Potential Solutions for Mitigating Technical Challenges Arising from High RES-E Penetration on the Island of Ireland

A Technical Assessment of 2030 Study Outcomes

22 December 2021

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For queries relating to this document contact:

DS3@eirgrid.com or info@soni.ltd.uk

Published 22 December 21.

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Executive Summary

The governments in Ireland and Northern Ireland have set ambitious renewable energy targets for 2030 in line with the European Union and UK government's major climate action commitments. EirGrid and SONI, in our roles as Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively, are actively engaging with relevant stakeholders and undertaking technical studies to support the transition to operation with higher shares[1] of variable non-synchronous generation in the all-island power system.

It is evident that this transition of the all-island power system to one having higher shares of renewable non-synchronous generation will give rise to several technical challenges, and these have been extensively investigated as part of the Horizon 2020 EU-SysFlex project (Task 2.4) [1] and documented in the Shaping Our Electricity Future consultation report [2].

This report presents findings of mitigation studies (e.g. EU SysFlex Task 2.6 [3]) conducted within EirGrid and SONI for addressing the major technical challenges identified in [1], [2]. As such, the results and outcomes presented in this report are intended for an all-island audience comprising market participants, regulatory authorities and industry stakeholders.

The major technical challenges considered in this report are not exhaustive; rather they are indicative of the potential issues that may arise in the power system of the future. Similarly, the aim of the analyses presented in this report is to demonstrate the capability of several technologies (rather than focussing on the specific technologies themselves) to mitigate the challenges.

It is acknowledged that the *technologies discussed throughout this document are not exhaustive*; rather they are indicative of the different technologies that can offer the needed mitigation capability. It is not intended to indicate that other technologies or resources with similar characteristics are not desirable or cannot make a valuable contribution to addressing the challenges.

Finally, as the name of this report suggests, this study is intended to be a technological assessment of potential mitigation options rather than being a cost-benefit analysis oriented quantitative exercise. A pictorial representation of the major technical scarcities[2] (inner circle) and mitigation technologies (outer circles) considered in this study is presented in Figure 1.

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[1] As quantified by the following metrics: achieving at least 70% renewable penetration and up to 95% System Non-Synchronous Penetration (SNSP, refer to Appendix B – Glossary of Technical Terms for definition) by 2030.

[2] A 'scarcity' can be broadly defined as a system attribute (e.g., inertia) which is usually in good supply in traditional power systems energised by (synchronous) conventional generators but is likely to fall below expected thresholds as a consequence of the transition to a power system with high levels of Renewable Energy Sources (RES) integrated [1].

As indicated in Figure 1, some typical technologies investigated as part of this report include Synchronous Condensers, Static Synchronous Compensators (STATCOM) and Static VAR Compensators (SVC), as well as renewable technologies such as wind and solar generation, plus batteries and demand-side technologies. It is demonstrated through simulations that these technologies are suitable for mitigating a range of scarcities that will manifest themselves at high levels of renewables. The most efficient way to deliver the right technologies with appropriate mitigation capabilities would be to develop and enhance the arrangements for provision of system services [3]. System services have already proven that they can incentivise investment in new technologies that can deliver a needed capability [3].

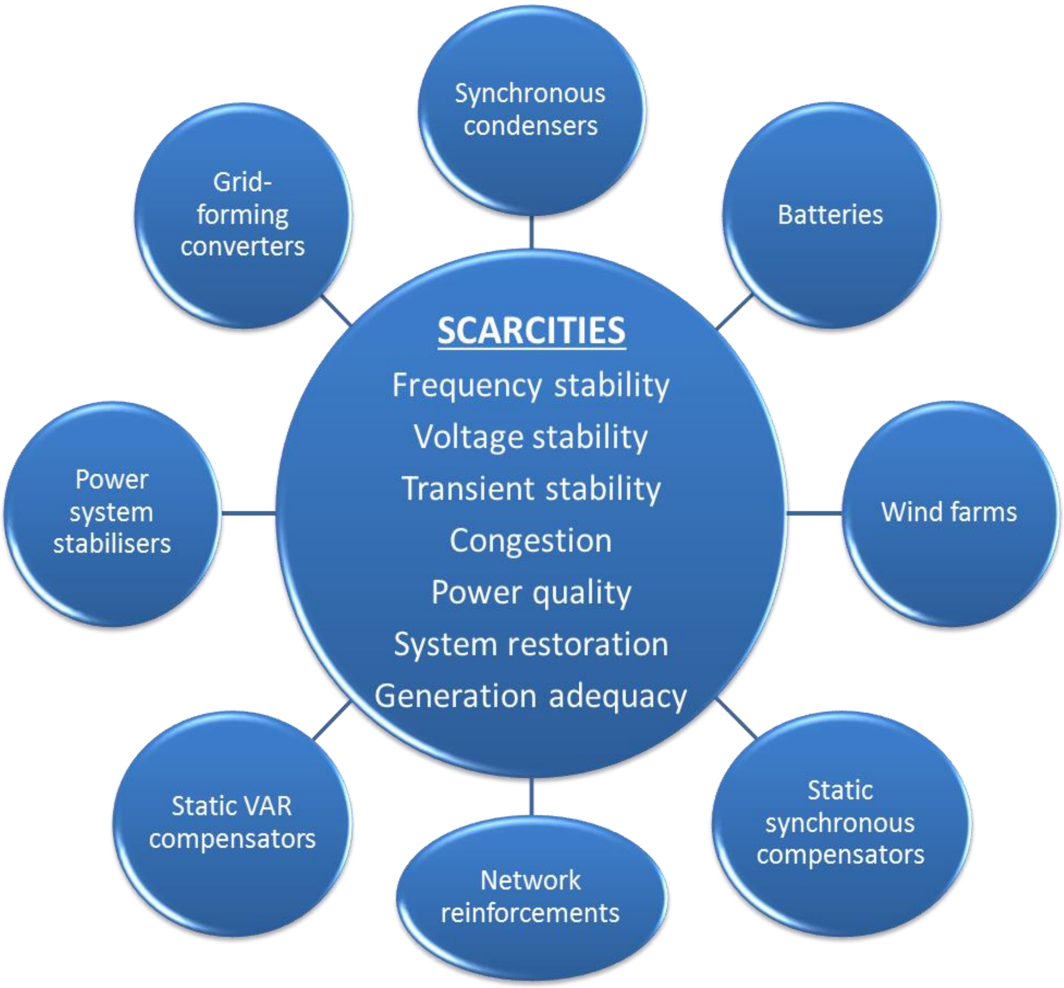

Figure 1: Major technical scarcities and mitigation technologies considered

This report deals with a range of system challenges as described in the remainder of this Executive Summary.

Frequency Stability

In terms of **frequency stability**, several (non-conventional) technologies were examined in [3] as potential mitigation solutions for alleviating the frequency stability-related challenges observed in [1]:

- *Synchronous Inertial Response (SIR) capability from synchronous condensers* has been demonstrated, whereby these devices have been found to be successful in increasing the system inertia and reducing the Rate-of-Change-of-Frequency (RoCoF), thereby resulting in a delayed and increased frequency nadir. However, it is important to note that synchronous condensers alone cannot mitigate frequency stability issues but can be very beneficial when used in conjunction with other mitigation resources, e.g., Battery Energy Storage System (BESS).

- *Primary Operating Reserve (POR) provision using frequency response control of wind farms* is investigated, and it is demonstrated that it could be beneficial in supporting frequency stability, particularly at times of high wind. This is important since fewer conventional generators are expected to be online during such times; hence less frequency response capability is expected to be available from the conventional generation units.

- *Fast Frequency Response (FFR) provision capability of Battery Energy Storage Systems (BESS)* is investigated, and it is demonstrated that rapid injection of active power from the batteries helps to decrease the RoCoF, thereby both delaying and increasing the frequency nadir and enabling other system resources with a slower frequency response provision to contribute.

- *FFR provision capability using synthetic inertial response from wind turbines* is investigated, and it is demonstrated how this could be an important mitigation measure for maintaining frequency stability, especially at times of high wind availability.

Voltage Stability

In terms of **voltage stability**, simulations performed as part of EU-SysFlex Task 2.4 [1] identified numerous issues in terms of both steady-state and dynamic voltage control. A lack of reactive power and the optimal placement of various reactive power related technologies are likely to become a significant challenge. The ability to control voltage within our planning and operational criteria, providing the right amount of reactive power at the right locations will be key to ensuring successful voltage control.

The Voltage Trajectory Tool (VTT), which is a comprehensive voltage/reactive power optimisation package currently under development, will become a part of our Control Centre Tools suite. This tool is a significant step towards enhancing our reactive power scheduling and voltage control capabilities.

With a significant portion of renewable generation connected to the distribution system in Ireland and Northern Ireland, both EirGrid and SONI are already committed to TSO-DSO collaboration activities in the area of voltage control with ESB Networks and NIE Networks, respectively. In particular, we are working collaboratively to examine how windfarms connected to the distribution system can provide voltage support to the transmission system.

In addition, some other reactive power providing technologies and services were investigated in [3] for mitigating these scarcities:

- Mitigation of steady-state voltage scarcities will require the *provision of Steady State Reactive Power (SSRP) support from non-conventional technologies* deployed in specific geographic locations [3]. Technologies providing adjustable/dynamic (e.g., STATCOMs and SVCs) or discrete/static (e.g., Mechanically Switchable Capacitors (MSC)) reactive power compensation are found to be effective in mitigating this scarcity.

- *Dynamic Reactive Response (DRR) provision capabilities of technologies like synchronous condensers, STATCOMs and SVCs* are investigated for mitigating dynamic voltage control scarcities. Analysis shows that the fast provision of DRR along with the location of the resource is key to mitigating this scarcity [3].

- *Reduction in system strength stemming from increased shares of Inverter-based Resources* (IBR) comprising current source (CSC) or grid following (GFL) converters are discussed. It is clear that with a high penetration of IBRs in the power system by 2030 along with the associated displacement of conventional generation, fault current contribution (which is directly related to system strength at the IBR's point-of-connection) will need to be sourced from non-synchronous technologies [2]. Further studies would need to be conducted in this area, but one *potential mitigation strategy is to incorporate higher shares of grid forming (GFM)-based IBRs or low carbon inertia solutions such as synchronous condensers* into the system.

Transient Stability

In terms of **transient stability**, studies conducted as part of EU-SysFlex Task 2.4 [1] observed localised damping and synchronising torque scarcities for some of the hourly snapshots simulated. Several mitigation technologies were subsequently examined in [3] for alleviating the identified scarcities:

- Technologies providing additional electromechanical torque or damping, e.g., synchronous condensers, STATCOMs and Power System Stabilisers (PSS) are investigated as potential options for mitigating damping torque scarcities. Simulations demonstrate that the addition of PSS or STATCOMs provides significant damping, with a slightly less effective mitigation impact observed for synchronous condensers.

- *DRR-providing technologies such as STATCOMs, SVCs and synchronous condensers* are considered as potential mitigation options for alleviating synchronising torque scarcities. Analysis shows that large quantities of these technologies would be required to alleviate this localised issue [3]. Studies reveal that all rare instances of instability observed under this category pertain to some generators losing synchronism following a fault on a heavily loaded transmission line in their vicinity. Simulations demonstrated that a more appropriate mitigation option for alleviating this specific scarcity would be the consideration of a new system constraint. Such a constraint would be imposed only for these specific and rare system conditions to avoid dispatching the unit that loses synchronism to its maximum output when a heavy flow through the concerned line (in the unit's vicinity) is expected [3].

- Potential technical challenges arising in a power system dominated by Grid Following (GFL) converter enabled IBRs are discussed, as are *potential benefits of installing Grid Forming (GFM) converters in terms of provision of additional services, e.g., contribution to system strength, synthetic inertia and black start capability*. EirGrid and SONI are working on developing state-of-the-art GFM-based dynamic models as they are the most important pre-requisite for conducting further studies to investigate use of these configurations with higher RES penetrations.

Congestion

In terms of **congestion**, steady-state analysis carried out in EU-SysFlex Task 2.4 [1] indicated that as SNSP increases, there will be a significant rise in both the magnitude and frequency of transmission circuit loading above 100% of rated thermal capability unless constraint is applied. In the studies undertaken, the greatest overloading of circuits was observed around the Dublin region followed by the North-West of Ireland. Two strategies – strategic incorporation of network reinforcements and employment of operational mitigation measures (e.g., generation re-dispatch and load shifting) – were explored as potential mitigation options in [3]:

- Four approaches to network development – generator-led, developer-led, technology-led and demand-led – were presented in [2], and it was concluded from extensive multi-criteria analysis that regardless of the approach chosen, *significant network reinforcements will need to be made in both Ireland and Northern Ireland to facilitate integration of new RES generation, interconnectors and large energy users in the all-island power system by 2030*. It is worthwhile to note here that a 'final network development approach' combining elements of each of the four (above-mentioned) approaches has now been published as part of EirGrid and SONI's Shaping Our Electricity Future roadmap [4].

- In addition, it was demonstrated through simulations performed as part of EU SysFlex Task 2.6 [3] that strategic incorporation of selected reinforcements does help in alleviating significant congestion issues for many critical hours of the year.

However, these reinforcements alone cannot be expected to remove all network congestion issues for all hours of the year [3].

- Operational mitigation measures, e.g., generation adjustments, load shifting, phase-shifting transformer (PST) angle and transformer tap changes can offer additional flexibility to control room engineers for facilitating mitigation of infrequent congestion events that crop up for some hours of the year despite the strategic incorporation of selected reinforcements. Additional tools such as incorporating power flow control devices, demand side management and dynamic line ratings, can also help mitigate congestion issues in the operational timeframe. Simulations performed as part of Task 2.6 [3] demonstrated how these operational tools can be used in conjunction with network reinforcements for successful mitigation of anticipated congestion events.

- The degree to which operational mitigation measures can be implemented in practice is limited in terms of the time and capabilities that are at the control room operator's disposal. Thus, it is very important to find the right balance and a high degree of coordination between the planning and operational domains in relation to resolving congestions in the power system of the future.

Power Quality

In terms of **power quality**, a technical study is currently underway by EirGrid using all available recorded harmonic data from the past five years in order to determine if any trends pertaining to increased harmonic distortion levels with higher RES penetration are evident. The data analysis is still being carried out, but the *indications are that harmonic distortion is relatively constant across the system, and within the limits of international standards despite the numerous new devices that have connected*. This has largely been made possible due to the development of a policy on harmonics and the implementation of power quality requirements as part of the standard connection offer process to new customers.

As for the future, there is currently a great deal of interest in offshore generation which will be connected to the bulk power system through high voltage cables. These *cables have the potential to introduce resonances that can lead to breaches of the harmonic planning limits. This is an area that will be studied carefully over the next few years*, particularly in relation to offshore wind generation applications on the east coast as well as upcoming transmission developments, e.g., the Kildare-Meath 400 kV Grid Upgrade project [5].

System Restoration

In terms of **system restoration**, Power System Restoration Plans (PRSP) are in place in both Ireland and Northern Ireland to ensure that power is restored to all customers in a safe, secure and timely manner in the unlikely event of a blackout.

However, *the all-island power system is expected to undergo several key changes over the current decade that can potentially affect the respective PSRPs*. These include, but are not limited to: expected retirement of large conventional generators (including existing Black Start Units), an increase in the amount of distributed energy resources, planned key network development projects, incorporation of new technologies such as batteries, GFM-enabled RES generation and new interconnectors, as well as expected operational policy changes to accommodate higher RES penetration and increased SNSP.

In order to successfully accommodate and manage the above changes in the future, it is clear that an optimal balance needs to be struck between changing the PSRP on one hand (e.g., to reflect the retiring Black Start units and new network infrastructure) and exploring novel restoration strategies (incorporating new technologies) on the other.

Capacity Adequacy

In terms of **capacity adequacy**, the latest publicly available Generation Capacity Statement (GCS 2021-2030) [6] highlights a significant shortfall in generation capacity in the Irish power system. New renewable gas ready power plants, plus storage and demand side measures will be required to satisfy gaps out to 2030. The GCS noted that the Northern Ireland power system was adequate against core scenarios, however, sensitivity analysis investigated credible risks that could lead to shortfalls in adequacy, in particular the impact of run hour restrictions on gas plants plus the early closure of older plant.

In addition, the recently concluded SOEF consultation document [2] emphasised the uncertainties that are expected to impact on system adequacy: increasing demand, lower generation availability of existing power plants, new capacity terminating their awarded capacity, risks around delays in building new capacity, as well as emission limits. *2 GW of conventional generation is expected to retire in Ireland and Northern Ireland over the next five years, and new gas fired plants will be a part of the solution to manage future power system adequacy and security*, especially at times when renewable generation levels are low, which could extend in duration across multiple days. EirGrid and SONI continue to assess the security of supply situation, while monitoring the different uncertainties discussed previously, along with the evolving generation portfolio in the system.

Summary

Simulation results discussed throughout this report (and indeed in [3]) have revealed that renewable and non-conventional technologies are well capable of mitigating a host of technical challenges by means of system service provision. This is important as with increasing penetration of these technologies in the power system of the future, there is less likelihood of traditional service providers (e.g., conventional synchronous generation) to be in operation for providing these services. It is also important to note that the different mitigation technologies and strategies presented in this report were investigated in isolation; however, in reality, a range of such solutions would be needed [3].

It is shown that while some challenges can be mitigated by several technologies, multiple technologies can be used for alleviating a given challenge. The key therefore is to holistically identify the right mix of services/capabilities that will be needed for efficiently mitigating technical challenges in the power system of the future. In order to ensure that the right technical capabilities are available to the TSOs when needed, appropriately designed future markets and commercial arrangements will need to be in place that promote choice for investors and incentivise investment in appropriate technologies [3].

EirGrid and SONI are cognisant that there are likely to be additional technical and operational challenges that may appear in the path to 2030 and beyond [1]. *Apart from the challenges and potential mitigation strategies discussed, it is critical that appropriate operational policies, tools, standards, system services, and other supporting measures be put in place to facilitate realisation of the renewable energy policy ambitions by 2030*. With this in mind, EirGrid and SONI will continue to undertake extensive studies and analyses on the power system of the future, seeking to integrate any learning from system events/disturbances, and work in collaboration with other TSOs, DSOs, industry organisations and research institutions to ensure continued operation of the power system in a safe, secure and reliable manner.

1. Introduction

Environmental concerns coupled with economic challenges have spurred governments worldwide to propose ambitious targets for fulfilling their international obligations in relation to climate change mitigation. As a European Union (EU) member state and in line with EU commitments for realising the goals of the Paris Agreement, Ireland has recently released the Climate Action Plan 2021 (CAP21) which sets, amongst others, a target of achieving up to 80% renewable energy sources-electricity (RES-E) penetration (i.e., having up to 80% of all electricity generated from RES) by 2030 [7]. The CAP21 also includes an increased target of installing up to 5 GW of offshore wind energy capacity [7]. Similarly, the Department for the Economy in Northern Ireland (NI) has also set ambitious renewable energy targets for NI [8] in line with the UK government's major climate action commitments.

As transmission system operators (TSO) for the island of Ireland, EirGrid and SONI have a major role to play in facilitating the implementation of their respective government's renewable energy policies. EirGrid and SONI have partnered with several European power sector entities (e.g. TSOs and research organisations) to undertake technical studies for facilitating the realisation of 70% RES-E penetration and up to 95% system non-synchronous penetration (SNSP[3]) by 2030 [2] on the island of Ireland. Operating the power system at such high renewable penetration levels is unprecedented, so it is critical that detailed analyses are carried out for understanding potential technical challenges that may arise from implementing such policies.

One of the key projects currently underway at EirGrid and SONI for addressing potential challenges associated with operating power systems of the future is the Horizon 2020-funded EU-SysFlex project [9]. This project addresses the technical issues and challenges associated with high penetration levels of variable non-synchronous generation across different European power system configurations. It also provides solutions for mitigating these practical technical issues such as frequency and voltage instability. In the context of Ireland and Northern Ireland, EirGrid and SONI have performed technical analyses on different scenarios based on high levels of SNSP by 2030 for identifying potential challenges and devising corresponding mitigation strategies.

Work on EU-SysFlex started at EirGrid and SONI in 2017 and various stages have been successfully completed since. A key milestone was achieved in October 2018 with the completion of Task 2.2 'EU-SysFlex Scenarios and Network Sensitivities' [10] and Task 2.3 'Models for Simulating Technical Scarcities on the European Power System with High Levels of Renewable Generation' [11]. While Task 2.2 was aimed at modelling future scenarios for representing the generation, demand, interconnection and storage portfolios across the European power system in 2030 and beyond, the focus of Task 2.3 was on developing dynamic models for use in further simulations.

[3] Refer to Appendix B – Glossary of Technical Terms for definition

EU-SysFlex Task 2.4 'Technical Shortfalls for Pan European Power System with High Levels of Renewable Generation' [1], delivered in April 2020, built upon the scenarios and models developed in Tasks 2.2 and 2.3, and performed detailed technical studies for identifying scarcities[4] that are expected to occur in the European power system in 2030 with high levels of variable non-synchronous generation integrated. From an all-island perspective, seven such scarcities were identified in the study as presented in Table 1 [1], [2].

Table 1: Summary of technical challenges arising from high RES-E penetration [2]

Scarcity		***Why is it a challenge?***
Frequency Stability (Section 2.1)	*Inertia*	Higher RES-E penetration and SNSP levels would generally lead to lower system inertia due to displacement of conventional generation, which in turn leads to faster frequency dynamics and higher RoCoF[5] values following a system disturbance.
	Reserves	Reduction in system inertia at high SNSP levels and increase in the Largest Single Infeed/Outfeed (LSI/LSO[6]) size would require an increase in the volume of reserve as well as the need for faster frequency containment reserve provision. The composition of reserve (traditionally provided by conventional generation) is also likely to be significantly changed in the future with wind generation, solar PV, batteries and demand side units, amongst others, providing most of the system reserve needs.
	Ramping	Increased need of ramping reserves to counteract potentially large forecast errors associated with variable, weather-dependent generation. A common weather event, e.g., a storm, affecting a large number of online RES units can also impose significant changes to the generation profile, thereby necessitating the need for greater volumes of ramping services to be made available in the appropriate timeframe.
	Very low frequency oscillations	Though a definitive root cause is yet to be ascertained, preliminary studies indicate that the all-island power system may be exposed to very low frequency oscillations when subject to certain combinations of specific unit commitment and low system strength conditions. The most likely causes of such events appear to be the reduced inherent damping of the system at higher RES penetration levels as well as potential delays in the turbine-governor control systems of certain synchronous machines taking part in frequency response.
Voltage Stability (Section 2.2)	*Static voltage stability*	Displacement of conventional generation at high SNSP levels can lead to a significant scarcity of steady state reactive power capability, especially in weaker parts of the system with high RES penetrations far from conventional generation. This can lead to an increase in both severity and frequency of voltage deviations and their propagation through the network that breaches the corresponding planning and operation standards.
	Dynamic voltage	Reduction in online reactive power support capability of conventional

[4] Refer to Appendix B – Glossary of Technical Terms for definition

[5] Refer to Appendix B – Glossary of Technical Terms for definition.

[6] Refer to Appendix B – Glossary of Technical Terms for definition of LSI/LSO. The current LSI is 500 MW corresponding to one of the two existing HVDC interconnectors importing at full capacity. This is expected to increase to 700 MW following the commissioning of the Celtic interconnector, for example.

	stability	generation at high SNSP levels generally leads to poorer dynamic voltage performance. Studies indicate a system-wide scarcity in dynamic post-fault voltage control during some hours of the year, but localized issues for the majority of hours.
	Reduction in system strength	Fault current contributions from inverter-based resources (IBR), e.g., wind and solar, are inherently lower than synchronous generators. A future power system dominated by IBRs connected to weaker parts of the grid coupled with reduced numbers of conventional generators online can have important ramifications on the management of system voltage, protection performance and the stability of IBR controls.
Transient Stability (Section 2.3)	*Damping torque scarcities*	The all-island power system has been subject to very low frequency oscillations (0.03 to 0.08 Hz) for a number of years. These oscillations are likely to occur under low inertia and certain specific dispatch conditions. To mitigate these oscillations, it is important to ensure enough positive system damping to avoid uncontrollable high magnitude oscillations.
	Synchronising torque scarcities	As the system begins to operate with fewer synchronous units, each of the remaining units will be required to contribute more electromagnetic torque during a given fault. Furthermore, a reduction in the number of units may lead to changes in the geographic distribution of units, which could isolate certain units and expose them to an increased risk of losing synchronism, particularly for faults in close proximity (as the torque contribution during the fault is heavily dependent upon electrical distance to the fault).
	Inverter-driven Stability/Security	The control and dynamic behaviour of IBRs is different from that of synchronous generators. Interactions between IBR controls in weaker parts of the network can pose significant stability issues. Traditionally used Root Mean Square (RMS) dynamic simulations and the simplified modelling of Phase Lock Loops and current control loops might not be adequate especially for low system strength conditions.
Congestion (Section 2.4)		With increasing RES and load connections in the system, evacuation of power from generation centres such as the west of Ireland (which has significant renewable resources) to load centres in the east implies that existing transmission assets are at a high risk of being overloaded, especially following a credible outage of a transmission line.
Power quality (Section 2.5)		With increasing numbers of inverter-based generation displacing conventional units, the total harmonic distortion experienced in the system can potentially increase over the coming years. Another area of concern is the amplification of existing distortion levels stemming from resonances introduced by underground cables used for connecting wind farms to weaker parts of the grid.
System restoration (Section 2.6)		Increasing connections of variable non-synchronous generation to the grid using current source converters implies that black start capability in the system is likely to significantly decline in the future in the event of a catastrophic failure. Continued displacement of synchronous generation by RES implies that geographic locations of generation units would change, requiring regular review of established system restoration paths.
Capacity adequacy (Section 2.7)		A power system is considered adequate if there is sufficient generation capacity to meet the system demand under various system uncertainties, e.g., demand growth, generation availability and variable RES outputs. With increasing RES penetration in the power system and the consequent displacement of conventional generation, one of the main concerns is to have adequate system capacity to meet the demand both reliably and economically.

It needs to be noted that the list of challenges presented in Table 1 is not exhaustive; rather the challenges are indicative of the potential issues that may be encountered in the power system of the future. A brief overview of some additional technical issues [1] that may appear in a power system with a higher penetration of renewable resources is provided in Appendix A – Additional Technical Challenges.

Mitigation strategies for addressing the different technical challenges identified in Table 1 were developed in EU-SysFlex Task 2.6 'Mitigation of the Technical Scarcities Associated with High Levels of Renewables on the European Power System' [3]. Extensive simulations were performed and key findings on relevant technologies that can mitigate the technical scarcities presented in Table 1 are presented in Section 2. It is to be noted that while the majority of the mitigation strategies presented in Section 2 were indeed developed in Task 2.6 [3], some were designed as part of other studies conducted within EirGrid and SONI. References to such studies are provided in relevant subsections where the corresponding mitigation strategies are discussed.

2. Mitigation Strategies

Each technical scarcity and associated mitigation strategies are considered in this section.

2.1. Frequency Stability

SUMMARY:

Operating a power system means balancing the generation and load at any moment. Any imbalance (between the active power components of the generation and load) results in a change of the system frequency [2]. Frequency stability describes the ability of a power system to return to an operating equilibrium following a severe system disturbance without crossing the thresholds of load or generation shedding.

Conventional synchronous generators connected to a power system contribute significantly to system inertia, which is essentially the amount of kinetic energy stored in the rotating masses of these machines [2]. The power system's inertia determines the sensitivity of the system frequency towards supply demand imbalances, i.e., the higher the inertia, the lower the sensitivity of the frequency towards temporary imbalances. Another important metric in relation to frequency stability is the Rate-of-Change-of-Frequency (RoCoF) which represents the rate at which the system frequency changes in the timeframe immediately following a system event which disconnects a generator or load from the system [2]. The RoCoF is inversely proportional to the amount of system inertia, i.e., when the inertia is high, the RoCoF following a system event is lower.

Increasing RES penetration and the consequent displacement of conventional synchronous generating units is therefore expected to bring about a significant decline in system inertia along with changes in the reserve portfolio. Increased RoCoF in a low inertia system implies that the frequency is expected to decay faster, with its nadir (i.e. the lowest value) occurring sooner following a system event. In a future power system dominated by non-synchronous resources, there is therefore a need for fast frequency response (FFR) to deliver sufficient MW response to halt this frequency decay.

Several mitigation technologies and strategies are presented in this section for provision of system inertia, reserves and FFR. The contribution of synchronous condensers in increasing system inertia and preventing frequency instability is demonstrated, whereby these devices are successful in reducing the RoCoF thereby enabling the activation of slower frequency provision resources before the occurrence of the nadir. Reserve provision using frequency response control of wind farms is investigated, and it is demonstrated that these could be beneficial in supporting frequency stability, particularly in times of high wind. FFR provision capabilities of batteries and wind turbines are also successfully demonstrated.

As described in the Executive Summary, the governments in Ireland and Northern Ireland have set or are in the process of setting ambitious goals for RES-E penetration by 2030 [7], [8]. There are also ambitions to achieve up to 95% SNSP (i.e., instantaneous renewable penetration) levels in the all-island power system by 2030 [12]. The all-island power system is therefore undergoing changes at an unprecedented pace as a result.

Increasing RES penetration and the consequent displacement of conventional generation units is expected to bring about a significant decline in system inertia along with changes in the reserve portfolio. As per current convention, at least 8 large synchronous generators are kept online in the all-island power system at all times, with a minimum threshold for system inertia (i.e., the inertia floor constraint) being equal to 23 GWs [2]. In the absence of other non-conventional technologies replacing the inertia capability lost as a result of the displacement of (conventional) synchronous generators, it is clear that increasing SNSP will lead to a corresponding decline in system inertia levels. This projected reduction in system inertia corresponding to the 2030 Low Carbon Living (LCL) Scenario[7] is presented through the (blue) inertia duration curve in Figure 2, where the increased probability of the percentage of the year spent at inertia levels that are lower than the current floor (23 GWs) can be clearly observed.

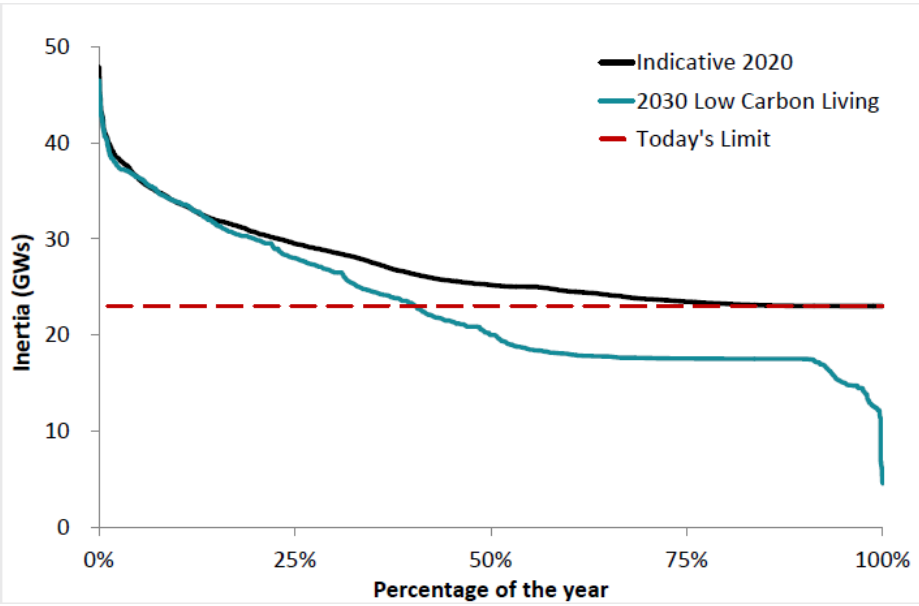

Figure 2: Comparison of inertia levels in 2020 and in the 2030 LCL scenario

[7] The Low Carbon Living (LCL) is the scenario with the highest level of renewable generation utilised for the all-island power system studies in EU-SysFlex [1]. Given that most results presented in this report reflect the outcomes of simulations performed as part of EU SysFlex Task 2.6 [3], it follows that unless specifically mentioned otherwise, these results are generated under the assumption of the LCL scenario.

Reduced inertia coupled with an expected increase in the LSI/LSO size (from 500 MW to 700 MW following the commissioning of the Celtic interconnector) would likely necessitate the procurement of higher volumes of reserves that can be made available at a faster rate. The rate of change of frequency (RoCoF) due to loss of the LSI in a low inertia system is typically steep causing frequency to decay faster, with its nadir likely to occur sooner. In a future power system dominated by non-synchronous resources, there is therefore a need for fast frequency response for delivering sufficient MW response to halt this frequency decay.

In order to expose technical scarcities in the all-island power system, a number of Operational System Constraints [13] were relaxed for the EU-SysFlex studies. These are related to SNSP limits, inertia floor, RoCoF, and the minimum number of units on system constraints [1], [2], [3]. Extensive investigations on frequency stability as part of EU-SysFlex Task 2.4 [1] revealed that excessive RoCoFs could be experienced in the 2030 all-island (AI) power system with SNSP levels approaching 90%. In Ireland and Northern Ireland, RoCoFs should not exceed 1 Hz/s[8] for any credible contingency.

Figure 3 shows Task 2.4 frequency results for the LCL scenario following the loss of the LSI (at t = 1 second) in the AI power system for different hours of the year. Analysis carried out revealed a number of cases (approximately 0.6% of all cases) where the frequency nadir[9] deviated below the acceptable level of 49 Hz. Frequency drop/rise in Ireland should not exceed ±1000mHz as per System Operation Guideline (SOGL) requirements [14] and to provide a margin of safety to avoid the triggering of Under Frequency Load Shedding(UFLS) or Over Frequency Generation Shedding (OFGS) schemes [15], [16].

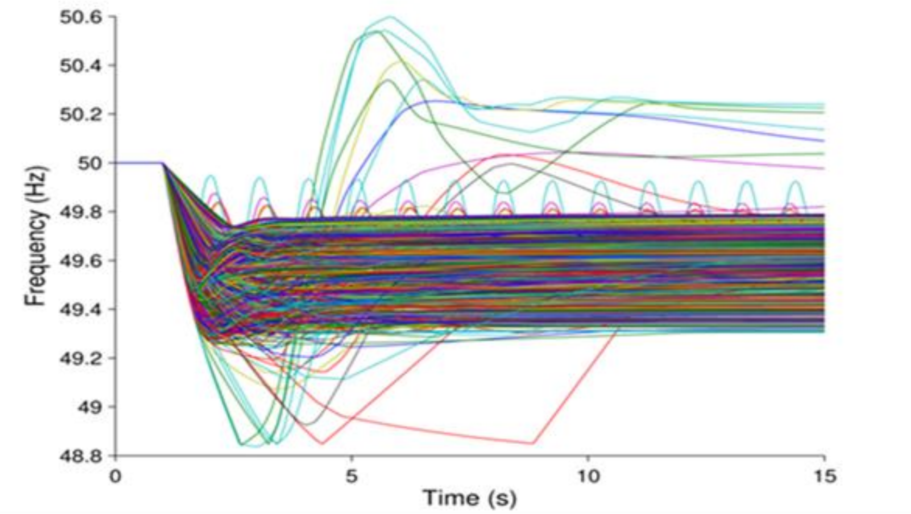

Figure 3: Frequency profiles for LCL following loss of LSI

[8] This limit is currently being trialled.

[9] Refer to Appendix B – Glossary of Technical Terms for definition

Mitigation strategies for addressing the different frequency stability related technical challenges identified in Task 2.4 were devised as part of EU-SysFlex Task 2.6 [3], and those are presented in the following subsections. All cases associated with frequency breaching the 49 Hz security limit as presented in Figure 3 were considered, and different mitigation technologies applied, one at a time, to this 'base case' model. The volume of the concerned technology was increased in steps until a point was reached where the system frequency did not breach the 49 Hz limit. The final volume of the resource which mitigated the frequency instability was then reported.

It is to be noted that the aim of the analyses carried out as part of EU-SysFlex Task 2.6 [3] is to demonstrate the capability of a number of proposed technologies to mitigate the issue of frequency excursions on the all-island power system. As such, the demonstration of the capabilities that are needed to solve the technical scarcities is the main focus here; not the technologies themselves. It is acknowledged that the technologies discussed in the following subsections are not exhaustive; rather they are simply indicative of the different technologies that can offer the needed mitigation capability.

2.1.1. Inertia

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

The role of synchronous condensers[10] in increasing system inertia and mitigating frequency instability is investigated in this section [3]. For the simulation snapshot under consideration, the base case SNSP is 69.38% with a potential RoCoF of 1 Hz/s and total system inertia of 17.5 GWs. In terms of reserve provision under the base case, pumped hydro and demand side units (DSU) provide a cumulative reserve of 472 MW and 180 MW, respectively. The remaining three HVDC interconnectors (the fourth one being the LSI and hence cannot provide reserve) have an available reserve capacity of 75 MW each. The volume of BESS dispatched for this case is 39.5 MW. Finally, three large synchronous units are online and dispatched to 1107 MW (total) under the base case, with two of the three units operating at their respective maximum capacities.

As mentioned in Section 2.1, the synchronous condensers (each assumed in the studies to have a 400 MVA capacity with a 3s inertia constant) were added to the base case model one at a time, and it was noted that a large number of such devices would need to be incorporated to bring the frequency above the 49 Hz security limit. Given this large requirement, it was observed that a combination of different technologies would more likely be needed as discussed further.

[10] Refer to Appendix B – Glossary of Technical Terms for definition

The frequency traces corresponding to the base case and with the mitigation strategy applied (i.e., with the synchronous condensers added) are presented in Figure 4. It can be clearly observed from the figure that increasing system inertia results in a slower RoCoF, shifting the occurrence of the frequency nadir form 2.66s to 4.12s, while also ensuring that the nadir does not breach the 49 Hz threshold.

The support available from slower-acting reserves, e.g., DSUs and pumped hydro, are presented in Figure 5 - Figure 6, respectively. For comparison sake, both figures also contain the frequency traces corresponding to the base case as well as with the synchronous condensers added. It can be verified from the figures that the incorporation of synchronous condensers and the consequent delaying of the frequency nadir facilitates the disconnection of 90.4 MW of DSUs and three hydro units operating in a pumping mode (amounting 219 MW) prior to the nadir being reached.

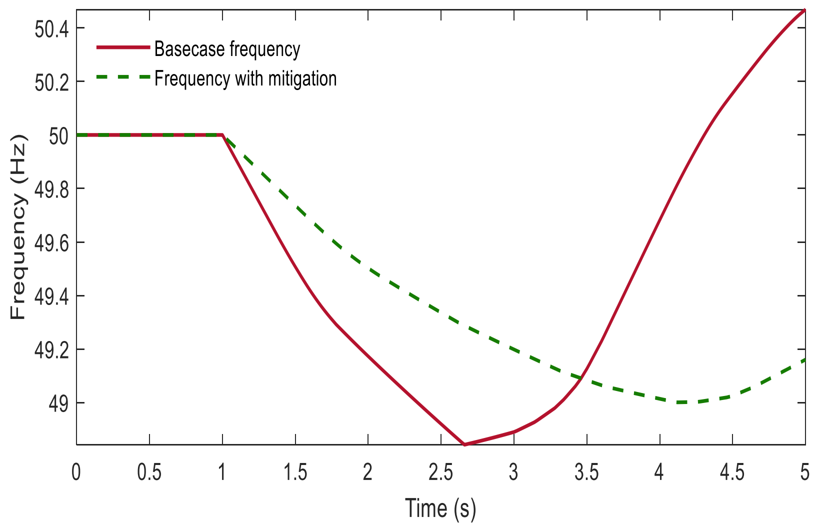

Figure 4: System frequencies for base case and with mitigation

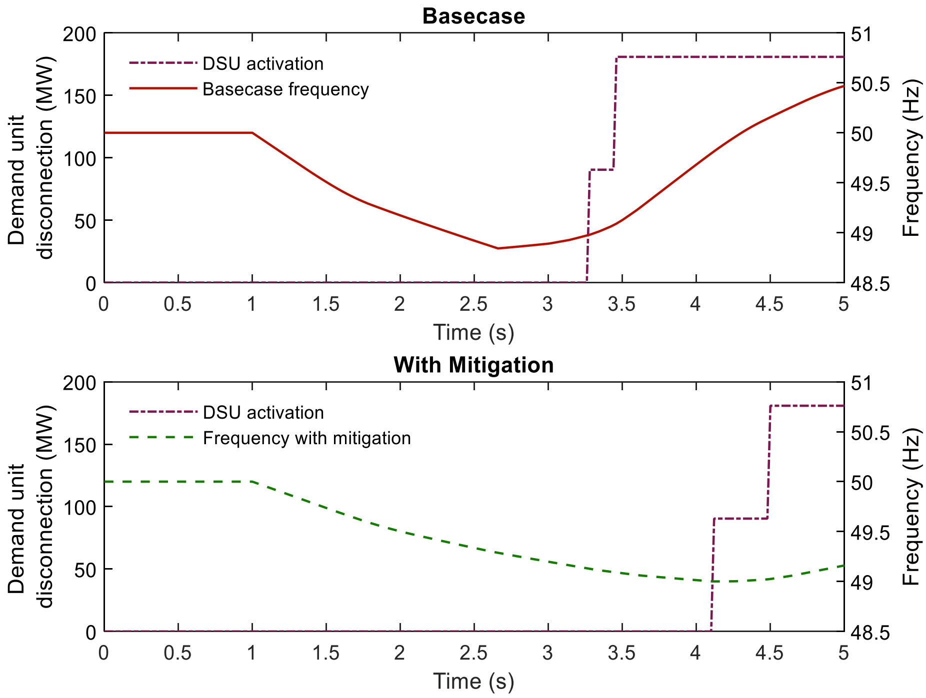

Figure 5: Response of demand side units for base case and with mitigation

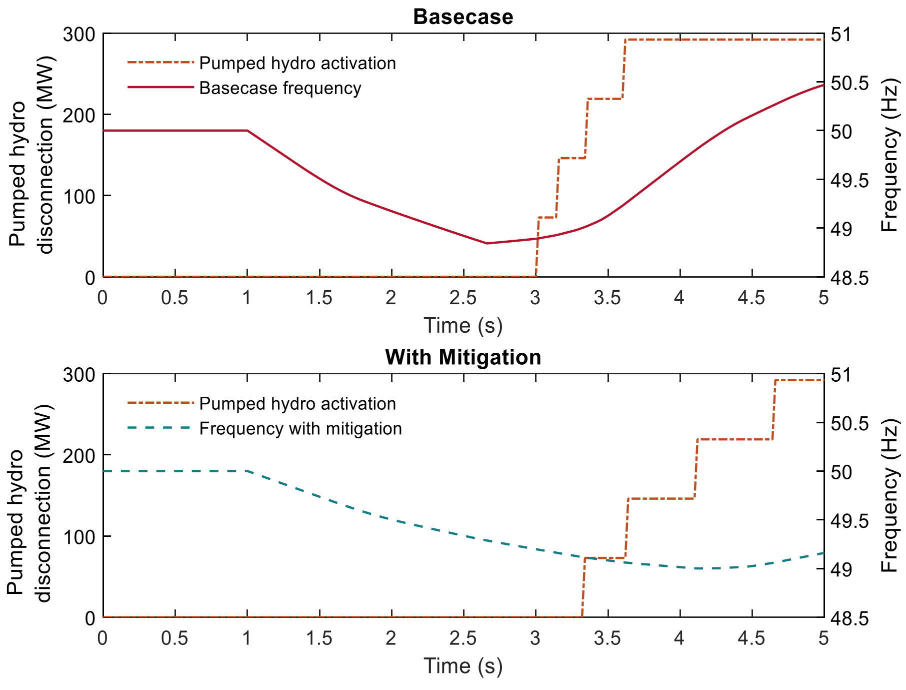

Figure 6: Pumped hydro response for base case and with mitigation

In conclusion, it may be noted from the results presented in this section that synchronous condensers do help to delay the frequency nadir, thereby enabling the activation of slower-acting reserves prior to its occurrence. However, these devices are not successful in dealing with frequency stability issues on their own but can be quite beneficial when used in combination with other mitigation measures discussed in the following subsections.

2.1.2. Reserves

This section investigates the impacts of reserve provision[11] from non-synchronous generation, e.g., wind turbines and batteries, on frequency excursions (and consequently the RoCoF) following a system disturbance. Two distinct sets of simulations were performed, as detailed under the following sub-headings.

2.1.2.1. Reserve provision from wind generation

In order to demonstrate the capability of renewables providing Primary Operating Reserve (POR), frequency response control of wind farms is investigated 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 for controlling their response to system frequency changes [17]. APC is 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 under the condition that the wind farm’s output is already being constrained or curtailed owing to network or system security issues. It is to be noted here that only when the wind farm is operating below its maximum available generation capacity level would it be in a position to further increase its output for improving the system frequency [3].

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[11] It is worthwhile to note here that the simulations presented in the following sub-sections pertain to positive reserves only. Traditionally, the loss of the LSI has been the focus of frequency stability studies in the all-island power system. However, the loss of the (new) Celtic interconnector at 700 MW full export (this is expected to become the Largest Single Outfeed (LSO) in 2030) becomes a credible threat to the system, and was therefore evaluated as part of EU SysFlex Task 2.4 [1]. It was revealed through simulations carried out in [1] that frequency zeniths always remained below the highest acceptable threshold of 50.75 Hz following the loss of the LSO, and that no resulting under-frequency issues were observed after the subsequent activation of the OFGS scheme.

At present, most wind farms in Ireland operate with a ‘default’ setting of 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 [17], so they are essentially responding to contingency events only. When APC and frequency response capability are both turned on, the deadband is reduced to ±15 mHZ to facilitate a more dynamic response from the wind farms [17]. For this set of simulations, a base case scenario associated with a high volume (3040 MW) of dispatched wind was chosen to better highlight the wind farm’s capability to provide this frequency response service. It was assumed that the available headroom for wind farms to respond to under-frequency events is 7.5% of the dispatched wind, as per typical values recorded for Ireland and Northern Ireland [18]. Two droop values, 2% and 4%, were considered for the simulations, with the deadband being set equal to ±200 mHz.

Frequency traces for the base case and with the proposed mitigations (i.e., 2% and 4% droop characteristics) applied are presented in Figure 7. It can be seen from the figure that operation of the wind farm with a 4% droop setting merely defers the occurrence of the nadir from 2.66s (corresponding to the base case) to 3s, without improving the value of the nadir itself. However, by changing the droop characteristic to 2%, the frequency decay is limited to 49 Hz, with the nadir now occurring at 3.4s.

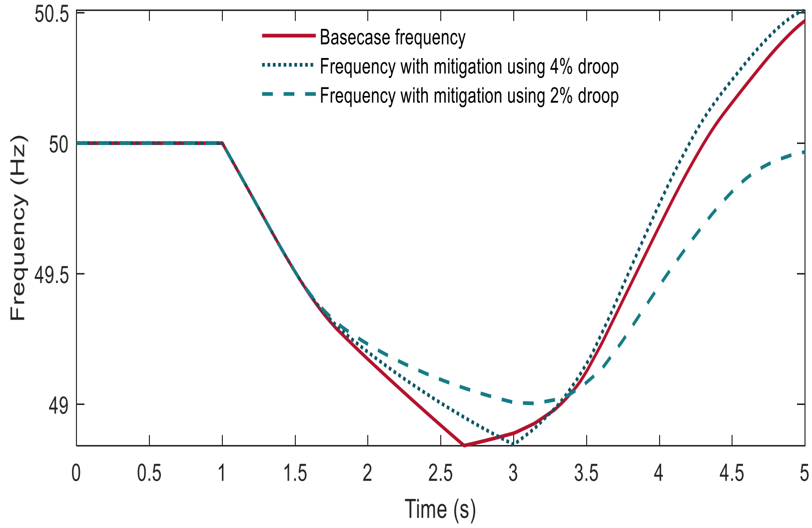

Figure 7: Frequencies for base case and with mitigations (2% and 4% droop) applied

The additional MW injection from the wind farm at the time of occurrence of the nadir is presented in Figure 8 for both the 2% and 4% droop scenarios. Considering that the area under the grey dotted lines in Figure 8 represents the total energy injected by the wind farms after the system disturbance, it can be appreciated that while the quantum of energy injected for the 4% droop scenario is sufficient for delaying the occurrence of the nadir, it is not enough to arrest the decay of the frequency to below 49 Hz.

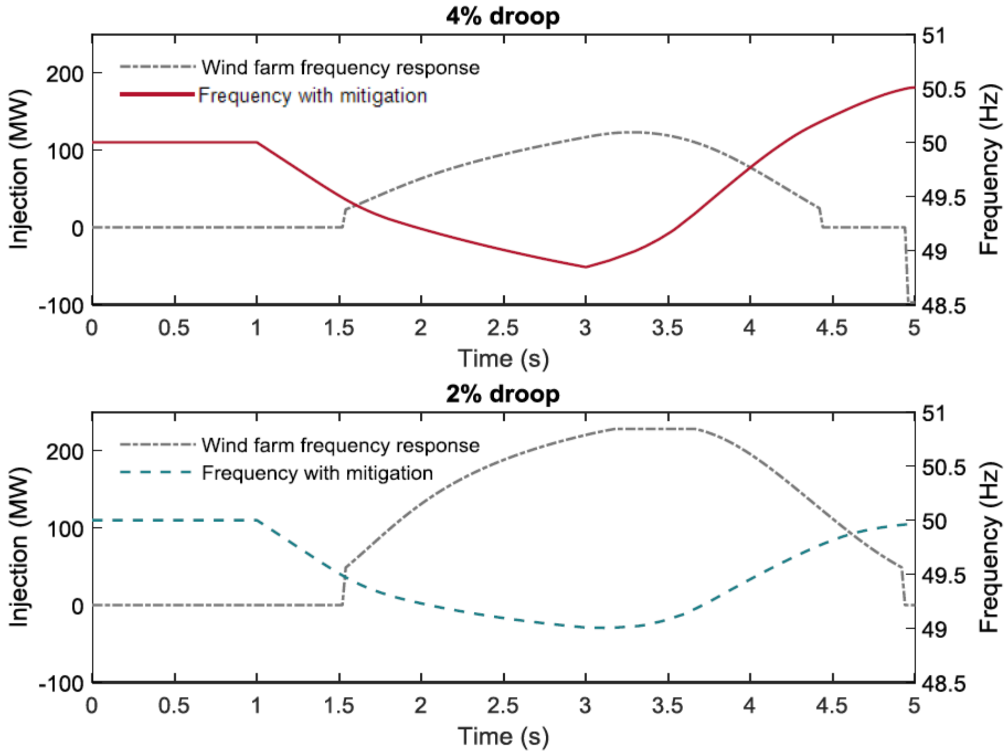

Figure 8: Active power injection from wind farm with 4% and 2% droops applied

This analysis has therefore demonstrated that the 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 fewer conventional generators are expected to be online during periods of high wind, hence lesser frequency response capability available from the conventional units.

2.1.2.2. Increasing the level of Fast Frequency Reserve (FFR) provision

Within the DS3 System Services arrangements, EirGrid's and SONI's FFR service is defined as the additional increase in MW output from a generator or reduction in demand following a frequency event that is available within 2 seconds of the start of the event and is sustained for at least 8 seconds [19]. The extra energy provided in the 2s – 10s timeframe must be greater than any loss of energy in the 10s – 20s timeframe due to a reduction in the MW output/MW reduction with respect to pre-event levels [19]. The FFR provision from two non-synchronous technologies – batteries and wind generators – is investigated further in this subsection.

For demonstrating the FFR provision capability of battery energy storage systems (BESS), the same base case scenario utilised for the simulations incorporating synchronous condensers in Section 2.1.1 is selected. It may be recalled from Section 2.1.1 that the base case corresponded to a significantly low level of BESS dispatch (39.5 MW), so the aim of the simulation results presented in the following paragraphs is to highlight the capability of BESS to alleviate frequency instability issues through additional MW reserve injection. Similar to the results presented in Figure 4, the system event leading to the frequency nadir studied in this subsection is the loss of a 700 MW HVDC interconnector (likely LSI in 2030).

The volume of reserve coming from the BESS is gradually increased from the 'base case' level till a point is reached when the frequency does not decay below 49 Hz following the system disturbance. The corresponding frequency traces (for the base case and with BESS incorporated) are presented in Figure 9. The amount of MW reserve injected by the BESS for the base case and with the mitigation applied is shown in Figure 10.

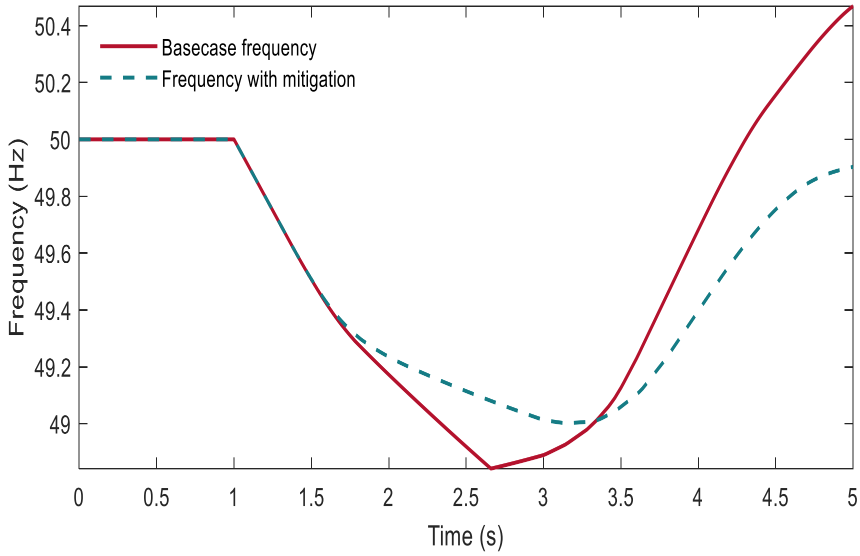

Figure 9: System frequency for base case and with BESS integrated

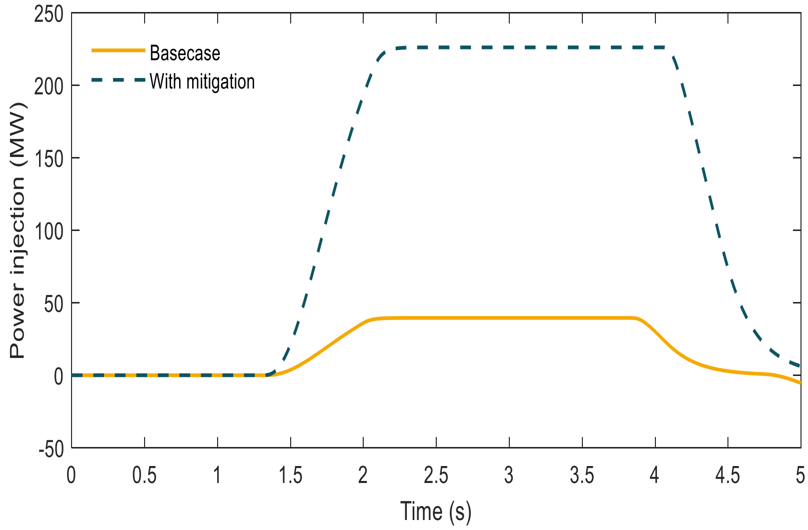

Figure 10: Battery dispatch for base case and with mitigation applied

It can be seen from Figure 9 - Figure 10 that the injection of 226 MW of reserve from the BESS (compared to only 39.5 MW being injected under the base case) facilitates maintenance of the frequency level above 49 Hz, while also delaying the occurrence of the nadir by almost 500 ms. The frequency response from pumped hydro is presented in Figure 11. It can be verified from the figure that the provision of additional FFR from the batteries facilitates the disconnection of one block of 73 MW of pumped hydro before the occurrence of the nadir.

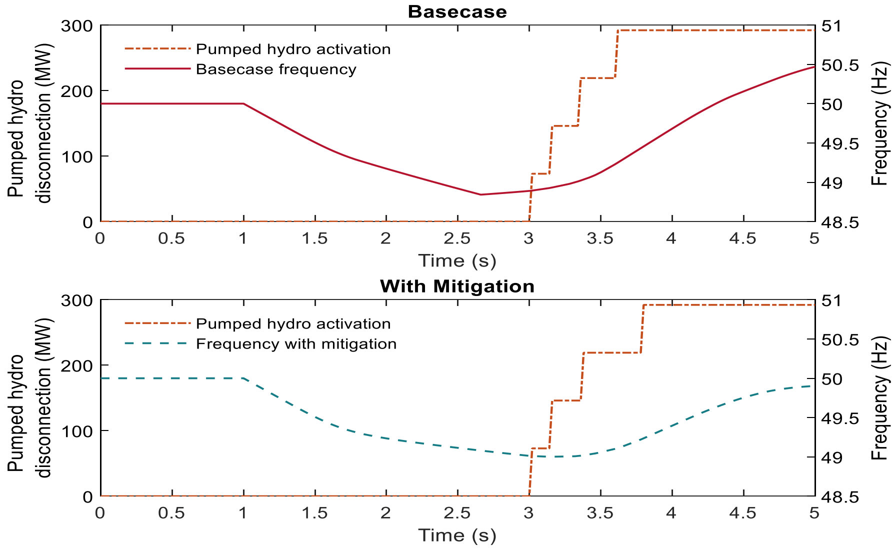

Figure 11: Pumped hydro response for base case and with mitigation applied

The results presented so far in this subsection demonstrate the FFR provision capability of BESS. The supplementary injection of active power from the batteries at a rapid pace helps to decrease the RoCoF, thereby delaying the frequency nadir and enabling the slower-acting reserves (e.g., pumped hydro units) to be activated beforehand.

The remainder of this subsection will be focussed on demonstrating the FFR provision capability of wind turbines. Latest developments in wind turbine 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 worldwide [20] where wind turbines are used to provide fast response by harnessing their stored rotational energy, an action usually referred to as an emulated or synthetic inertial response.

According to ENTSO-E [21], emulated 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 that generator. This provision of electrical torque resists changes in frequency and thus mimics the release of energy from a rotating synchronous generator. It should be noted that in EirGrid and SONI, emulated inertia is considered as a FFR product, and not a synchronous inertial product.

The wind turbine controller model used in the simulations was based on GE's WindINERTIA control system [22]. 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. For large under-frequency events, this feature temporarily increases the power output of the wind turbine in the range of 5% - 10% of the rated turbine power [22]. 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. However, it is important to note that as the wind turbine is slowed by the controller to provide a fast injection of active power using the inertial energy from the rotor, the extracted energy will eventually need to be recovered [22].

A base case scenario associated with approximately 730 MW of wind power output was simulated first, and the corresponding frequency traces with and without FFR provision from the wind turbines are presented in Figure 12. It can be observed from the figure that while the FFR provided by the wind generators does help to both delay and increase the frequency nadir, it is not sufficient to keep the frequency from breaching the 49 Hz security limit.

It was found in relation to Figure 12 that a higher contribution of FFR from wind cannot be realised with this level of wind power output (of 730 MW) owing to the limitations on the turbines themselves. To demonstrate this, the wind output was increased gradually from 730 MW until the frequency was restored above 49 Hz at a wind generation level of 1020 MW, as shown in Figure 13.

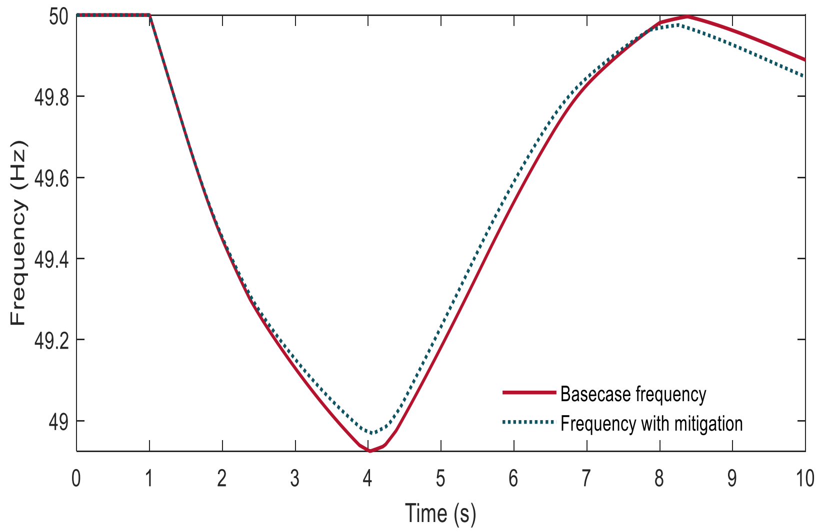

Figure 12: System frequency without and with FFR provision from wind turbines

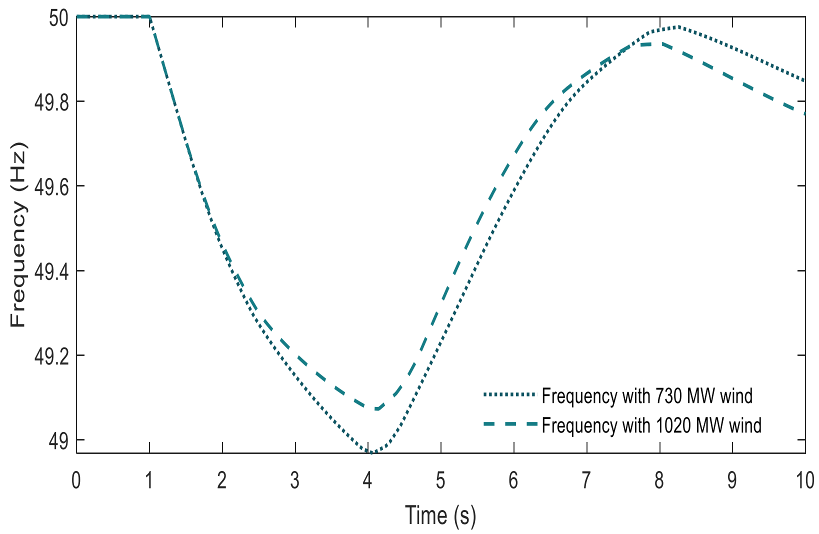

Figure 13: System frequency with increased wind output

The additional contribution of emulated inertia when the dispatched wind is increased from 730 MW to 1020 MW is shown in Figure 14. It can be observed from the figure that with the increased wind dispatch, about 100 MW (i.e., approximately 10% of the available wind generation capacity) is injected by the wind farms as FFR contribution. As a result, the corresponding system frequency does not dip below the 49 Hz threshold as shown in Figure 13.

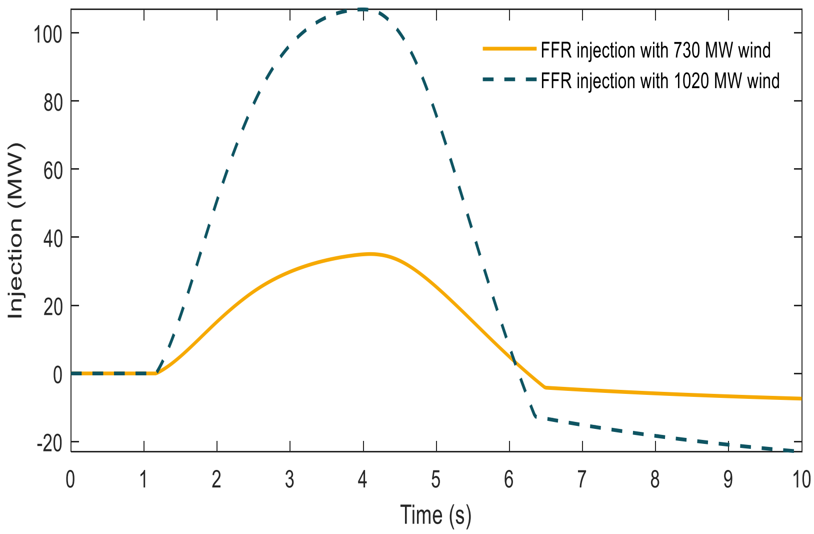

Figure 14: Provision of FFR at different levels of wind generation

It is important to note from Figure 13 - Figure 14 that once the frequency recovers after about 4s, the energy generated by the wind turbines starts to drop and eventually becomes negative. This demonstrates how the energy injected into the grid (in the form of synthetic inertia contribution) is eventually returned back to the wind generators. This is as per specifications of the emulated inertia controller considered as part of the corresponding FFR product procured in Ireland and Northern Ireland [23]. It is important to understand that while the synthetic inertia appears to be beneficial in terms of halting frequency decay; further studies/considerations are required to understand its impact on POR, SOR and frequency recovery.

The results presented in this subsection in relation to FFR provision from wind turbines have demonstrated this as an important mitigation measure for maintaining 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 is limited to about 10% of the available wind generation capacity. A significant contribution of FFR from wind is therefore difficult during times of low wind availability.

2.1.3. Ramping

Renewable generation, e.g., wind, delivered to the power system is heavily dependent on accurate forecasting, and the comparatively high installed capacity of such generation resources in the all-island power system consequently results in forecast errors that are a significant proportion of system demand [24]. Moreover, with increasing penetration levels of such resources in the system, the magnitude of the forecast error is only likely to increase in the future. This will inevitably lead to increased occurrences of system scarcities that reveal themselves in the 1 – 8 hour time horizon, thereby creating complex problems for the system operators to manage [2].

The problem with increased weather forecast errors is exacerbated by Ireland's location on the edge of Europe and the influence of the jet stream on its weather (which in turn increases the potential errors), combined with the limited number of weather measurement points in the Atlantic Ocean [2]. Particularly concerning is the challenge of dealing with weather patterns that arrive either ahead of or after they are forecast to at a time when a large proportion of the system demand is being served by renewables, e.g., wind and solar.

An example of the spread of wind power forecasts, looking ahead over the next 30 hours, is presented in Figure 15 corresponding to a storm event in October 2018 [24]. The figure consists of the mean wind power forecast (coloured purple) which is delivered to EirGrid by the vendor, along with the ensemble (i.e., likely scenarios) of forecasts from which the mean values are generated [24]. The degree of uncertainty (especially during adverse weather events) associated with prediction of wind power even a few hours into the future can be appreciated from the spread of the forecast ensembles presented in Figure 15.

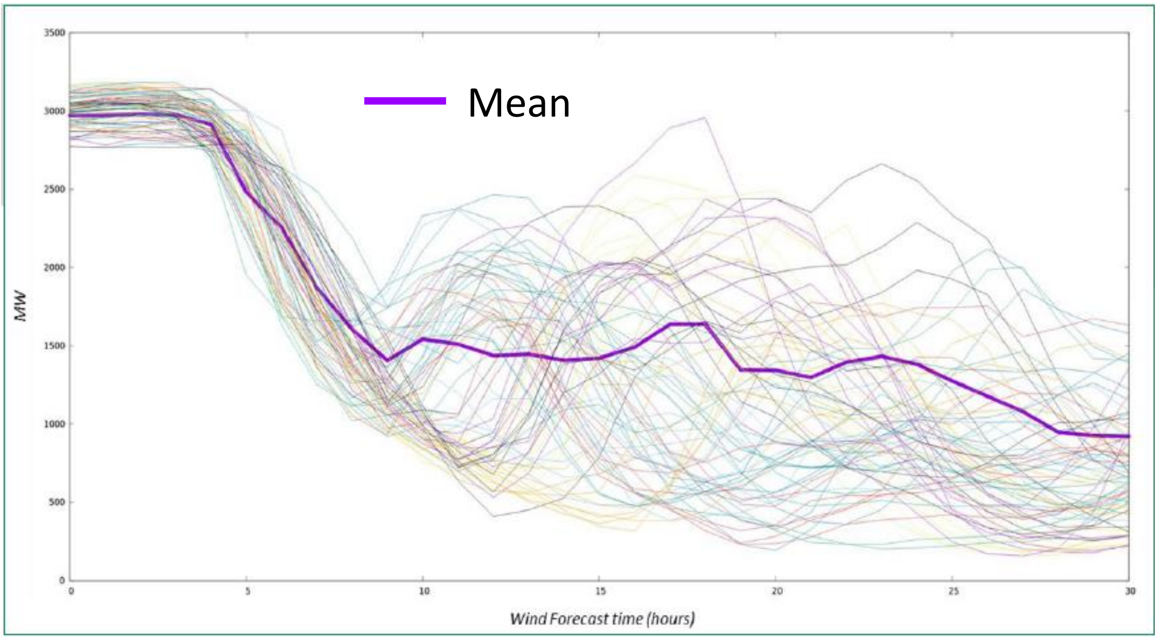

Figure 15: Vendor's ensemble of wind power forecasts

EirGrid and SONI currently schedule the system to meet the median production forecast of variable generation, and at 2020 levels, the associated forecast errors can still be managed [2]. However, with significant amounts of renewable resources predicted to be connected to the system by 2030, a number of conventional generators are expected to be displaced [24]. It is essential to maintain a flexible amount of 'dispatchable' generation (or demand response) that can ramp up (or down in the case of demand response) and replace the capacity not delivered by renewable resources owing to forecast errors.

One of the most cost-effective ways to ensure that sufficient resources are available to cover forecast error uncertainty is to explicitly include this risk in the operational scheduling process. In view of this, and as part of the DS3 programme [25], EirGrid and SONI developed a ramping tool for incorporating new multi-period active power reserve constraints into the operational scheduling framework [24]. These new products are referred to as Ramping Margin reserves (RM-reserves), and they provide additional confidence that sufficient resources would be available to support potential supply deficits stemming from forecast error events that evolve over time horizons of one (RM1), three (RM3) and eight (RM8) hours [24]. RM-reserve requirements are time-varying as they need to reflect the forecast uncertainty associated with current weather conditions.

With increasing penetration of renewable generation in the coming years, there will be an increased need for RM-reserve provision given the low availability of thermal generators (due to fewer running hours causing them to be increasingly offline/cold rather than online/hot) [24]. In view of this, an enduring ramping strategy needs to be put in place before 2030 for addressing the increased requirement for ramping services. In the future, the sources of ramping are increasingly likely to come from long-duration battery storage technologies, interconnectors, sophisticated forecasting, and also, potentially from the demand side [2]. Further work is required to dimension these ramping needs and capabilities to ensure that operators are able to run the all-island power system in a safe, secure and reliable manner while honouring relevant RES-E penetration targets for 2030.

2.1.4. Very Low Frequency Oscillations

Since late 2009 very low frequency (VLF) oscillations (between 0.03 and 0.08 Hz) have been seen on the Ireland and Northern Ireland power system [26]. These oscillations can be observed as an oscillation in the system frequency with the active power of the synchronous generators moving in phase with the frequency.

Whilst these oscillations are usually of low magnitude, several events have occurred since 2014 with peak to peak magnitudes of up to 500 mHz. Events of this nature could pose a threat to secure operation, if they are not well managed. An example of a VLF oscillation event is shown in Figure 16 (red trace) and compared against a normal frequency trace (blue trace at the top). It is evident that the oscillation frequency is around 0.05 Hz with a relatively small peak to peak magnitude of around 70 mHz.

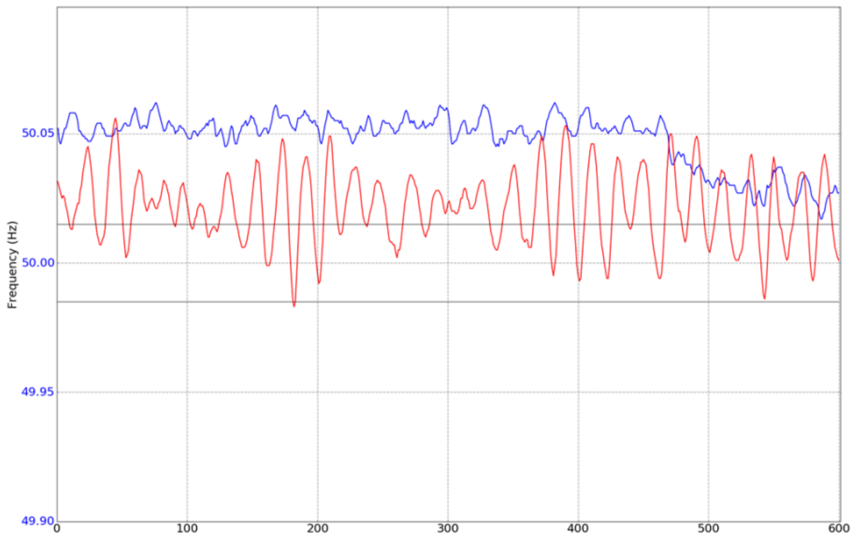

Figure 16: Normal frequency trace (blue) and a VLF oscillation trace (red) [26]

These VLF oscillations might be triggered by different perturbations (for example, pumped storage units switching to a pumping mode or a loss of a unit or the interconnectors switching from an export to import mode of operation – forced oscillations) or sometime no perturbation might initiate them (natural oscillations).

Every generator on the power system has a natural frequency of oscillation. This frequency is dependent on the inertia of the generator, the strength of the power system to which the generator is connected to and the generator's power output level. A generator's inertia is constant, but the transmission system's strength and the generator's output level are variable. A generator's natural frequency of oscillation will vary with the changing strength of the transmission system and the changing loading of the generator.

The strength of a transmission system is a function of the number and size of the lines in the system and its power loading. If a system is composed of many high voltage lines that are lightly loaded it is a strong transmission system. If a system is composed of only a few low voltage lines that are heavily loaded it is a weak transmission system. Most transmission systems are somewhere between these two extremes. When a generator is disturbed it will oscillate at a higher frequency if it is connected to a strong transmission system. The generator will oscillate at a lower frequency if it is connected to a weak transmission system. This is another indication that the all-island power system when subject to certain scheduling/demand conditions might not have sufficient strength to prevent these very low frequency oscillations especially if exposed to delays in the governor system of the units taking part in frequency response.

The output level (MW and Mvar) of a generator also affects its natural frequency of oscillations. In general, as the loading of the generator increases its natural frequency of oscillation reduces. If we assume that the generator and system voltages stay relatively constant, the loading level of the generator can be related to its torque angle. As the generator's torque angle rises toward 90° its natural frequency of oscillation reduces.

To deal with oscillation a transmission system operator relies on an oscillation management process that consists of three different stages as indicated in Figure 17:

- Detection of Oscillations
- Identification of oscillation sources
- Mitigation actions to reduce the impact of mitigation sources and involve/enable oscillation damping resources

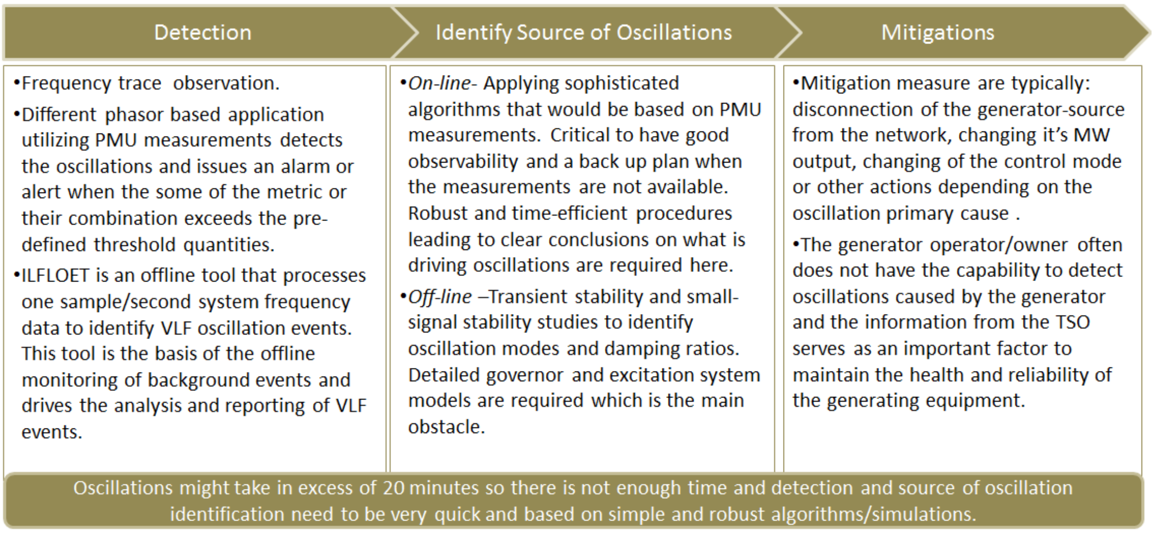

Figure 17: A typical oscillation management process [27]

To enable operators to manage the VLF mode the Wide Area Monitoring System (WAMS) is equipped with a VLF oscillation monitoring screen. This screen provides a detailed view of the system frequency over a specified window and estimates the mode frequency and amplitude over this time [26]. In addition, ILFLOET is an offline tool that processes one sample/second system frequency data to identify VLF oscillation events. This tool is the basis of the offline monitoring of background events and drives the analysis and reporting of VLF events [26]. EirGrid has a number of tools on its disposal for detection of oscillations such as ILFLOET and PI Coresight. These tools can provide information related to frequency of oscillation mode, peak to peak oscillation magnitude and indicate duration of these oscillations. Based on the analyses carried out through these tools, previous experience and the main characteristic of the existing operational scenario (unit status, demand, available wind, constraint levels, and operational plans) the operators will decide which mitigation actions would make the most significant impact in terms of damping the oscillations. An example is given in Figure 18, where:

- A VLF oscillation of growing amplitude (~200 mHz peak to peak magnitude and ~0.09 Hz) was detected on 10th of April 2021 at 00:40 AM after switching one of the pumped storage units in a pumping mode (see red arrow indicating timing of it).

- The response from the control room was within two minutes of the triggering event so the entire oscillation detection and source identification stage were completed in a very short time with an instruction given to one of the oscillation sources to cancel provision of its frequency response (see the green circle indicating timing of this).

- The action resulted in eliminating the oscillation after the corresponding control action. It is important here that it is not only important to detect the source of oscillation but to detect units that would act toward damping oscillations and at the same time be engaged more in compensating a lack of frequency response in this situation.

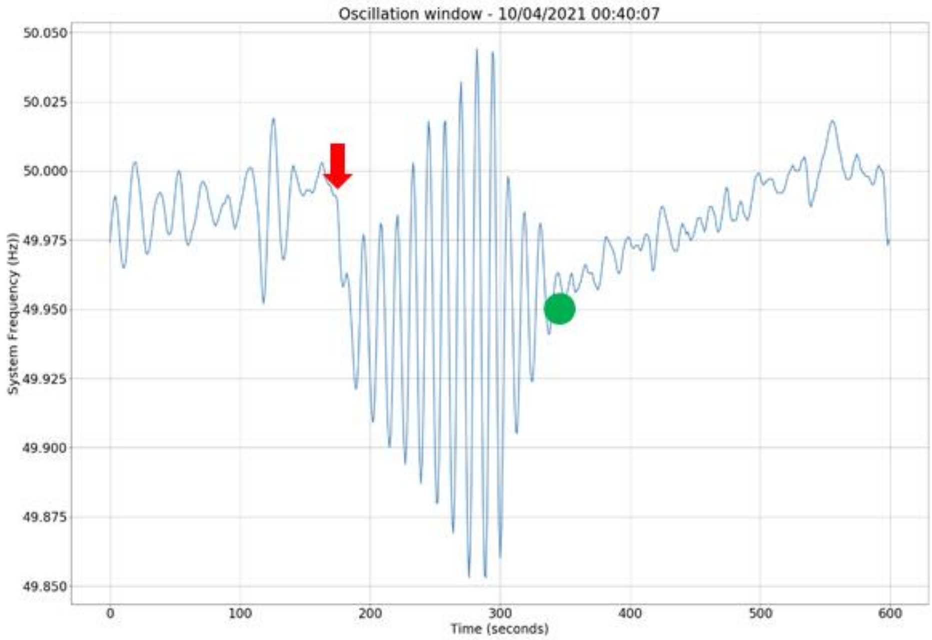

Figure 18: VLF oscillation event dated April 10, 2021 with oscillations initiated by one of the pumped storage units switching to the pumping mode (red arrow) and switching off frequency control of an unit exciting oscillations (green circle)

Looking into the mitigation options listed for the last stage of the oscillation management shown in Figure 17 one can conclude that most of the options target synchronous generation. Using Automatic Power Control (APC) through APC is an effective control action involving wind generation. While using APC for high frequency event is a plausible option and more likely (very low frequency oscillations are observed more frequently in the over-50Hz frequency domain), using APC for low frequency event is only possible when there is wind resource available for it. This further means that with higher SNSP levels the operators will have fewer options at their disposal and potentially less time to make appropriate decision through the oscillation management process.

Our small-signal stability studies and novel methodologies in analyses of the PMU measurements related to recent oscillation events indicate the following:

- Quality of frequency response needs to be addressed with a special emphasis on the Grid Code OC.4.3.4 and delayed response of the Governor Control System.
- Bringing further innovations, robustness and shortening time for detection and source of oscillation identification stage in the oscillation management process.
- Further understanding and full review of the governor models utilised in our transient stability software tools.
- Further studies to investigate the impact of increased SNSP level on the VLF oscillations.

2.2. Voltage Stability

SUMMARY:

Voltage stability refers to the ability of a power system to maintain steady voltages at all system buses following a disturbance [37]. It may either pertain to static voltage stability (i.e., maintaining steady-state voltages within acceptable security limits following a contingency) or dynamic voltage stability (i.e., maintaining dynamic voltage control and reactive power imbalance during or immediately after a large disturbance).

Analysis performed as part of EU SysFlex Task 2.4 [1] revealed that with increasing RES penetration in the system, unless mitigation measures are put in place, there would be a significant lack of Steady State Reactive Power (SSRP) capability due to RES units displacing conventional generational. This would in turn result in a large increase in both the magnitude and frequency of occurrence of low voltage deviations below the acceptable security threshold of 0.9 per unit (pu). A contributing factor to this is the fact that a significant proportion of RES generation is connected at the distribution level, and considering reactive power losses from transmission, any resulting reactive power support from these units at the transmission grid level is relatively low. 110 kV transmission buses located in weaker parts of the system, e.g., the north-west region of Ireland, were found to be primarily impacted by the lack of local SSRP at higher RES penetration levels [1].

In terms of dynamic voltage stability, one of the fastest and most significant ways of ensuring this control is the inherent response from synchronous machines. It is therefore evident that the loss of this capability owing to the displacement of conventional generation by higher levels of renewables leads to concerns over the emergence of a dynamic voltage control scarcity.

Several technologies and strategies are examined in this section for potential mitigation of SSRP and dynamic voltage control scarcities. In terms of alleviating SSRP scarcities, adjustable/dynamic reactive power compensation devices (e.g., synchronous machines, Static Synchronous Compensators (STATCOM) and Static VAR Compensators (SVC)), or static/discrete capacitor banks are considered.

Similarly, for mitigating dynamic voltage control scarcities, technologies such as synchronous condensers, STATCOMs and SVCs are investigated. While the first two technologies are found to be viable options in this regard, SVCs, on the other hand, are found to be less effective owing to their limited reactive support capability at low voltages and a slower-acting (comparatively, with respect to synchronous condensers and STATCOMs) ramping response for reactive power injection.

Operational security standards in Ireland and Northern Ireland set out the acceptable steady-state voltage ranges under intact/normal (0.95 pu – 1.1 pu) as well as N-1 contingency (0.9 pu – 1.11 pu) conditions [15], [16]. To maintain transmission system voltages within the specified limits, power system operators can utilise a number of different grid connected resources, e.g., conventional units, transmission-connected wind farms, capacitor banks, Static Synchronous Compensators (STATCOM), Static VAR Compensators (SVC), shunt reactors, transformer tapping as well as HVDC.

Reactive power is a local phenomenon and cannot be transmitted over long distances [3]. 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 steady-state reactive power support are typically determined using P-V analysis as discussed in detail in EU-SysFlex Task 2.3 [11] and 2.4 [1] reports. Such analyses are used to determine the respective voltage stability margins. Where there is an insufficient stability margin, adequate reactive power planning procedures need to be put in place to determine the quantum and type of reactive support required.

EU-SysFlex Task 2.4 [1] 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 normal and N-1 conditions due to the number of online conventional generators. Analysis revealed that as SNSP increases, there is a significant lack of SSRP capability due to RES units displacing conventional generation which results in a large increase in both magnitude and occurrences of low voltage deviations[12] under 0.9 pu as shown in Figure 19. A contributing factor to this is the fact that a significant proportion of RES generation is connected at the distribution level; therefore, considering reactive power losses from transmission, any resulting reactive power support from these units at the transmission grid level is relatively low. Results from Task 2.4 indicate that 110 kV transmission buses located in weaker parts of the system, e.g., the north-west region of Ireland, are primarily impacted by the lack of local SSRP at higher levels of SNSP. It is therefore important to investigate this further in terms of the amount and type of steady-state reactive support required at the affected buses, and the corresponding results are presented in Section 2.2.1.

[12] Apart from issues with low voltage deviations below operational security thresholds, there are also concerns about experiencing high voltages within specific regions of the all-island power system. This phenomenon is more pronounced during low wind conditions in areas where the transmission network is dominated by electrical cables. Having sufficient SSRP capability in both directions (leading/lagging) is important and one of our top priorities with many studies and trials currently ongoing in this domain. As per simulations carried out as part of EU SysFlex Task 2.6 [3], the results presented in Section 2.2.1 of this report in relation to lack of SSRP capability at specific regions of the grid are focused on the management of under-voltage issues only.

Another area of concern in relation to voltage stability is dynamic voltage control and maintaining the reactive power imbalance during and after a large disturbance, e.g., 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 from synchronous machines is one of the fastest and most significant sources of dynamic voltage control. It is therefore evident that the loss of this capability owing to the displacement of conventional generation by higher levels of renewables leads to concerns over the emergence of a scarcity in dynamic voltage control either in terms of the overall volume of response required or the geographical distribution of the resources [1].

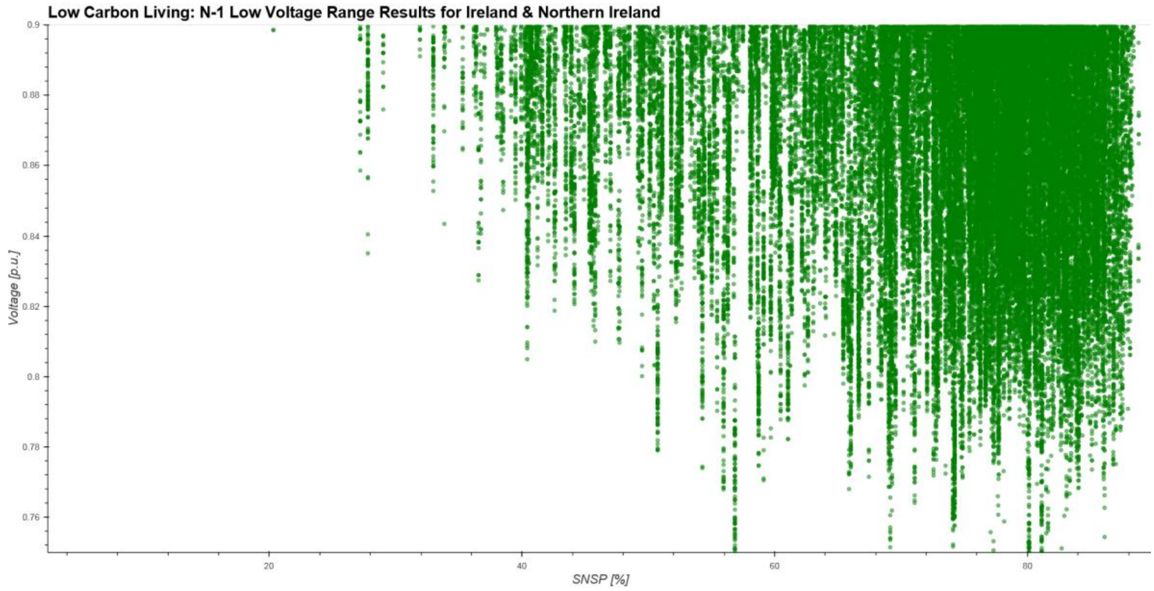

Figure 19: Plot of low voltage deviations in transmission buses against SNSP

In order to address the dynamic voltage control scarcities, 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, e.g., through a voltage dip-induced frequency dip (VDIFD). The DS3 programme [25] introduced the concept of a 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 the ability of a Providing Unit connected to the power system to deliver reactive current for voltage dips in excess of 30% of the nominal voltage at the connection point [19]. Section 2.2.2 presents the mitigation of the dynamic voltage scarcities (identified in EU-SysFlex Task 2.4 [1]) using the DRR system service[13] which can be provided by a number of different technologies.

[13] It is important to note here that though DRR is a defined DS3 system service, it has not yet been procured in practice.

2.2.1. Static Voltage Stability

As mentioned in Section 2.2, scarcities in SSRP capability in specific parts of the all-island power system were identified in EU-SysFlex Task 2.4 [1] using P-V analysis. The next step is to determine the reactive power injection that is required to mitigate these scarcities. This is achieved using Q-V analysis (presented in this subsection) which allows for the determination of the reactive power injection required at a concerned bus in order to maintain the required voltage operating range. In addition, the Voltage Trajectory Tool (VTT), which is a comprehensive voltage/reactive power optimisation package currently under development in EirGrid and SONI, will become a part of our Control Centre Tools suite in the future. This tool is a significant step toward enhancing our reactive power scheduling and voltage control capabilities as it will enable grid controllers to optimise the use of available reactive power resources for maintaining a secure voltage profile with reduced numbers of conventional plans online.

The methodology adopted in this study for determining the quantum and type of additional reactive support requirement is based on recommendations of relevant CIGRE technical documents [28], [29]. The first step is to build a Q-V curve for a fixed load and power transfer for the most voltage sensitive bus (determined from earlier P-V analysis) and the most onerous contingency. Q-V curves are built through a series of load flow calculations assuming a range of voltage targets at the concerned bus and having a fictitious and unlimited reactive power source connected at the bus for achieving each of the considered voltage targets.

The next step, which poses a more challenging problem, is the sizing of the additional reactive support and how to determine the right mix of fast-acting automatic vs. slow-acting switchable reactive power compensation. The underlying philosophy behind the Q-V curve concept adopted for this study is that reactive power reserves required for post-fault voltage stability must be switched in by some automatic control action [28]. For the slow dynamics of progressive monotonic voltage instability, these reactive power reserves may be held either using Q-controllable technologies (e.g., synchronous machines, Static Synchronous Compensators (STATCOM), Static VAR Compensators (SVC), or Power Park Modules (PPMs, referring to transmission-connected wind farms)) or remotely block-switchable Mechanically Switchable Capacitors (MSC).

Studies conducted as part of EU-SysFlex Task 2.4 [1] revealed the north-west region of Ireland to be the most vulnerable in terms of voltage issues. Accordingly, steady-state Q-V studies were performed at the two most vulnerable buses from the north-west region and for the following two conditions: intact network and the worst N-1 contingency. The resultant Q-V curves generated for the concerned buses are presented in Figure 20 and Figure 21, respectively. The presented curves capture the following combinations of load models and combinations:

- Intact network 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

It can be observed from Figure 20 and Figure 21 that the incorporation of the contingency causes significant under-voltages to occur at the two most vulnerable buses. Focussing on the Q=0 axis in both figures, it may be observed that the voltage drops from 0.97 pu in the intact case (right curve) to 0.83 pu post-fault (left curve) for Bus 1 (Figure 20), and similarly, from 0.94 pu to 0.84 pu for Bus 2 (Figure 21).

For the sizing of additional reactive power compensation, the approach outlined in [28] and [29] was adopted under the following assumptions:

- A critical voltage V_c is chosen equal to 0.9 pu as per the minimum post-fault steady-state voltage threshold considered in Ireland and Northern Ireland [30]
- Adding a margin of 1.5% over and above V_c, a minimum target voltage U_{min} was computed equal to 0.9135 pu as indicated in Figure 20 and Figure 21
- The intersection of the U_{min} ordinate line and the post-fault Q-V curves indicate that the additional reactive power support ΔQ for the two vulnerable buses are 57 Mvar and 101 Mvar, respectively, as shown in Figure 20 and Figure 21
- Considering an additional 10% margin over and above ΔQ, the final reactive power requirements for the two buses can be worked out to be 62.7 Mvar and 111.1 Mvar, respectively

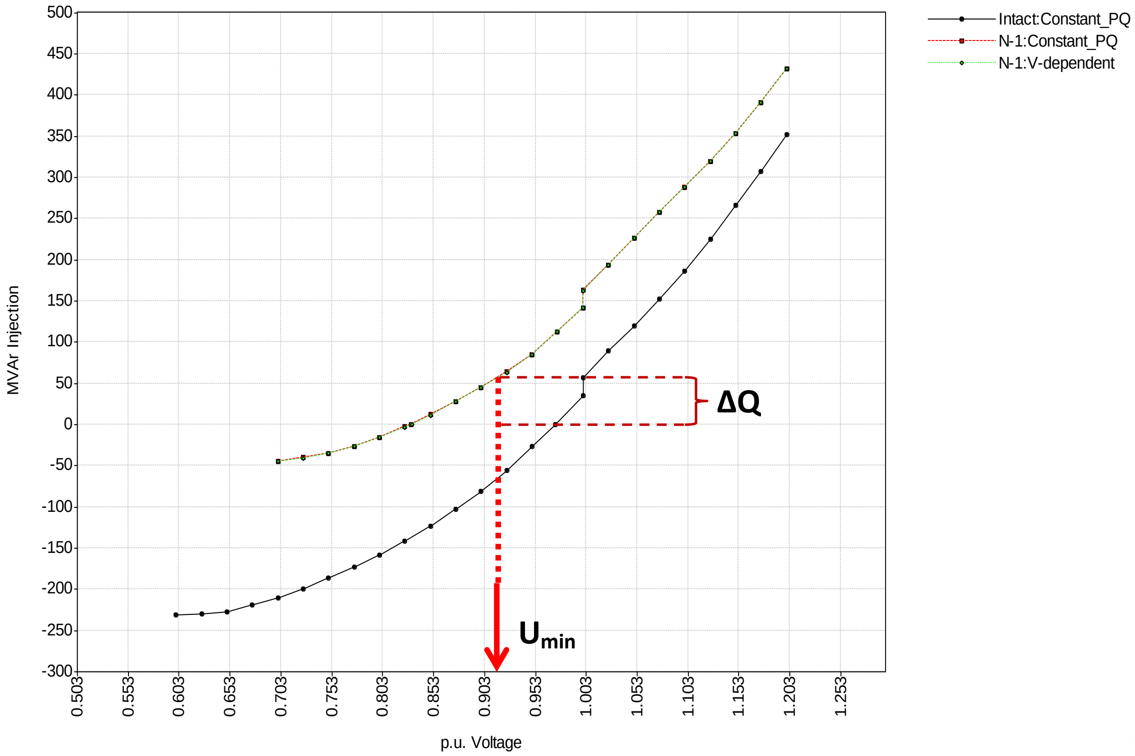

Figure 20: Intact and N-1 Q-V plots for Bus 1 with different load models

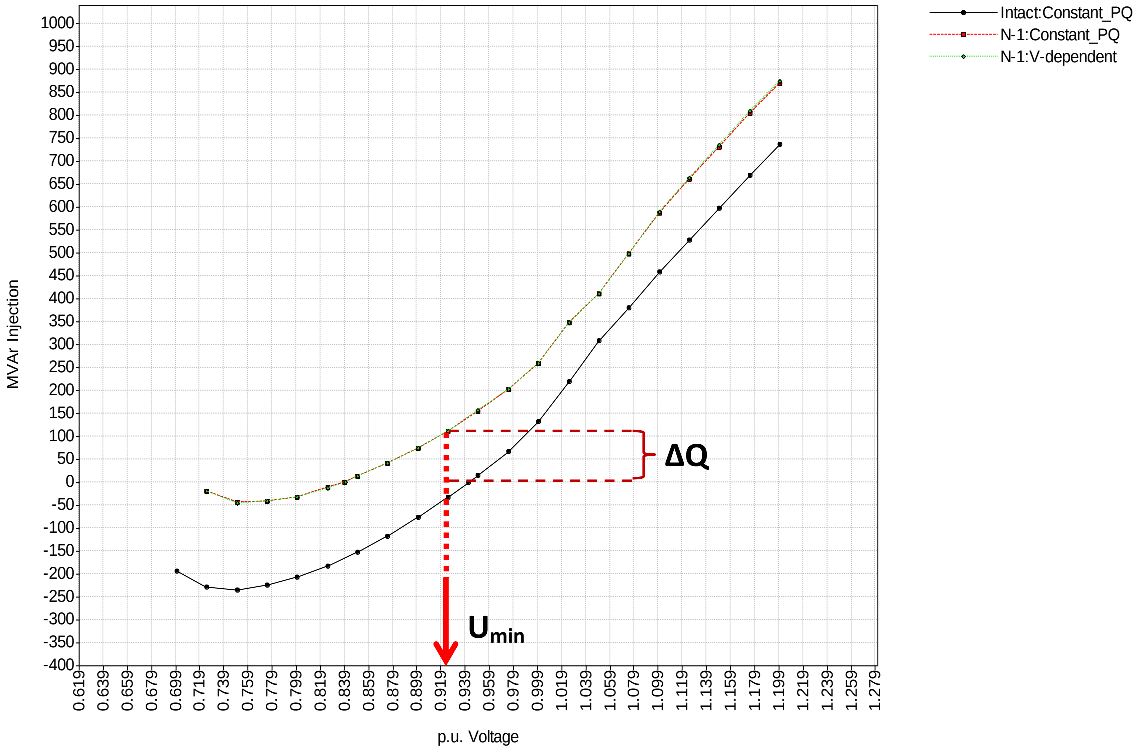

Figure 21: Intact and N-1 Q-V plots for Bus 2 with different load models

With reference to Figure 20 and Figure 21 along with the above discussions, it can be appreciated that a significant reactive support is required for mitigating lack of SSRP capability at vulnerable buses and for maintaining acceptable steady-state voltage levels under both intact and N-1 contingency conditions. It may be noted that both static (e.g., MSCs) and dynamic (e.g., synchronous machines, STATCOMs, SVCs and transmission-connected wind farms) reactive resources are effective in providing this support.

The reactive compensation required for mitigating identified SSRP scarcities could be provided, and indeed incentivised, by a system services product such as SSRP [19] which is already deployed in Ireland and Northern Ireland [3]. Indeed, the grid codes in Ireland and Northern Ireland require that PPMs (referring to transmission-connected wind farms) should have the technical capabilities to modify 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 [31]. Additionally, PPMs operating in any of the three previously mentioned control modes should be at least capable of operating at any point within their P-Q capability range [31]. This implies that the SSRP/reactive power capability that will be needed at high levels of renewables is already a requirement in the existing grid codes [3].

2.2.2. Dynamic Voltage Stability

As mentioned in Section 2.2, dynamic voltage scarcities for Ireland and Northern Ireland were identified in EU-SysFlex Task 2.4 [1], and these can be classified under the following categories:

- A **global scarcity** that results in voltage stability issues for almost all contingencies regardless of location
- A **localised scarcity** that only results in voltage stability issues for contingencies in a specific location or region of the system

The localised scarcities identified in [1] can be further grouped into systematic localised scarcities, which occur for almost all hours; and specific localised scarcities, which occur for only a small subset of hours. To mitigate the systematic localised scarcities, DRR-providing technologies are proposed as a solution, as mentioned in Section 2.2. Relevant (DRR-providing) technologies considered in this study are synchronous condensers, STATCOMs and SVCs. While a synchronous condenser can either generate or absorb reactive power instantaneously (similar to conventional generators), STATCOMs and SVCs are power electronic devices that provide dynamic ramping reactive power through their voltage controllers. The principal advantage of using STATCOMs over SVCs is that the former can provide required VAR support at both high and low voltages, whereas in comparison, SVCs have limited VAR output capability at low voltages.

The dynamic models of DRR technologies used in this study were developed as part of EU-SysFlex Task 2.3 [11]. Task 2.4 [1] selected 36 snapshots of the Low Carbon living (LCL) scenario based on different combinations of SNSP levels, system inertia and number of large (conventional) units online. The different DRR technologies under consideration were then incorporated into these snapshots for carrying out the analyses as part of this study.

A **dynamic voltage profile** metric (originally proposed in Task 2.4 [1], and subsequently improved upon in Task 2.6 [3]) was used in this study for assessing the dynamic voltage performance of the system. This metric[14] quantifies the number of buses where the corresponding dynamic voltage performance does not exhibit the desired voltage response during a fault. In plain terms, the metric equals the total number of buses where the post-fault voltage magnitude drops below the 0.5 pu threshold (determined as per Task 2.4 analysis) and does not recover until the fault is cleared. An illustrative example of the application of this metric is presented in Figure 22. The figure portrays three unique voltage violations (below the 0.5 pu threshold) for Buses 1, 2 and 3, out of which two (Buses 2 and 3) exhibit early recovery before the fault clearance time[15]. The dynamic voltage profile metric used in this study therefore equals one (corresponding to

[14] Readers are advised to refer to [1] and [3] for more details pertaining to the rationale behind the particular choice of this metric.

[15] Note that the second voltage violation for Bus 3 is not counted as a 'unique' violation; rather it's classified as a repeated violation.

Bus 1) for this example, i.e., it quantifies the total number of buses associated with **non-recoverable unique voltage violations** within the fault clearance time.

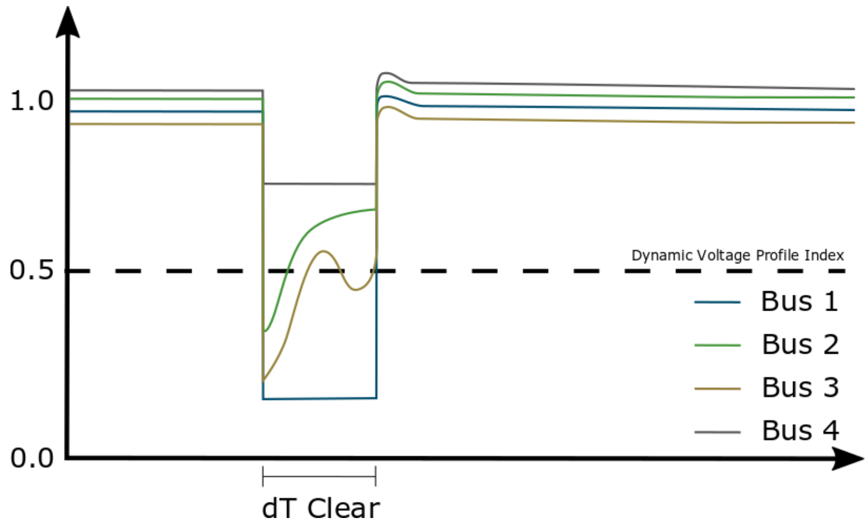

Figure 22: Illustrative example for computation of the dynamic voltage profile metric

The DRR-providing mitigating technologies considered in this section, i.e., synchronous condensers, STATCOMs and SVCs, are added (one-by-one) at a substation, and their typical post-fault responses after a three-phase-to-earth fault is applied at a 220 kV line close to the concerned substation are presented in Figure 23 [3]. It can be observed from the figure that while synchronous condensers (yellow trace) are capable of providing instantaneous reactive power, STATCOMs and SVCs (red and green traces, respectively) have a ramping response in terms of reactive power injection post-fault.

Assuming equal sizes for the different DRR providing technologies, the effect of their incorporation (one-by-one) on their adjacent bus voltage magnitude is presented in Figure 24. It can be observed from the figure that the base case bus voltage magnitude (black curve) drops below the 0.5 pu threshold post-fault and recovers only after the fault is cleared. In comparison, the bus voltage magnitude with synchronous condensers installed (yellow trace) never drops below 0.5 pu due to the instantaneous reactive power injection from these devices.

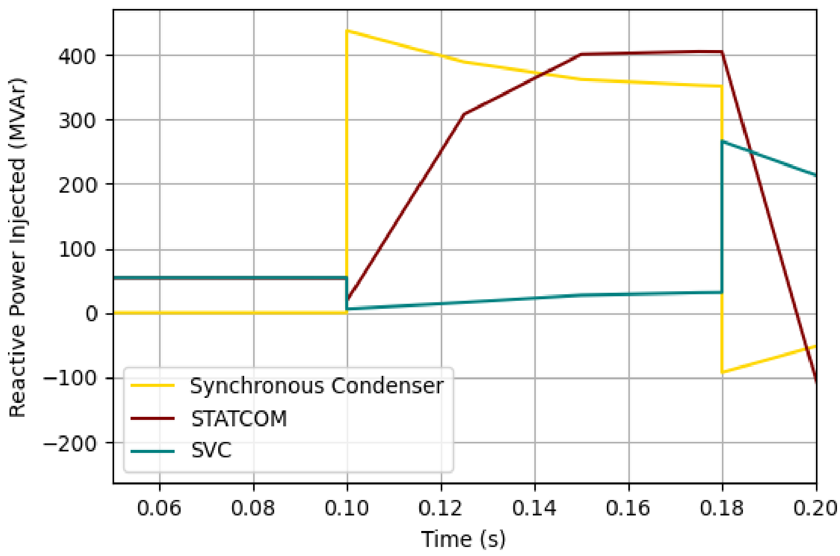

Figure 23: Injection of reactive power from different technologies

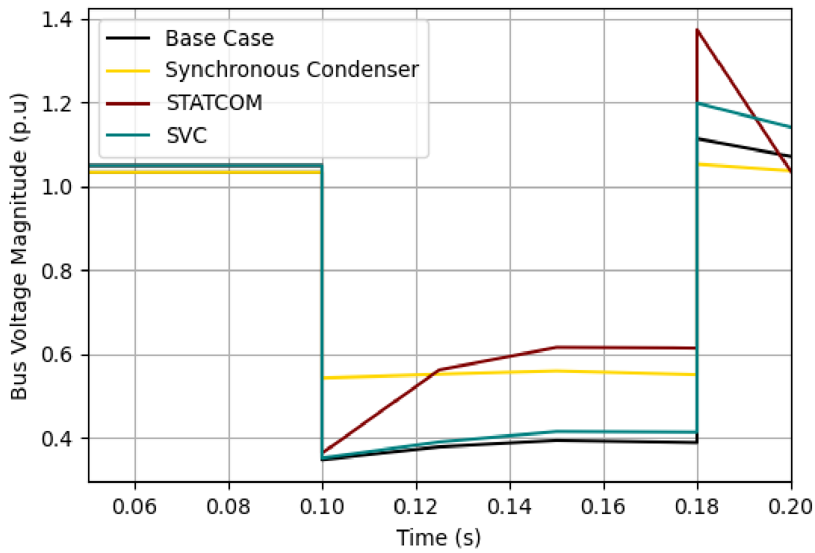

Figure 24: Effect of installation of different DRR technologies on bus voltage magnitude

It can also be observed from Figure 24 that with STATCOMs (red trace) and SVCs (green trace) installed, the voltage magnitude drops below the 0.5 pu threshold in view of the ramping reactive response provided by these technologies (in comparison to the instantaneous injection of reactive power from synchronous condensers). However, detailed analysis utilising a STATCOM reveals that the bus voltage magnitude is able to recover above the 0.5 pu threshold before fault clearance, simply because the STATCOM can provide adequate reactive support even during low voltage conditions. In comparison, SVCs have limited reactive output capability at low voltages, and it can be verified from Figure 24 that these devices provide adequate reactive support only after the fault clearance time (green trace at t = 0.18 s) when the voltage is recovered to near its pre-fault values.

Intuitively speaking, it can be inferred from the above discussions that synchronous condensers and STATCOMs would be expected to offer better dynamic voltage control capability as compared to SVCs. To quantify this observation using the metric defined as per Figure 22, the total number of non-recoverable unique voltage violations reported for a 3-phase-to-earth fault on a 220 kV line close to the assumed installation site for individual DRR-providing technologies are presented in Figure 25. It can be verified from Figure 25 that as compared to the base case scenario (i.e., without any additional reactive support considered) where 323 bus voltage violations are reported, both synchronous condensers and STATCOMs achieve comparable efficiency in reducing that number down to about 265. SVCs, on the other hand, are found to be not as effective owing to their limited reactive output capability during low voltage conditions as well as their (comparatively) slower-acting ramping response for reactive power injection.

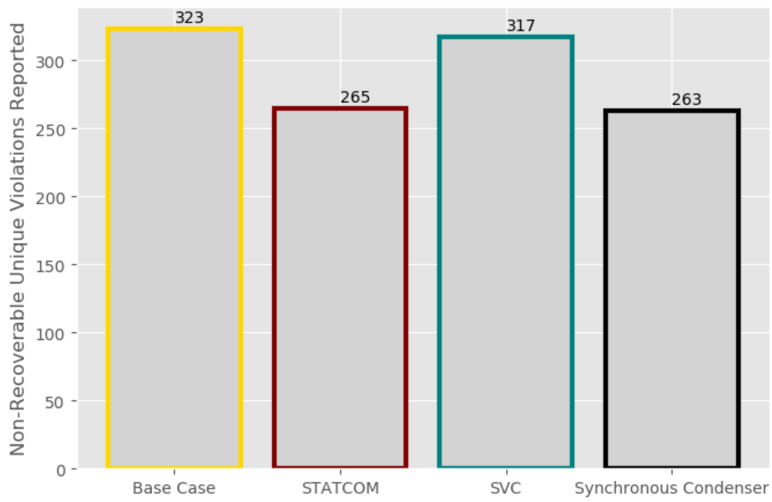

Figure 25: Non-recoverable unique voltage violations reported for different mitigation technologies

Figure 26 presents the results of applying the dynamic voltage profile metric (defined as per Figure 22) to the 36 snapshots selected in Task 2.4 for the LCL scenario base case. The box plots in Figure 26 are used to represent the distribution of the total non-recoverable unique violation counts for each of the 36 hours under consideration. 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 of the distribution. Using a threshold of 250 unique violations[16] to demarcate vulnerable hours/contingencies, it can be

[16] The threshold of 250 has been selected through analyses carried out as part of EU-SysFlex Task 2.6, refer to [3] for details on rationale used for selection.

observed from Figure 26 that for many hours, only the outliers (i.e., the top 5 percentile) are above the considered threshold. Note that the types 1-8 presented in the legend of Figure 26 denote different groups of hours associated with specific combinations of inertia, SNSP and demand levels as well as number of units online [1].

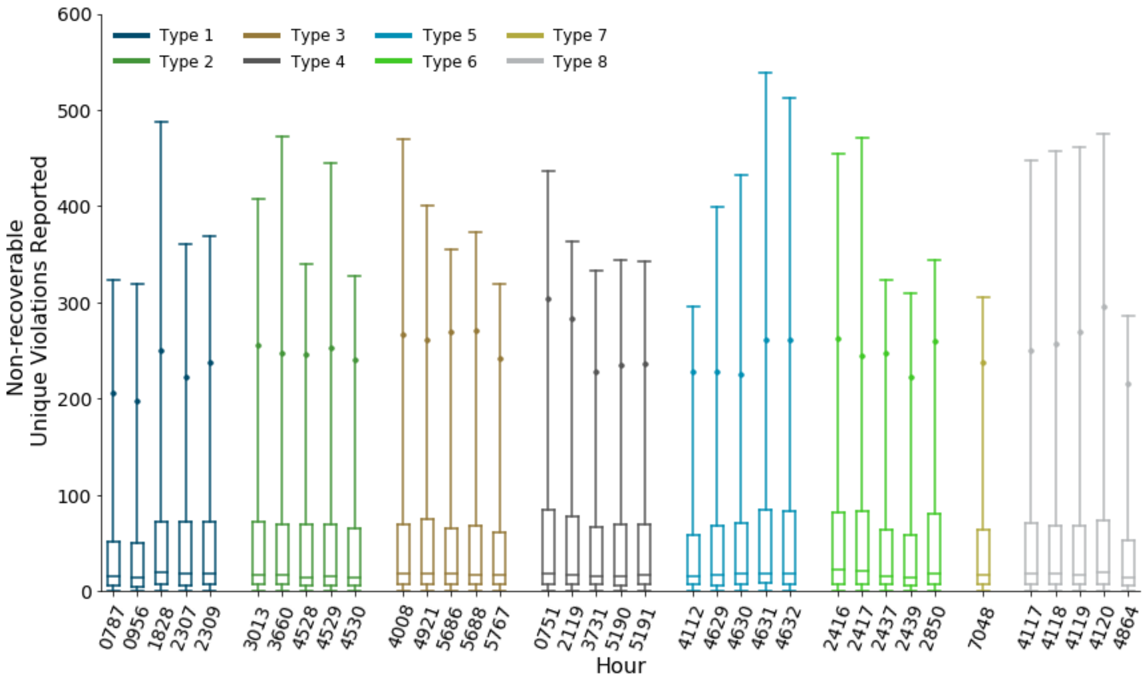

Figure 26: Box plot distribution of non-recoverable voltage violations for different contingencies grouped by LCL snapshots under base case

The information presented in Figure 26 is regrouped in Figure 27 by contingencies, wherein each box plot corresponds to a particular contingency and represents the associated distribution of total non-recoverable unique violation counts for all 36 LCL snapshots under consideration. Using the same violation count threshold of 250 (as in Figure 26), it can be observed from Figure 27 that the box plots can be broadly categorised under three groups: contingencies with universally low violation counts (i.e., counts that never exceed 250 as denoted in blue), contingencies having universally high counts (i.e., counts that always exceed 250 as denoted in brown), and contingencies with high counts only for few hours (denoted in green). This essentially demonstrates 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.

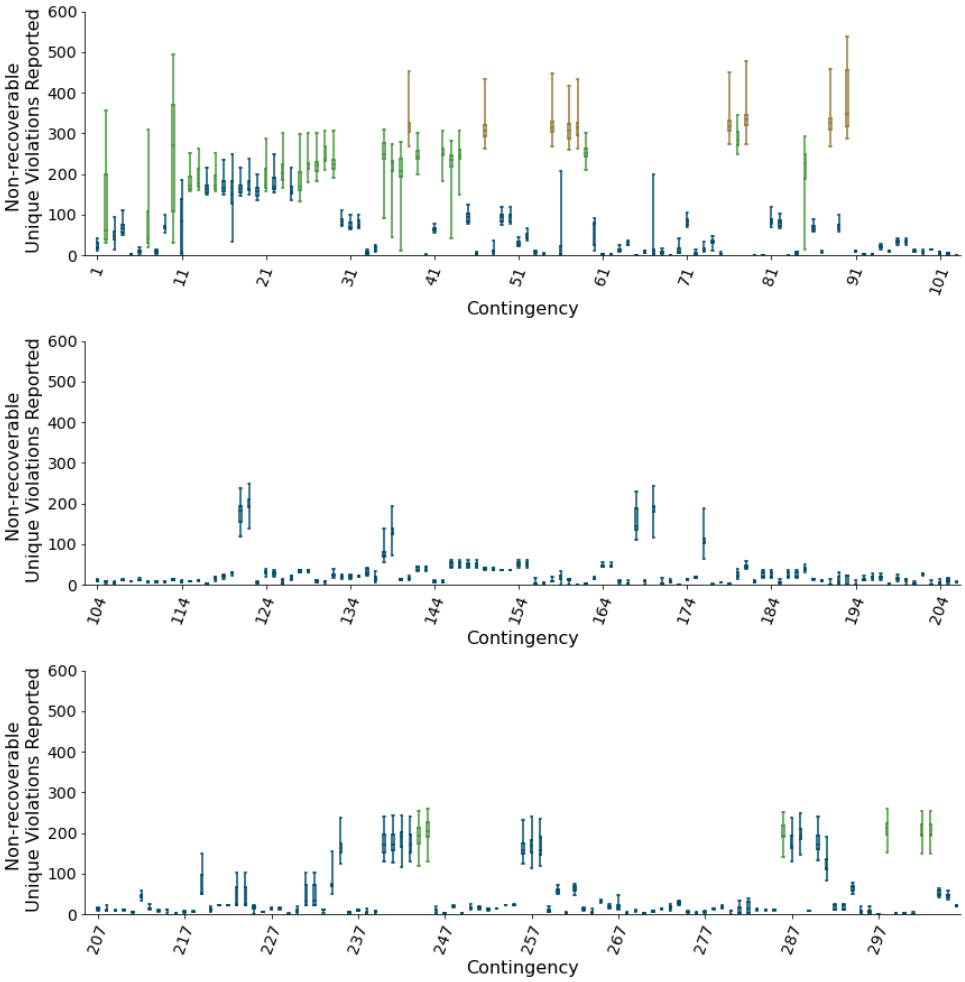

Figure 27: Box plot distribution of non-recoverable voltage violations for different LCL snapshots grouped by contingencies under base case

Numerous simulations are performed next with different combinations of locations (i.e., substations) with DRR-providing technologies installed, and the combination associated with the least count of dynamic voltage violations is selected. The corresponding DRR technologies are then applied to the 36 snapshots selected in Task 2.4 for the LCL scenario, and the total non-recoverable unique voltage violations thereby calculated using the dynamic voltage profile metric (defined as per Figure 22) are presented in Figure 28. It can be observed from the figure that the top 5 percentile outliers (denoted by the black ellipses) exceed the considered threshold of 250 for only a few hours under consideration (as compared to several hours under the base case presented in Figure 26).

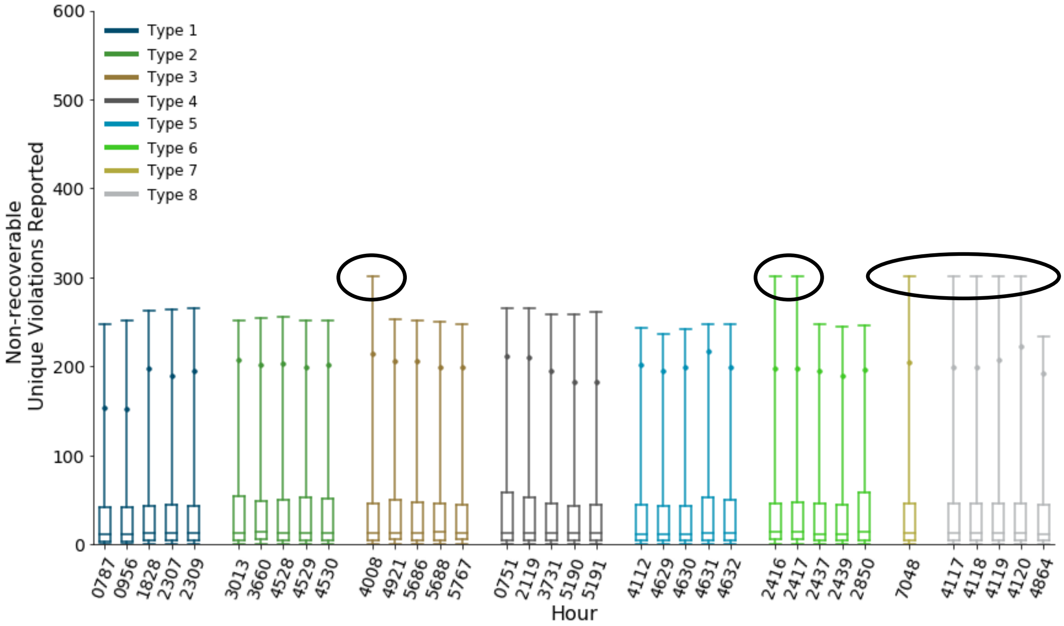

Figure 28: Box plot distribution of non-recoverable voltage violations for different contingencies grouped by LCL snapshots with mitigations applied

The information presented in Figure 28 is again regrouped in Figure 29 by contingencies, with each box plot corresponding to a particular contingency and representing the associated distribution of non-recoverable unique violation counts for all 36 LCL snapshots under consideration. It can be verified from the figure that the dynamic voltage control localised scarcities observed in Figure 27 (as denoted by the brown bars) have been mitigated following the incorporation of the proposed DRR technologies.

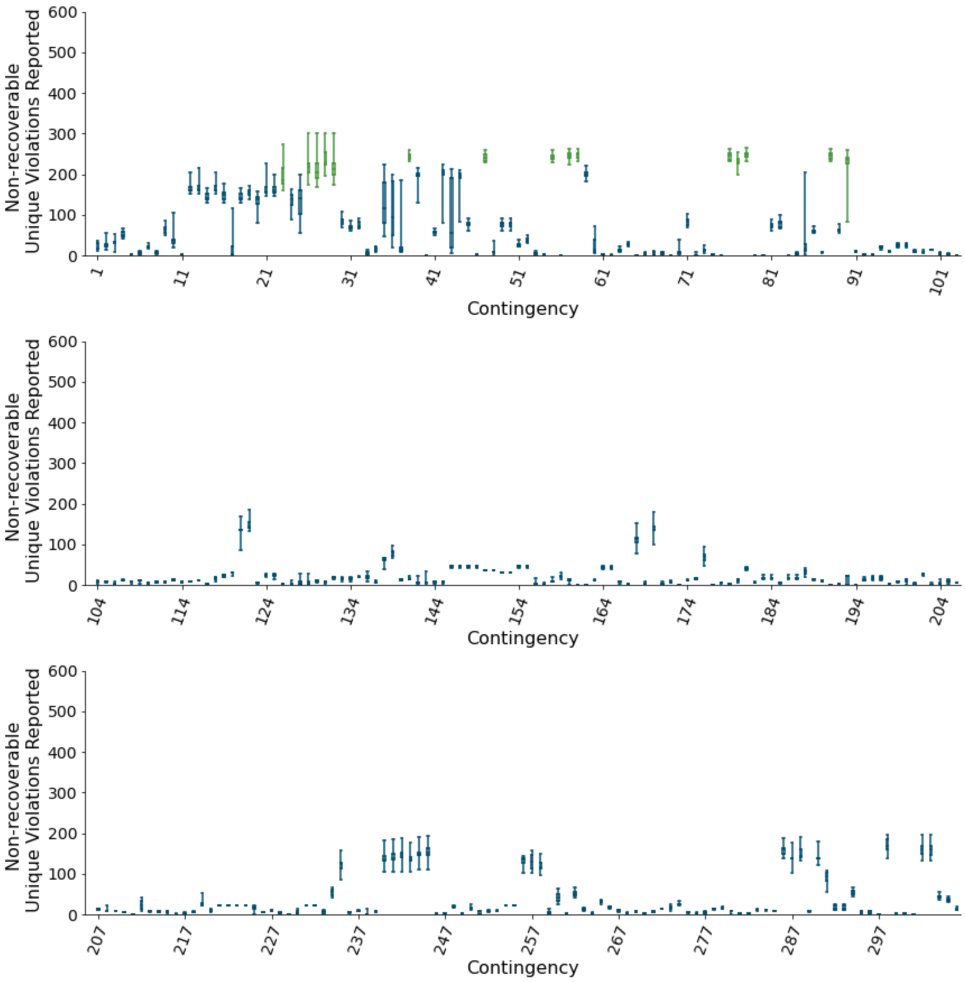

Figure 29: Box plot distribution of non-recoverable voltage violations for different LCL snapshots grouped by contingencies with mitigations applied

It needs to be noted here that the location of the DRR technology is vital to mitigating the concerned dynamic voltage control scarcities, and further work on determining the optimal placement of DRR capability would be required in future. Another important point to consider is that this analysis was performed in isolation of other mitigation measures. Measures to mitigate frequency stability issues, for example, may also support the mitigation of dynamic voltage issues. Future work will need to conduct a holistic analysis to explore the optimal mix of mitigations for the system as a whole, while acknowledging the synergies between disparate mitigation technologies.

2.2.3. Reduction in System Strength

Renewable generation such as wind and solar interface with the AC grid through power electronic converters, and the increasing penetration of these so-called inverter-based resources (IBR) are creating challenging issues for system operators in terms of management of system voltage as well as the stability of relevant IBR controls [32]. By virtue of the geographic availability of renewable resources in the all-island power system, most IBRs connect to remote areas of the grid (e.g., the North-West of Ireland), and this problem is exacerbated by the fact that IBRs generally do not contribute in the same way to system strength as conventional synchronous generation [32].

There are varying definitions of system strength used by different utilities and transmission system operators (TSO), but the broad consensus is that it is indicative of the local dynamic performance of the system following a disturbance [33], as well as the ability of a power system to maintain voltage and frequency as steadily as possible at a network connection point (e.g., that of an IBR) under all operating conditions [34]. Different metrics are used by utilities for quantifying system strength at individual transmission buses, e.g., short-circuit/fault level (MVA), short-circuit/fault current level (kA) [33], Short Circuit Ratio[17] (pu), Weighted Short Circuit Ratio[18] (pu), Composite Short Circuit Ratio[19] (pu) and Equivalent Short Circuit Ratio[20] (pu) [34].

From the above discussion, it can be inferred that the system strength at the point of connection of an IBR is directly related to the fault current in-feed at that point. Considering that most IBRs use current source (CSC) or grid following (GFL) converters to interface with the AC grid, they are inherently worse off (as compared to synchronous generators) in terms of fault current contributions during short-circuit conditions. This is due to the limited short-term current ratings of its power electronic components. One of the immediate implications of reduced fault current contributions is the failure of protection relays to clear the fault in a timely manner, thereby likely causing the fault to propagate further into the network [2]. Potential issues that can be encountered in a power system dominated by CSC/GFL-enabled IBRs are further detailed in Section 2.3.3.

A case study [32] was recently conducted by EirGrid in collaboration with EPRI to screen for potential low system strength areas and weak grid issues in the Irish transmission network. Using EPRI's Grid Strength Assessment Tool (GSAT), different indices for quantifying system strength (as discussed above) were calculated. Additionally, to investigate potential controller instability issues, the critical clearing time (CCT) of an IBR with respect to a 3-phase fault at its point of interconnection (POI) was computed using GSAT.

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[17] Refer to Appendix B – Glossary of Technical Terms for definition

[18] Refer to Appendix B – Glossary of Technical Terms for definition

[19] Refer to Appendix B – Glossary of Technical Terms for definition

[20] Refer to Appendix B – Glossary of Technical Terms for definition

A 2025 Delayed Transition (DT) scenario[21] was modelled in this study [32], whereby the short circuit MVA (SCMVA) level was calculated for all buses with a nominal voltage of 110 kV or higher, and which are located in the South-West, Mid-West, West and Border regions of Ireland. The resulting histogram portraying the spread of SCMVA values amongst the concerned buses is presented in Figure 30 [32]. Considering that the system strength at a bus is directly proportional to the short circuit MVA associated with that bus, the study used a SCMVA cut-off of 500 MVA to filter out the 33 buses with low SCMVA values as shown in the figure. Of these 33 buses, 24 were IBR plant POI buses associated with a total of 77 wind farms.

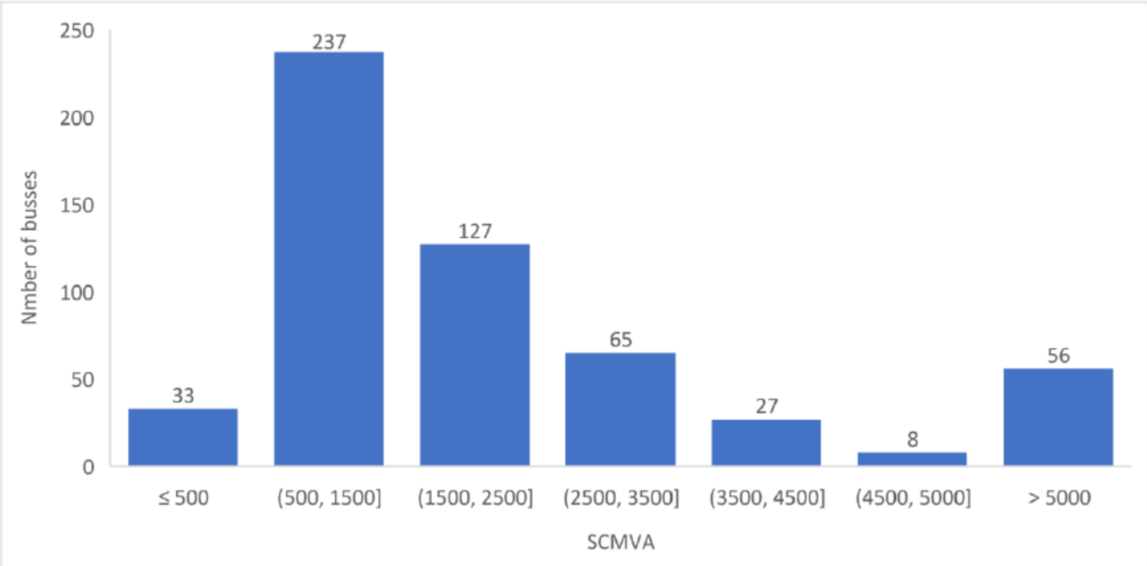

Figure 30: Histogram of SCMVA values of all 110 kV and above buses in the South-West, Mid-West, West and Border regions of Ireland for the 2025 DT scenario

For the 24 IBR buses associated with low SCMVA values as shown in Figure 30, GSAT was used to calculate the corresponding SCR values associated with a winter off-peak and a winter peak load case under the DT scenario. The resultant figure is presented in Figure 31 [32]. It can be observed from the figure that the SCR values for the two planning cases are largely similar despite the fact that the off-peak load case is associated with a much higher penetration level of IBRs. Further investigations revealed that of the 550+ generators associated with the two planning cases, only 16 of them changed status (between the off-peak and peak cases). This implies that the SCR would be relatively unchanged unless the IBR in question was electrically close to one of the synchronous generators that changed its status [32].

[21] The Delayed Transition (DT) scenario represents a “world in which decarbonisation progress is made but not sufficient enough to meet climate objectives” [50]. This scenario assumes new connections of 1 GW of wind, 0.5 GW of solar and one additional HVDC interconnector with respect to the 2019 figures.

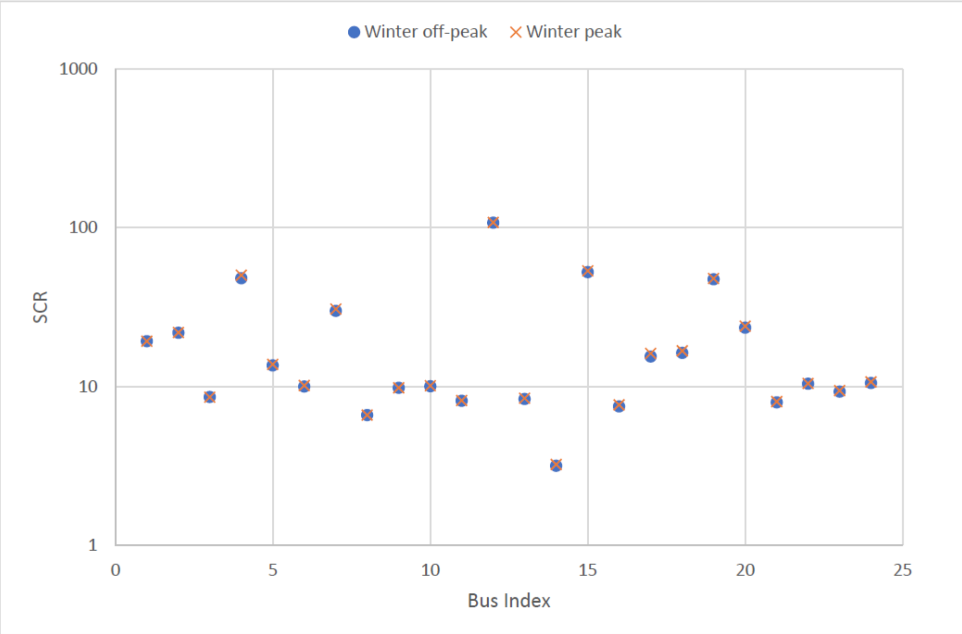

Figure 31: Comparison of SCR values associated with individual IBR buses for winter off-peak and winter peak load cases (DT scenario)

There are two important characteristics of each power system – *stiffness* and *pliability* – that are complementary to each other, and balancing them is the fundamental design task for grid connected plant controls [35]. The former is a measure of resistance to changes imposed. For example, voltage stiffness is greater for systems with higher strength which in turn ensures a better voltage response (i.e., less severe voltage dips, better recovery, less pronounced overshoots and shorter settling times) to voltage disturbances. The latter is a measure of the power system's flexibility to move from one operating point to another [35], and this can be adversely affected at low system strength conditions by IBR controls that are driven by reference signals obtained from the grid.

A simplified illustration of the degree of challenges likely to be experienced as a function of SCR at an IBR's POI is presented in Figure 32, without considering the impact of nearby IBRs [35]. The green area in the figure denotes the region where standalone tuning of IBR control systems is oftentimes sufficient to achieve satisfactory outcomes. The orange region indicates that standalone tuning is no longer sufficient; rather site-specific control system tuning might be required due to increased risk of interactions with adjacent IBRs. Finally, the (most critical) orange region denotes that even control system tuning may not be sufficient and additional equipment that can contribute to system strength, e.g., synchronous condensers and grid-forming (GFM) inverters, will most likely be required for achieving acceptable outcomes. While most utility-scale projects in Australia are in the yellow and orange regions, the majority of European projects are currently in the green zone [35]. From an Irish perspective, careful observation of Figure 31 reveals that there is at least one IBR bus with a SCR value below 5, i.e., it is approaching the yellow zone.

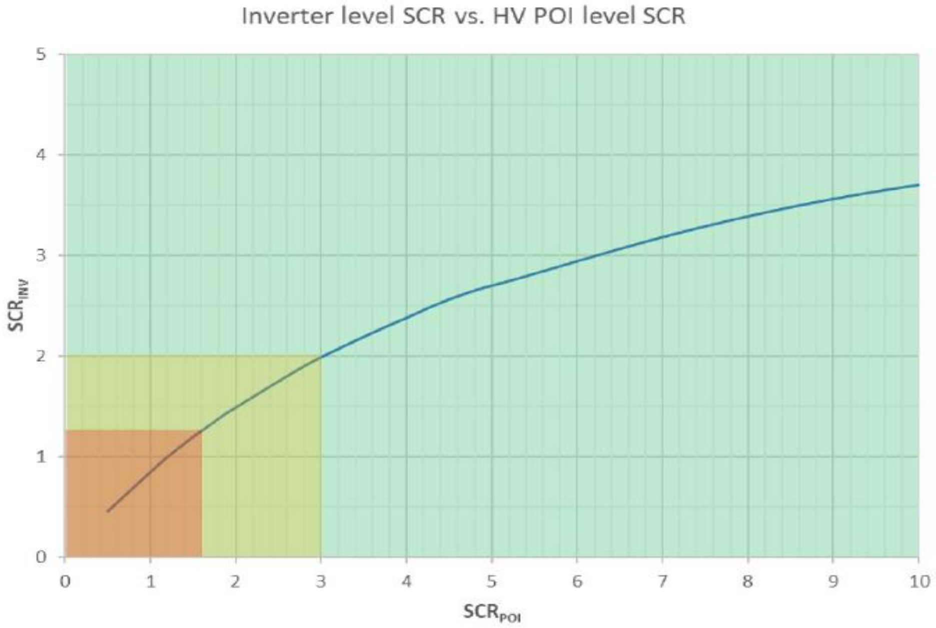

Figure 32: Impact of range of system strength on complexity of IBR connection [35]

With increasing penetration of IBRs in the power system, detailed investigation of their impact on system dynamics and control becomes increasingly critical. Most generic positive sequence transient stability models of IBRs do not have detailed representation of some of the vital control blocks pertaining to the converter, e.g., the inner current control loop or the phase-locked loop (PLL) [32]. Such inner control loops are more adequately represented by more complex Electro-Magnetic Transient (EMT) models. For IBRs (particularly CSC/GFL-based) connected to weaker parts of the grid, these control blocks can have a significant role to play in maintaining inverter stability.

In view of these observations, EPRI developed a CCT calculation module as part of GSAT for analytically solving the non-linear dynamic equations of the inverter PLL, AC voltage and DC voltage controllers for a 3-phase fault at the IBR's POI[22]. This in turn offers additional visibility into the type of controller induced oscillations that may occur with IBRs connected to weak networks [32]. However, it should be noted that the validity of the CCT calculation using this tool is dependent on the correct parameterisation of these controllers for the IBR analysed.

The resultant CCT values (associated with individual IBR buses) calculated for the winter off-peak and peak load planning cases in [32] under the DT scenario are presented in Figure 33. It can be observed from the figure that there are three IBR plants that are associated with CCT values lower than 100 ms, and consequently, these would be candidates to conduct further detailed EMT analyses on. Comparison of Figure 31 and

[22] On EirGrid's part, it has been undertaking a significant effort in collaborating with external experts to enrich the existing RES RMS models (e.g., of wind, solar PV and HVDC interconnection) to incorporate PLL logic for the corresponding generator/converter control blocks, as detailed in Section 2.3.3.

Figure 33 also reveals that the variation in CCT between the off-peak and peak load cases is higher than that observed for the corresponding SCR values presented in the former figure.

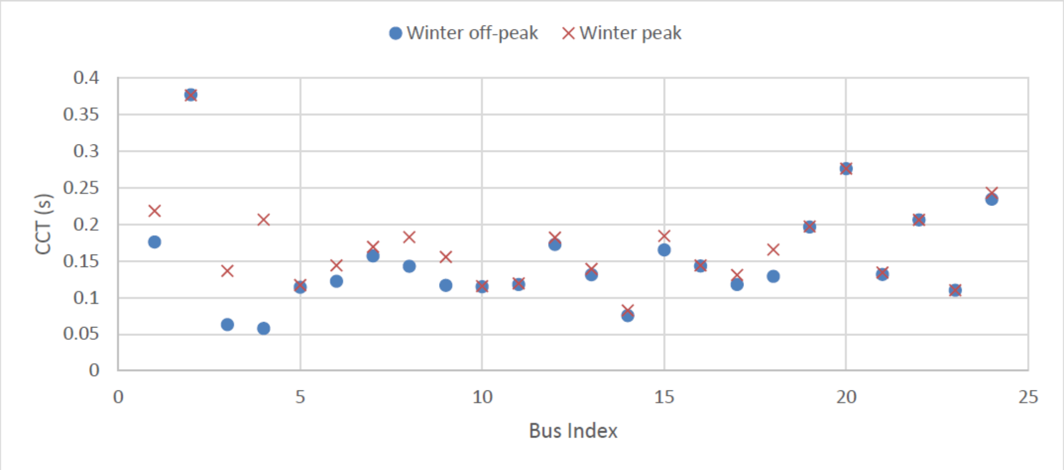

Figure 33: Comparison of CCT values between winter off-peak and peak load cases under DT scenario

Although detailed EMT analyses were not performed as part of the EPRI project discussed above in this subsection (it simply screened for potential IBRs which would be candidates for such studies), a recent study published in [36] presented results of EMT studies conducted for investigating post-disturbance voltage oscillations experienced in weaker parts of the Australian power system stemming from sub-synchronous interactions between electrically close IBRs.

It was observed as part of this study that the stable operation of an IBR is directly related to the system strength available at its POI, the adequacy of the internal design and tuning of its control system and the potential use of auxiliary equipment, e.g., synchronous condensers and SVCs, implemented for low system strength scenarios [36]. However, it was noted that it is the coordinated response of all electrically close IBRs (rather than the stable design and tuning of individual IBRs in isolation) that determines whether adverse interactions are likely to occur between these devices following a disturbance.

From an all-island perspective, it is clear that with a high penetration of IBRs in the power system by 2030 along with the associated displacement of conventional generation, system strength contributions will need to be sourced from non-synchronous technologies [2]. Further studies would need to be conducted in this area, but one potential mitigation strategy is to incorporate technologies that can contribute to system strength, e.g., GFM-enabled IBRs (refer to Section 2.3.3) as well as low carbon inertia solutions such as synchronous condensers.

2.3. Transient Stability

SUMMARY:

Transient stability describes the ability of a power system to maintain synchronism when subjected to a severe transient disturbance, e.g., a three-phase transmission line fault or a loss of generation or large load [37]. If large amounts of generation capacity are lost due to transient instability, the power system may collapse. Voltage and transient stability issues are inter-related and the same mitigation measures may apply.

With fewer synchronous generators available online, the overall electromagnetic torque contribution from these machines is expected to decrease in the future. Additionally, a reduction in the number of online synchronous machines can change the geographic dispersion of these units, thereby potentially exposing some of them (particularly those connected to weaker parts of the grid) to an increased risk of losing synchronism in the event of faults occurring in their close proximity.

The change in electromagnetic torque of a synchronous machine after a disturbance consists of the damping and synchronising torque components. Localised scarcities (i.e., involving certain synchronous generators and for certain N-1 contingencies only) of both components were observed from simulations performed as part of EU SysFlex Task 2.4 [1]. Several mitigation strategies were accordingly developed in Task 2.6 [3] for tackling the above scarcities, and the same are presented in this section.

Technologies like synchronous condensers, STATCOMs and Power System Stabilisers (PSS) are considered as potential mitigation options for alleviating damping torque scarcities, with STATCOMs and PSSs demonstrated to offer significant damping capabilities. Similarly, DRR-provision capabilities of synchronous condensers, SVCs and STATCOMs are considered as potential options for mitigating synchronising torque scarcities.

While these devices are indeed successful in this regard, analyses show that large quantities of these technologies would be required for alleviating the localised scarcities. In that regard, studies indicate that the most appropriate mitigation strategy appears to be the consideration of an operational policy under specific circumstances and system conditions that involves modification of the considered unit commitment by dispatching down the unit that loses synchronism and increasing the output of another generator to accommodate the generation shortfall from the dispatch-down process [3].

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 [1], [37]. This requires that each synchronous generator must maintain the existing equilibrium or attain a new equilibrium between its electromagnetic and mechanical torques post-occurrence of a disturbance in the power system. Failure to do so will cause a synchronous machine to experience loss of synchronism and consequent disconnection from the rest of the system [37].

Transient stability is concerned with the ability of a power system to maintain synchronism after a severe disturbance, e.g., a three-phase transmission line fault [1], [37]. As the system begins to operate with fewer synchronous units, each of the remaining units will be required to contribute more electromagnetic torque during a given fault. Furthermore, a reduction in the number of units may lead to changes in the geographic distribution of units, which could isolate certain units (or groups of units) and expose them to an increased risk of losing synchronism, particularly for faults close to such units or groups (as the torque contribution during the fault is heavily dependent upon electrical distance to the fault).

Some form of oscillation in the rotor angle of machines is almost inevitable after a fault or other disturbance in the system. These oscillations are a natural part of the behaviour of any dynamic system and are not a concern as long as they are sufficiently well damped [37]. The change in the electromagnetic torque of a synchronous machine after a disturbance consists of two components which affect the damping of oscillations:

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

Sections 2.3.1 and 2.3.2 respectively present the scarcities identified in the damping and synchronising torque components as part of EU-SysFlex Task 2.4 [1] and the corresponding mitigation strategies proposed in Task 2.6 [3]. As mentioned in Section 2.2.2, 36 snapshots of the LCL scenario were identified in Task 2.4 based on different combinations of SNSP levels, system inertia and number of large (conventional) units online. These snapshots are reused in this section after incorporation of the proposed mitigation technologies.

2.3.1. 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 [37]. The metric proposed in EU-SysFlex Task 2.4 for quantifying oscillation damping was the decay time, and this is reused in Task 2.6 [3] for performing relevant simulations. The decay time constant of an oscillation is a function of its natural frequency and damping ratio. It is also equivalent to the time constant of the exponential decay function, which implies that the oscillation reaches 36.8% of its initial value after this time.

As per findings from Task 2.3 [11] and 2.4 [1], an upper threshold of 7 seconds was chosen for the decay time in this study. Rotor angle oscillations associated with decay times exceeding 7 seconds would therefore indicate a scarcity of damping torque in the system. In Task 2.4, it was found that damping had indeed significantly reduced for all 36 snapshots in the LCL scenario and at times was outside of acceptable limits.

In this section, technologies providing additional electromechanical torque or damping are considered as potential mitigation options, e.g.: synchronous condensers, STATCOMs and Power System Stabilisers (PSS)[23]. The 36 LCL snapshots identified in Task 2.4 were modified by incorporating these technologies, and simulations were performed to investigate their impact on mitigating damping torque scarcities in the system.

Box plot distributions of decay time for each of the 36 LCL snapshots under the base case are presented in Figure 34. Similar to Figure 26 and Figure 28, each box plot in Figure 34 is associated with 306 data points, one for each contingency under consideration. Note that the types 1-8 presented in the legend of Figure 34 denote different groups of hours associated with specific combinations of inertia, SNSP and demand levels as well as number of units online [1]. A localised damping torque scarcity for two hours (i.e., associated with decay times in excess of 7s), and an emerging trend of a localised scarcity for the other hours can be observed from the figure.

For better insight on the root cause of these oscillations, further investigations were performed for hours 2307, 2309, 5190 and 5191 (indicated by the black circles in Figure 34) associated with oscillations with higher decay times. Synchronous machine rotor angle traces for these hours are presented in Figure 35, which clearly show the oscillating units (red traces). For all four hours, it is observed that the same generator units oscillate. These oscillations can be found to exist for Type 1 hours characterised by low SNSP, high inertia and high number of units online. Hence, these oscillations are not related to any other operational metrics, e.g., SNSP, inertia or number of units online.

[23] Refer to Appendix B – Glossary of Technical Terms for definition

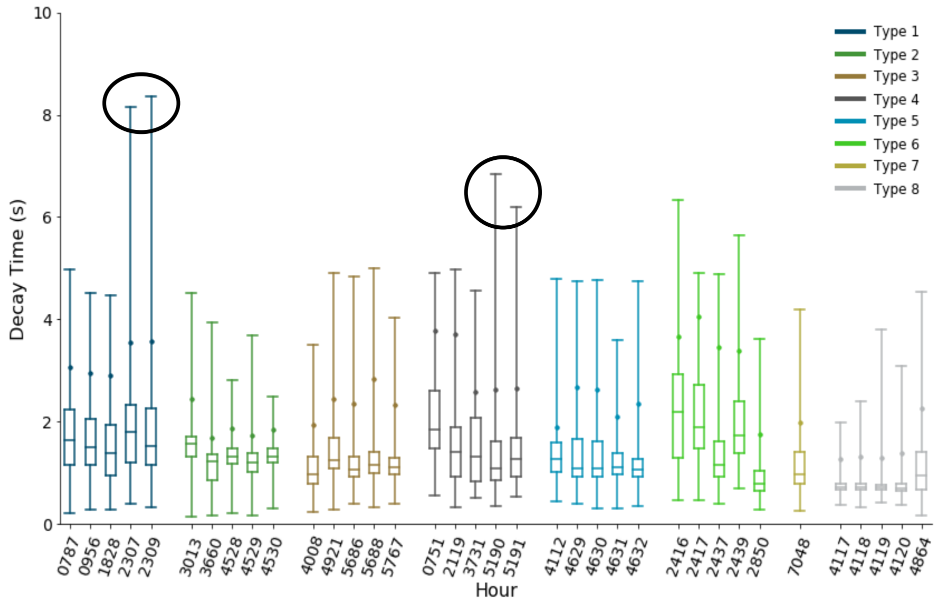

Figure 34: Box plot distribution of decay times for LCL snapshots under base case

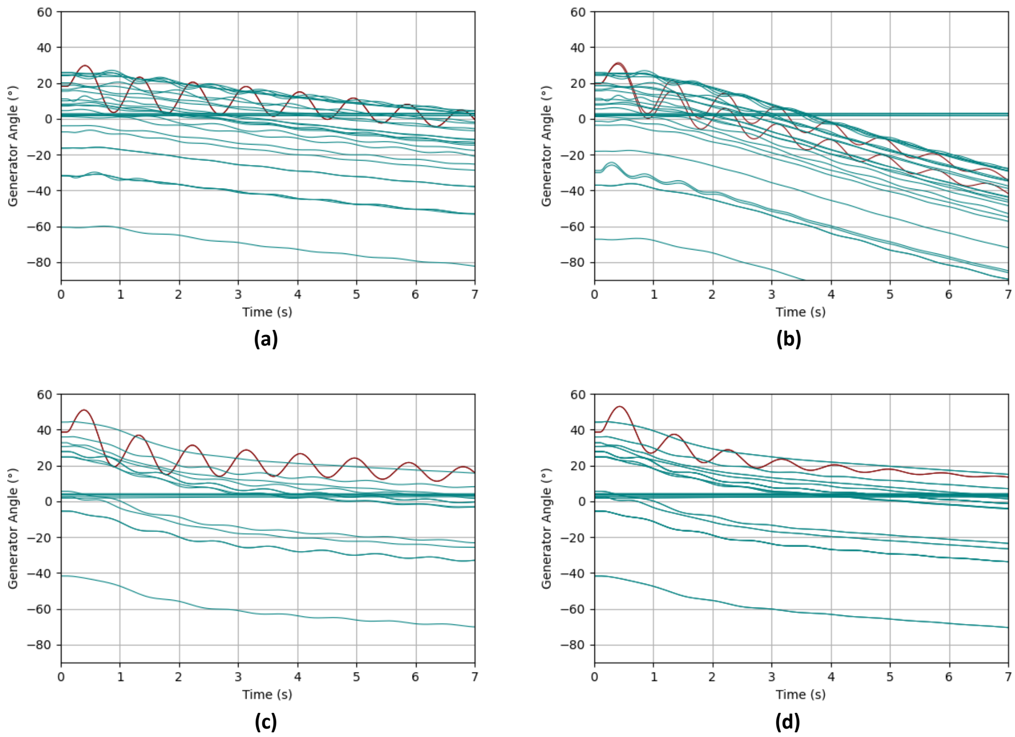

Figure 35: Time domain rotor angle traces for oscillation cases. (a) Hour 2307, (b) Hour 2309, (c) Hour 5190, and (d) Hour 5191

As previously mentioned in Section 2.3.1, a number of technical solutions incorporated at/close to the oscillating units, e.g., synchronous condensers, PSSs and STATCOMs, were considered for mitigating the damping oscillation scarcities. Cost implications for incorporating the technologies were ignored as part of the simulations. A case study was performed for the hour with the highest decay time (Hour 2307, contingency 274), and the resultant decay times with individual mitigation technologies incorporated are presented in Table 2. It can be seen from the table that all three mitigation options reduce the decay time to less than 7s, with PSS and STATCOM offering the most significant benefits.

Table 2: Decay time for different mitigations

Mitigation technology	***Decay time (s)***
Base case	8.16
With PSS	4.39
With synchronous condensers (400 MVA each)	6.42
With STATCOMs (400 MVA each)	3.63

Rotor angles of all generators for hour 2307 are presented in Figure 36 for the base case as well as with mitigations applied. The oscillating unit's generator angles are presented through the red traces, synchronous condenser rotor angle is presented through the yellow trace (Figure 36(c)) and other synchronous generating unit angles are presented through the green traces.

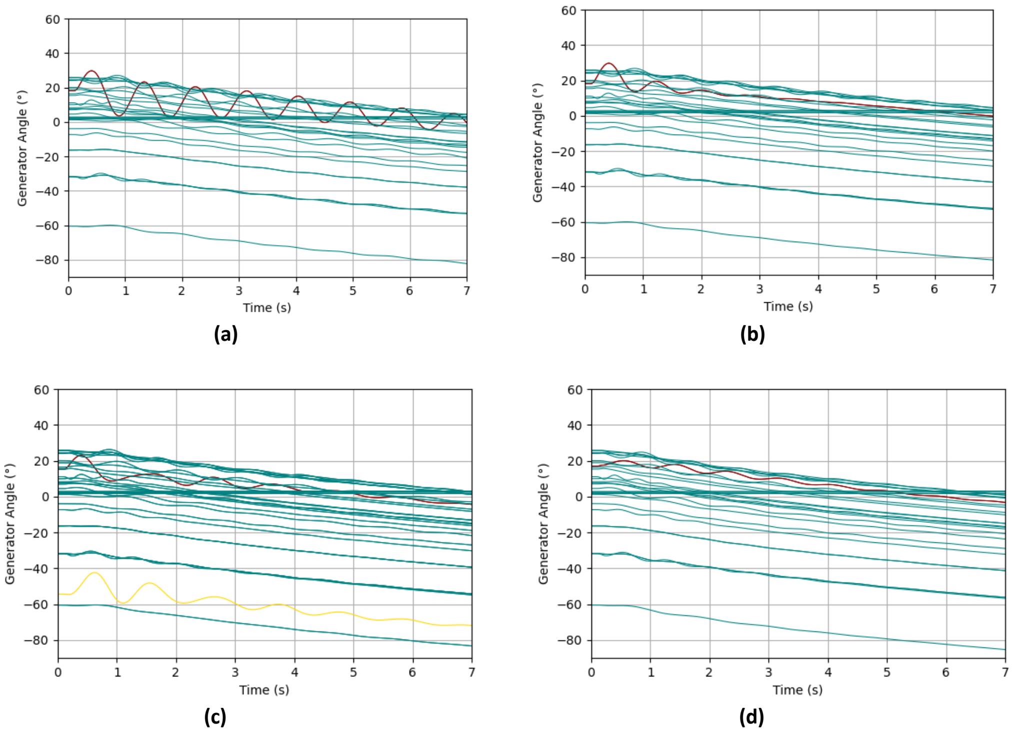

Figure 36: Time domain rotor angle traces for oscillation cases for hour 2307. (a) Base case, (b) Adding PSS, (c) Adding synchronous condensers, and (d) Adding STATCOM

Figure 37 presents the active power output of the oscillating units under the base case and with mitigations applied. Comparing Figure 36(b) and Figure 37(b) with Figure 36(a) and Figure 37(a), it can be observed that the incorporation of a (traditional basic) PSS model 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 integrated. The response speed from such PSS is therefore not sufficient to reduce the first swing in generator angle and the initial overshoot in the generator active power output. It should be pointed out that high-initial-response PSS models have not been considered in these studies, but these will be looked into in more detail while dealing with similar scarcities in our future studies.

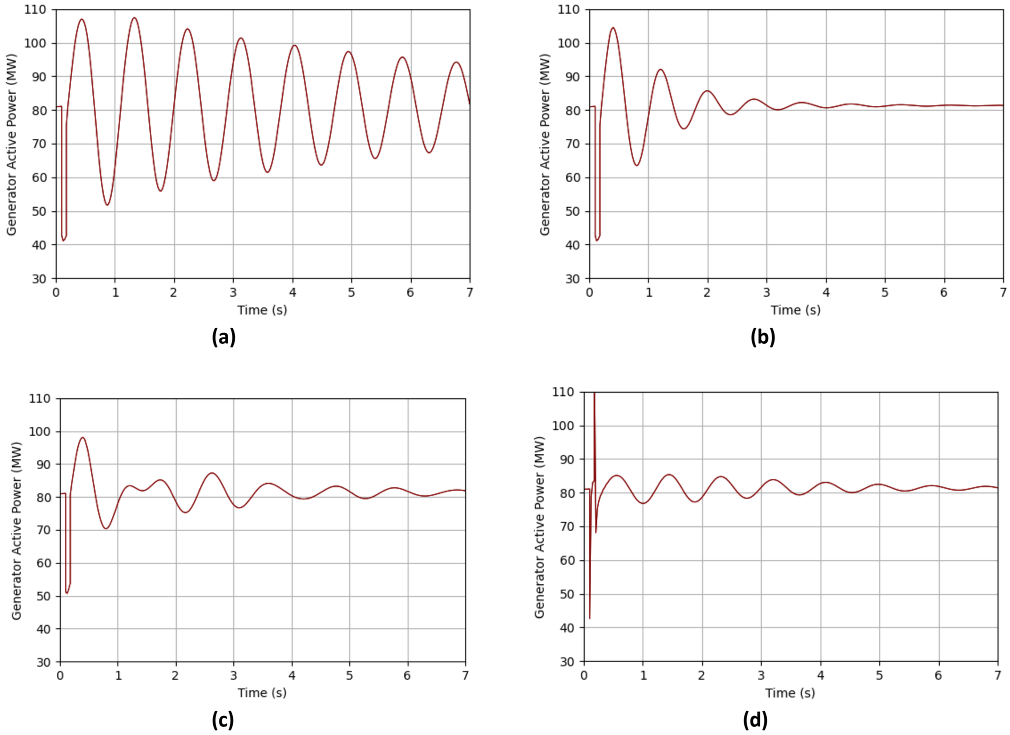

Figure 37: Active power output of oscillating units for hour 2307. (a) Base case, (b) Adding PSS, (c) Adding synchronous condensers, and (d) Adding STATCOM

Figure 36(c) and Figure 37(c) indicate that the damping provided by synchronous condensers is a bit more limited in comparison to PSS. This observation coupled with the decay time presented in Table 2 suggests that synchronous condensers have a slightly more limited mitigation effect in terms of alleviating damping torque scarcities.

Figure 36(d) and Figure 37(d) suggest that STATCOM[24] not only provides sufficient damping but also offers a significant reduction in the first swing of the generator angle and overshoot in the generator active power. Since STACOM provides a faster response along with sufficient damping, it appears to be the most appropriate option (out of the three investigated in Table 2) for mitigating damping oscillation scarcities.

Finally, Figure 38 presents the box plot distributions of the decay time for each of the 36 LCL snapshots under investigation but with relevant mitigation technologies incorporated. Each box plot is associated with 306 data points, one for each contingency under consideration. It is evident from the figure that the incorporation of the mitigation technologies facilitates the removal of all localised damping oscillation scarcities observed earlier in Figure 34, i.e., there are no hours associated with outliers (i.e., the top 5 percentile) that exceed the 7s decay time threshold.

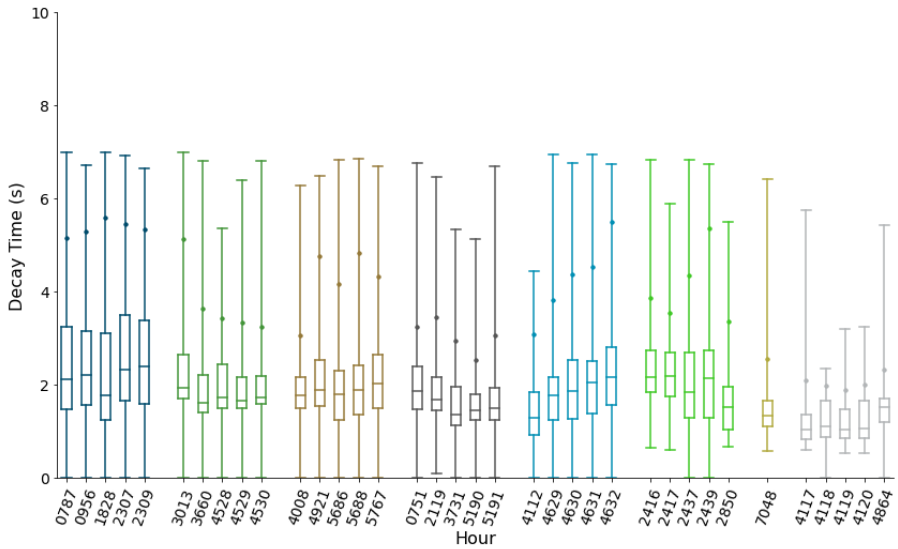

Figure 38: Box plot distribution of decay times for LCL snapshots with mitigations applied

2.3.2. Synchronising Torque Scarcities

The electrical distance between various synchronous generations is an indicator of available synchronising torque in the system, with higher synchronising torque resulting in better transient stability. A better dispersion of synchronous units across the system yields better reactive injection during a fault, thereby resulting in an improved dynamic voltage support during the fault and directly influencing the transient stability in the process [1].

[24] As presented in EU-SysFlex Task 2.3 [11], the generic SVSMO3 model (which includes an additional control block for introducing damping in the system) of STATCOMs was used for performing the dynamic studies as part of this report.

With increasing RES penetration and the consequent reduction in the number of synchronous generators online, synchronising torque levels in the system are expected to reduce with each of the remaining synchronous units required to contribute more electromagnetic torque during any given fault [1], [2]. Additionally, a reduction in the number of synchronous units may lead to changes in the geographic dispersion of such units, thereby resulting in the isolation of certain generators and exposing them to an increased risk of losing synchronism (particularly for faults close to such generators). The scarcity studied in this subsection therefore focussed on the synchronising torque available between the remaining synchronous units in the system, with the scarcity likely to manifest itself in one of the two following ways as defined in EU-SysFlex Task 2.4 [1]:

- A **global scarcity** that results in several groups of generators separating from one another but remaining synchronised to each other within the group
- A **localised scarcity** that results in one generator or a small group of generators separating from the rest of the system

The objective of the synchronising torque scarcity studies presented here was to study credible faults, i.e., events such as loss of infeed/outfeed and system separation, for investigating potential loss of synchronism. The studied faults are compiled using known protection settings and are driven by our extensive operational experience. Obviously, the longer it takes to clear a fault, the more severe its impact on the system, e.g., a generator might become unstable and lose synchronism as the accelerating torque encountered through the fault might cause it to exceed its critical angle. The synchronising torque scarcities studied in this section are quantified using two metrics: **angle margin** and **critical clearing time** (CCT).

The angle margin is used for comparing 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 angle margin is defined in Equation (1), where δ_{max} is the maximum difference between the relative rotor angles across all generators within the simulation timeframe [38]. The angle margin can vary between -100 to +100, with positive values indicating a stable system and negative values indicating otherwise (i.e., at least one generator will lose synchronism post-contingency).

$$\eta = \frac{360-\delta_{max}}{360+\delta_{max}} * 100 \qquad (1)$$

The CCT (expressed in cycles) is the longest fault clearing time for which the system will remain stable (i.e., all generators will remain in synchronism) 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 based on the angle margin defined in Equation (1). The fault clearance range used for this study is in between 4-70 cycles, which implies that all CCT values calculated in the simulations would be within this pre-defined range. Given the current protection design in the all-island power system, most credible faults are expected to be cleared within 4-8 cycles. The worst case fault clearance time, allowing for a complete failure of primary and redundant communications, the failure of any accelerated tripping schemes and a zone-2 fault, is 25 cycles. This is an extreme worst case scenario that is unlikely to occur but it provides a useful reference point for when CCTs may potentially require further study [1].

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

The rotor angle dynamics of synchronous generators is numerically presented in Equation (2), which is essentially the swing equation for synchronous machines. In (2), M is the machine inertia constant, δ is the rotor angle and P_m, P_e and P_a are the mechanical, electrical and accelerating powers, respectively. Considering a scenario where the generator is transferring power (across a transmission system) to a load connected to an infinite bus, the terms E, V and X in (2) respectively denote the generator's internal EMF, terminal voltage at the infinite bus and the total transfer reactance (comprising the generator's internal reactance and the transmission system reactance) between the generator and the infinite bus [39].

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

Generators are more likely to remain stable if they continue to transfer electrical power to the grid during the fault, as the imbalance between the mechanical and electrical powers (and in turn, the accelerating power P_a in (2)) would be reduced. When a fault is remote from a generator, it will have very little impact on the electromagnetic torque (which is in turn proportional to the electrical power P_e in (2)) of the machine owing to the fact that the reactance X between the machine and the load it is serving remains largely unchanged under such a scenario [3]. 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 associated with shorter CCT values. However, there is no doubt that the CCT is influenced by the pre-fault loading of a machine and its proximity to the fault.

It can be inferred from Equation (2) that the accelerating power P_a can be reduced by increasing the generator terminal voltage during the fault. Hence, technologies such as STATCOMs, SVCs and synchronous condensers are considered as potential mitigation options in this section for alleviating the synchronising torque scarcities. Also, it can be observed from (2) that reducing the mechanical power P_m can help in reducing P_a; hence consideration of an operational policy (involving incorporation of a new system constraint) under specific system conditions that would reduce the dispatch of the generator that loses synchronism and increase the output from an alternative generator was also investigated as a potential mitigation option in this study [3].

Figure 39 presents the box plot distributions of angle margins calculated in Task 2.4 [1] for each of the 36 snapshots studied as part of the LCL scenario base case. Each box plot represents the angle margin distribution for a specific hour and 306 data points (one for each contingency under consideration). However, it is to be noted that contingencies associated with unstable results are excluded from the distributions and are plotted instead as dots in Figure 39.

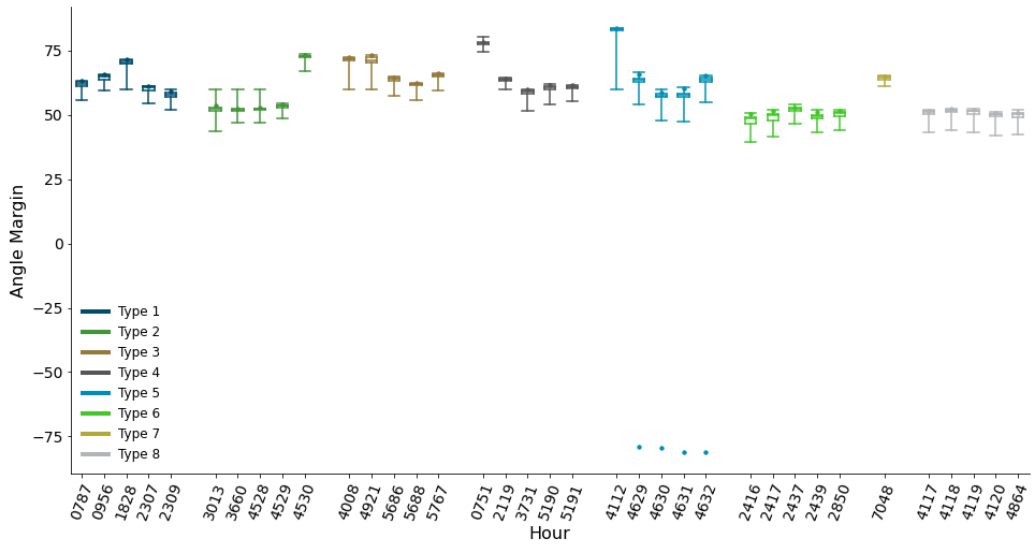

Figure 39: Box plot distribution of angle margins for LCL snapshots under base case

Task 2.4 [1] did not find any global scarcities of synchronising torque, as there is no hour in Figure 39 that is associated with a particularly poor angle margin. However, a localised scarcity was 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, as indicated by the blue dots in Figure 39 for hours 4629, 4630, 4631 and 4632.

For each of these four hours, the concerned generator and a nearby large unit were operating at maximum dispatch and the nearby interconnector was at maximum import before this infeed was taken out in a fault. These localised (synchronising torque) scarcities were investigated in detail in Task 2.4 and it was found that these will likely emerge for specific combinations of unit commitment and contingencies.

In order to prevent the generator from losing synchronism (as presented in Figure 39), mitigation technologies like synchronous condensers, SVCs and STATCOMs are required in large numbers, which may be prohibitive from a cost perspective. The best mitigation option in this scenario therefore appears to be the consideration of an operational policy under specific circumstances and system conditions that involves modification of the considered unit commitment by dispatching down the unit that loses synchronism and increasing the output of another machine (that is electrically distant from the fault) to make up for the shortfall in generation from the dispatch-down process [3].

Box plot distributions of all 36 LCL snapshots and for all 306 contingencies under consideration are presented in Figure 40, but with mitigation technologies discussed in Sections 2.2.2 (dynamic voltage scarcities) and 2.3.1 (damping torque scarcities) incorporated. It is evident from the figure that the synchronising torque localised scarcities are cleared (i.e., the blue dots in Figure 39 corresponding to negative angle margins are absent in Figure 40) following the incorporation of relevant mitigation technologies. Additionally, the distribution of angle margin values can be observed to lie in the range of 45-65 in Figure 40, thereby indicating that the technologies used to mitigate other scarcities (e.g., synchronous condensers and STATCOMs) did not deteriorate transient rotor angle stability.

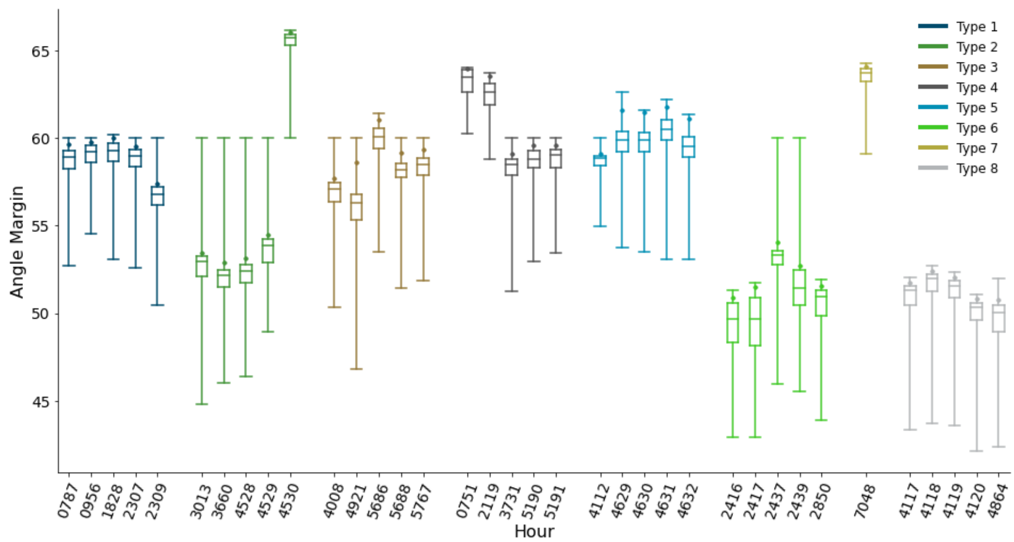

Figure 40: Box plot distributions of angle margins for LCL snapshots with mitigations applied

Figure 41 presents the EU-SysFlex Task 2.4 [1] results of the CCT index for each of the 36 LCL snapshots under the base case. As before, each box plot corresponds to 306 data points, one for each contingency under consideration. With reference to the 4 hours in Figure 39 that are associated with negative angle margins, it can be observed from Figure 41 that the same hours also correspond to 4 cycle (i.e., below the minimum protection target of 5 cycles as specified in EirGrid's Operating Security Standards [40] for 220 kV and higher (voltage level) circuits) CCT values. The box plots in Figure 41 also show that no other hours of operation have the bottom 5 percentile of faults for which the CCT values approach the minimum study threshold of 4 cycles (though the outliers for most hours are below 10 cycles), thereby indicating the absence of any global CCT scarcity.

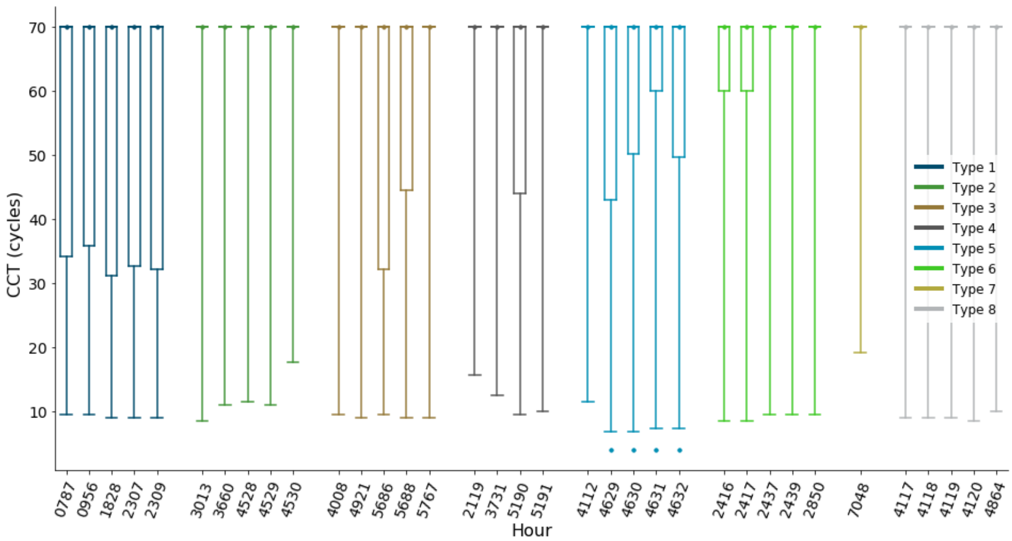

Figure 41: Box plot distributions of critical clearing times for LCL snapshots under base case

A case study is performed next for the scenario with the lowest CCT (Hour 1828 and contingency 30). In this case, two large synchronous generators which are in close proximity to the fault are found to be operating at maximum power. Both generators experience loss of synchronism post-fault. 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 outputs of both generators by 100 MW is explored, and relevant results are presented in Table 3.

Table 3: CCT values for different mitigation strategies

Mitigation options	***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

It can be observed from Table 3 that the improvement in CCT values from adding STATCOMs or synchronous condensers is not significant considering cost implications. However, these technologies are used for mitigating other issues, e.g., dynamic voltage scarcities in Section 2.2.2 and damping torque scarcities in Section 2.3.1, and therefore their impact on CCT values for all LCL snapshots is considered.

Box plot distributions of CCT values for all 36 LCL snapshots but with the above mentioned mitigation technologies implemented are presented in Figure 42. It can be observed from the figure that there are no hours of operation for which the bottom 5 percentile of CCT values approach the minimum study threshold of 4 cycles. The outliers of most hours can also be seen to be below the absolute worst case clearing time of 25 cycles (refer to discussions on CCT thresholds and ranges in Section 2.3.2). Finally, the box plots presented in Figure 42 reveal that the incorporation of mitigation measures for tackling dynamic voltage and damping torque scarcities (refer to above paragraph) do not affect the CCT distributions and related stability issues adversely.

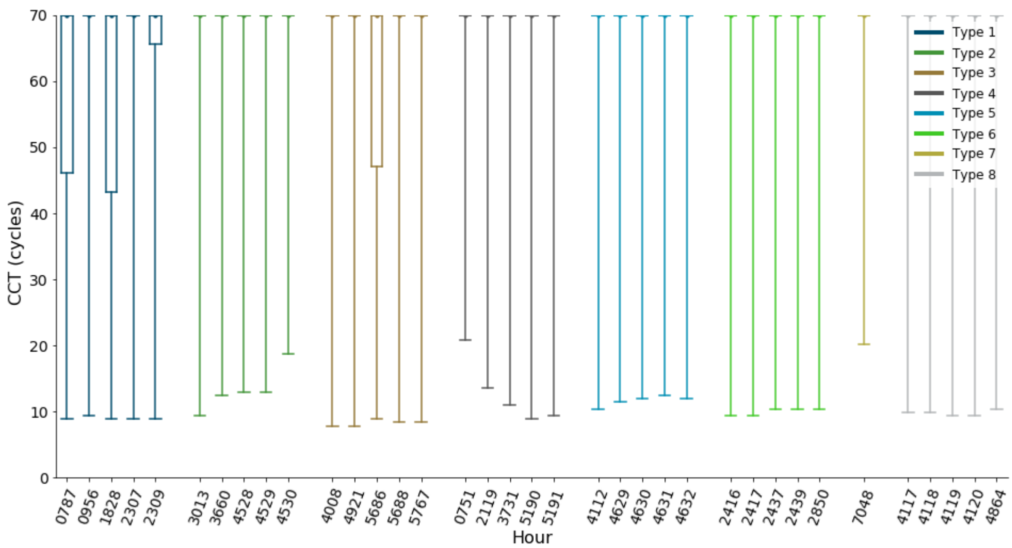

Figure 42: Box plot distributions of critical clearing times for LCL snapshots with mitigations applied

From the results presented in this section, it can therefore be concluded that in the event a transient instability does arise in the system, reducing generator output (as demonstrated in Table 3) or modifying the considered unit commitment (as discussed under Figure 39) appear to be the most effective mitigation options for tackling synchronising torque scarcities.

2.3.3. Inverter-driven Stability/Security

Growth of inverter-based resources (IBR) at the expense of synchronous generation prompts transmission system planners and operators to look at the following questions:

- How will the growth of IBRs impact power system stability, quality and security?
- What are the required system services to deal with a significant deployment of IBRs? There are two distinctive categories of services here: (i) mandatory services stipulated in the respective Grid Codes, and (ii) procured services that are secured through different market mechanisms. It is important that such services are considered in a technology-neutral and cost-efficient manner.

It might be worth outlining some of the main characteristics of IBRs here. IBRs became prevalent due to the presence of:

- Wind generation (variable speed generation)
- Solar
- Batteries
- Regulated loads (battery charges and variable speed motor drives)
- HVDCs
- STATCOMs

All of these listed resources require power conversion and their most important general features are: a lack of inertia, no difference between their short and long term current rating and tendency to have a high bandwidth control (having their specified performance guaranteed at high frequencies) and often quite complex current control loops that is proprietary information [41].

To maintain power system security and stability without compromising power quality, TSOs start from widely accepted general transmission system needs. In the area of power stability these needs are directed toward angle, voltage and frequency stability and preventing uncontrolled system oscillations. Power quality cannot be compromised, and it requires adequate synchronisation, voltage and frequency regulation and damping of the oscillations.

In terms of security there are requirements to ensure energy security, provide enough generation capacity to meet peak demand, protect the transmission system against all types of faults and provide system restoration for the fault affected area and at a system level through a black start. All of these system needs are subject to different IBR limitations that are already well known, e.g., those related to synchronisation and to remain locked to the system, a lack of mechanical inertia, power and energy availability on the prime mover side, absence of short-term ratings and unknown current control loop dynamics as well as some of the already reported concerns related to voltage dip induced frequency delay (VDIFD) and momentary cessation [2].

These general needs can be further decomposed in another set of layers that are now more specific and driven by the system characteristics. For example, when it comes to the frequency stability and regulation, such layers for the all-island power system would be:

- How to maintain the system frequency within normal limits considering power fluctuations of IBRs and demand?
- How to ensure that due to a large loss of demand/infeed there is enough fast response to halt frequency decay and ensure that the frequency zenith/nadir is not exceeding the specified thresholds that would cause damage, malfunction or loss of the equipment. In relation to the all-island power system, the maximum instantaneous frequency deviation needs to be limited to 1000 mHz [2].
- How to limit Rate of Change of Frequency (RoCoF) to 1Hz/s, especially bearing in mind that, for example, system separation is a credible contingency for the all-island power system that might cause one of the jurisdictions or certain areas within the two jurisdictions to operate with low system inertia. For example, the Northern Ireland total kinetic energy might be less than 4,000 MWs (the current inertia floor is 23,000 MWs in total for both jurisdictions) with a significant RES power output.
- How to provide enough primary (POR), secondary (SOR) and tertiary (TOR) reserve in a timely manner to recover frequency after a loss and recover it to its pre-disturbance values. It is important to notice that within the frequency recovery and restoration periods the following requirements need to be fulfilled:
    - Time to recover frequency – 1 minute within 500 mHz range
    - Time to restore frequency – 15 minutes within 200 mHz range

Similarly, in the area of voltage and angle stability the corresponding general needs can be further decomposed into another set of layers (as already discussed in the previous sections) that obviously create a complex problem space to be explored by various system studies taking into account many scenarios, different system services available, new technologies and changes/amendments/updates in terms of the transmission network, generation and demand portfolio and interdependencies.

In terms of the IBR configurations, there are two distinctive types [41]:

- Grid Following (GFL) that is currently dominant in the Irish system that can provide services related to both frequency (especially for high frequency events) and voltage regulation, it has been already used for damping very low frequency oscillations and has some potential in terms of restoration that has been currently trialling by many TSOs.
- Grid Forming (GFM) that is a new technology with recognisable potential to provide some additional services (with respect to GFL resources) such as: voltage forming, synthetic inertia, contribution to system strength and provision of cranking power for system restoration needs.

A simplified GFL configuration, as shown in Figure 43, is a current source that relies on the current control loop to match the network current with specified reference values. To achieve this, the alternating grid current needs to be converted though a d-q transformation in a pair of d,q phasors with a phase angle θ obtained from a Phase Lock Loop (PLL) block. The PLL block takes the alternating grid voltages and calculates the corresponding frequency and further on phase angle as outlined in Figure 43.

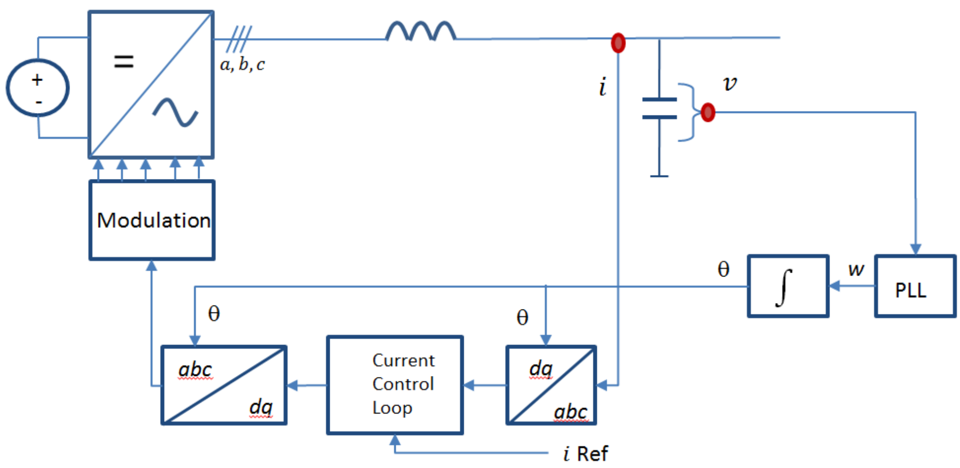

Figure 43: Simplified GFL configuration [41]

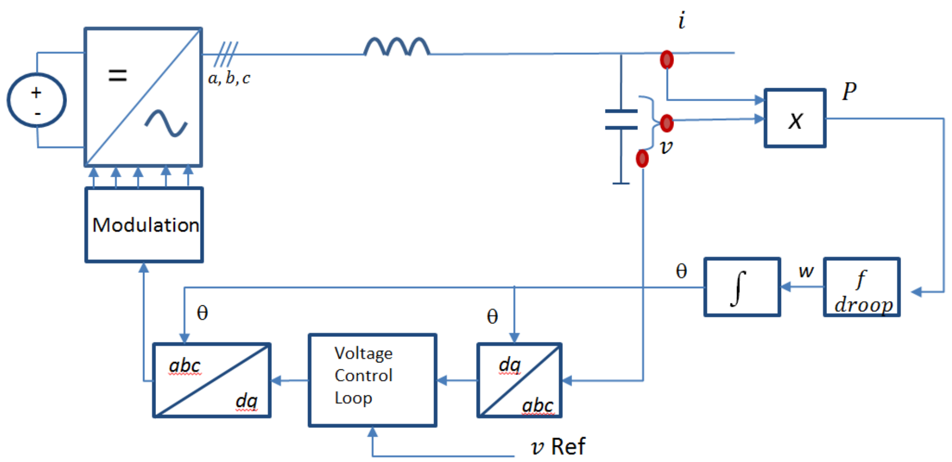

Figure 44: Simplified GFM configuration [41]

A simplified GFM configuration, as shown in Figure 44, is a voltage source that drives the grid voltage to follow the specified voltage reference values. Similarly, to GFL phase angle is again required to enable control of the phasor quantities, however this time it is realised by the calculation of the grid power and consequently the required frequency through a frequency droop block.

The main difference as outlined above is that [41]:

- With GFL, frequency is set by PLL control block locking to the existing grid frequency
- With GFM, on the other hand, frequency is set by droop function using the exported power

In simple terms the main objective of the PLL block is to align grid voltage with the d-axis and as soon as there is a detection of a q-component that will be interpreted as an error by the phase detector. Based on Figure 43, it is clear that phase angle is one of the main inputs for obtaining the d-q quantities and further control through the Current Control Loop block, so any errors in terms of phase angle detection would propagate through the current control loop and therefore might lead to instability. The research and analyses conducted so far indicate that potential instability cannot be attributed specifically to the PLL control but rather to the entire control part presented in Figure 43.

The calculated frequency from a PLL is not of adequate fidelity and consequently not used in relaying and protection functions. Instead these functions are based on digital-signal processing and it is typically the most accurate frequency identification. More importantly the positive-sequence driven power system dynamic simulations performed in power system planning and operation calculate frequency at a given bus in the network using the derivative of the voltage angle. The problem here is that when a sudden change occurs in the voltage angle – for example a nearby transmission fault it might result in essentially a very large frequency spike (infinite derivative in theory due to the step change in angle). It is therefore expected that the calculated frequency by protection, PLL and RMS tools are significantly different.

The other important point is that a PLL frequency is one of the most important inputs to the current control loop. EirGrid has been undertaking a significant effort in the modelling domain to enrich the existing RES RMS models to incorporate common PLL configurations into the corresponding generator/converter control blocks.

In addition to those differences with respect to the synchronisation (GFL – locking to grid voltage versus GFM – adjusting instantaneous frequency) and the source type (GFL – current source versus GFM – voltage source), there are differences with respect to their 'prime mover' (i.e., the RES source behind the inverters) logic too [41]:

- GFL - it exports constant power that is driven by what is delivered by the 'prime mover' to its DC busbar, e.g., with a solar panel – the inverter follows the 'prime mover'.
- GFM - the power extracted from the 'prime mover' and exported to the grid depends on the network load and associated signals generated by the inverter controls – the 'prime mover' follows the inverter from that point of view.

Some of the important GFM characteristics that could well complement the current dominance of the GFL IBR are:

- Voltage forming – considering a significant deployment of IBR there is a need that these resources take their share with respect to forming grid voltage which means that they should be capable of running in parallel with other voltage sources and they should not depend on them to form their voltage. This automatically disqualifies use of any control logic that is driven by PLL.

- Contribution to the system strength – the voltage source characteristics of GFM means that they contribute to the system strength of the power system. The desired behaviour during a fault depends on fault location and type however GFM resources should be capable of providing fault current that is limited to the converter's overcurrent capacity within $\frac{1}{4}$ of a cycle which is important for the protection system that requires sufficient amplitude of fault current in the first 20-30 ms after the fault.

- Inertia – the fact that the prime mover follows the inverter can be beneficial in providing synthetic inertia.

- System restoration – bearing in mind that GFM can be used to form the voltage (they do not need to lock to the grid voltage), they can be utilised for the provision of cranking power for system restoration purposes.

EirGrid has been working on developing state-of-the-art GFM related dynamic models as the most important prerequisite for further studies to investigate use of these configurations with more RES. The Migrate (an EU Horizon 2020) project [42] indicates that power systems having a significant share of the power electronic GFL generation might cause a number of issues in terms of stability, security and quality of supply and as such might not be sustainable. However, with the right balance between GFL and GFM, this percentage can be significantly increased. Further studies will be required to investigate the way forward in terms of these new technologies, especially in many domains and with respect to the following concerns:

- Fault propagation likely to reach deeper in a grid, far from the fault with more severe voltage depression across the affected grid.

- Generator fault ride through will be significantly affected with increased levels of IBR.

- Voltage and power oscillations are expected to be more pronounced as the system recovers from a fault with a more notable Voltage Dip Induced Frequency Dip (VDIFD[25]) impact.

- Reduction in fault current is expected to compromise power system protection performance.

- GFL RES generation ability to lock to the grid voltage and remain synchronised might be significantly affected.

[25] Refer to Appendix A – Additional Technical Challenges for more details

- GFL current control loop functionality/operability will be challenged in the areas of low system strength with a potential amplification of the control interactions.

- There might be a need for more advanced and computationally intensive modelling techniques (as discussed in 2.2.3) by system operators to capture dynamics of the system, such as the use of Electromagnetic Transients (EMT) simulation or hybrid simulations with a combination of the EMT and standard RMS dynamic simulations. The Australian Energy Market Operator (AEMO) has been using EMT simulation models for several years. Their EMT model comprises approximately 3,000 busbars and 200 detailed EMT dynamic models, with an EMT dynamic simulation run lasting 30 seconds completed within three hours. Clearly, moving to more detailed models will increase computational burden.

- Further considerations would need to be given to deriving a new metric for the evaluation of the system strength and the corresponding alarm/warning thresholds.

2.4. Congestion

SUMMARY:

The transmission and distribution systems have to transport power from where it is generated to where it is consumed. The capacity of all components on any route has to be adequate for these power flows. If this is not the case, the network is said to be congested [2].

Analyses carried out as part of EU SysFlex Task 2.4 [1] indicate that as SNSP and RES penetration increase in the future, there would be a significant rise both in the magnitude and frequency of transmission line loading above 100% of rated thermal capacity.

The recently concluded SOEF consultation [2] examined four potential approaches, i.e., generation-led, developer-led, technology-led and demand-led, to network development in the future to facilitate realisation of Ireland's and Northern Ireland's renewable ambitions by 2030. Regardless of the approach taken, it was evident from the analyses that significant network reinforcements would be required for safe and secure integration of new RES connections, interconnectors and large energy consumers into the network in the future.

Ultimately, the selection of required reinforcement candidates is done through an extensive multi-criteria analysis carried out by the relevant TSO. It was demonstrated through simulations performed as part of EU SysFlex Task 2.6 [3] that strategic incorporation of selected reinforcements (in the form of installation of new circuits) does help in alleviating significant congestion issues for many critical hours of the year. However, these reinforcements (i.e., those considered as per Task 2.6 [3]) alone may not remove all network congestion issues for all hours of the year.

Operational mitigation measures e.g., generation re-dispatch and load shifting are helpful in providing additional flexibility to control room engineers for tackling infrequent congestion events that are not dealt with through network reinforcements. Other operational tools, e.g., power flow controllers, dynamic line rating and demand side management, proposed as part of the technology-led approach in [2] can also help in the mitigation of similar congestion issues.

However, the number of operational mitigation measures that can be considered is limited in terms of time and capabilities that are at the control room engineer's disposal. Therefore, it is very important to find the right balance between network reinforcements and operational mitigation measures in relation to resolving congestions in the power system of the future.

There is strong evidence across Europe that transmission network congestion will be one of the most difficult challenges to resolve with increasing integration of RES in the system. Congestion drivers (e.g. variable RES outputs, demand variations, outages of both transmission network and generation) are of a primarily stochastic nature. This makes the problem particularly challenging mainly due to a vast space of potential congestion scenarios. Project deliverability assessments (including relevant cost-benefit analyses) demonstrate that it may not be viable to develop transmission networks that would guarantee compliance with the applicable security/planning criteria under all conditions/scenarios. Both the magnitude and frequency of congestions will play an important role when deciding how to tackle the issue.

The experience of many countries dealing with high RES penetration levels indicates that the pace of transmission network development usually struggles to match the pace of RES integration, which often leads to the imposition of constraints on renewable generation outputs. As a result, the congestion problem that was formerly dealt with through planned network investments tends to shift to operational mitigation measures by the TSO. It is therefore very important to take a coordinated approach to tackle those congestion problems across both the planning and operational domains.

The Ireland and Northern Ireland power system is operated at 400 kV, 275 kV, 220 kV and 110 kV levels. The network is generally comprised of overhead lines with the exceptions of the city centres of Belfast, Dublin and Cork, some renewable generation connection circuits and some carefully selected new circuits, where underground cables are used [11]. Steady-state analysis was carried out in EU-SysFlex Task 2.4 [1] to assess the impact of increasing levels of RES on the all-island transmission system in order to investigate potential congestion issues. The analysis indicated that as SNSP increases, there will be a significant rise in the magnitude and frequency of transmission circuit loading above 100% of rated thermal capability unless constraint is applied.

Figure 45 shows the results of the 2030 LCL transmission network thermal overloading analysis from Task 2.4 for N-1 system conditions [1]. The results shown are for both the summer (red) and winter (blue) seasons with each dot representing a transmission circuit loading above 100%. The positive correlation between the magnitude and frequency of overloads and the SNSP level can be clearly observed from the figure.

Analyses carried out as part of Task 2.4 as well as for the Shaping Our Electricity Future report [2] clearly demonstrate that the greatest overloading of lines is experienced 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, can experience thermal overloads at both high and low SNSP levels. This is due to the large number of conventional generators and offshore wind farms connected.

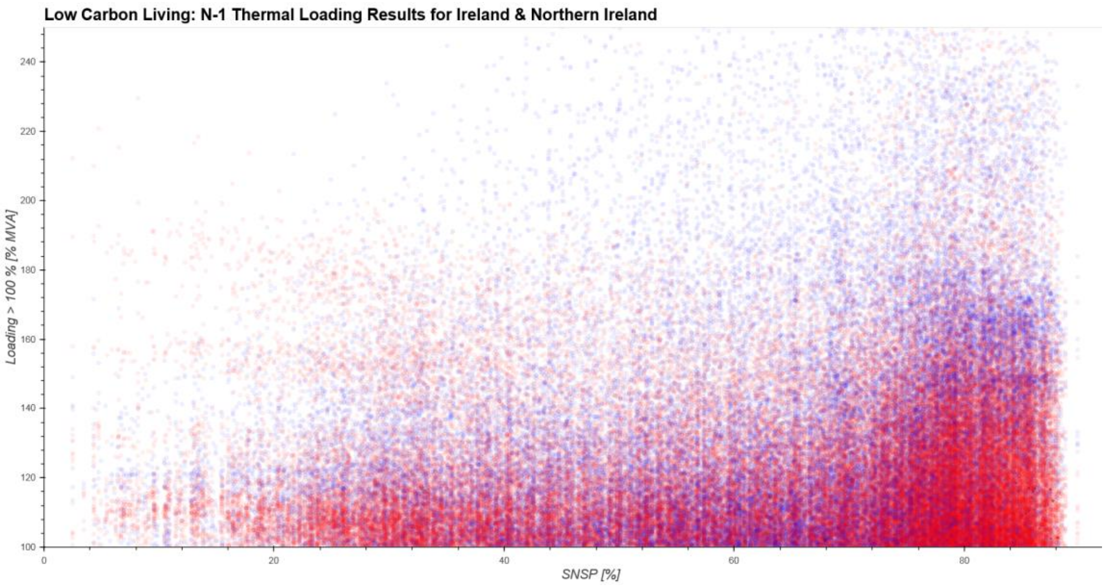

Figure 45: Comparison of 2030 LCL transmission network thermal overloading against SNSP

The methodology used for resolving congestions identified in Task 2.4 [1] is focused on several potential mitigation strategies, which can be broadly classified under two groups – network reinforcements and operational mitigation measures. As such, the outlined methodology is of a qualitative nature and not a comprehensive quantitative assessment that would result from the optimal investment decision process following appropriate analyses that would be exercised in both planning and operational domains.

As with other sections of this report, the aim here 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 that while the network reinforcement strategy discussed (as follows) in this section is indeed an integral part of the four approaches to network development proposed in the recently concluded SOEF consultation process [2], the technology-led approach in [2] also mentions operational mitigation measures, e.g., the use of power flow control devices and dynamic line ratings.

Network reinforcements: This involves identification of the top priority network corridors to reinforce and determination of the reinforcement requirements. Significant network reinforcements (be it installation of new circuits, substations, transformers or even up-rating and up-voltage of existing circuits) need to be delivered in both Ireland and Northern Ireland. This is to ensure the safe and secure integration of the significant amount of new RES generation, interconnectors and large energy users that are planned to connect to the all-island power system by 2030.

Ultimately, the selection of required reinforcement candidates is done through an extensive multi-criteria analysis carried out by the relevant TSO. It was demonstrated through simulations performed as part of EU SysFlex Task 2.6 [3] that strategic incorporation of selected reinforcements (in the form of installation of new circuits) does help in alleviating significant congestion issues for many critical hours of the year. However, these reinforcements (i.e., those considered as per Task 2.6 [3]) alone may not remove all network congestion issues for all hours of the year. The following paragraphs present several operational mitigation measures that, when used in conjunction with strategic network reinforcements, can offer additional flexibility in terms of mitigating anticipated congestion events.

Operational mitigation measures: Despite the strategic incorporation of selected candidate reinforcements, simulations performed as part EU SysFlex Task 2.6 [3] indicated that there would still be infrequent congestion events that crop up for some hours of the year for which operational mitigation measures would provide a more cost-effective solution. Operational mitigation measures such as, for example:

- Generation adjustments,
- Load shifting
- Phase-shifter (PST) angle and transformer tap changes, and
- Demand side management (DSM)

can offer additional flexibility to control room engineers for facilitating mitigation of such network congestion events.

Additional tools proposed as part of the technology-led approach in [2], for example:

- Incorporating power flow control (PFC) devices, and
- Dynamic line ratings

can also help in managing congestion issues in the operational timeframe by opportunistically controlling the available unused capacity on transmission circuits. These tools can facilitate short-term deferral of significant grid developments and reduction of dispatch-down of renewable generation owing to transmission constraints [2].

Simulations performed as part of Task 2.6 [3] demonstrated that when using the above tools without considering network reinforcements, any benefit accrued in terms of congestion management is minimal. However, it is unlikely that these tools will be deployed as the only mitigation against congestion; hence it is important to consider their positive contributions to congestion management when employed in conjunction with reinforcements.

Another important point to note in terms of DSM is that the focus of the discussion here is on demand side response from residential and small commercial customers (Residential DSM, or, RDSM), as opposed to large demand side units (DSU). Currently, DSUs in Ireland and Northern Ireland are typically large commercial and industrial-scale demand sites that are already proven to be able to provide several system services, e.g., FFR through to TOR2, Replacement Reserve and all three ramping services [3]. The demand side response potential of residential and small commercial customers, however, needs to be further explored [3].

However, in order to enable end-consumers to participate in Residential DSM programmes and to explore their capability to provide congestion management services, aggregation of demand needs to be possible and appropriate incentives would need to be in place. It is anticipated that this incentive could come in the form of a congestion management system service product [2], [3]. Given that network congestion issues are location-specific, an important point to consider while designing such a system service is the location of the demand aggregator vis-à-vis the specific congestion events that are being targeted for management.

Obtaining optimal operational mitigation measures is typically achieved through some commercial optimisation tool. In relation to this, it was observed from simulations performed as part of Task 2.6 [3] that the ability of the optimisation tool (used in [3]) to produce feasible outputs was severely affected by the size of the problem under consideration. In other words, while dealing with complex optimisation problems which needed to find the optimal mix of mitigation measures for removing several overloads spread across different geographic regions in the network, the optimisation tool in [3] often times failed to converge.

Additionally, even if optimal mitigation measures are generated, the ability to implement them in an operational timeframe is limited in terms of the time and capabilities that are at the control room operator's disposal. Thus, it is very important to find the right balance and a high degree of coordination between the planning and operational domains in relation to resolving congestions in the power system of the future.

2.5. Power Quality

SUMMARY:

Power quality is a measure of how closely the frequency, voltage level and (voltage/current) waveforms correspond to the nominal system specifications [2]. Non-linear power electronic devices, such as converters in wind/solar farms, STATCOMs, batteries and HVDC links, can draw or produce non-sinusoidal currents (having both the 50 Hz fundamental and higher-order harmonic components), which can in turn contribute to harmonic voltage distortion issues in the power system [43]. Increasing use of such devices can therefore have a potentially adverse impact on power quality, and this needs to be actively studied in detail.

A technical study is currently underway at EirGrid using all available recorded harmonic data from the past five years in order to determine if any trends pertaining to increased harmonic distortion levels with higher RES penetrations are evident. The data analysis is still being carried out, but the indications are that harmonic distortion is relatively constant across the system, and within limits of international standards despite the numerous new devices that have connected. This has largely been made possible due to the development of a policy on harmonics and the implementation of power quality requirements as part of the standard connection offer process to new customers.

As for the future, there is currently a great deal of interest in offshore wind generation which will be connected to the bulk power system through high voltage cables. These cables have the potential to introduce resonances that can lead to breaches of the harmonic planning limits. This is an area that will be studied carefully over the next few years.

Power quality can be broadly defined as a measure of how well the voltage, frequency and (voltage/current) waveforms in a power system conform to nominal specifications [2]. Conventional generators provide a significant support to power quality due to their ability to alter their voltage output quickly in response to a system event as well as acting as a sink for harmonics[26].

On the other hand, (non-linear) power electronic devices connected to the power system, e.g., converters in wind/solar farms, STATCOMs, batteries and HVDC links, can draw or produce non-sinusoidal currents which in turn interact with the system impedance creating harmonic voltage distortion [43]. The increasing use of such devices as part of the power system's transition towards a higher share of renewables has therefore led to an increased focus on harmonics and their impacts on the system.

[26] Refer to Appendix B – Glossary of Technical Terms for definition

EirGrid and SONI have a long track record of managing power quality issues, utilising an extensive network of disturbance and power quality recorders. These devices are used to monitor different aspects of power quality, e.g., voltage dips and swells, supply interruptions as well as voltage and current harmonics up to 2500 Hz. Voltage and current harmonic magnitudes measured at a 110 kV wind farm site over the course of a month are presented in Figure 46. With reference to the legend shown in Figure 46, note that ‘5th harmonic’ (for example) refers to a waveform associated with a frequency that is five times that of the fundamental value, i.e., a frequency of 250 Hz.

EirGrid and SONI also maintain an up-to-date harmonic model of the power system in DIgSILENT PowerFactory [44] which is used for studying new connections and their impact on harmonic distortion levels. A recent study was undertaken using all available harmonic data from the past five years in order to determine if any trends are evident. The data analysis is still being carried out, but the indications are that harmonic distortion is relatively constant across the system, and within limits of international standards (e.g., IEC TR 61000-3-6:2008 [45]), despite the numerous new devices that have connected[27]. This would tend to suggest that much of the harmonic distortion is incoherent and effectively cancelling itself out. Once the analyses are completed, the intention is to review and simplify the methodology by which harmonic limits are allocated to customers.

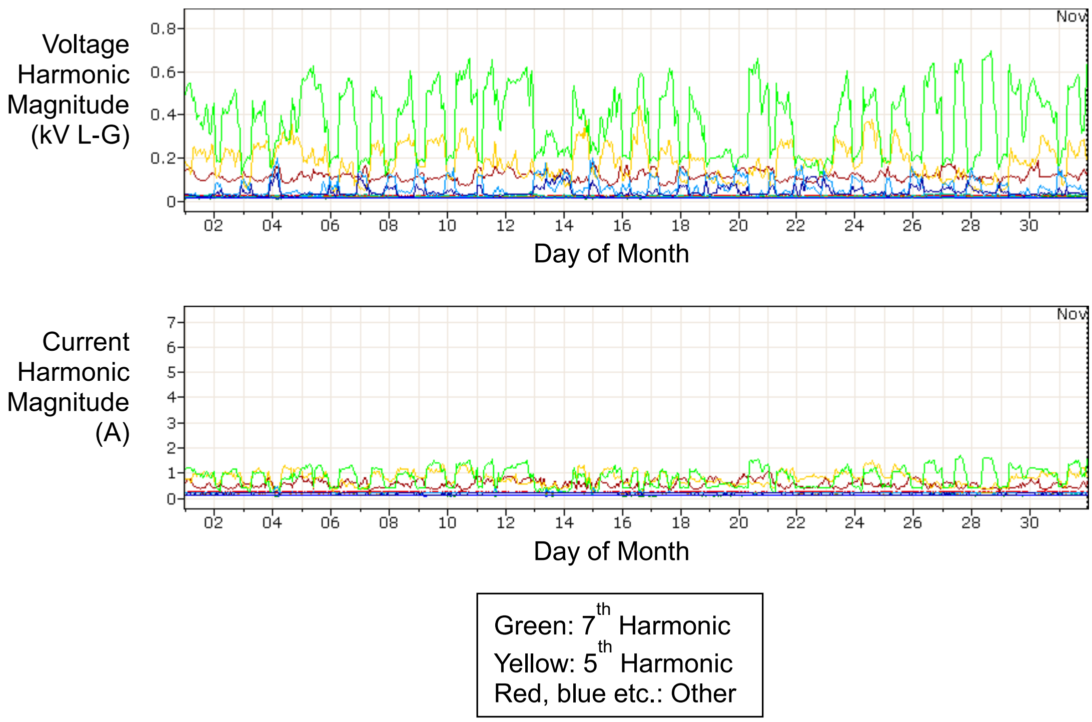

Figure 46: Examples of voltage and current harmonic measurements at a 110 kV wind farm

[27] This has largely been made possible owing to the increased emphasis placed over the past few years on limiting harmonic emissions. This has been achieved through modifications to the grid codes, the development of a policy on harmonics and the implementation of power quality requirements as part of the standard connection offer process [2].

As for the future, there is currently a great deal of interest in offshore generation which will be connected to the bulk power system through high voltage cables. These cables have the potential to introduce resonances that can lead to breaches of the harmonic planning limits. This is an area that is currently being studied, particularly in relation to East Coast wind applications. There are also significant transmission developments underway (e.g., the Kildare-Meath Grid Upgrade project [5]) that have the potential to introduce resonance conditions that could lead to excessive harmonic distortion levels, unless mitigated with filters. This is an area that will be studied carefully over the next few years.

Mitigation of potential harmonic issues arising in the future is a complex task involving several options as presented in Table 4. As seen from the table, every option has its pros and cons and the task is to determine the most cost-effective and enduring solution given the problem at hand. It is possible that a combination of different options listed in Table 4 may be required to best tackle a given issue.

Table 4: Mitigation strategies to overcome potential harmonic issues

Option	***Details***	***Issues***
Passive filters	Tuned inductive reactors and capacitance attenuate select frequencies	Depends on system impedance which changes over time
System reinforcement	Increase short circuit level in a region	Potentially expensive with possible long lead times. Also, increasing system strength at 50 Hz does not automatically guarantee acceptable performance at higher frequencies, especially when dealing with resonances.
Isolation transformers	Some higher frequencies can be attenuated with certain transformer winding configurations	Not applicable for all harmonic orders, potentially expensive
Harmonic injection limitation	Reduce injections from plant by enforcing limits	Some plants perform better than others for minimising harmonic injections, can potentially be the cheapest viable solution though not always an attractive option from the customer's viewpoint
Active filters	Automatically tuned reactors and capacitance attenuate select frequencies	These have a smaller footprint in comparison to passive filters, can provide stable operation against impedance changes, but are not effective against resonance conditions (hence application may be limited)

EirGrid and SONI will continue working on the integration of new RES and new technologies in a safe and reliable manner to ensure adequate power quality to all users of the transmission system, as stipulated in the grid codes. It is therefore important to continue carrying out relevant power quality studies, and employ suitable mitigation measures if required, to ensure secure operation of the power system at all times.

2.6. System Restoration

SUMMARY:

In the unlikely event of a total/partial system blackout, the restoration of continuous power supply as quickly and safely as possible to all parts of the system, i.e., generation, transmission, distribution and eventually consumers, is critical [1].

A Power System Restoration Plan (PSRP) is traditionally developed by system operators for laying out relevant guidelines and procedures for system restoration in the unlikely event of a blackout. The underlying principle of the PSRP is to use generation stations that can be started without an external power supply in order to energise other parts of the transmission system, including larger 'target' generators [1].

A variety of changes that are expected to occur in the all-island power system over the current decade can affect the respective PSRPs. These include, but are not limited to:

- Expected changes to the synchronous generator portfolio, given that several conventional units (potentially including Black Start units) have or are going to retire over the next few years
- Substantial network development expected over the next few years as per [2]
- Potential deployment of new technologies, e.g., batteries (including those located in data centres), GFM-enabled RES and new interconnectors, as part of the re-energisation process
- Expected operational policy changes to accommodate higher RES penetration and increased SNSP

In order to successfully accommodate and manage the above changes, significant efforts will need to be put in place in several areas pertaining to system restoration, including: black start contracting, black start capability and islanding testing, voltage and reactive power management during re-energisation, performing appropriate EMT and RMS re-energisation studies, as well as updating/approving the PSRP along with its implementation in the control room. It is expected that an optimal balance will need to be struck between changing the PSRP (e.g., for reflecting retired Black Start units and new network infrastructure) and exploring novel re-energisation options (e.g., incorporating new technologies) to ensure that power will continue to be restored in a safe, secure and timely manner in the unlikely event of future blackouts.

The Power System Restoration plan (PSRP) [46], [47] is a procedure that is exercised in the event of a partial or total blackout of a power system. A blackout is one of the most serious incidents that a power system can be exposed to. As a result of the serious nature of this incident, all users of the power system are obliged to maintain a high level of awareness and training in respect of Power System Restoration. The PSRP's ultimate goal is to ensure that all customers are re-connected safely, securely and as quickly as possible.

Most generators on the power system require external supply to start up. EirGrid has contracts in place with Restoration Service Providers or Black Start Units that have the ability to start up without an external supply. The providers include a diversity of fuel types, including hydro generators, pumped storage, gas turbines, and an interconnector. These are located strategically, to restore supply to generation stations and customers in four different areas of the Irish power system simultaneously. There is a total of twenty Black Start Units located across seven Black Start Stations. They receive payments for every half hour they are available to provide black start services. Payments for black start services are reviewed annually and subject to the approval of the Commission for Regulation of Utilities (CRU). One or more Black Start Units in each Black Start Station is tested annually.

Were a blackout to occur, the Irish transmission system would be divided into four different subsystems referred to as the North, East, South and West. Each of these subsystems would contain at least one Black Start Unit. Once the re-energisation of each of these subsystems is completed with multiple generators operating in a stable/secure manner providing supply to enough customers, the next stage of the PSRP would take place to synchronise them and form a single system. Synchronising facilities are available at various locations on the transmission system for this purpose. The power system restoration process would continue until supply is provided to each customer. Different stages of the Ireland PSRP are depicted in Figure 47. A similar PSRP is considered in Northern Ireland with some specific differences in most of the steps presented in the figure, i.e., from acknowledging a blackout to resuming normal operation.

In Northern Ireland, SONI has the ability under Grid Code to designate generating units with black start capability as black start stations within their connection agreement in order to ensure that the Northern Ireland System continues to have a Black Start Capability. Currently in Northern Ireland, black start capability is provided by conventional generators. During a system blackout in Northern Ireland, the system is divided into three subsystems based on the location of designated black start stations. As black start units within each of the three subsystems are brought online, they are used to re-energise customers in designated blocks in conjunction with the Northern Ireland DSO. Once each of the three subsystems is operating in a stable manner, they are then synchronised to form a single Northern Ireland system again and the PSRP process is deemed complete once all customers have been re-energised.

The Network Code on Emergency Restoration (NCER) distinguishes between top-down and bottom-up re-energisation strategies during power system restoration. Top-down refers to re-energisation where the cranking power is supplied by the neighbouring power system through the extra high voltage network and further downstream to both high voltage network and the corresponding distribution system.

For example, in the case of Ireland, this would mean using either East-West Interconnector's (grid-forming (GFM) HVDC technology, refer to Section 2.3.3 for details) black start capability, or perhaps receiving the cranking power from Northern Ireland (assuming it is itself not affected by the blackout). Bottom-up re-energisation is driven by hydro or diesel units to start larger conventional machines and the propagation of re-energisation is from a low to higher voltage levels. It is expected that a combination of top-down and bottom-up re-energisation strategies would be used in the unlikely event of a blackout.

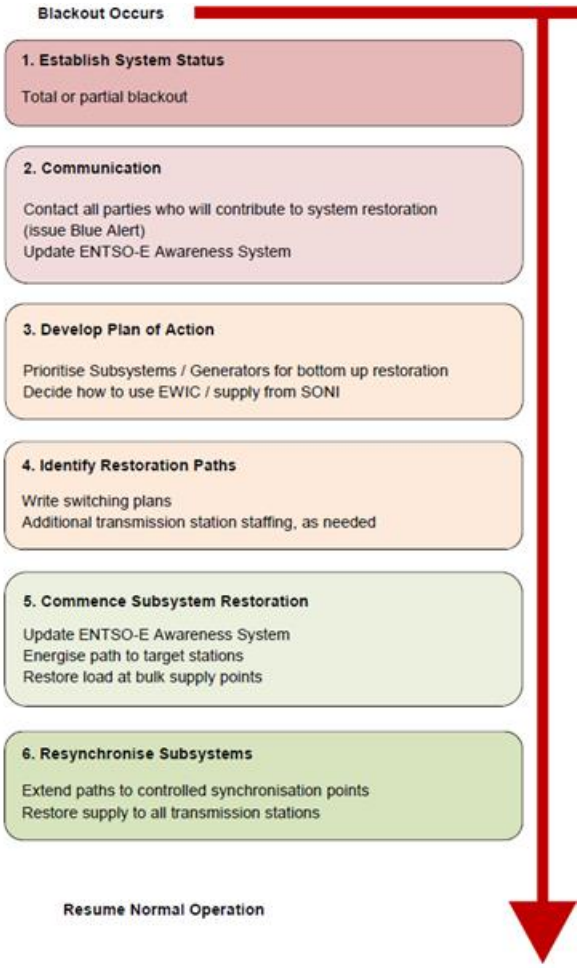

Figure 47: Overview of the power system restoration plan stages

It is well known that the all-island power system will be subject to many changes that can affect its restoration plans:

- The synchronous generation portfolio is expected to be significantly altered by 2030 with some units already retired recently and others expected to retire by 2030. Assuming that some of these units might be Black Start Units or ‘target’ units, this might affect the existing PSRP.
- Substantial network development is expected in the next 10 years as set out in the Shaping Our Electricity Future roadmap [4].
- Deployment of new technologies such as batteries and GFM RES generation (as per Section 2.3.3).

- New interconnectors such as Celtic and Greenlink that are GFM based technologies that can be potentially utilised for top-down restoration plans in the same way as the East-West Interconnector.
- New network users such as data centres with their backup supply – these are expected to increase in the future.
- Expected Operational Policy changes to accommodate more RES and increase SNSP.

The new RES generation[28] that will be connected to the all-island power system, particularly GFM-based, would be able to form the system voltage and as such be able to be considered as an alternative to Black Start Units or 'target' units in the new PSRP. This would likely require policy changes to enable the participation of this new RES generation in the PSRP (especially when moving toward 100% SNSP). Potential use of new HVDC interconnections such as Celtic and Greenlink as well as Battery Energy Storage Systems[28] might increase options in terms of providing cranking power for the all-island power system restoration. The changes listed above will impact the restoration plans and a significant effort will be required to address the following phenomena/concerns:

- Operational Policy changes
- Communication changes
- Black start contracting
- Black start capability and islanding testing
- Voltage/reactive power management during re-energisation
- Ensuring compliance with resynchronisation requirements (frequency deviation, voltage deviation, voltage phase angle deviation, SCR, impedance between the two systems to be synchronised and many others)
- The corresponding EMT and RMS re-energisation studies
- Operator training
- Updating and approving PSRP and its implementation in the control room
- Potentially limited capability of GFM technologies to provide sufficient inrush current for energising transformers in the restoration path

An optimal balance between the efforts required in terms of PSRP changes and implementation of new re-energisation options that might become available due to the power system's evolution/changes (discussed above) needs to be achieved. EirGrid and SONI will continue to assess the impact of all of these changes to the power system restoration plan and undertake corresponding actions to ensure that power can be restored securely, safely and in a timely manner.

[28] Introducing energy limited technologies in the PSRP is a significant challenge.

2.7. Capacity Adequacy

SUMMARY:

Capacity adequacy pertains to the probabilistic evaluation of a power system’s ability to maintain adequate capacity levels for meeting the system demand reliably and economically. With increasing penetration of variable, uncertain RES generation coupled with the displacement of conventional synchronous units, it is crucial to conduct adequacy studies regularly to be able to identify potential shortfalls in capacity in the coming years and take corrective actions (e.g., procuring capacity through capacity market auctions) accordingly.

From an all-island perspective, EirGrid and SONI publish findings of adequacy studies, on an annual basis, through the Generation Capacity Statement (GCS), which outlines the expected electricity demand and the corresponding level of generation capacity that will be required on the island of Ireland over the next ten years. The latest publicly available GCS (2021-2030) [6] highlights a significant shortfall in generation capacity in the Irish power system. New renewable gas ready power plants, plus storage and demand side measures will be required to satisfy gaps out to 2030. The GCS noted that the Northern Ireland power system was adequate against core scenarios, however, sensitivity analysis investigated credible risks that could lead to shortfalls in adequacy, in particular the impact of run hour restrictions on gas plants plus the early closure early of older plant.

Additionally, the recently concluded Shaping Our Electricity Future consultation [2] identified several uncertainties that are expected to impact on system adequacy, e.g., increasing demand, lower generation availability of existing power plants, new capacity terminating their awarded capacity, risks around delays in building new capacity, as well as emission limits. Considering that more than 2 GW of conventional generation is expected to retire in Ireland and Northern Ireland over the next five years, new gas fired plants will be a part of the solution to manage future power system adequacy and security, especially at times when renewable generation levels are low. EirGrid and SONI continue to assess the security of supply situation, while monitoring the different uncertainties discussed previously, along with the evolving generation portfolio in the system.

The transmission system operators have a regulatory requirement to publish forecast information about the power system, including an assessment of the balance between supply and demand. In systems with a significant proportion of variable generation, one of the main concerns is to have adequate system capacity to meet demand both reliably and economically. Different adequacy standards are used across Europe and based on different reliability indices. For example, in Great Britain a generation security standard used over a significant period of time stipulated that demand disconnections expected to occur in not more than nine winters in one hundred years. In Ireland another metric is used for assessing generation adequacy: Loss of Load Expectation (LOLE). LOLE is the mathematical expectation of the number of hours in the year during which the available generation plant will be inadequate to meet the instantaneous demand. The standard set by the relevant Authorities requires LOLE of less than 8 hours in Ireland and less than 4.9 hours in Northern Ireland per annum.

To assess capacity adequacy, a TSO performs adequacy studies on a regular basis, presents the results to the Regulatory Authorities and publishes them through the corresponding generation capacity statements. The results of these studies initiate further actions/incentives for example use of the corresponding capacity market mechanism to ensure that sufficient capacity is procured to meet future demand levels and operational requirements such as reserves and transmission outage planning requirement and in accordance with the standard agreed.

In Ireland and Northern Ireland, the Generation Capacity Statement (GCS) outlines the expected electricity demand and the level of generation capacity that will be required on the island of Ireland over the next ten years. As part of the strategy to support sustainability and decarbonisation, the grid is undergoing a process of modernisation, with greater needs for flexible capacity to ensure security of supply. EirGrid and SONI are working to ensure that everyone has electricity when they need it, at the most economic price possible while preparing the grid to provide at least 70% of our power from renewable sources by 2030.

In our adequacy assessment studies, the generation portfolio is modelled against the range of the demand forecast using the accepted standard of reliability LOLE. These studies are carried out individually for Ireland and Northern Ireland, and jointly on an all-island basis once the 2nd North-South interconnector is assumed to be in service. A range of scenarios are prepared to forecast electricity demand over the time horizon of the report.

The latest publicly available GCS (2021-2030) [6] shows that further capacity is required to ensure that system reliability standards are maintained over the course of the 2021-2030 decade. The report outlines that:

- A deficit of capacity is observed in Ireland for most of the scenarios assessed for the period.
- There are no deficits of capacity (out to 2030) for Northern Ireland assessed for the core scenarios under consideration. The studies did show that if capacity shut early or if new capacity had restrictions, then this would negatively impact on the capacity adequacy.

Furthermore, recent work on security of supply and analysis [2] has communicated that a range of credible risks/ uncertainties that impact on system adequacy have been identified, as follows:

- **Decrease in generation availability** – the availability of a number of existing generators, including those plants expected to decommission in the coming years, has been lower than previous years.
- **Forecasted new generation failed to materialise** – new generation that was previously successfully cleared in the capacity market auctions has been withdrawn by the developers.
- **Delays in building new capacity** – additional new capacity that was forecasted for delivery in 2022/23 has been delayed because of planning compliance, emissions audits and the global pandemic.
- **Emissions Limits** – Some fossil fuel generation has been excluded from the capacity market from October 2024 because the plant has advised they will exceed new EU emission limits.
- **Demand uncertainty** - demand is driven by economic activity, assumptions on energy efficiency and the growth of large energy users and data centres.
- Furthermore, there are uncertainties relating to the new interconnectors and operational challenges with interconnector trading and capacity reliance on North to South flows.
- Risks around extended periods of low RES output

The transition to low-carbon and renewable energy means that there are assumptions on the retirement of aging plants due to climate action plan requirements, restrictions from industrial emissions directives and other planning related issues. Over the course of the next 5 years around 1650 MW of generation will retire in Ireland with up to a further 500-600 MW retiring in Northern Ireland. New low carbon gas fired plant will be part of the solution to manage future power system adequacy and security especially at times when the wind and solar output levels are low and for what may be extended periods of time. This will be further investigated through the generation capacity studies.

Furthermore, in order to meet the 8-hour LOLE standard in Ireland, and 4.9-hour LOLE standard in Northern Ireland, we must factor in the realities in the operation of the transmission system. These realities include the need to:

- Provide for reserves for when plant is not available
- Manage the power system in the event of a contingency
- Planned outages of network equipment

These operational requirements are in line with the Transmission Planning and System Security Standards [30] and Operating Security Standards [16] as approved by the CRU in Ireland and UR in Northern Ireland, respectively. The results and recommendations of the GCS are intended to inform market participants, Regulatory Authorities and policy makers on the overall demand/supply balance, and they are important drivers for all our network studies. As such, they will be assessed on a regular basis and accordingly reflected in the overall study process.

3. Conclusion and Future Work

This report presents various mitigation strategies developed as part of studies conducted within EirGrid and SONI for addressing potential technical challenges arising in the power system of 2030 incorporating 70% RES-E. The technical challenges discussed in this report, as outlined in Table 1, are broadly based on those identified in the 'Shaping Our Electricity Future' consultation document [2] recently published by EirGrid. A summary of the different mitigation technologies and strategies discussed throughout this report along with the potential technical challenges that can be addressed using each of those is presented in Table 5.

Table 5: Summary of mitigation strategies to address different technical challenges

Mitigation strategy/technology	***Technical challenge(s) to be resolved***
Synchronous Condenser (SC)	**Frequency stability** – *provision of inertia* (SCs can help to delay frequency nadir, thereby facilitating the activation of slower-acting reserves prior to its occurrence. Their benefits are even more pronounced when used in conjunction with other mitigation measures)
	Voltage stability – *provision of DRR* (SCs can help mitigate systematic localised dynamic voltage control scarcities)
	Transient stability – *mitigation of damping torque scarcity* (SCs can technically contribute to reducing rotor angle oscillation decay times, but are not as efficient in damping generator rotor angle/MW output oscillations as, e.g., STATCOMs)
	Transient stability – *mitigation of synchronising torque scarcity* (SCs can help in improving angle margins and CCT values, but under specific circumstances and system conditions, simulations reveal that a more appropriate mitigation strategy appears to be the consideration of an operational policy involving modification of the unit commitment (UC) schedule by dispatching down the unit that loses synchronism and increasing the output of an alternative generator to make up for this shortfall in generation
System service provision from wind turbines (WT)	**Frequency stability** – *provision of reserve* (WTs can successfully contribute to reserve provision during under-frequency events provided their output is already being constrained/curtailed due to network/system security issues)
	Frequency stability – *provision of inertial response using synthetic inertia* (WT controllers enabled by GFM technology can provide synthetic inertial response by harnessing their stored rotational energy, however the fast MW injection from the WT immediately following the fault needs to be recovered once the frequency stabilises, also quantum of inertial response provision from WTs is constrained owing to limitations on wind turbine mechanics and the need to avoid aerodynamic stall)
System service provision from BESS	**Frequency stability** – *provision of FFR* (Supplementary injection of active power from BESS at a rapid pace helps to successfully reduce

	the RoCoF, thereby delaying the frequency nadir)
STATCOM	**Voltage stability** – *provision of SSRP* (STATCOMs can provide adjustable reactive power compensation for mitigating SSRP scarcities)
	Voltage stability – *provision of DRR* (Like synchronous condensers, STATCOMs can also help in successful mitigation of systematic localised dynamic voltage control scarcities)
	Transient stability – *mitigation of damping torque scarcity* (As compared to synchronous condensers, STATCOMs appear to be better performing for faster mitigation of damping torque scarcities. STATCOMs not only provide sufficient damping, but also offer a significant reduction in the first swing of the generator rotor angle and overshoot of generator MW output)
	Transient stability – *mitigation of synchronising torque scarcity* (Similar to synchronous condensers, STATCOMs can technically help in improving angle margins and CCT values, but under specific circumstances and system conditions, a more appropriate mitigation strategy appears to be the consideration of an operational policy involving modification of the considered UC schedule)
SVC	**Voltage stability** – *provision of SSRP* (Similar to STATCOMs, SVCs are able to provide adjustable reactive power compensation for mitigating SSRP scarcities)
	Voltage stability – *provision of DRR* (SVCs can technically help in mitigating dynamic voltage control scarcities, but are less effective as compared to, e.g., synchronous condensers and STATCOMs, owing to their limited reactive output capability during low voltage conditions as well as slower-acting ramping response for reactive power injection)
	Transient stability – *mitigation of synchronising torque scarcity* (Similar to synchronous condensers and STATCOMs, SVCs can technically help in improving angle margins, but under specific circumstances and system conditions, a more appropriate mitigation strategy appears to be the consideration of an operational policy involving modification of the considered UC schedule)
PSS	**Transient stability** – *mitigation of damping torque scarcity* (Similar to STATCOMs, PSSs are demonstrated to provide significant damping)
GFM-enabled IBRs	**Frequency stability** – *provision of inertial response and FFR* (GFM-enabled IBRs can provide synthetic inertia by virtue of these being able to simulate a 'prime mover following the inverter' control. The GFM based solutions might incorporate short-duration energy storage devices that can provide frequency response beyond the inertial period.)
	Voltage stability – *contribution to system strength/fault current* (Voltage source characteristics of GFM-enabled IBRs imply that they can contribute to system strength. GFM resources might be able to provide some additional fault current (that is limited by the converter's overcurrent capacity) within 1/4th of a cycle, and this is crucial for the normal operation of protection relays that rely on a sufficient amplitude of fault current in the first 20-30 ms after the fault)
	System restoration – *provision of black start capability* (Given that GFM-enabled IBRs, e.g., wind turbines, are capable of independently

	forming a stable grid voltage at the POI, they are capable of providing black start capability. However, changes to existing/new wind farms and corresponding incentives along with some operational policy modifications (e.g., enabling curtailment of wind generation at medium or high wind) might be required to facilitate this provision)
Network reinforcements, along with, Operational mitigation measures	**Managing network congestion** – *network reinforcements* (Simulations indicate that the strategic incorporation of selected reinforcements (as per [3]) does help in alleviating significant congestion issues for many critical hours of the year. However, these reinforcements alone may not remove all congestion issues for all hours of the year. Operational mitigation measures (mentioned below) are therefore proposed to be used in conjunction with these reinforcements for offering additional flexibility in mitigating anticipated congestion events.)
	Managing network congestion – *operational mitigation measures* (Simulations indicate that implementing operational mitigation measures (e.g., generation re-dispatch, load shifting, phase-shifter angle and transformer tap changes as well as incorporation of power flow control devices, demand side management programmes and dynamic line ratings) can offer additional flexibility in mitigating less frequent congestion issues that crop up even with the strategic incorporation of network reinforcements. However, the extent to which these measures can be implemented in the operational timeframe is limited in terms of the time and capabilities that are at the control room engineer's disposal. It is therefore very important to find the right balance and a high degree of coordination between the planning and operational domains in relation to resolving congestions.)

It can be observed from Table 5 that a number of technologies can be used for mitigating multiple technical challenges. It is demonstrated in Section 2.3.2 that technologies used for mitigating dynamic voltage control and damping torque scarcities, e.g., synchronous condensers and STATCOMs, can be utilised for alleviating synchronising torque scarcities as well. In any case, apart from the different challenges and mitigation strategies discussed throughout this report, it is critical that appropriate policies, tools, system services, licenses and data handling requirements be also put in place to facilitate realisation of the 70% RES-E penetration and 95% SNSP targets by 2030.

The aim of the analyses carried out as part of this document is to demonstrate the capability of a number of proposed technologies to mitigate the technical issues identified in Table 1. As such, the demonstration of the capabilities that are needed to solve the different technical scarcities is the main focus here; not the technologies themselves.

It is accordingly acknowledged that the mitigation technologies and strategies presented in Table 5 are not exhaustive; rather they are indicative of the different technologies that can offer the needed mitigation capability. Resources like DSUs, DSM and pumped hydro can provide system services too, e.g., reserves, and it is demonstrated in Sections 2.1.1 and 2.1.2 that technologies such as synchronous condensers and BESS can well complement the provision of system services from such resources.

Based on the extensive simulations performed and the significant findings presented throughout this report, a number of areas of future work can be identified for the different technical challenges, as presented in Table 6. It is acknowledged that the list of future studies presented in the table is not exhaustive; rather it is indicative of EirGrid's and SONI's commitment to continue pursuing technical studies and analyses as required to ensure safe, secure and reliable operation of the all-island power system.

Table 6: Potential areas of future work for different technical challenges

Scarcity	***Scope of future work***
Frequency stability	Development of an enduring ramping strategy for 2030 – the study will be focussed on ramping margin constraints to ensure that one, three and eight hours ramping requirements are met with relaxed Operational System Constraints in place, e.g., those related to SNSP, N-S tie-line import/export, inertia floor and the minimum number of units on.
	Fast frequency response (FFR) studies to investigate the need for FFR with the inertia floor lowered to 20 GWs (from 23 GWs) and a minimum number of seven (reduced from eight) conventional units on.
	Low Carbon Inertia Solutions (LCIS) studies to identify the need for such solutions and to determine the optimal placement of LCIS technologies (for 2025 and beyond) to increase system strength and ensure stable operation of the all-island power system with a number of Operational System Constraints relaxed and significant system changes incorporated.
Voltage stability	Study to identify the potential need for DRR technologies (e.g., synchronous condensers and STATCOMs) for efficient mitigation of dynamic voltage control scarcities.
	Minimum number of units (MNU) study to consider the relaxation of specific Operational System Constraints in relation to MNU at the system, jurisdictional and regional levels for the study period 2022-2026.
	Investigation of potential voltage stability issues as a result of progressively increasing the SNSP level to 80% and higher (from the current enduring policy of operating the system at up to 70% SNSP) for enabling additional RES integration in the system.
	Modelling of Phase-Locked Loop (PLL) and Grid Forming (GFM) inverters – this project focusses on the development of improved Western Electricity Coordinating Council (WECC) 2nd generation models in the area of PLL and GFM inverters
	Identifying relevant metrics and developing appropriate tools for calculating system strength at representative HV buses (that are electrically close to IBR connections) across the all-island power system for getting better insights into areas affected by low system strength conditions and to facilitate the sizing and siting of reactive resources for such areas. Dynamic simulations need to be performed for investigating how IBRs adjacent to the considered HV buses

	behave during faults along with resultant voltage stability issues, if any.
	Use of EMT and hybrid simulations might be required here, and such simulations/modelling is a long-term objective and consideration for Control Centre of the Future projects.
Transient stability	Minimum number of units (MNU) study to consider the relaxation of specific Operational System Constraints in relation to MNU at the system, jurisdictional and regional levels for the study period 2022-2026.
	Investigation of potential transient stability issues as a result of progressively increasing the SNSP level to 80% and higher (from the current enduring policy of operating the system at up to 70% SNSP) for enabling additional RES integration in the system.
	Modelling of Phase-Locked Loop (PLL) and Grid Forming (GFM) inverters – this project focusses on the development of improved Western Electricity Coordinating Council (WECC) 2nd generation models in the area of PLL and GFM inverters
	Identifying relevant metrics and developing appropriate tools for calculating system strength at representative HV buses (that are electrically close to IBR connections) across the all-island power system for getting better insights into areas affected by low system strength conditions and to facilitate the sizing and siting of reactive resources for such areas. Dynamic simulations need to be performed for investigating potential oscillatory instabilities using EMT or hybrid RMS/EMT dynamic simulations.
	Use of EMT and hybrid simulations might be required here, and such simulations/modelling is a long-term objective and consideration for Control Centre of the future projects.
Congestion	Obtaining an optimal solution of operational mitigation measures can be challenging for an optimisation tool like PSCOPF (as used in Task 2.6 studies [3]), while handling a complex problem space involving a significant number of N-1 overloads spread across different geographical regions. Advanced non-linear optimisation techniques and tools might be required for future studies to deal with such problems.
Power quality	Investigation of potential breaches of harmonic planning limits owing to resonances introduced from upcoming/existing high voltage cable installations (e.g. those to be used for connecting planned offshore wind generation to the grid) as well as new IBR connections Review of methodology used for allocating emission limits to new customer connections, as well as of methods used for monitoring/managing harmonic distortion and other power quality indices in real time.
System restoration	Testing PSRPs through EMT studies using some of the new technologies such as GFM and new interconnectors, while bearing in mind all network, generation and demand changes.
Generation adequacy	Continue assessing the security of supply situation, while monitoring the different uncertainties that are expected to impact on system adequacy, e.g., increasing demand, lower generation availability of existing power plants, new capacity terminating their awarded capacity, risks around delays in building new capacity, as well as emission limits.

The following main conclusions can be drawn from the results and discussions presented throughout this report:

- Renewables and non-conventional technologies are well positioned to offer a range of system services capability needed for mitigating relevant technical scarcities. This is critical as these mitigation options will be available during hours of high renewable generation when the scarcities are typically more severe due to the displacement of traditional service providers such as conventional synchronous units.

- It can be appreciated from Table 5 that while some scarcities can be mitigated by a range of different technologies/strategies, individual technologies can be utilised for mitigating multiple technical challenges. Though the different mitigation strategies presented in this report for tackling individual challenges were developed in isolation of each other, the key will be to identify the right mix of technologies (for offering the required system services) along with their optimal placement for ensuring the safety and reliability of the all-island power system and for delivering value to consumers. The required mix of solutions will need to be assessed holistically for the system as a whole, while acknowledging the synergies between disparate mitigation technologies.

- Finally, future markets will need to be designed to promote choice for investors and to incentivise investment in technologies with the right capabilities to support the power system's transition to a cleaner and greener future.

Appendix A – Additional Technical Challenges

In addition to the seven major technical challenges discussed in Sections 2.1 - 2.7, it is acknowledged that there are other potential issues that may crop up in the power system of the future. A brief overview of some of these further challenges was presented in [1], and the same is reproduced here for reference sake:

- **Voltage Dip Induced Frequency Dip** (VDIFD) – A VDIFD is a phenomenon whereby a voltage dip, caused by a fault on the system, can lead to a drop in frequency. The voltage dip can lead to a drop in the active power output of large quantities of IBRs. While conventional generators recover their active power output very quickly following a voltage dip, some IBRs can be slower to restore their active power. This slower recovery of active power output from these inverter-based resources can result in a very rapid fall in frequency.
  - The delayed recovery of active power in wind turbine generators after a severe fault is typically implemented in order to limit the mechanical stress in the drivetrain. Figure A-48 shows an actual recording of the response of a wind farm to a system fault in Ireland. The active power recovers to the pre-fault value in approximately 1s after fault clearance.
  - The greyed area represents the approximate energy deficit with respect to a synchronous generator, which would recover active power almost instantly upon fault clearance. This energy deficit can represent a threat to frequency stability in scenarios of high penetration of wind generation depending on the power system's size and characteristics as well as the recovery characteristics of individual wind farms connected across the system. EirGrid and SONI are undertaking system studies to quantify the risk and develop mitigation options.
  - A voltage dip, caused by a fault on the system, could also result in a rise in frequency if large demand customers were to disconnect from the power system.

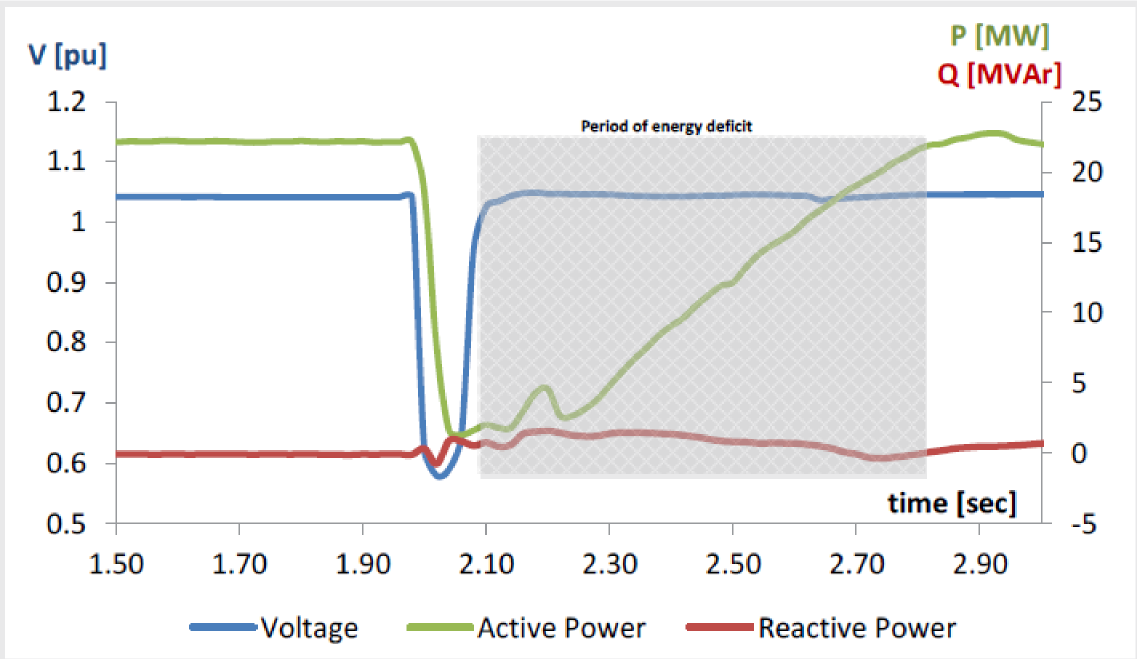

Figure A-48: Energy deficit as a result of delayed recovery of active power

- **Frequency regulation** – This is the power system's ability to maintain system frequency within its normal operating range. Traditionally, frequency regulation is performed automatically by conventional generators. However, frequency regulation could become a challenge in the coming years due to the displacement of conventional fossil-fuel based generation coupled with the frequency fluctuations caused by the inherent variability of the RES.

- **Power system protection schemes** – The fundamental operation of most common power system protection schemes is based on the presence of large numbers of synchronous generators on the power system providing enough fault current. The presence of increasing levels of IBRs will result in challenges for protection devices around available short circuit current and the detection of faults.

  - Within the MIGRATE (an EU Horizon 2020) project [42], the influence of increasing levels of IBRs on the operation of various standard protection schemes, including differential protection, distance protection and over-current protection was investigated.

  - It was found that the widely used distance protection would be impacted the most. Extensive analysis and real-time digital simulations showed that by increasing IBR penetration, distance protection experiences difficulties to identify and detect some faults and under specific circumstances may not operate. System integrity protection schemes were also found to be less reliable under conditions with high levels of IBRs.

    - New tools, a clear definition of the required response of power electronics during short-circuits, and a more cross-disciplinary approach with the power electronics field will be required to prepare for the future.

- **Telecoms/cyber security** – As operators and developers of critical national infrastructure, we must ensure that our plans incorporate appropriate measures to manage cyber security risks posed to the power system and information systems.

- **New HVDC interconnections** – We will need to manage any additional operational complexity that could arise from the integration of future HVDC interconnectors between the island of Ireland and neighbouring systems (Great Britain and France). We will need to review the systems and practices of the control centres in Ireland and Northern Ireland to ensure the necessary policies and systems are in place to manage the new interconnectors.

- **Power system modelling** – The power system will change from one that is largely based on passive network and synchronous generation to one with active network devices and IBRs. Understanding and reflecting the characteristics of these technologies in appropriate models will be critical to our planning and operation of the power system.

- **Data requirements** – The transition to a power system with greater levels of decentralised RES and system service provision will also see the advent of much greater quantities of data that will undoubtedly provide much valuable information. However, there are challenges associated with processing huge volumes of data. There will be data to be processed from the transmission system level, but also from the distribution system level, as well as from the supply-side, and increasingly from the demand-side. The Commission Regulation (EU) 2017/1485 establishing a guideline on system operation (System Operation Guideline [14]) covers off some of these data requirements via the Key Organisational Requirements, Roles and Responsibilities (KORRR) document [48].

- **Maintenance/outages** – Outages on the transmission system or of generators either as a result of capital project works, routine or emergency maintenance result in system configurations which can cause challenges for TSOs. The energy transition will require increased numbers of outages to facilitate capital works which will be a complex scheduling task. Furthermore, the scheduling of routine outages on the grid will become increasingly complex as the generation portfolio and transmission grid evolve.

- **Short term forecasting** – The increasing penetration of weather-dependent resource, such as wind and solar, on the power system coupled with more complex demand characteristics will drive the need for an increased focus on short-term forecasting. The magnitude of short-term alterations in weather-dependent generation will increase as penetration increases and it will be important to ensure we are as informed as possible of these changes to ensure secure operation of the power system. The increase in demand side participation and the roll-out of electric vehicles and electric heating will also drive more complex demand profiles with the potential for large changes in short periods of time. Again, it will be important to ensure we are as informed as possible of these changes to ensure secure operation of the power system.

- **Frequency quality** – Based on our operational guidelines, the system frequency should be maintained within a standard range of ±200mHz. To ensure frequency quality, there are the prescribed time thresholds for both frequency recovery and frequency restoration. Considering a significant amount of new technologies providing reserve and replacing traditional synchronous generation, new studies will be required in this domain to determine the optimal strategy and other relevant parameters of frequency control to meet these quality requirements.

EirGrid and SONI are cognisant that there are likely to be technical and operational challenges which have not yet been identified in the path to 2030 and beyond. With this in mind, EirGrid and SONI will continue to undertake extensive studies and analyses on the power system of the future, seeking to integrate any learning from system events/disturbances, and work in collaboration with other TSOs to ensure we identify and address these challenges as they materialise.

Appendix B – Glossary of Technical Terms

Table A-7: Glossary of technical terms

Term	*Abbreviation*	*Description*
Composite Short Circuit Ratio	CSCR	The CSCR is an index used to jointly model multiple IBRs in close electrical proximity that connect to the rest of the system through the same high-voltage (HV) bus/buses. For calculation of CSCR, the concerned IBRs are approximated as a single aggregated IBR connected to a common 'virtual' medium-voltage (MV) bus [34].
Demand Side Management	DSM	The modification of normal demand patterns, usually through the use of incentives and/or control actions [2]
Equivalent Short Circuit Ratio	ESCR	Though the WSCR and CSCR indices are suitable for calculating the aggregated SCR for multiple IBRs connected at the same region of a power system, the calculation is done with respect to a common 'virtual' point of connection, i.e., the impedance between IBRs are ignored. The ESCR, on the other hand, incorporates the voltage sensitivity between IBRs (i.e., the voltage change observed at one IBR bus with respect to a small voltage change at another) as an approximate indicator of the interactions amongst the IBRs [34].
Frequency Nadir	-	The frequency nadir is the lowest point the system frequency reaches following a system event such as the loss of a large unit or the LSI
Harmonics	-	Harmonics are voltage/current waveforms at multiples of the fundamental frequency (e.g., 50 Hz for Ireland) of the system. They are caused by non-linear devices connected to the power system, e.g., power electronic converters, STATCOMs, SVCs and HVDC links [2], [43]. The voltage/current harmonics are essentially superimposed on the fundamental frequency waveforms of the system, thereby distorting the smooth sinusoidal curves. Harmonic-related distortions can lead to failure or mal-operation of end-use equipment, increased current flows in the system (i.e., higher losses), overheating in transformers, motors and neutral wires and can even cause improper operation of protection relays [43].
Inverter-based Resources	IBR	IBRs are (non-synchronous) generation sources, e.g., wind and solar farms, batteries and HVDC links, that interface with the AC grid through power-electronic converters
Largest Single Infeed/Outfeed	LSI/LSO	The size (MW) of the largest single source/sink of active power. The LSI/LSO dictates the amount of under/over frequency reserve that is carried.

Power Flow Control (PFC) devices	PFC	PFCs are devices that provide series compensation to modify the reactance of the lines to which they are connected [2]. This is beneficial in a meshed transmission network where, in some circumstances, they can help route power away from where the network is congested to areas where it is less utilised. The ability to control power flow in a network can improve how it is used and assist in deferring the more significant developments required to increase network capacity [2].
Primary Operating Reserve	POR	A DS3 System Services product, it refers to the additional MW output (and/or reduction in demand) required at the frequency nadir, as compared to the pre-incident output (or demand) where the nadir occurs between 5 and 15 seconds after the event [2].
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 [37].
Rate-of-Change-of-Frequency	RoCoF	The RoCoF is an operational metric that quantifies the rate at which the system frequency changes immediately following a fault/ disturbance that affects the load /generation power balance.
Scarcity	-	Scarcity can be broadly defined as a system attribute, e.g., inertia, which is usually in good supply in traditional power systems energised by (synchronous) conventional generators; but is likely to fall below expected thresholds as a consequence of the transition to a power system with high levels of RES integrated [1].
Short Circuit Ratio	SCR	The SCR is defined as the ratio of the MVA fault level at the connection point (e.g., of an IBR) to the rated active power output of the IBR [34].
Synchronous Condenser	-	A synchronous condenser is a rotating machine which only generates reactive power, i.e., it does not generate active power. These devices are generally used to improve system voltage regulation/stability by continuously generating/absorbing reactive power (using excitation current control) and frequency stability by providing synchronous inertia.
System Non-Synchronous Penetration	SNSP	SNSP is a real-time measure of the percentage of generation that comes from non-synchronous sources, such as wind and HVDC interconnector imports, relative to the system demand [2].
Weighted Short Circuit Ratio	WSCR	The WSCR is used to jointly model the impact of adjacent IBRs within a subsystem which is in turn weakly connected to the rest of the system. WSCR is essentially used to calculate an aggregated SCR for the subsystem at its common 'virtual' point of connection [34].

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