.1 [2] and the Task 3.2 [3] reports, which detail a range of different innovative system services products and potential market designs for procuring, activating and remunerating innovation system services products, respectively.

While some aspects of the economics of the various technologies have been touched upon in various chapters in this report, the specifics are largely out of scope here. However, it has been demonstrated in Task 2.5 of EU-SysFlex that there is significant value to the power system in utilising system services capability in order to enable the evolution of the system operation [4]. Thus, it could be concluded from WP2 that the **need** for system services (Task 2.4), the **capability** of system services from many technologies to mitigate scarcities (Task 2.6) and the **value** of system services (Task 2.5) have all been well demonstrated in EU-SysFlex.

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12. ANNEX I: PSCOPF SENSITIVITY STUDIES

12.1 RESULTS OF PSCOPF SENSITIVITY RESULTS

12.1.1 SIMULATION SETUP METHODOLOGY

All simulations presented in Section 7.1.1.2 in relation to the PSCOPF optimisation tool were run with the following settings:

- All branches in the 'All Ireland' (AI) system were monitored for potential overloading
- Maximum thermal capacity of transmission lines were considered to be 100% of their nominal ratings

In order to investigate the impacts of different simulation settings on the 'success rate' (i.e., the ratio of the number of hours where all overloading violations are removed by PSCOPF to the total number of hours associated with the given cluster, refer to Section 7.1.1.2) of the PSCOPF tool, the simulations were repeated for the following 8 scenarios for each hour cluster:

1. Monitor AI lines, 100% nominal ratings, no reinforcements – denoted as 'Without REINF, 100%, AI'
2. Monitor AI lines, 100% nominal ratings, with reinforcements – denoted as 'With REINF, 100%, AI'
3. Monitor AI lines, 120% nominal ratings, no reinforcements – denoted as 'Without REINF, 120%, AI'
4. Monitor AI lines, 120% nominal ratings, with reinforcements – denoted as 'With REINF, 120%, AI'
5. Monitor only Dublin area lines, 100% nominal ratings, no reinforcements – denoted as 'Without REINF, 100%, DUB'
6. Monitor only Dublin area lines, 100% nominal ratings, with reinforcements – denoted as 'With REINF, 100%, DUB'
7. Monitor only Dublin area lines, 120% nominal ratings, no reinforcements – denoted as 'Without REINF, 120%, DUB'
8. Monitor only Dublin area lines, 120% nominal ratings, with reinforcements – denoted as 'With REINF, 120%, DUB'.

The rationale behind monitoring only Dublin area lines (as opposed to AI) is that most overloads were identified from the 220 kV Dublin area (and 110 kV North-West area) in Task 2.4. Additionally, all 7 reinforcements listed in Table 7-1 have been implemented in the 220 kV Dublin area and monitoring only Dublin area lines therefore helps to reduce the constraint space for the optimisation tool, thereby facilitating its successful solution, i.e., removal of all overloading violations using the control options at its disposal. Similarly, the rationale behind performing simulations with maximum thermal limits of lines assumed to be 120% of their nominal ratings is to (indirectly) consider implementing dynamic ratings for transmission lines for hour clusters associated with high overload indices.

12.1.2 SIMULATION RESULTS

The resultant success rates of the PSCOPF optimisation tool for the different hour clusters and scenarios under consideration are presented in Figure 12-1. As seen from the figure, the scenarios with the highest success rates are the ones with the most relaxed and smallest constraint space, i.e., only Dublin area lines being monitored and maximum thermal limits of lines assumed to be 120% of nominal ratings. In fact for the scenario 'With REINF, 120%, DUB', the success rates for the critical, upper-mid and lower range hour clusters are found to be 100%, 74% and 77.27%, respectively.

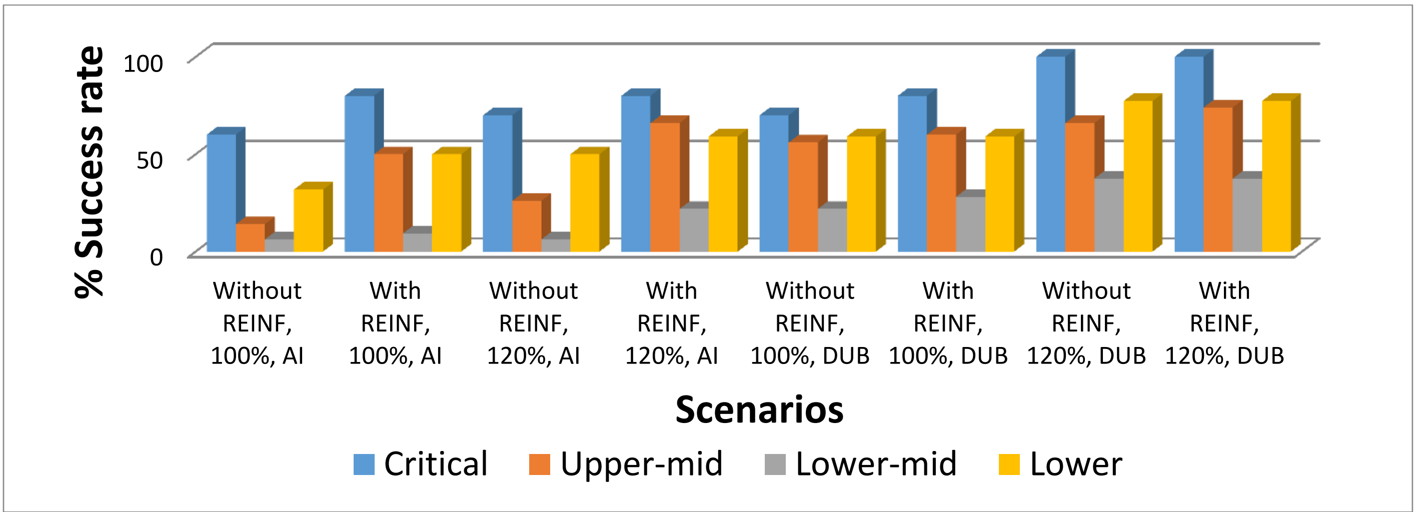

FIGURE 12-1: PSCOPF SUCCESS RATES UNDER DIFFERENT HOUR CLUSTERS AND SIMULATIONS SCENARIOS

However, the success rate for the lower-mid range hour cluster is found to be consistently low across all scenarios under consideration, with the highest value of 37.5% recorded for the 'Without REINF, 120%, DUB' and 'With REINF, 120%, DUB' scenarios. Also, it can be observed from Figure 12-1 that the improvement in the success rate after addition of reinforcements under the lower-mid range cluster is the least across all hour clusters under consideration. The reason for this was investigated in detail and the same is presented in the following section.

The average MW load shifted and the average MW wind constrained across all scenarios and hour clusters under consideration are presented in Figure 12-2 to Figure 12-5. For comparison sake, only those hours under a given cluster that are associated with feasible PSCOPF outputs across all 8 scenarios under consideration are used for generating the bar graphs in Figure 12-2 to Figure 12-5. It can be observed from the figures that the addition of reinforcements help to significantly reduce both the average MW load shifted and the average MW wind constrained values across all scenarios and hour clusters.

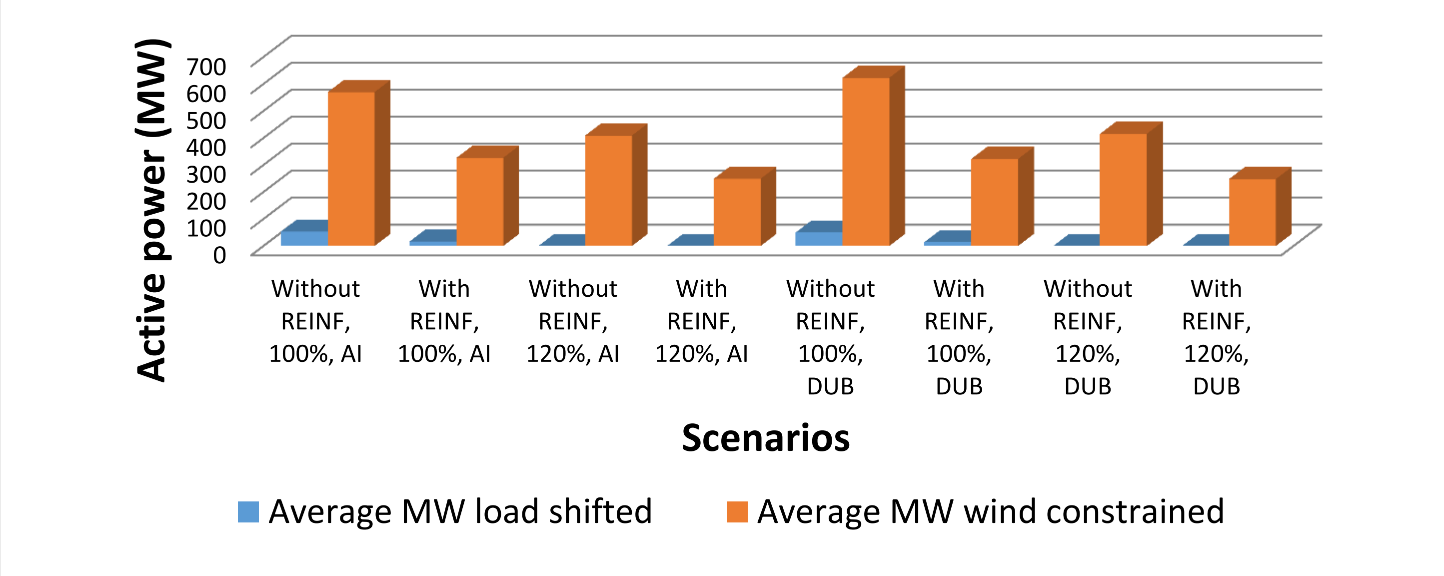

FIGURE 12-2: AVERAGE MW LOAD SHIFTED AND WIND CONSTRAINED UNDER CRITICAL HOUR CLUSTER AND DIFFERENT SCENARIOS

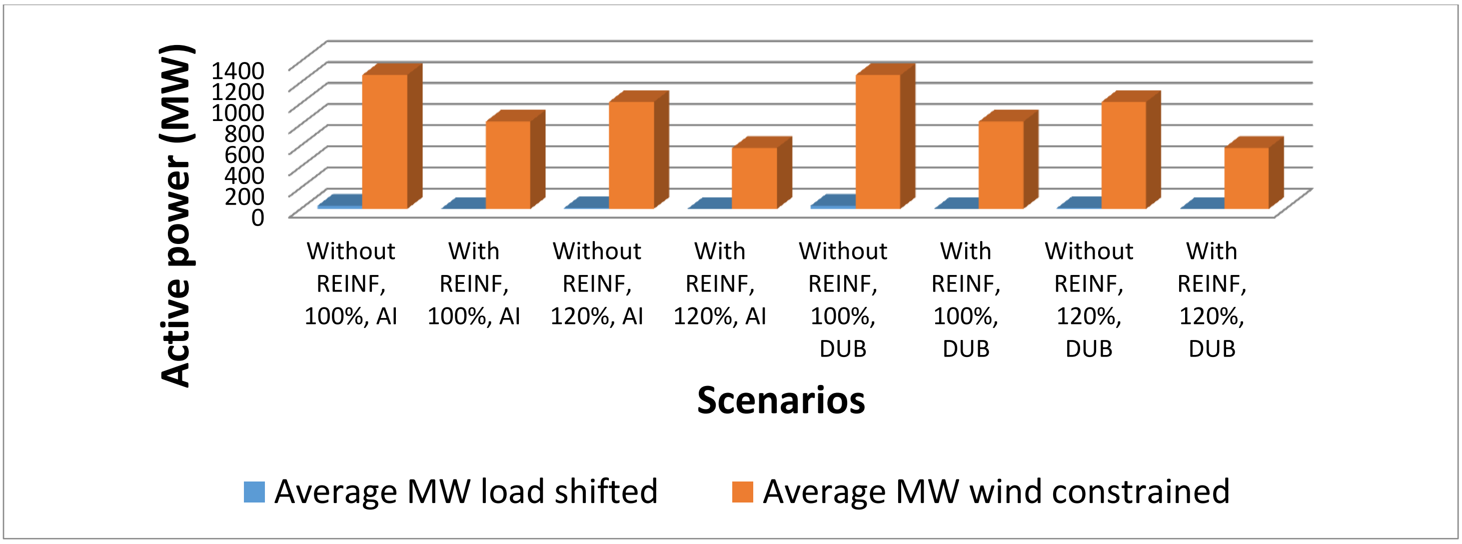

FIGURE 12-3: AVERAGE MW LOAD SHIFTED AND WIND CONSTRAINED UNDER UPPER-MID RANGE HOUR CLUSTER AND DIFFERENT SCENARIOS

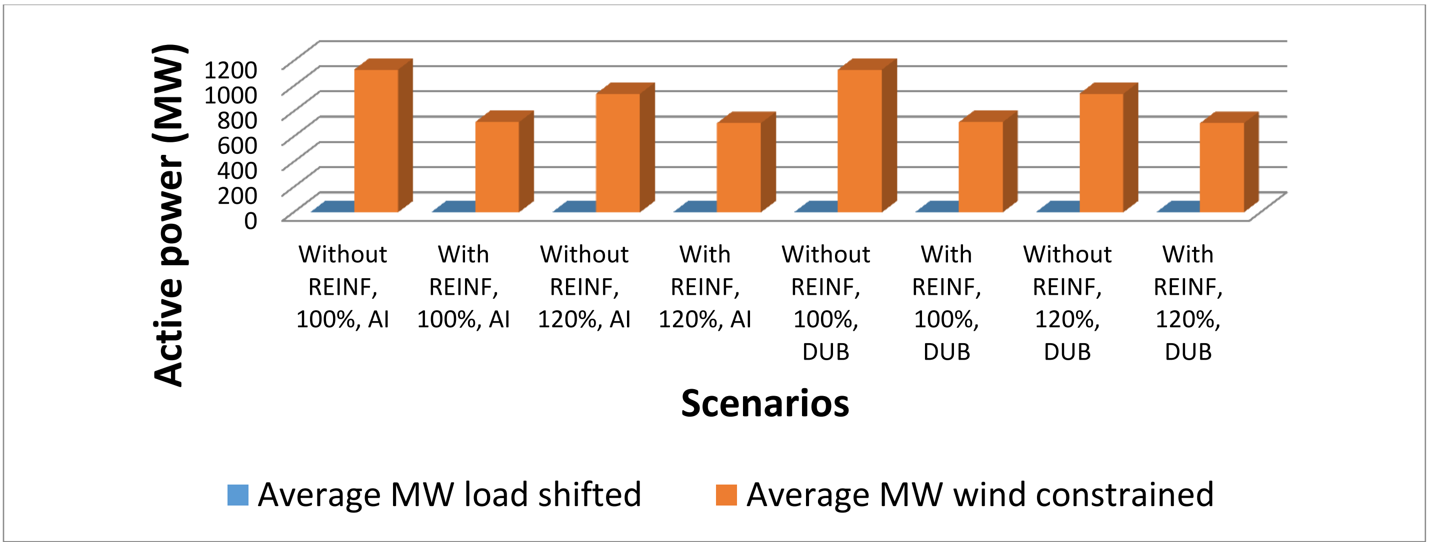

FIGURE 12-4: AVERAGE MW LOAD SHIFTED AND WIND CONSTRAINED UNDER LOWER-MID RANGE HOUR CLUSTER AND DIFFERENT SCENARIOS

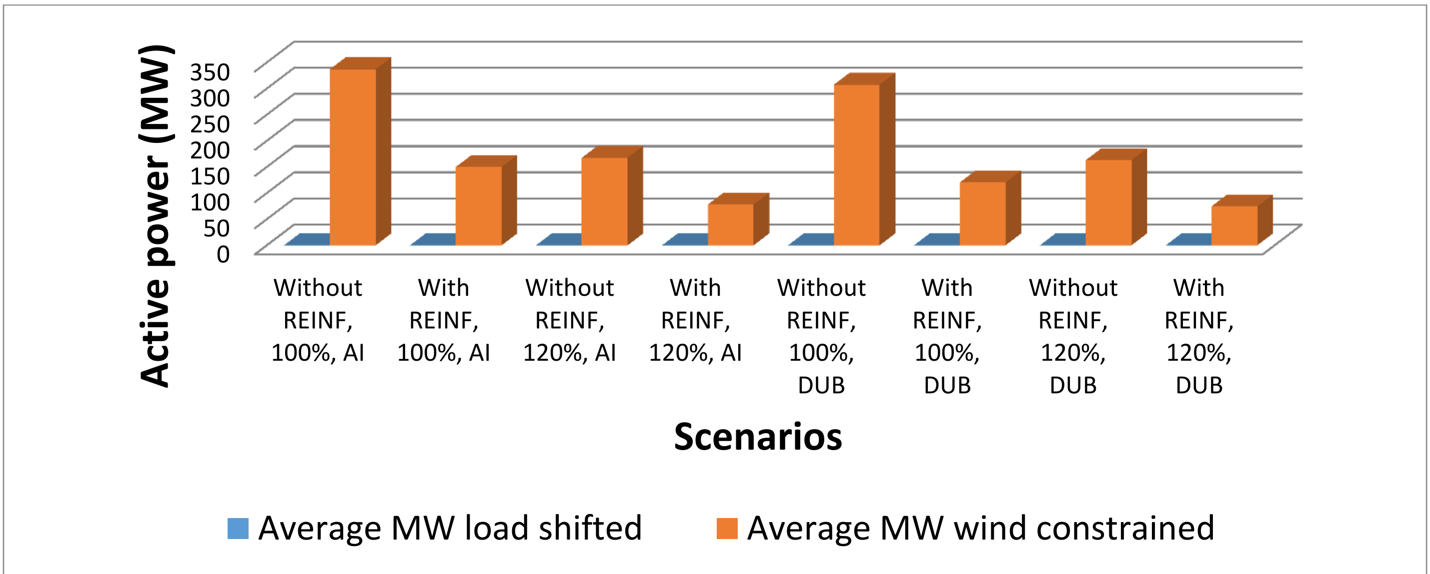

FIGURE 12-5: AVERAGE MW LOAD SHIFTED AND WIND CONSTRAINED UNDER LOWER RANGE HOUR CLUSTER AND DIFFERENT SCENARIOS

12.2 INVESTIGATION OF PSCOPF INFEASIBILITIES

This section presents the results of analyses carried out for obtaining insights into the reasons why PSCOPF is unable to remove all overloading violations even after utilising all 6 control actions at its disposal. The simulations are performed on the system with and without all 7 reinforcements (refer to Section 7.1.2) added, and for all 4 hour clusters under consideration (refer to Section 7.1.2).

All results presented in this section pertain to the following scenarios only: 'Without REINF, 100%, DUB' and 'With REINF, 100%, DUB' (refer to Section 12.1). However, the conclusions drawn from the presented results are generic and observed for the other scenarios as well.

For performing the simulations, only those hours from a given cluster that are associated with infeasible PSCOPF outputs are considered. For such hours, the following are recorded:

- 'Active constraints' - transmission lines that are still overloaded after PSCOPF uses all 6 control actions at its disposal, are noted.
- For each line with an active constraint, the 'frequency of occurrence', i.e., the total number of hours under the concerned cluster when the line is overloaded is measured.

The resulting frequencies computed for the system without and with 7 reinforcements added and for the four hour clusters under consideration are presented in Figure 12-6 to Figure 12-9. Two key findings from Figure 12-6 to Figure 12-9 are described below.

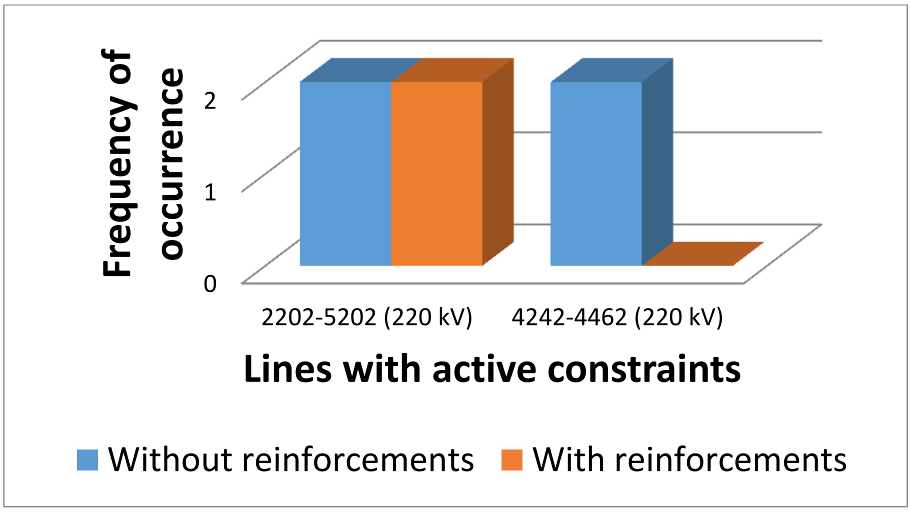

FIGURE 12-6: FREQUENCY OF OCCURRENCE OF ACTIVE CONSTRAINTS FOR CRITICAL HOURS CLUSTER (SCENARIOS 'WITHOUT REINF, 100%, DUB' AND 'WITH REINF, 100%, DUB')

It can be observed from Figure 12-6 to Figure 12-9 that the PSCOPF optimisation tool is unable to remove overloading violations in certain 220 kV and 110 kV lines even after using all 6 control actions at its disposal.

With reference to the discussions in Section 7.1.2.2 pertaining to reinforcements being considered, it is to be noted here that all 7 reinforced lines belong to the 220 kV network in Dublin. It is to be also noted that the primary yardstick considered for implementing reinforcements was the reduction in overload index values. It can therefore be observed from Figure 12-6 and Figure 12-7 that active constraints in 220 kV lines 4242-4462 and 2563-4242 (which were indeed reinforced) disappear after reinforcements are added. Line 2202-5202, on the other hand, did not contribute significantly to the reduction in overload indices and was therefore not considered for reinforcement. As a result, this line can be observed to be consistently overloaded with varying frequencies for all hour clusters under consideration Figure 12-7).

The first key message from this investigation of the infeasibilities is that reinforcement of some 220 kV lines which help to reduce overload indices can lead to changed power flows which can cause overloading in other (non-reinforced) 220 kV lines, which in turn leads to the PSCOPF outputs for concerned hours being infeasible.

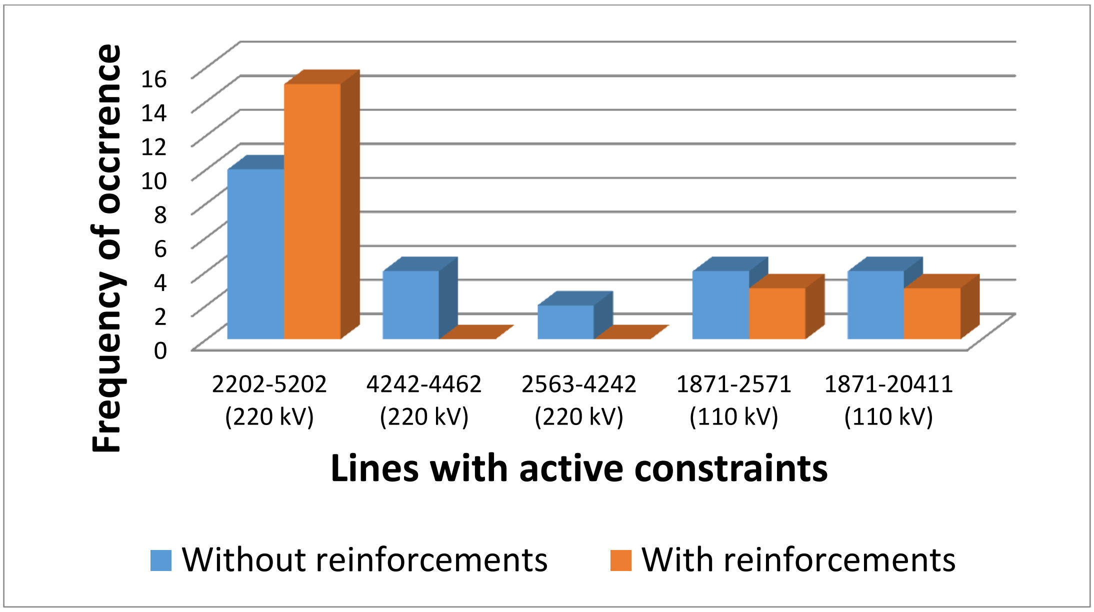

FIGURE 12-7: FREQUENCY OF OCCURRENCE OF ACTIVE CONSTRAINTS FOR UPPER-MID RANGE HOUR CLUSTER (SCENARIOS 'WITHOUT REINF, 100%, DUB' AND 'WITH REINF, 100%, DUB')

It can be observed from Figure 12-6 and Figure 12-7 that while the addition of reinforcements improves the PSCOPF success rate for most scenarios under the critical and upper-mid range hour clusters, its impact is considerably muted for the lower-mid and lower range clusters. Accordingly, it can be verified from Figure 12-6 to Figure 12-9 that while the frequency of occurrence of violations in 110 kV lines (1871-2571 and 1871-20411) is significantly lower than their 220 kV counterparts under the critical and upper-mid range hour clusters, the trend reverses (i.e., frequency of overloading violations in 110 kV lines is higher than 220 kV values) for the lower-mid and lower range hour clusters.

The second key message from this analysis is that changes in power flow brought about by the addition of reinforcements can sometimes lead to evacuation of power from the 220 kV to the 110 kV level. Recalling from Section 7.1.2 that only 220 kV lines in the Dublin area which help to significantly reduce overload indices were chosen for reinforcements, it can be easily deduced that the incorporation of reinforcements under the lower-mid and lower range clusters has a minimal impact on improving the PSCOPF success rate.

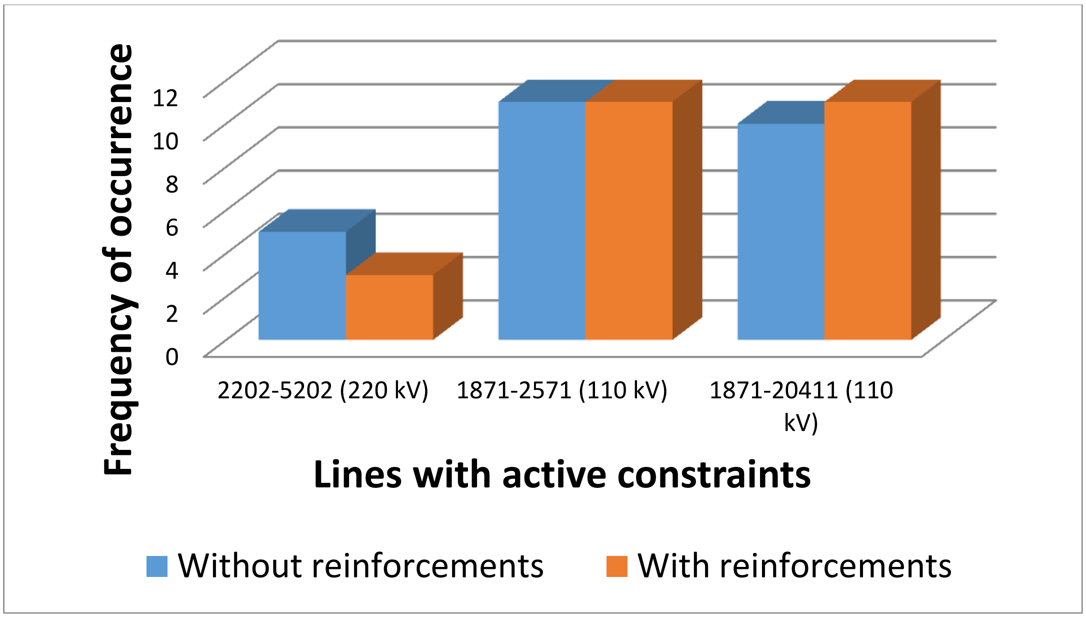

FIGURE 12-8: FREQUENCY OF OCCURRENCE OF ACTIVE CONSTRAINTS FOR LOWER-MID RANGE HOUR CLUSTER (SCENARIOS 'WITHOUT REINF, 100%, DUB' AND 'WITH REINF, 100%, DUB')

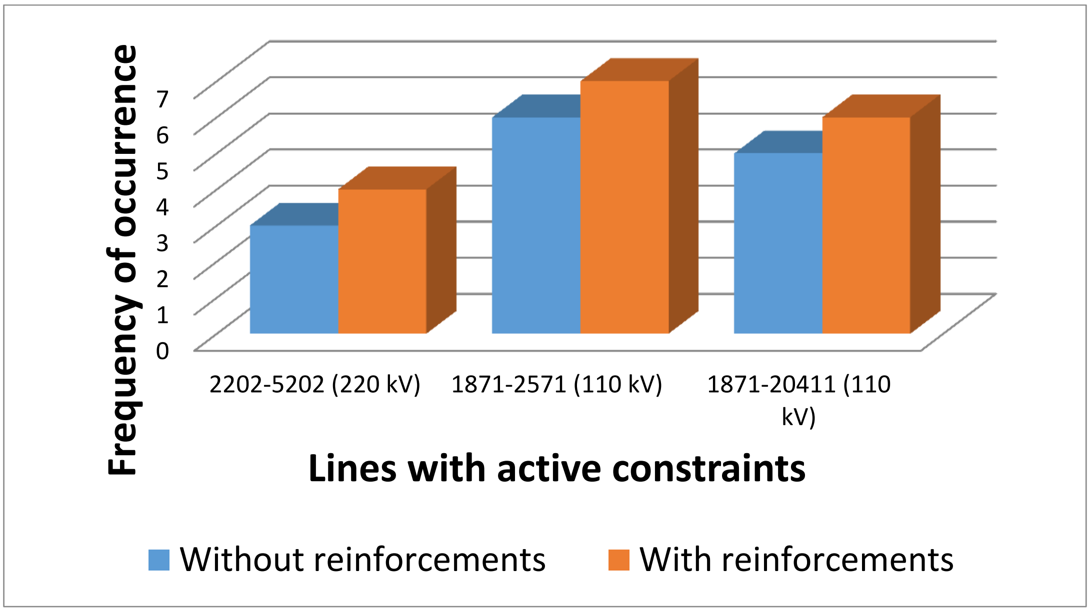

FIGURE 12-9: FREQUENCY OF OCCURRENCE OF ACTIVE CONSTRAINTS FOR LOWER RANGE HOUR CLUSTER (SCENARIOS 'WITHOUT REINF, 100%, DUB' AND 'WITH REINF, 100%, DUB')

In conclusion, it can therefore be argued that while the addition of carefully selected reinforcements can help to significantly reduce overload indices in the grid, it does not necessarily translate to seeing improved PSCOPF success rates across all hour clusters under consideration. With increasing levels of wind generation and consequent evacuation of power from generation to load centres, it is evident that the system would experience increased overloading violations in the future. With reference to the methodologies and concepts presented in Chapter 7 a combination of carefully selected reinforcements along with operational support from optimisation tools (e.g., PSCOPF) and devices (e.g., smart power flow control devices) is therefore required for efficient management and resolution of resultant network congestions.

13. ANNEX II: COSTS USED FOR TECHNOLOGIES IN CHAPTER 8

The costs are computed using O&M and investment costs assumptions coming from [58] and [63]. They are displayed on Table 13-1. Costs hypotheses for vRES come from the 2018 WEO New Policy Scenario at horizon 2040 and take into account updated prospective costs for vRES investment and maintenance costs.

TABLE 13-1: COSTS ASSUMPTIONS FOR POWER PLANTS [57], [63]

	Overnight cost (€/kW)	Lifetime (years)	Discount rate	Investment annuity (€/kW.an)	O&M cost (€/kW.y)
CCGT	830.0	30	7%	66.9	36.0
OCGT	450.0	30	7%	36.3	26.0
Offshore wind	2509.8	30	7%	202.3	65.3
Onshore wind	1513.0	30	7%	121.9	39.2
PV large scale	676.4	25	7%	58.0	16.02
PV buildings	890	25	7%	76.4	19.58