European Commission | Horizon 2020 European Union funding for Research & Innovation

State-of-the-Art Literature Review of System Scarcities at High Levels of Renewable Generation

D2.1

EU-SysFlex

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 773505.

PROGRAMME	H2020 COMPETITIVE LOW CARBON ENERGY 2017-2-SMART-GRIDS
GRANT AGREEMENT NUMBER	773505
PROJECT ACRONYM	EU-SysFlex
DOCUMENT	D2.1
TYPE (DISTRIBUTION LEVEL)	☒ Public ☐ Confidential ☐ Restricted
DUE DELIVERY DATE	30/04/2018
DATE OF DELIVERY	27/04/2018
STATUS AND VERSION	Final – V1
NUMBER OF PAGES	114
Work Package / TASK RELATED	WP2/Task 2.1
Work Package / TASK RESPONSIBLE	EirGrid / Imperial College
AUTHOR (S)	Anastasios Oulis Rousis (Imperial College), Goran Strbac (Imperial College), Noel Cunniffe (EirGrid), Sheila Nolan (EirGrid), Hannele Holtinnen (VTT), Caroline Bono (EDF), Ye Wang (EDF), Marie-Ann Evans (EDF), Endika Urresti Padrón (NCNR), Wojciech Jaworski (NCNR), Przemyslaw Kacprzak (PSE), Bernardo Silva (InescTec)

DOCUMENT HISTORY

VERS	ISSUE DATE	CONTENT AND CHANGES
0.1	31/03/2018	First version
0.2	17/04/2018	Second version – Changes proposed through the internal review, reviewers: Noel Cunniffe (EirGrid), Marie-Ann Evans (EDF)
0.3	21/04/2018	Third version – For submission to the PMB, changes proposed through the internal review
1	27/04/2018	Final version – For submission to the European Commission, minor changes proposed through the review from the PMB

DOCUMENT APPROVERS

PARTNER	APPROVER
EirGrid	John Lowry

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS AND ACRONYMS

AC	Alternating Current
AEMO	Australian Electricity Market Operator
aFRR	Automatic Frequency Restoration Reserve
AIS	All-Island Power System
AS	Ancillary Services
BESS	Battery Energy Storage System
CACM	Capacity Allocation & Congestion Management
CCT	Critical Clearing Time
CNE	Critical Network Element
DC	Direct Current
DCC	ENTSO-E Demand Connection Code
DFIG	Doubly Fed Induction Generator
DLR	Dynamic Line Rating
DRR	Dynamic Reactive Response
DSO	Distribution System Operator
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Emergency Power Control
EU	European Union
EU-SysFlex	Pan-European System with an efficient coordinated use of flexibilities for the integration of a large share of Renewable Energy Source
ERGIS	Eastern Renewable Generation Integration Study
FACTS	Flexible Alternating Current Transmission System
FB MC	Flow-Based Market Coupling
FCR	Frequency Containment Reserve
FOR	Facilitation of Renewables
FPFAPR	Fast Post-Fault Power Recovery
FRR	Frequency Restoration Reserve
FRT	Fault ride through
HVDC	High Voltage Direct Current
HVDC code	ENTSO-E Network Code for HVDC Connections
KPI	Key Performance Indicator
LMP	Locational Marginal Pricing
LFSM-O	Low Frequency Sensitivity Mode – Over frequency
LFSM-U	Low Frequency Sensitivity Mode – Under frequency
LoM	Loss of Mains
LSI	Largest Single Infeed
mFRR	Manual Frequency Restoration Reserve
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
OLTC	On Load Tap Changer
OWF	Offshore Wind Farm
PE	Power Electronics
PED	Power Electronics Device

PMU	Phasor Measurement Unit
POR	Primary Operating Reserve
PSS	Power System Stabiliser
PST	Phase Shifting Transformers
RA	Remedial Action
RoCoF	Rate of Change of Frequency
RES	Renewable Energy Sources
RfG	ENTSO-E Requirements for Generators Code
RPM	Regulation Power Market
RRD	Replacement Reserve Desynchronised
RRS	Replacement Reserve Synchronised
RSCI	Regional Security Coordination Initiatives
SIR	Synchronous Inertial Response
SNSP	System Non Synchronous Penetration
SO	System Operator
SONI	System Operator Northern Ireland
SOR	Secondary Operating Reserve
SSRP	Steady State Reactive Power
STATCOM	Static Compensator
STD	Single Tie-line Decomposition Method
SVC	Static Var Compensator
TOR	Tertiary Operating Reserve
TSC	TSO Security Cooperation
TSO	Transmission System Operator
VDIFD	Voltage Dip-Induced Frequency Deviation
VG	Variable Generation
VSC	Voltage Source Converter
WF	Wind Farm
WP	Work Package
WWSIS	Western Wind and Solar Integration Study

EXECUTIVE SUMMARY

This report provides the outcome of the review performed as part of Task 2.1 of the EU-SysFlex project.

In total, 25 recent projects and research studies, as well as 3 regulations, have been reviewed. Such a comprehensive list of studies was analysed to ensure that the EU-SysFlex project is informed of the main technical scarcities that have been identified in the scientific and industrial communities and considered as technical constraints or barriers for system operators to maintain the safety and reliability of future power systems with high penetration rate of variable renewable energy.

This review has revealed 6 main categories of technical scarcities which are recurrently identified. These shortfalls will manifest while moving towards power systems with high integration of variable, distributed renewable energy sources (RES) that are in general connected to the grid via power electronics interfaces. These system scarcities may arise across a very wide spectrum from frequency, voltage and rotor angle stability to increased congestion, limited capability for restoration in case of a power system collapse and system inadequacy.

Figure 1 indicates the categories and prevalence of the technical scarcities discussed in the projects and reports reviewed.

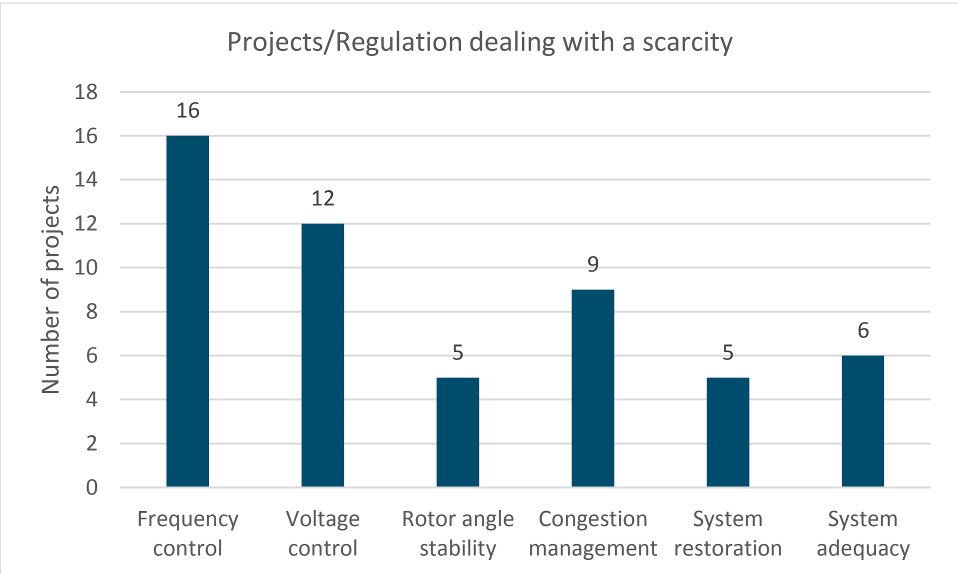

FIGURE 1 NUMBER OF PROJECTS DEALING WITH EACH SCARCITY

Table 1 summarises the findings from the projects and reports reviewed.

SCARCITY IN SYSTEM NEED	ASSOCIATED ISSUES	WHY IS IT BECOMING A SCARCITY?	SOLUTIONS IDENTIFIED
Frequency control	1) Inertia 2) Reserves 3) Ramping	Reduced synchronous generation on the system providing inertia and reserve capability means that frequency varies more quickly in case of power equilibrium incidents and are less manageable.	**Technical solutions**: Technologies providing frequency response in various timeframes, in the range of seconds to hours, e.g. compensators, wind, synthetic inertia, energy storage, demand side response (DSR), cross-border interconnection, required must-run conventional units, etc. **System control:** enhanced transmission system operator (TSO) – distribution system operator (DSO) coordination, especially in case of activation of frequency reserves procured from distribution grid. **Enhanced market design:** Design of new services & products (e.g. reserves, response, etc.).
Voltage control	1) Short circuit power 2) Steady state voltage control 3) Dynamic voltage control	Less synchronous generation available to provide reactive power support. Reduced short circuit power due to the replacement of synchronous machines and the limited capacity of converters in terms of short-circuit current injection. Voltage variation effects due to connection of RES in the distribution system.	**Technical solutions**: Synchronous compensators, reactive power static compensator, inductance, condenser, wind, photovoltaic (PV), static VAr compensators (SVCs), on-load tap changers (OLTCs) **System control**: enhanced TSO-DSO coordination, especially in case of activation of reactive power reserves procured from distribution grid. **Enhanced market design** (reactive): Design of new services (e.g. steady-state reactive power and dynamic reactive power).
Rotor angle stability	1) Small signal stability 2) Transient stability	Less synchronous generation to maintain inertia and stability. Reduction in synchronising torque deteriorates stability margins. Reduction of transient stability margins due to the displacement of conventional plants. Introduction of new power oscillation modes. Reduced damping of existing power oscillations.	**Technical solutions**: Some solutions are identified, e.g. voltage support from modern variable renewable generators, but further studies are needed for this complex phenomenon. **System control**: Within the review, no such solutions have been identified to mitigate rotor angle instability issues. **Enhanced market design**: Design of new services (e.g. dynamic reactive power to increase transient stability).
Congestion management	1) Network hosting capacity 2) RES curtailment 3) Capacity allocation	Increase in distance between generation and load, and generation variability. Increased feed-in power (e.g. solar PV plants) and bidirectional power flows noted in distribution networks.	**Technical solutions**: Application of network control and measurement technologies, distributed energy resources, advanced control and forecasting tools **System control**: TSO-TSO coordination, TSO-DSO coordination **Enhanced market design:** Nodal network pricing, market for non-network technologies providing network flexibility services

System restoration	1) Black-start capability 2) Network reconfiguration 3) Load restoration	Less black start capable plants on the grid. Current restoration strategy mainly refers to large synchronous generation.	**Technical solutions**: Utilisation of distributed energy resources, microgrids, local power islands, flexible technologies **System control**: TSO-DSO coordination, enhanced restoration strategy **Enhanced market design:** black-start market, incorporation of black-start services in capacity market
System adequacy	1) Uncertainty of RES generation 2) System interdependencies	Reduction in load factors and decommissioning of conventional generation driven by penetration of renewables.	**Technical solutions**: Potential solutions lie in the utilisation of conventional generation, distributed generation, energy storage, DSR, interconnection **System control**: Cross-border coordination, TSO-TSO coordination, TSO-DSO coordination **Enhanced market design:** Capacity market, incorporation of non-generation technologies in capacity market (energy storage, demand side response), cross-border capacity market, etc.

TABLE 1 SYSTEM SCARCITIES IDENTIFIED IN THE STATE-OF-THE-ART REVIEW

The key findings of the review conducted are briefly discussed hereafter with reference to the individual scarcities.

Frequency Control

It can be observed that a significant proportion of research activities focused on considerations on frequency control. The frequency-related issues identified highlight that frequency control is becoming most challenging in Ireland and United Kingdom (given their island positions). Such issues in the future continental power system occur during some "worst case scenarios" (high RES instantaneous penetration vs. low load), and that if not appropriately managed frequency instabilities may soon start deteriorating the security of the European power systems. The issues primarily relate to the progressive drop of system inertia, which causes frequency to deviate significantly even during small active power imbalances in the case of some systems. This can cause several effects on either a small or large scale, i.e. unwanted disconnection of distribution connected generation units due to Rate of Change of Frequency (RoCoF) relays or wide-area frequency instability. Solutions proposed within the reviewed projects are either technical in nature (e.g. installation of synchronous machines, use of relaxed RoCoF settings, etc.) or market-related through the specification of appropriate system services. For example, frequency response and reserves are proposed to effectively contain frequency excursions. Particularly at high renewable generation penetration, studies have shown that these services are required in the time frame immediately following a system event, such as the loss of a large generator. Such service provision can be sought in technologies including onshore and offshore wind farms, interconnectors, demand side response, and energy storage, since it has been shown that there is a system benefit to provision from these technologies, especially at higher shares of variable renewable generation.

Solutions should enable coordination across the system levels (i.e. transmission and distribution systems) and across the countries given the emerging variation in frequency deviations across different locations, driven by growing penetration of renewable generation. Design of new system services to increase the resilience of the system and ensure a secure and cost-effective power system should also be considered as part of the solutions. The review conducted suggests that the market design still needs to evolve to allow distributed energy resources, that exhibit uncertainties in active power output, to participate in frequency support markets. For example, the Ireland and Northern Ireland TSOs, EirGrid and SONI, and the GB TSO, National Grid, have undertaken developments with the design and implementation of new frequency control services covering a wide range of applications (response, reserves, ramping capability) and timescales (milliseconds to hours). Other studies have demonstrated that harmonisation of markets and sharing of resources between countries are also required to achieve the desired outcomes in a cost-effective way.

Voltage control

The reviews conducted highlight that voltage regulation becomes more challenging as reactive power supply and demand balance is disrupted due to penetration of renewable generation and displacement of synchronous generators (which traditionally provided the reactive power required). The primary reason for voltage instability is the inability of the system to maintain reactive power balance.

The issue of reactive power balance largely relates to the reduced system strength (i.e. short-circuit power contribution) noted in many regions. A number of studies, such as the System Operability Framework of National Grid and the South Australia System Strength Assessment of the Australian Electricity Market Operator (AEMO) have revealed that since renewable generators do not have as much capability as synchronous generators to contribute in system strength, in cases of high instantaneous penetration of RES the system strength may be compromised. This could mean that voltage control will become more challenging and existing network protection approaches may not detect faults equally as effectively. Additionally, it is worth highlighting that displacement of synchronous generation on the system by non-synchronous renewables will also reduce the overall voltage control capability which would have been historically available on the power system.

The analysis clearly indicates that enhanced reactive power support will be requested in various timeframes (e.g. static and dynamic reactive power, etc.) to effectively manage different types of voltage disturbances. As an example, EirGrid has designed a suite of suitable services, including dynamic reactive power accounting for transient voltage response (in a timescale of ms to sec), steady-state reactive power to regulate voltage deviation during normal operation (i.e. in a timescale of sec to min) and finally network adequacy measures for the longer timescales (i.e. min to hours). Reactive power compensating devices (e.g. static compensators (STATCOMs), SVCs, etc.) or converter-fed RES, which have an inherent capability to independently produce/consume reactive power are proposed to provide these services instead of synchronous generators.

The studies reviewed indicate that dispersed RES can indeed mitigate voltage rise effects occurring due to increased RES penetration and voltage drop due to demand variation particularly at low voltage levels during normal operating conditions. The idea of utilising distributed resources for mitigating voltage-related issues is enhanced by the fact that voltage is largely a local phenomenon, hence reactive power is most effective when close to the region of imbalance; this is clearly demonstrated in several of the reviewed projects (GRID4EU with experimental demonstrations, System Operability Framework, etc.). During voltage disturbances, dynamic reactive power provision is even more important, especially as system strength reduces over the years. In such cases, protection systems accounting for the smooth integration of RES may not operate satisfactorily, and even worse voltage stability may be compromised to a greater extent in the presence of severe contingencies (e.g. three-phase faults in the transmission system). New voltage services can be created to exploit the dynamic reactive power response of RES generators. Note that wind farms (onshore/offshore and HVDC-connected), PV plants, energy storage systems, etc. have been proven to be able to provide reactive power dynamically even for major disturbances in the transmission system.

However, another shortfall identified with respect to amassing the potential of distributed resources relates once again to the lack of an appropriate market and regulatory framework for allowing and incentivising the provision of reactive power from such resources. It is, therefore, proposed within the various projects that an appropriate market mechanism to create a level playing field for all players (i.e. suitable remuneration of the services provided by distributed resources to both distribution and transmission systems), in association with enhanced collaboration between TSOs and DSOs, could support such services and ensure that the system is secured in a cost-effective way.

Rotor angle stability

The results of the reviews conducted relating to rotor angle stability, show that transient stability margins across the European region would be reduced, mainly due to the displacement of synchronous machines by power electronics-interfaced variable renewable generators. This can lead to reduced damping of existing power oscillations. Furthermore, the integration of power electronics could induce new oscillation modes. Especially at high levels of instantaneous penetration, the stability of the power system may be compromised. One of the consequences is that the number of contingencies with reduced critical clearance times (< 200 ms) in such cases can be increased. Hence, voltage disturbances can lead to transient instability due to lower levels of synchronising torque. However, other studies have indicated that the increase of power electronics penetration affects transient stability in various, interdependent ways, and currently it is not clear whether the absolute impact is negative or positive. In overall, the impact of variable renewable generation integration on rotor angle stability depends on the superposition and interaction of several influencing factors (i.e. technology, specific penetration level, pre-fault operating point, etc.). This highlights the complexity of rotor angle stability issues and points out that it remains an open question according to current research findings.

Congestion management

The review reveals that congestion management will pose risks in the operation of both distribution and transmission systems and thus requires due attention to ensure that the European power system will be secure and reliable as the penetration of renewable energy resources increases. Increase in penetration of distributed generation (DG) will stress the networks towards their thermal limits. As a way to avoid extensive investments for network reinforcements, appropriate voltage control strategies, utilisation of smart techniques in the on load tap changers (OLTCs) of transformers and flexible technologies (such as Flexible Alternating Current Transmission System, Phase Shifting Transformers, DSR, Special Protection Schemes, etc.) can be deployed to manage congestion, as demonstrated by GRID4EU and GridTECH projects.

On top of managing congestion, the key important effect is the reduction of RES curtailment, where TSOs and DSOs currently curtail RES generation to relieve network congestion. Alternatively, increased monitoring of assets in order to allow for temporary overloadings has also been proposed. For example, typical distribution level transformers could operate overloaded by up to 40% without significant impact on their lifetime. An essential step towards allowing such measures to be implemented would be the revision of planning and operational standards. These currently require high redundancy levels leading to low utilisation of network assets, and often due to the need for increasing network reinforcement requirements driven by increased penetration of renewables.

Additionally, cross-border interconnection will play a vital role towards the creation of a unified European energy market, as per the ENTSO-E regulations (refer to ANNEX II for more details). However, the energy market needs to evolve in allowing network congestion issues as a result of renewable generation to be mitigated in a cost-reflective manner. Capacity allocation may be a critical aspect for ensuring security of supply in an economically efficient manner. The reviewed projects highlight that various methods exist for calculating capacity allocation and managing congestion in wide areas such as the European Union (EU); however, when it comes to wide geographical areas it is still not clear what the most effective cost-sharing mechanism should be.

System restoration

The review performed indicates that as the penetration of variable renewable generation (both in transmission and distribution systems) becomes higher, the need for ancillary services, including system restoration, will accordingly increase. System restoration services have been traditionally provided by large-scale synchronous generators (e.g. hydro or coal plants), which have black-start capability. However, the transition to systems with high share of renewable and non-synchronous generation will result in a reduction in the number of synchronous generation capacity and thus a reduction in traditional system restoration capability. As such, new strategies for system restoration need to be developed enabling non-synchronous generators to provide the required restoration. New restoration strategies should be designed that leverage the flexibility of other providers.

With the displacement of synchronous generation, other technologies need to be enabled for provision of black-start services (e.g. distributed generation and other converter-fed variable generation). This creates an opportunity both for variable generators to provide services, which would increase their revenue, and the system operators, who can increase the flexibility in their systems and lower the operational costs (i.e. running out-of-merit generators only to provide a service in case of a disturbance increases the cost of operation). This suggests that system restoration in the future should be realised in a bottom-up way rather than following the traditional top-down philosophy. In this context, black-start capabilities of distributed energy resources are being explored. Restoration could be initiated at the district level (e.g. from microgrids), utilising small-scale technologies such as back-up distributed generation or batteries, which would then support the restoration of larger areas of the distribution network and then the transmission system. To achieve this effectively, the system restoration process could be enhanced by greater coordination between TSOs and DSOs, since a non-negligible amount of non-synchronous generation is connected to distribution systems. On the other hand, a market accounting for and suitably remunerating the capabilities of all non-synchronous generators able to provide restoration services should be considered.

System adequacy

With regards to system adequacy, the studies reviewed indicate that as a result of penetration of renewable generation thermal plants are being decommissioned, and hence the capacity margins will become tighter. Uncertainty of generation capacity and system interdependencies appear to be areas that may affect the target to achieve a capacity-adequate European power system. A way to deal with system inadequacy relates to planning new transmission corridors within and between countries (i.e. interconnections). Especially, as we move towards a unified energy market characterising the pan-European system, interconnections would enable countries to share capacity leading to a pro-EU approach rather than a member state centric one. Therefore, interconnections are considered as a key factor in supporting adequacy in a large-scale system such as the European one. In this context, suitably designed capacity markets may need to be in place; these are currently not considered by most European countries. Such markets could create a level playing field between traditional generation and distributed energy resources (i.e. energy storage, wind, PV, DSR, etc.).

Potential solutions for effective management of scarcities

The analysis of individual scarcities highlights the challenges that will need to be addressed to facilitate cost effective integration of large volumes of renewable energy resources. In particular the analysis highlights the benefits of focusing on:

1. The **application of emerging flexibility technologies** such as energy storage, demand side response, and advanced network technologies; and
2. **Advanced coordinated system control** such as the application of real time preventive and corrective frequency, stability, voltage and power flow control, and application of advanced protection systems.

In response to the scarcities identified, recommendations are made in accordance with the key outcomes gathered by the reviewed demonstration and research projects. The review has pointed out that the potential solutions for delivering effective management of scarcities can be classified in three broad categories, (*i*) technical solutions per scarcity, (*ii*) coordinated system control (e.g. improved transmission – distribution systems interaction) and (*iii*) enhanced market design for energy and security services.

A broad range of technical solutions has been identified through the review. These typically include utilisation of equipment with a capability to provide desired functionalities. For example, synchronous generators, wind farms, demand side response, etc. can provide frequency response in various timeframes in order to alleviate frequency disturbances. Similarly, static compensators, OLTCs, solar PV plants, etc. can be utilised for provision of dynamic reactive response to mitigate voltage disturbances. The review has identified several appropriate technology solutions to resolve the majority of the scarcities.

Furthermore, effective coordination between transmission and distribution system operators is shown to enable flexibility provision from generators currently not participating in scarcities management (e.g. wind farms for frequency response services in the transmission system, or solar PV plants for voltage regulation at the distribution level). Coordinated operation, as well as design, of the transmission and distribution networks would enable distributed energy resources to maximise the overall system benefits by managing the synergies and conflicts between local and national level objectives. For example, maximising the value of combined benefits delivered through energy arbitrage, providing support to local and national network infrastructure, delivering various ancillary services to optimise and secure system operation, while also reducing the investment in conventional and low carbon generation, and creating architectures in a market context for provision of ancillary services.

The review also reveals that the full realisation of these overall system benefits requires an appropriate energy and flexibility market design. This design needs to capture the multiple value streams of the available technologies and aligns the cost savings/revenues of the owners of these technologies in the different markets with the respective system scarcities addressed. The current market framework is limited by the fact that the significance of flexibility and capacity markets has been largely neglected. A fundamentally new market design would be required, developing new market segments across multiple timescales ranging from capacity markets with a horizon of multiple years to (close to) real-time balancing markets. Additionally, the locational element of various services needs to be captured in the market framework in order to effectively represent the location-specific value in new market arrangements including cross-border exchange of energy, flexibility and system resilience services. The review has also shown that the various resources delivered by new flexible technologies would need to be appropriately remunerated by suitable markets.

Towards this direction, EU-SysFlex will consider, through the demonstration projects (i.e. Work Package(WP) 6 – 9), the impact of deploying different mitigation measures to address various scarcities by demonstrating the capabilities of RES as well as centralised and decentralised storage to provide flexibility solutions and system services, addressing cross-border exchange of services and enhanced transmission and distribution coordination. When developing solutions to mitigate scarcities, it will also be critical to consider the potential side-effects as well as the interactions between the various systems. These scarcities and associated issues will be further investigated through the simulations that will follow within the other tasks of WP2. Moreover, the evaluation of the system scarcities will help defining the conditions for the emergence and deployment of appropriate technical solutions through market products (i.e. WP3) that can help deliver more efficiently and in a cost-reflective way the low carbon objectives of the European Union.

1. INTRODUCTION

1.1 SCOPE OF THE EU-SYSFLEX PROJECT AND THE REPORT

The H2020 funded EU-SysFlex project aims at a large-scale deployment of solutions driven by system actors after the end of the project based on strong business propositions. A strong connection between market design, technical performance, system benefits and business models is ensured across all the activities and duration of the project.

EU-SysFlex uses a multi-dimensional approach as illustrated in Figure 2. Starting from the characterisation of systems needs to integrate more than 50% renewable energy sources (RES), embedding these needs on the identification of the necessary enhancements of market design and regulation, and demonstrations of a wide range of innovative approaches and solutions, before finally building a roadmap for flexibility to support a swift implementation of solutions.

Examples of results include:

- A comprehensive analysis of the operation of the pan-European system ability to balance demand and generation at all timescales and to have a stable operation of the system and the grids. Such analysis has not been done in the past for such wide range of issues and geographical scale.
- Recommendations for concrete evolutions of market design to integrate the needed blend of services and products based on role models and business use cases analysis and advanced market simulation to test the effectiveness of the solutions and the definition of innovative and coherent demonstration use cases, in line with the system needs and the proposed market organizations.

The project results will contribute to enhancing system flexibility, resorting both to existing assets and new technologies.

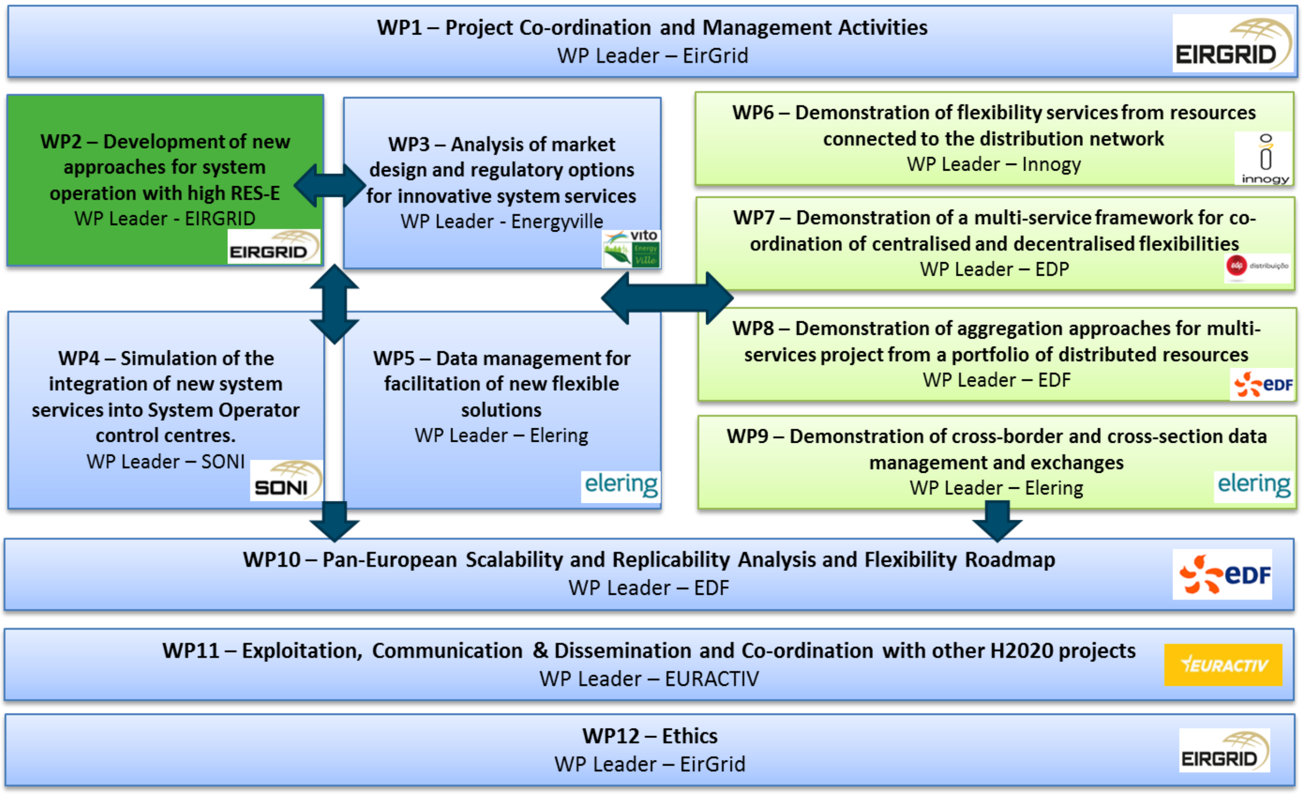

FIGURE 2 EU-SYSFLEX WORK PLAN

In the project, Work Package 2 (WP2) constitutes a starting point for the project, identifying upcoming power system scarcities with high penetration of renewables. Task 2.1 (T2.1) provides the first step of this WP, by reviewing the latest international developments and recent European research, giving new insights regarding effectiveness of different scarcity management measures. The review will form the basis for scoping and developing scenarios studied in the more detailed simulations of the system operating with high shares of RES in the following tasks of WP2. T2.1 will also directly inform the corresponding innovative services designed within Task 3.1 of WP3, as a basis for demonstrations' use cases. The demonstration WPs (i.e. WP6 – WP9) will then show the impacts of deploying different mitigation measures to address the various scarcities, and very importantly will focus on investigating the interactions across transmission and distribution boundaries.

Task 2.1 therefore started immediately as the EU-SysFlex project kicked-off in order to provide a solid and effective foundation in a 6-month timeframe, for the following tasks and activities of the project.

1.2 TECHNICAL BACKGROUND

The aim of this subsection is to highlight the power system challenges associated with the integration of renewable energy resources. In this context, this section provides the basic information related to technical scarcities and introduces corresponding reviews that are conducted in following dedicated sections of this report.

The European Union (EU) has set up ambitious targets for the reduction of carbon emissions from the energy sector (European Commission, 2009). As part of this effort, the EU's energy strategy envisages the development and wide-scale deployment of low-carbon electricity generation from RES to be a cornerstone towards this transition. According to the current EU Climate and Energy package, the proportion of electricity generation obtained from RES should increase from 20% in 2010 to 30–45 % in 2020 with a target of 55% by 2050 (European Commission, 2013).

In the coming decades, due to this ever-increasing penetration of RES (i.e. wind, photovoltaic (PV), etc.) the EU electricity system is facing exceptional challenges. These challenges are very much related to the variable nature of their output and their connection to the system via power electronics (PE) (EDF R&D Division, 2015). The challenges can broadly be grouped into the several categories described below:

Ability to accommodate high shares of renewable energy resources – Significant penetrations of variable renewable generation, and specifically variable wind and solar energy, will radically increase the complexity of real time demand-generation balancing. Greater levels of ancillary services (AS) associated with balancing demand and supply across all time horizons (from seconds and hours to days and seasons) will be required and this may impose a limit on the ability of the system to integrate variable, renewable energy technologies (Poyry, Imperial College London, 2017). Furthermore, in many countries wind and solar generators do not currently contribute to ancillary services, which limits further the system's ability to accommodate renewables. Growth of renewable generation, particularly located in remote areas, also causes network congestions and stability problems.

Frequency Stability – The connection of variable renewable generation to the grid via power-electronics leads to a reduction in the system inertia (EDF R&D Division, 2015). Ireland and UK, which are both countries with high levels of RES penetration, have already experienced a reduction in the system inertia (EirGrid and SONI, 2010) (National Grid, 2016). It is anticipated that as the RES penetration increases in the pan-European system, similar trends will be experienced. Due to this reduction, the robustness of the system following a frequency disturbance will be affected. Especially, as the penetration of RES grows, the impact will increase, which in some cases may even be translated into critical conditions equivalent to a frequency nadir lower than the 49 Hz that triggers under frequency load shedding (EDF R&D Division, 2015). In such cases, the instantaneous penetration of renewable generation should be limited to maintain system security. As an example, Ireland already limits the instantaneous penetration of non-synchronous sources as a mitigation measure against frequency instabilities (EirGrid and SONI, 2010).

The reduction in system inertia due to the displacement of synchronous generators leads to significant frequency excursions, which may result in frequency stability issues (Quoc Hung, D. et al., 2016). An incident in Electricity Reliability Council of Texas (ERCOT) system on Feb. 26, 2008 demonstrates such a situation, where the unexpected loss of some synchronous generators with wind generator ramp down and load ramp-up led to a decline in system frequency (NREL, 2008). It is anticipated that such events will continue to occur as penetration of renewable generation increases creating adverse conditions with respect to frequency stability. Within this context, a study by (Yan, R. et al., 2015) has assessed the impact of high penetration of solar and wind on the frequency stability of the South Australian power system. The analysis has demonstrated that low system inertia and secondary voltage tripping of solar PV generators can create serious frequency stability issues in the South Australian power system under high penetration of renewable generation (Yan, R. et al., 2015).

Innovative solutions, such as provision of synthetic inertia and frequency response from wind farms (WFs), may be introduced to increase the system security without the need for renewable generation curtailment and therefore achieve higher levels of renewable generation (EirGrid, 2016). Research and development activities worldwide report novel ways for provision of synthetic inertia, frequency response, etc., but significant work is still required before the power system industry can accept these solutions (National Grid, 2016).

Voltage Stability – The increased penetration of renewable generation leads to a reduction of system strength which may result in larger propagation of voltage disturbances (MIGRATE Consortium, 2016) (Australian Electricity Market Operator, 2017). System strength is an indicator of the local dynamic performance of the system and behaviours in response to a voltage disturbance (National Grid, 2016). In practical terms, it can be measured through short-circuit power, which is the fault current contributed by all generators during a fault (National Grid, 2016). Even though renewable generators do contribute to this fault current, their capability is limited when compared with synchronous generators (EirGrid and SONI, 2010). Furthermore, lower short-circuit levels can negatively impact on the protection schemes (e.g. overcurrent protection, differential protection, etc.), so due attention is required in the design of protection schemes in light of low short-circuit levels in the near future.

Due to the decrease of the system strength, it is anticipated that the voltage stability of the system may be compromised under very high levels of renewable penetration. The effect of renewable generation on the voltage magnitude and stability of the transmission and sub-transmission systems has been investigated in the studies of (Vittal, E. et al., 2012) and (Shah, R. et al., 2012). The study by (Vittal, E. et al., 2012) has demonstrated that due to the displacement of conventional generators and the limited reactive power capability of some of the renewable generators, a reduction of voltage stability margins of both long and short-terms is anticipated in the system. A potential solution to this issue would be operation of renewable generators with extended power factor range or the utilisation of STATCOM or SVCs (WECC, 2014).

Rotor Angle Stability – Relevant work in this area has revealed that the reduction of synchronising torque between synchronous generating units will deteriorate the rotor angle stability margins (EirGrid and SONI, 2010). The study by (Vittal, E. et al., 2012) have analysed the impact of reactive power control methodology on power electronics-interfaced renewable generators and revealed that the reactive power control employed in their converter control can directly influence the transient stability of the system.

In addition to the transient stability, small-signal stability has also received some attention. Detailed studies by (Quintero, J. et al., 2014) have dealt with the impact of converter-based generation on small-signal stability. The analysis investigated the controller interactions with the damping torque and has identified that there is relatively low interaction between converter control generators and synchronous generators in inter-area modes (Quintero, J. et al., 2014). Two new types of low-frequency modes associated with converter control generators have also been identified. The first mode is dominated by converter-controlled generators and the second is originated due to the interaction between synchronous generators and converter-controlled generators in the system. Academic and power system industry have focused on proposing methods for assessing this issue (Vittal, E. et al., 2012) (Mithulananthan, N. et al., 2014).

Network congestion – The transition from a traditional power system (with a few synchronous generators supplying the loads) into a renewable energy-based power system (with a significant portion of the generation being dispersed in small-scale units) constitutes a major paradigm change which will significantly affect the power flows both at the transmission and distribution system (Verzijlbergh, R.A. et al., 2017). The typical plant size of RES is much smaller than those of conventional thermal energy plants. Hence, the number of energy feed-in points will increase. Furthermore, significant energy produced by RES will be injected in the distribution networks (i.e. especially the case for solar PV). Additionally, bidirectional energy flows will occur in the distribution system (Verzijlbergh, R.A. et al., 2017). This, together with increase in demand driven by electrification of transport and heat sectors, may further increase congestion in distribution networks. With reference to transmission systems, the rapidly increasing penetration of large-scale renewable energy plants, particularly wind, has added to the network congestion problem (Yingzhong, G. et al., 2011) (Jianhua, Z. et al., 2011). The large penetration of renewable generation has increased the focus on congestion management for transmission system operators (TSOs), without which further renewable integration will be impeded (Banerjee, B., 2016). During periods of high congestion, significant amounts of wind farm output may need to be curtailed in real time operations to ensure that network constraints are met and system security and reliability are not compromised (dena - German Energy Agency, 2014).

System restoration – Power systems are nowadays being operated closer to their limits (Quoc Hung, D. et al., 2016). High capacity and long transmission networks are widely used to meet the power supply demand. Wind and solar PV generation are increasingly adopted, but they are inherently volatile and intermittent. Therefore, partial failures, which are not appropriately mitigated, could cause cascading effects that may lead to blackouts (Liu, Fan, & Terzija, 2016). Such blackouts have recently been reported in the literature in several occasions. For example, the blackout in North America on August 14, 2003 caused significant loss of the system, with its restoration lasting for almost two weeks (Allen, E.H. et al., 2012). Additionally, the power outage in the European power system on November 4, 2006 affected 15 million people and lasted for 2 hours (Li, C. et al., 2007). The largest power outage in Northern India involved 50 GW of load, affected 670 million people and lasted from July 30-31, 2012 (Xue, Y.S. et al., 2013).

Risks for large-scale blackouts still exist and can be considered inevitable, however significant work is invested in increasing the resilience of power systems against outages (Massound, A. et al., 2014). Historically, system restoration has relied on conventional generation and hence the concern is that growth in renewable generation and consequent decommissioning of conventional plant would increase the complexity of supply restoration process. Hence, research on how to restore the future power system with significant penetration of RES quickly and effectively after outages is growing in importance.

System adequacy concerns – Renewable generation technologies will displace energy produced by conventional plants, but their ability to displace highly reliable capacity is limited. In addition, decarbonising the broader energy system through electrification of segments of the heat and transport sectors may lead to increases in peaks that may be disproportionately higher than the corresponding increases in annual electricity demand. These peaks may require significant reinforcement of generation and network infrastructure. In fact, network developments at a local level within the distribution network and at a national level within the transmission networks along with new interconnectors may be needed to bridge the gap between the natural diversity in demand and the production from renewable plants (DNV GL et al., 2014).

Need for flexible technologies and control systems – In this context, there will be an increased need for operational *flexibility* to deal with growing variability and uncertainty in supply, in order to cost effectively integrate low-carbon generation and demand technologies as the cost associated with the business-as-usual operating paradigm would be very high. In response to this challenge, novel flexible technologies that can make more efficient use of the existing infrastructure are emerging, such as demand side response (DSR), energy storage, advanced network technologies and flexible generation technologies. Furthermore, the benefits of cross-border interconnection will be significant as, in addition to energy trading, interconnection can enable exchange of various balancing services and enhance security of supply given the ability to share secure generation capacity among different countries. In this context, operational flexibility will be at the core of facilitating resilient and decarbonised pan-European system, while meeting end consumer’s needs in a cost-effective way, and EU-SysFlex project will provide important new evidence through a range of demonstration activities.

1.3 METHODOLOGY & OBJECTIVES OF TASK 2.1

The objective of the EU-SysFlex WP2 is to identify the system scarcities of the pan-European system with high levels of renewables. In order to deliver a basis for the demonstration projects and the subsequent system scarcities analysis within WP2, the first task of this WP, Task 2.1, is based on a literature review, which was carried out in the first 6 months of the project.

This report provides the outcomes of Task 2.1, based on the review performed across various research, demonstration and industrial projects conducted in the recent past by European organisations amongst others[1], as well as European network codes on generators, high voltage direct current (HVDC) systems and demand.

[1] A number of high renewables studies from the USA and Australia have also been considered in the review.

A methodological approached was adopted to ensure that all system scarcities are captured, as described below:

1. A list of 28 projects and regulatory frameworks (see Table 2) has been selected to form the basis for the review. Other research papers and technical reports have also been used to supplement the findings of the core projects.

2. A classification summary of each study reviewed was provided and a taxonomy was created to capture the major findings of each project/study. A short overview of this summary can be found in Table 10, ANNEX I.

3. The major findings were analysed and divided into broad categories as a first step towards classification of the scarcities (e.g. frequency-related, voltage-related, etc.). For example, the frequency-related issues identified were added in the 'Lack of frequency control' scarcity.

4. The derived scarcities were then further classified into sub-scarcities, which aimed to create a consistent way of identifying issues reported in the various projects. For example, the 'Lack of frequency control' scarcity was divided into (i) lack of system inertia, (ii) lack of operating reserves and (iii) lack of ramping reserves, as the reviewed projects indicated that the frequency related issues can be generalised into these three sub-categories.

5. Subsequently mitigation measures proposed in the reviewed projects and regulatory frameworks were identified based on the effectiveness for addressing each of the sub-scarcities.

The broad categories of scarcities, as emerged from the review, are:

- Lack of frequency control
- Lack of voltage control
- Rotor angle instability
- Network congestion
- Need for improved system restoration
- Degradation of system adequacy

The evaluation of these system scarcities is in the core of this report, as they will form the basis for the development of appropriate technical solutions and market products that can help deliver the energy transition and low carbon objectives of the EU more efficiently.

2. OVERVIEW OF THE STUDIES/REPORTS

A broad range of recently conducted technical and techno-economic studies and European regulations addressing future system needs with a high share of RES have been reviewed for the needs of Task 2.1.

Figure 3 illustrates the European countries considered in the review. In addition to these, projects relating to similar issues encountered in Australia and USA have also been included in the review.

FIGURE 3 COUNTRIES COVERED THROUGH THE REVIEW IN A EUROPEAN MAP CONTEXT

Table 2 lists the studies reviewed, indicating the category of scarcity mainly investigated within each of them. The scarcities are not decorrelated and most studies deal with intertwined issues, that have been simplified for the sake of this summary. The emergence and weight of the scarcities is strongly linked to the studies, depending on the share of RES considered, as well as the strength of the system (generation mix, interconnections, etc.). Therefore, no hierarchy is made between the scarcities apart from the number of occurrences in the different projects reviewed.

Table 10 within ANNEX I provides a short description of the objectives and outcomes of these projects. More detailed information can be found in Sections 3 - 8, each of which focuses on one of the identified system scarcities and analyses the key findings, lessons learnt and potential solutions for resolving it as suggested by the projects' results. Additionally, any potential areas for further development identified within the reviewed studies are highlighted.

Note that a part of the review has been focused on the ENTSO-E regulations[2], as they describe the requirements the European system needs to adhere to and hence dictate the advancements required in the power system sector in a European context. These regulations are especially topical given that national regulations are in most cases outdated documents referring to power systems operating mainly based on conventional generation units (e.g. coal plants, etc.) with no or very limited penetration of renewables (especially distributed renewable energy sources (RES)) (Poyry, Imperial College London, 2017) (DNV KEMA, COWI, 2013). An update of these regulations is needed to establish a level playing field between traditional network infrastructure and emerging flexible technologies. While recently there have been efforts to modernise these regulations, a lot of progress is still required before alignment with the EU renewables objectives is achieved. Hence, a summary of the most important requirements and their interpretations, as analysed by the participants of Task 2.1, have been included in ANNEX II.

[2] Requirements for Generators (RfG), Network Code on HVDC Connection (HVDC code) and Demand Connection Code (DCC)

	LACK OF FREQUENCY CONTROL	LACK OF VOLTAGE CONTROL	ROTOR ANGLE INSTABILITY	NETWORK CONGESTION	NEED FOR SYSTEM RESTORATION	SYSTEM INADEQUACY
DS3	X	X	X			
All-Island Grid study	X	X				
Facilitation of Renewables (FOR) Study	X	X	X			
Massive Integration of Renewable Energy (MIGRATE) project	X	X	X			
System Operability Framework	X	X				
Technical and Economic Analysis of the European Electricity Power System with 60% Renewable Energy Sources	X			X		X
PROMOTION	X	X				
Challenges and Opportunities for the Nordic power system	X			X		X
100% RES in Baltic sea countries	X					
e-Highway 2050	X	X	X	X		
MARKET4RES	X					
NORTHSEAGRID						
GRID4EU		X		X	X	
RESERVICES	X	X				
GRIDTECH				X		X
RAOM/RAO tool				X		
UMBRELLA				X		
CIGRE - Innovation in power systems industry				X		
Coordinating cross-country congestion management				X		
Future system inertia 2	X					
Future Power System Security Program	X	X				
Eastern Renewable Generation Integration Study (ERGIS)	X			X		
Western Wind and Solar Integration Study (WWSIS)	X	X	X			
Mid-term Adequacy Forecast						X
European Power System 2040: Completing the map & assessing the cost of non-grid	X					
ENTSO-E RfG	X	X	X		X	
ENTSO-E HVDC	X	X			X	
ENTSO-E DCC	X	X		X		

TABLE 2 SYSTEM SCARCITIES CONSIDERED BY THE REVIEWED PROJECTS

3. FREQUENCY CONTROL

3.1 INTRODUCTION TO FREQUENCY CONTROL

AC power systems need to maintain a continuous balance between the active power generated and active power consumed on the system. The basic indicator of this instantaneous balance is the power system frequency. The power system frequency is set by the rotational speed of the present electrical machines connected to the system. This speed is measured in rad/s or, more typically, in Hertz (Hz)[3]. Typically, when generation and demand are balanced, frequency remains constant (usually at 50 Hz[4]) and all synchronous machines rotate at the same speed. Any imbalance between generation and demand will cause the frequency to deviate from nominal. Maintaining the generation-demand balance, to ensure that the frequency remains at nominal, is called frequency control.

Following a large system disturbance or imbalance (e.g. sudden loss of generation) the frequency can deviate from nominal rapidly (Zhu, 2017). The speed at which the frequency deviates is known as the rate of change of frequency (RoCoF). RoCoF is related to the amount of kinetic energy stored in the rotating masses of electrical machines connected to the power system. This kinetic energy is called system inertia within this document. When the system inertia is high, more energy is stored in the rotating masses and thus the frequency change is slower. This occurs as the stored energy is provided to the system following any under frequency disturbance, or the stored energy absorbs more power from the system, i.e. the rotating machines speed up, following any overfrequency disturbance.

Conventional generators usually have governor controls which monitor the machine speed, and thus system frequency, and can accordingly adjust the input valve to regulate their speed. During normal operation and for small imbalances, adjusting the input valve varies the mechanical power input and ensures the speed, and thus system frequency, is restored to nominal (Wood & Wollenberg, 1996). During large disturbances, governor control acts to minimise the deviation of the frequency from nominal. Conventional generators are equipped with additional control systems and these, coupled with manually issued dispatch instructions, assist the system operator (SO) in managing the generation-demand balance in real-time. A wide suite of frequency control services from generators, loads and other devices, over different times, are deployed to mitigate frequency disturbances.

Operating a power system with high levels of renewables introduces an element of uncertainty and variability, due to the often weather-dependant nature of the renewable resources. In order to manage this variability, particularly in the longer timeframe (mins to hours), it is important that the generation portfolio is sufficiently flexible. The ability of a generator to respond to large variations in renewable generator output over longer timeframes is known as ramping capability. This is a capability which is increasing in importance as power systems transition to higher and higher penetrations of variable renewable generation.

---

[3] Frequency can also be seen as the number of alternating current (AC) cycles per second produced by generators.

[4] Of the systems considered in this review, only the power system in USA operates with a frequency of 60 Hz.

Historically, frequency control services have been provided by conventional synchronous generators, as well as from the shedding of very large industrial loads. However, as increasing levels of renewable energy sources displace conventional synchronous generators, the levels of traditional frequency control service capability are also decreasing. This means that there is an increasing need for non-synchronous generators to provide frequency control services (Poyry, Imperial College London, 2017).

Consequently, frequency control services have recently been trialled from non-synchronous generators, such as wind farms, as well as from energy storage and demand side response technologies. National Grid (UK), EirGrid (Ireland) and SONI (Northern Ireland) have trialled frequency response from wind farms (EirGrid, 2017), (National Grid, 2017) and are now procuring such services. Additionally, the TSOs in Spain and Denmark have already procured, and are utilising, frequency control services from wind farms.

In addition to the initiatives taken by the various system operators, a number of projects focusing on renewable integration and dealing with the frequency control system scarcity are listed in Table 3 below. Additionally, the table demonstrates the aspects of frequency control that the studies have considered.

PROJECT TITLE	SYSTEM INERTIA	RoCoF	NEED FOR RESERVE CAPABILITY	RAMPING
Facilitation of Renewables Study	X	X	X	X
Delivering Secure Sustainable Electricity System (DS3)	X	X	X	X
System Operability Framework	X	X		
Technical and Economic Analysis of the European Electricity Power System with 60% Renewable Energy Sources	X			
Challenges and Opportunities for the Nordic power system	X		X	
Inertia 2 (Nordic)	X	X	X	
REserviceS (EU)			X	
MARKET4RES (EU)			X	
Massive Integration of Renewable Energy (MIGRATE) project	X	X		
Eastern Renewable Generation Integration Study				X
Western Wind and Solar Integration Study	X		X	
PROMOTioN	X			
e-Highway 2050			X	
European Power System 2040: Completing the map & assessing the cost of non-grid	X	X		

TABLE 3 PROJECTS DEALING WITH FREQUENCY CONTROL CONSIDERATIONS

3.2 LACK OF SYSTEM INERTIA

System inertia is the aggregated inertia of all rotating machines directly coupled to the power system (e.g. synchronised conventional power plants) (Bian, et al., 2017). All synchronously connected machines inherently contribute to the system inertia. Machines connected indirectly to the grid (i.e. via a power electronics converter) do not contribute to system inertia. As a result, and as illustrated in numerous studies, increased shares of renewables (i.e. inverter-based power generation) in the generation mix displace conventional generation and reduce the system inertia (EirGrid and SONI, 2011) (National Grid, 2016) (EDF R&D Division, 2015).

The Facilitation of Renewables study has identified that increasing levels of non-synchronous wind generation in Ireland and Northern Ireland will displace synchronous conventional plant and will consequently result in falling inertia levels on the All-Island Power System (AIS) (EirGrid and SONI, 2011). Specifically, it has been shown in the study (EirGrid and SONI, 2011) that the simulated 2020 AIS could have inertia levels 25% lower than the average inertia levels in 2010. This is illustrated in Figure 4.

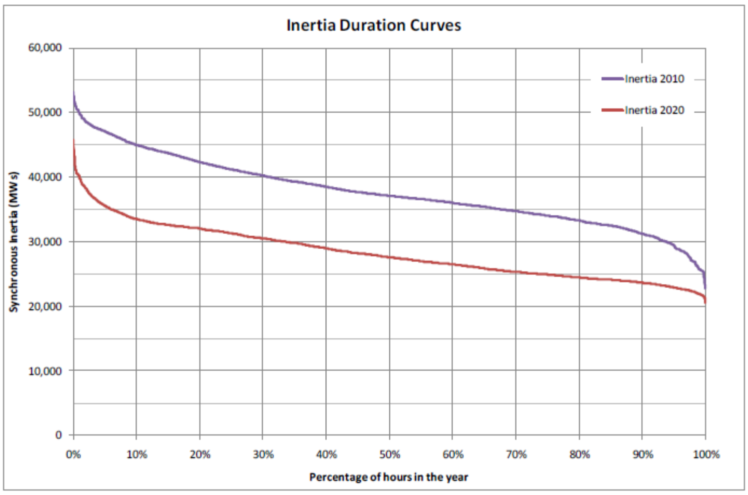

FIGURE 4: SYNCHRONOUS INERTIA DURATION CURVES CALCULATED FROM ACTUAL 2010 AND MODELLED 2020 DATA (EIRGRID AND SONI, 2011)

The work performed by National Grid as part of the System Operability Framework (SOF) also indicates that system inertia in the Great Britain (GB) power system is likely to drop in the coming years due to the displacement of synchronous generators. This concurs with the findings of studies on the island of Ireland.

It has also been identified that the same issue will appear in the Nordic power system. According to the results of a study by the Nordic TSOs (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016), by 2025 inertia levels are likely to fall below the required volume of 120-145 GWs between 1% and 19% of the time, with the average being 8%. This is based on analyses with historical reference period 1962-2012.

On a larger scale and with reference to the Continental European system, a study (EDF R&D Division, 2015) performed by EDF included technical and economic analysis of the European power system with 60% RES. It was demonstrated that for low to moderate penetration of variable RES, the synchronously interconnected European grid today has high inertia, which ensures that it has the capacity to accept a significant number of sources of production connected through power electronics interfaces. With 40% variable RES, for the majority of cases, the overall European network appears to be sufficiently robust.

A study by ENTSO-E examining the System Needs of the entire pan-European power system in 2030 and 2040, indicated that higher variable renewable energy scenarios in 2030 will have significant reduction in the estimated synchronous area system inertia (ENTSO-E, 2018). In particular, there will be an immediate reduction in the equivalent system inertia of the Ireland and Northern Ireland, Great Britain, and Baltic power systems. Similar trends are seen for the Continental European and Nordic systems for very high renewable scenarios in 2040. At times in the highest renewable scenario, the system inertia in the Continental Europe system will be less than 50% of the minimum system inertia in the baseline 2030 scenario. This demonstrates the trend of reducing system inertia will become a problem for island and isolated power systems first, but that larger power systems will ultimately see the impact of these issues also.

The reduction in system inertia can potentially lead to the following major impacts on system operation:

a) Excessive frequency excursions (following an energy imbalance)
b) Excessive rate of change of frequency

3.2.1 EXCESSIVE FREQUENCY EXCURSIONS

A key impact of reduced system inertia is the large magnitudes of frequency excursions following the sudden loss of a generation or load/export. The continental system study conducted by EDF (EDF R&D Division, 2015) found that critical situations could emerge equivalent to a frequency nadir lower than 49 Hz, which triggers under-frequency load shedding, and lower than the security level of 49.2 Hz. These are observed on the Central European system for periods with 25% instantaneous penetration of RES, when the overall system demand is low (<250 GW). The most critical periods for frequency stability are those when demand is low. During these periods, it will be necessary to limit the instantaneous penetration of RES in order to maintain the security of the system. A similar incident occurring during periods of high demand would not seem to pose a problem even for instantaneous penetration levels of RES as high as 70%, given that the load self-regulating effect will contribute naturally to the re-establishment of the system frequency.

Additionally, the FOR study (EirGrid and SONI, 2011) has shown that at high wind penetration levels, interconnection has a strong impact on the frequency stability of the All-Island power system after the loss of the Largest Single Infeed (LSI), i.e. the loss of the generator with largest active power output or loss of another importing interconnector. Significant import values were shown to result in severe frequency drops on account of the fact that import capacity displaces conventional generation (EirGrid and SONI, 2010) and thus reduces system inertia. Finally, it was identified that severe frequency disturbances can result in tripping of under-frequency relays on generation on the island of Ireland, both on conventional and wind generation, which may exacerbate the frequency deviation (EirGrid and SONI, 2010). To address this issue, the Ireland and Northern Ireland power system currently operates with a minimum system inertia level of 23,000 MWs (EirGrid & SONI, 2014).

The findings from the FOR, the SOF studies and studies of the Nordic system, in relation to falling inertia levels, are supported by studies performed in the United States (Miller, Shao, Pajic, & D'Aquila, 2014). The Western Wind and Solar Integration Study indicates that high RES penetration in the WestConnect group of utilities of the Western Interconnection will lead to falling inertia levels. Indeed, as can be seen in Figure 5, the loss of two large units has been found to result in a frequency excursion which is deemed to be severe for the Western Interconnection[5], with the frequency falling faster and a larger nadir occurring in the case with higher levels of renewables.

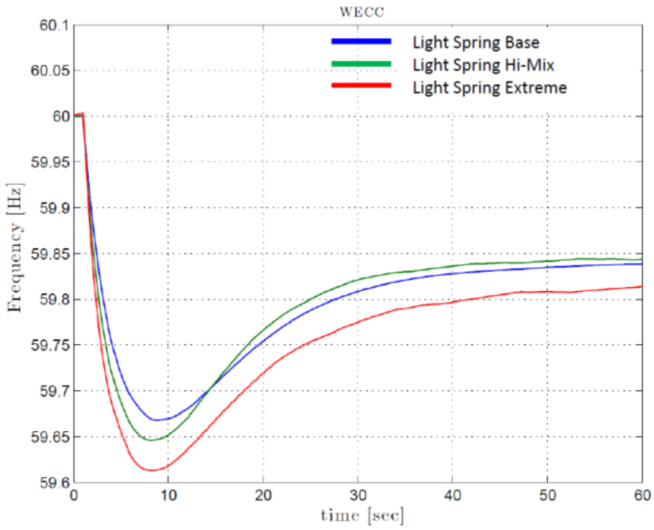

FIGURE 5 FREQUENCY RESPONSE FOLLOWING THE LOSS OF TWO LARGE UNITS UNDER LIGHT SYSTEM CONDITIONS IN THE WWSIS (MILLER, SHAO, PAJIC, & D'AQUILA, 2014)

These studies have demonstrated that reducing system inertia levels can pose problems to systems with high levels of non-synchronous renewable generation.

3.2.2 EXCESSIVE RATE OF CHANGE OF FREQUENCY

Synchronous machines provide an inherent inertial response, which enables to smooth the frequency decrease or increase following a load perturbance. This action is instantaneous. Synchronous machines ensure the frequency stability using their governor controls, whose actions start within a few seconds (Castro & Acha, 2016). Without special controllers, variable renewable generators do not participate in frequency control (Guggilam, Zhao, Dall'Anese, Chen, & Dhople, 2018) (Sun, Hou, Peng, & Hu, 2017). In the case of a loss of a large generating unit, the frequency dynamic of the system is then initially dominated by the inertial response of online conventional generators. As discussed in Section 3.2, as renewable penetration in power systems increases, the total system inertia is reduced and the inertial response capability of the system decreases.

RoCoF is the time derivative of the power system frequency (i.e. $\frac{df}{dt}$) (ENTSO-E, 2017). The increased penetration of renewables, and subsequent decrease in system inertia in many areas, has resulted in the potential for more sudden changes of the frequency, or higher RoCoF values, in the event of a system disturbance (National Grid, 2017).

[5] At 59.5 Hz, under-frequency load-shedding is initiated (Miller, Shao, Pajic, & D'Aquila, 2014).

Analysis of the synchronous areas in Europe by ENTSO-E show that the size of a contingency required to cause a RoCoF of either 1 Hz/s or 2 Hz/s on each synchronous area will decrease over time as further renewables connect on the power system (ENTSO-E, 2018). The analysis indicates that small synchronous areas, such as Ireland and Northern Ireland, Great Britain, or the Baltic synchronous area, would see rapid and large frequency excursions following a normal generation loss. However, large synchronous areas such as the Continental Europe and Nordic systems would not see the same size of frequency excursions unless a significant disturbance occurs such as a system split. Several mitigations to RoCoF issues are proposed including additional inertial response services, fast frequency response, use of synchronous condensers, real-time monitoring of system inertia, and implementation of the European Connection Codes.

The main issue with RoCoF, influencing the renewable energy penetration levels, arises due to the activation of RoCoF protection settings on generators, load and other grid-connected devices. In order to protect transmission–connected generating devices from damage due to excessively high RoCoF events and to prevent islanding, they are equipped with RoCoF relays, which disconnects them from the system when high RoCoF values are detected (EirGrid and SONI, 2010). The distribution system operators (DSOs) utilise 'loss of mains' (LoM) protection schemes to be able to detect islanding events and disconnect the generation from the power system (National Grid, 2016). LoM schemes are required to distinguish the frequency deviation caused by demand-generation imbalance, and they utilise RoCoF relays. These relays generally have protection settings tuned to RoCoF levels that correspond to the minimum system inertia being relatively high (National Grid, 2016). With the minimum system inertia dropping, RoCoF levels caused by generation or demand loss can exceed the settings of LoM schemes, therefore resulting in unnecessary disconnection of distribution generation units (National Grid, 2016). This, in combination with loss of synchronous generation, can cause widespread system frequency disturbances. It is, however, vital that generators are capable of maintaining synchronism with the system at higher RoCoF levels, if high levels of renewables are to be integrated.

Studies carried out by Imperial College (Poyry, Imperial College London, 2017), indicate that relaxation of the RoCoF setting in the UK from 0.25 Hz/s to 0.5 Hz/s would lower required frequency response and significantly reduce the associated ancillary services costs, particularly when the penetration of renewables increases. However, such an action would require coordination across the industry and significant changes in the operational standards applicable. The rising penetration of RES capacity in the system suggests, therefore, that a review of standards may be appropriate given the changing nature of the electricity system to which they apply.

Relevant work in the areas of RoCoF setting modification has taken place under the DS3 programme (EirGrid Group). EirGrid and SONI have undertaken a multi-year program of generator testing, to establish the RoCoF withstand capabilities of each unit (DGA Consulting, 2016), with a view to moving RoCoF standards to 1Hz/s measured over a 500 ms timeframe by 2020.

Issues associated with the disconnection of generators due to high RoCoF values can be exacerbated by under-frequency load shedding devices as well as units with activated low frequency sensitive mode-overfrequency

(LFSM-O) or low frequency sensitive mode-underfrequency (LFSM-U). This is a result of the fact that such devices require a certain time (several hundred milliseconds) for frequency measuring and acting (MIGRATE Consortium, 2016).

Furthermore, frequency excursions have an impact on the operation of protection mechanisms of distribution-connected generation. The unplanned disconnection of distributed generation units (e.g. wind, PV, etc.) and loads following high or low frequency events could worsen the frequency event, and increase/decrease the frequency zenith/nadir.

When the penetration of distributed generation initially began increasing, network code requirements for distributed power electronic-interfaced generation for under- or over-frequency tripping and subsequent reconnection, as well as participation in frequency containment, were less strict than for conventional transmission-connected generation. However, as the level of distributed connected generation further expanded, the subsequent risk of disconnection of this generation became increasingly important for secure transmission system operation. Potential disconnection of this generation following the loss of a large conventional power plant could result in a very large RoCoF event.

As a result of this issue, some TSOs are revising the LoM protection settings to mitigate the disconnection of distributed generation due to excessive system RoCoFs (EirGrid & SONI, 2014) (National Grid, 2016). In this context, in the UK, system inertia cannot fall below a specified limit to avoid the unwanted disconnection of distributed generation units in the event of a frequency disturbance (National Grid, 2016). This limit cannot be relaxed until generator protection settings are changed or relays are replaced, which needs to be coordinated across the industry.

Inertial Response is immediately available from synchronous generators, synchronous condensers and some synchronous demand loads (when synchronised) because of the nature of synchronous machines and is a key determinant of the strength and stability of the power system. Consequently, in order to mitigate falling inertia levels, SOs are exploring options to procure inertial response services from a variety of different sources. For example, EirGrid has introduced a Synchronous Inertial Response product (EirGrid and SONI, 2011). In the Nordic system, short term mitigation options have been identified as using active power injection by emergency power control (EPC) together with load disconnection and limiting the power output of the largest units and HVDC links (i.e. reduction of dimensioning incident) (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). In the longer term, more inertia can be added into the system installing rotating masses such as synchronous condensers, setting minimum system requirements for kinetic energy and adding synthetic inertia (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). New solutions for securing an adequate level of inertia should also be considered in the context of frequency containment reserve (FCR).

Other solutions to compensate for this decrease in inertia are being sought; however, no sufficient technical solutions exist yet (National Grid, 2016). For example, fast injection of active power differs significantly from system inertia due to the measurement delay introduced in the associated controllers. Research and development activities are required to effectively make fast active power injection to account for the system inertia reduction (National Grid, 2016). There is another service identified in the literature as synthetic inertia (also referred to as artificial, virtual or emulated) and can be provided by generators with power electronic devices (PEDs). Note, however, that synthetic inertia can only be provided within the remaining generating capacity of the PEDs but can also be provided by HVDC links connecting different synchronous areas (MIGRATE Consortium, 2016). This service falls under the category of a fast frequency response and will be discussed in more detail in Section 3.3, entitled 'Need for Reserve Capability'.

3.3 LACK OF OPERATING RESERVES

Maintaining a stable system frequency is dependent upon controlling the active power balance between generation and demand. With increasing levels of renewables on the power system, it is vital that there is sufficient capability across the power system to balance active power. This is evident in the FOR study which demonstrated that management of frequency following the loss of the largest unit (or LSI) will become progressively more difficult at high penetrations of wind (EirGrid and SONI, 2010).

The capability to manage frequency can come from a wide variety of resources and can be achieved through different mechanisms. The most widely utilised method for restoring active power balance is to hold and deploy operating reserves. Operating reserve, or simply reserve, is any capacity that is available for assistance in active power balance (Ela, Milligan, & Kirby, 2011)– this includes online and offline generation, load and storage devices. The activation and usage of reserves is different to the balance of generation and demand in real time, or frequency regulation, which constantly takes place. Operating reserves are deployed following a large power imbalance, typically the loss of a generating unit or large industrial demand. A range of reserve services are required to ensure that there is capability to balance active power, and thus control system frequency, across various timescales. The timescales involved range from milliseconds following a frequency-related event to multiple hours. Reserves can be classified either as upward or downward, i.e. upward is an increase in generation or decrease in demand, and downward is a decrease in generation or increase in demand respectively.

For clarity, the discussion on reserve capability, which follows, will be on the basis of the time-frame over which they operate.

3.3.1 SUB 5 SECOND TIME-FRAME

In Section 3.2.2, it was discussed that inertial response is critical to the system to maintain frequency stability and reduce the potential for fast RoCoF events. However, inertial response alone will not contain fast frequency events in systems with high penetrations of renewables. For that reason, fast frequency responses, or fast acting reserves, are necessary to counter-act some of the issues associated with increasing penetrations of variable renewable generation.

As system inertia reduces and potential RoCoF values increase, frequency disturbances should be contained quicker than in the past. In response to this, EirGrid and SONI (EirGrid Group). as well as National Grid UK have designed new fast frequency response products to mitigate the drop in inertia and associated high RoCoF values. The Fast Frequency Response (FFR) product on the island of Ireland, and Enhanced Frequency Response (EFR) product in Great Britain, are designed to provide a MW response faster than the existing Primary Operating Reserve (POR) times. It is intended that in the event of a sudden power imbalance, these products can potentially result in a quick arrest of frequency excursions.

These products can be procured from both synchronous and non-synchronous generators, as well as load and electricity storage devices. Given the deteriorating inertia levels which cause the frequency to deviate excessively, these services can help to ensure that there is sufficient, fast-acting operating reserve to restore the supply-demand balance.

Another issue identified, necessitating the use of fast reserve services, is the possibility of a voltage dip-induced frequency deviation (VDIFD) (EirGrid Group), (MIGRATE Consortium, 2016). This issue refers to the recovery phase of active power after short-circuit events. The active power recovery of transiently stable synchronous generators follows the recovering voltage and is therefore very quick. The active power recovery of wind turbine generators may be slower in order to keep mechanical stress on the structure at acceptable levels as shown in Figure 6. The impact of this issue is strongly dependent on the size of the synchronous area together with its inertia and the type-3 & 4 wind power turbine penetration. The issue is aggravated by decreasing inertia and a broader propagation of voltage dips. Power electronic-interfaced generation without a mechanical prime mover, such as photovoltaic plants, can be controlled in such a way that it does not significantly contribute to this issue.

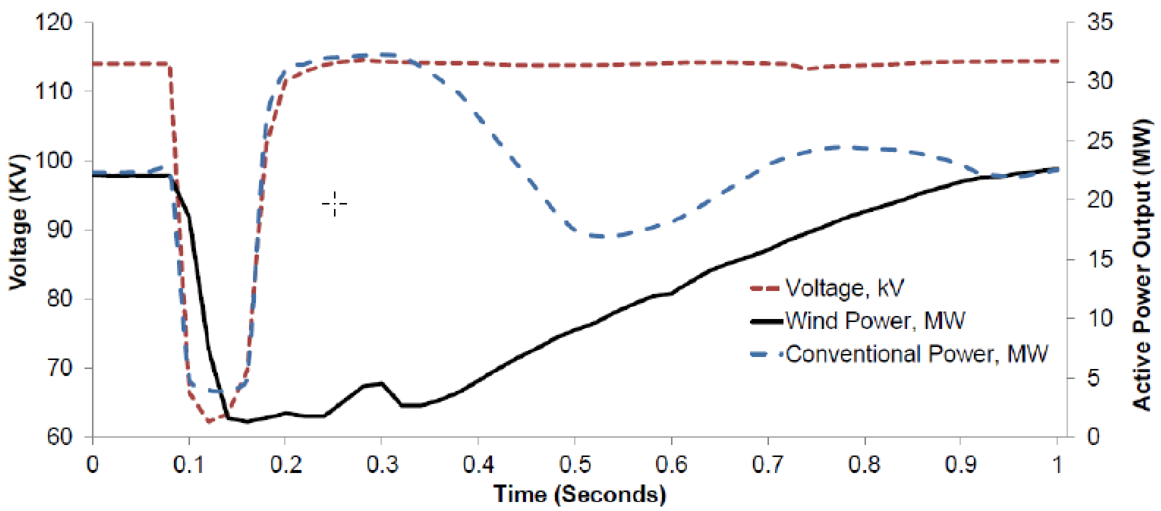

FIGURE 6 ACTIVE POWER RECOVERY CHARACTERISTICS OF CONVENTIONAL AND WIND GENERATORS (MIGRATE CONSORTIUM, 2016)

This occurs at high levels of non-synchronous generation penetration, when a voltage disturbance results in a sustained decrease in the active power output of wind generation in the surrounding area, which subsequently has a negative impact on the system frequency. If not managed, this could result in a significant frequency deviation which leads to load shedding or system collapse. At high penetrations of wind generation, a transmission fault of 100ms has the potential to result in a MW reduction greater than that of the largest single conventional generator trip in the system, potentially resulting in serious frequency events (i.e. VDIFD).

A service which could mitigate frequency dips resulting from voltage disturbances is the Fast Post-Fault Power Recovery (FPFAPR) which refers to the units that can recover their MW output quickly following a voltage disturbance (including transmission faults). This can mitigate the impact of such disturbances on the system frequency. It is important to note that this product is solely designed to incentivise fast active power recovery from renewable generators with power electronic devices. This service is currently being procured on the island of Ireland (EirGrid and SONI, 2011).

3.3.2 5 TO 90 SECOND TIME-FRAME

Frequency containment reserve are “reserves available to contain system frequency after the occurrence of an imbalance" (National Grid, 2016). This category typically includes operating reserves with an activation time up to 30 seconds (ENTSO-E RfG, 2016) (ENTSO-E HVDC, 2016). Primary Operating Reserve is an example of a reserve service in this category.

The importance of the fast and primary frequency reserve services is highlighted in a number of studies. The WWSIS study showed that the RoCoF in the Western Interconnection of the United States increases by about 18% between the base case scenario and the high renewables scenario (Miller, Shao, Pajic, & D'Aquila, 2014). This is a result of the displacement of conventional generation and a consequential decrease in system inertia. However, provided that sufficiently fast primary frequency responsive resources are maintained, it was shown in the WWSIS that while increasing levels of renewable generation indeed result in an increase in RoCoF, the impact of this is limited up to 50% instantaneous renewable penetration in the Western Interconnection (Miller, Shao, Pajic, & D'Aquila, 2014).

Similarly, work performed in the Nordic countries (i.e. VTT Technical Research Centre in Finland) assuming an hourly dispatch with 100% penetration of renewables and inertia levels reduced to about half from the Nordic 2050 TSO assessment indicates that the risk of under-frequency load shedding is about 0.1% of time, if fast reserves are increased and wind farms provide fast response services (Ikaheimo & Kiviluoma, 2017).

Similarly, a study on the capability of Ireland and Northern Ireland power system generating fleet illustrated that there is a Primary Operating Reserve (POR) (5-15 second) shortfall in comparison with the operational requirements by 2020 (EirGrid and SONI, 2011). Fortunately, the negative impact of this shortfall is somewhat counteracted by the fact that many of the units in the system have more POR capability than that required by the Ireland and Northern Ireland grid codes. However, with the gradual retirement of the older units in the fleet, which are the units most likely to have additional POR capability, the overall POR capability of the generation portfolio is set to decline.

A lack of POR capability in the power system could impede high levels of non-synchronous renewable generation. However, if generating units could alter their technical characteristics to increase POR capabilities, this could reduce the number of conventional generators required on the system, thereby allowing higher levels of wind and lower costs. In order to mitigate against the impact of low POR capability, generators with greater POR capabilities need to be incentivised. Significant work has been conducted by EirGrid and SONI in this area under the DS3 System Services programme (EirGrid and SONI, 2011). Similarly, National Grid's work indicates that new reserve products shall be developed to ensure that sufficient flexibility is available close to real-time (which becomes topical given the increased penetration of variable generation (VG)) and that in a national level there is compatibility with pan-European services.

A lack of primary reserve capability is not limited to the island of Ireland. In fact, the Nordic TSOs studies have indicated that there are geographically unbalanced volumes of primary reserves (FCR) in the synchronous system. Effectively, primary reserve capability is concentrated in one country of the Nordic system, resulting in congestion issues and an inability to balance active power in the timeframes required (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016).

With increasing levels of renewables and displacement of conventional generation, the shortfall in primary operating and frequency containment reserve needs to be compensated. There is abundant on-going research identifying new resources to provide such services. The PROMOTioN project is one example of such research. The project investigates the provision of frequency containment reserve service by offshore WFs connected through HVDC grids. The project identifies current control strategies for the provision of such services and refers to the existing ENTSO-E "Network code on HVDC connections" with regards to the service description (PROMOTioN consortium, 2017) (ENTSO-E, 2016). Within the project, FCR provision by offshore wind farm (OWF) has been assessed as part of Deliverable 3.5 (PROMOTioN consortium, 2017), and was based on the control schemes proposed in the academic literature by (Zeni, Sorensen, Anca, Hesselbaek, & Kjaer, 2015), (Sakamuri, et al., 2017). Simulations were performed using droop characteristics with different slopes based on the frequency disturbance magnitude. The results show that the HVDC-connected OWF were, in general terms, able to provide frequency support by reducing or increasing (whenever previously set to operate with reserve margin) the injected active power, participating in the frequency containment reserve. This is a significant finding towards ensuring that under-frequency load shedding events will be minimised.

While not specifically related to a frequency disturbance, increased levels of non-synchronous variable generation on the power system, and the subsequent displacement of conventional synchronous generation, may lead to increased deviation of system frequency out of nominal deadbands. This could encourage increased usage of the regulation capability of the remaining synchronous generators. In this circumstance, care must be taken to ensure the droop response, or system regulating strength is carefully tuned. An increased regulating strength may reduce the system stability and may potentially result in the system becoming unstable (ENTSO-E, 2018).

3.3.3 90 SECOND TO MULTIPLE MINUTE TIME-FRAME

After automatic response services have been delivered, other reserve services are typically manually instructed and are slower acting than fast frequency response, Primary Operating Reserve or FCR (National Grid, 2017) (EirGrid and SONI, 2011) (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). Such reserves are often classified as Frequency Restoration Reserves (FRR) (ENTSO-E RfG, 2016) (ENTSO-E HVDC, 2016). FRR replaces frequency containment reserve if the frequency deviation lasts longer than 30 seconds. Operating reserves of this category are typically activated centrally but could be activated automatically or manually.

However, in the context of decreasing system inertia, as discussed in Section 3.2, the analysis performed by the Nordic TSO reports, (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016) , (ENTSO-E, 2018), highlighted some important areas with respect to reserves. The analysis demonstrated that if the market has the same functions and products in 2025 as it does today, it will not be able to secure adequate frequency and balancing reserves. This will particularly be a problem in summer periods. The main challenges identified include larger intra-hour imbalances and changes around hour shift as well as an increased need and reduced access to reserve capacity (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016), (NREL, 2013).

In addition to the issue of geographically unbalanced volumes of primary reserves in the Nordic synchronous area discussed above, there are also Manual Frequency Restoration Reserve (mFRR) bid deficits on cold days. Therefore, there is a risk that reserves earmarked for disturbances have to be used for Nordic imbalances. It is pointed out that solutions for exchanging reserves should be further developed in order to allow reserves to be shared within and outside the synchronous area. This requires further harmonisation of markets for frequency control services and for this reason introduction of a new role in the Nordic area, the Balance Service Provider, is planned. A common market for automatic frequency restoration reserves (aFRR) should be developed (note that previously there was separate procurement for each Nordic country).

3.4 LACK OF RAMPING RESERVES

Ramping is the ability of a generator to start and stop on request, and the ramp rate defines the rate at which a generator can increase or decrease its output (Marshall, 2015). This type of flexibility is required to cope with variability in loads and therefore preserve the system's frequency stability.

The need for ramping capability is linked with the long time frame variation (usually intra-hourly) in system demand and renewable generator output. Many studies have highlighted that there is an increasing need for greater ramping capability in generation portfolios. There are two main drivers of this increase.

Firstly, with increasing levels of renewable generation, there is a displacement of conventional generation units, (i.e. gas generators, coal-fired power plants, etc.) which have traditionally been used to provide this type of flexibility, leading to a general of lack of ramping capability (NREL, 2013) (Bloom, et al., 2016). Indeed, detailed analysis in the FOR study for the power system on the island of Ireland has shown that generation portfolios that are adequate, from a capacity point of view, may not have sufficient ramping capability over all the necessary timeframes. Consequently, it may become increasingly difficult to efficiently and effectively manage the variable renewable sources and changes in interconnector flows, while maintaining system security (EirGrid and SONI, 2010).

Secondly, the increase in intra-hour load following and ramping reserves at high levels of RES is linked with variable and uncertain nature of renewable generation. As greater levels of variable renewable generation are installed, the importance of accurate forecasting increases. Many renewable integration studies from the United States, including the WWSIS, have indicated that there is an increase in load following (i.e. ramping) requirements as power systems transition to higher levels of variable renewable generation (IEA Wind Task 25, 2009). Similarly, studies of the power system of Continental Europe have demonstrated that there is an increase in the requirement for reserve services due to intra-hour wind variability and uncertainty (ENTSO-E EWIS, 2010).

As the management of variability and uncertainty is critical to a power system with high levels of variable generation, EirGrid and SONI have designed new ramping-up services that cover three distinct product time-horizons; one, three and eight hours (EirGrid Group). In some systems, ramping up or down services are supplied by operational reserves, such as secondary or tertiary.

3.5 SUMMARY OF FREQUENCY CONTROL-RELATED FINDINGS

The studies reviewed indicate that frequency management will be one of the key domains for secure operation of the system at high renewable penetration levels. The issues identified primarily relate to the progressive drop of system inertia, which causes frequency to deviate significantly even during small active power imbalances in the case of some systems. For example, a study by the Nordic TSOs (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016) demonstrates that in 2025 the levels of inertia in the Nordic countries will be below the required volume of 120-145 GW for up to 19% of time resulting in significant frequency excursions. Similar circumstances are reported in Ireland and GB (National Grid, 2016) (EirGrid and SONI, 2010). This can cause a number of effects on either a small or large scale (i.e. unwanted disconnection of distribution connected generation units due to RoCoF relays or wide-area frequency instability).

Proposed solutions for mitigating this are utilisation of rotating machines, such as synchronous compensators, or curtailment of RES generators which can be costly in the present market schemes (Solar Power Europe), but are efficient solutions. Other technical solutions (e.g. use of relaxed RoCoF settings) and system services (e.g. inertia reduction, frequency response for small deviations, frequency containment for severe disturbances, synthetic inertia, etc.) have been studied to mitigate the resulting scarcities (EirGrid and SONI, 2011) (National Grid, 2017) (ENTSO-E, 2018). As an example, modification of RoCoF settings could make the system less vulnerable to the risk of disconnection of significant volumes of generation due to a large RoCoF event following a system disturbance. Indeed, a study by (Poyry, Imperial College London, 2017), indicates that relaxation of the RoCoF setting in the UK from 0.25 Hz/s to 0.5 Hz/s would lower required frequency response and overall costs of operating the system. However, such an action would require coordination across the industry and significant changes in the operational standards applicable. The rising penetration of RES capacity in the system suggests, therefore, that a review of standards may be appropriate given the changing nature of the electricity system to which they apply. Such review and modification of RoCoF settings has taken place effectively in Ireland and Northern Ireland.

Numerous studies have identified that, in addition to modification of generator protection settings, new system reserve services are required (EirGrid and SONI, 2011), (National Grid, 2017). At high renewable generation penetrations, studies have shown that these services are particularly required in the time frame immediately following a system event such as the loss of a large generator (i.e. within 2 seconds). Furthermore, the review conducted has highlighted that in many systems, existing service capability will become more scarce as we transition to higher levels of renewables (EirGrid and SONI, 2011). This is due to the displacement of conventional generators. Thus, it is paramount that solutions are sought to enable service provision, both new and existing services, from less traditional technologies. Such technologies being considered in the literature, and in the industry, include onshore and offshore wind farms, interconnectors, demand side response (DSR), and energy storage.

However, it is worth noting that the increase of flexible technologies needs to be carefully treated, as some technologies displace demand at other times. This could lead to situation where a resource is deployed to correct an imbalance, but ultimately results in an exacerbation of the very issue which it set out to resolve. For example, DSR based provision of frequency response services generally shifts demand from one time-period to another. This results in a reduction in demand at a point in time aimed at providing reserve services, followed by an increase in demand during a subsequent period. This is most clearly understood in the use of thermostatic loads to provide frequency response, a resource which could create an increased requirement for secondary reserve (Poyry, Imperial College London, 2017). Such considerations should be accounted for in the market design, otherwise the value of this flexibility source would be overestimated.

On the other hand, however, other technologies, including wind and solar generation, have been proven to have capabilities for frequency support, as demonstrated within the REserviceS project (F. Van Hulle, et al., 2014). The study has shown that there is a system benefit to the provision of frequency services by variable renewable generators at higher shares (>20% of demand). It is noted, though, that, as there is a cost related to provision of frequency support, the burden of requirement for capabilities and service provision placed on the providing resources should not exceed what is needed by the system. Over specification of the requirement could result in excessive power system operating costs.

Unfortunately, barriers to enabling services from alternative resources remain. It was identified in the REserviceS project (F. Van Hulle, et al., 2014) and the MARKET4RES project (A. Morch, O. Wolfgang et al., 2016), that economic incentives for the provision of frequency services are missing in most countries or that the market is still considered under-developed.

The MARKET4RES project (A. Morch, O. Wolfgang et al., 2016) has revealed that post-2020 markets with a large share of variable generation should operate faster, i.e. as close as possible to real-time. Additionally, markets should consider multiple aspects, such as cross-border trade at all periods, involving day-ahead, intraday and balancing markets as well as maximal use of available infrastructure. Furthermore, traded products could be smaller and aggregated bids considered; however, the balance between liquidity and cost of implementation needs to be considered. Up and down-regulation products should be traded separately, and the same should apply to capacity and energy for provision of frequency support services. With respect to pricing mechanisms, they should be transparent and reflecting the cost of the scarcity; marginal pricing is recommended in that sense. These studies have highlighted the need for new system services to be defined and accordingly be compensated through cost-reflective market mechanisms.

The Ireland and Northern Ireland TSOs, EirGrid and SONI, have undertaken significant developments towards this direction with the design and implementation of new frequency control services covering a wide range of applications (response, reserves, ramping capability) and timescales (milliseconds to hours). Specifically, two services have been defined for providing response covering a timescale of 0 to 5 sec, namely synchronous inertial response (SIR) (inherent response in terms of active power output from synchronous machines) and fast frequency response (fast active power output from both synchronous and non-synchronous generators complementary to SIR). Primary and secondary operating reserves (SOR) are used in the timescale of 5-15 sec and 15-90 sec respectively. POR is deployed at the frequency nadir post-disturbance, while SOR needs to remain available for a longer period to support the system during recovery. Tertiary operating reserves (TOR) have also been defined (timescale of 90 sec – 20 min) to account for a short-term operating horizon. Replacement reserves have been defined to cover a much longer period (up to 1 hour) following an event. For the provision of these services, EirGrid has exploited the potential of flexible technologies applicable; e.g. they have trailed frequency response service from wind farms (EirGrid, 2017). Other products have been introduced for voltage control and are discussed in the subsequent chapter.

Finally, as it becomes increasingly challenging to manage renewables variability and interconnector rapid changes in power flow direction, three ramping-up services have been defined to cover three distinct product time horizons (i.e. 1 hour, 3 hours, 8 hours) (EirGrid and SONI, 2011).

Within the same context, the GB TSO, National Grid, utilises an extensive suite of response services spanning in various timeframes (National Grid, 2016). These comprise of four services, the Primary, Secondary and High dynamic response services as well as the newly introduced Enhanced Frequency response service (National Grid, 2016). The Primary response is defined as the minimum increase between 0 and 10 seconds and sustainable for 30 seconds, the Secondary response is the minimum increase between 0 and 30 seconds and sustainable for 30 minutes and the High frequency response is the minimum reduction between 0 and 10 seconds and sustained thereafter. The very recent service, called Enhanced Frequency response, is the minimum increase or decrease between 0 and 1 seconds and sustained for 15 minutes. With regards to reserves, there are services that are being procured ahead of time via regular tenders to manage demand forecasting errors and losses; e.g. Short Term Operating Reserve and Demand Turn-Up. Additionally, there are reserves procured much closer to real-time that offer both upward and downward flexibility. Nevertheless, National Grid envisages that these services will not be sufficient to cover for the variability and uncertainty surrounding RES, and therefore a new service is anticipated to be introduced in 2018/19 (National Grid, 2017). Another aspect that will lead National Grid to chase the development of other reserve services is the standardisation of services across Europe (National Grid, 2017). For example, the introduction of the Replacement Reserve and the manual Frequency Restoration Reserve services should be accounted in National Grid's market design. Last but not least, a new ramping product is anticipated for the next couple of years to mitigate the uncertainty in interconnector flows; especially this will become a necessity in the 3rd quarter of 2018 when the trading arrangements across interconnectors will change (i.e. trading available up to 1 hour ahead as opposed to 3 hours ahead today). (National Grid, 2017).

The Nordic power system studies have indicated that sharing resources between countries would be crucial, especially at least with regards to reserves (Statnett, Fingrid, Energinet.DK, Svenska Kraftnat, 2016). Again, this becomes relevant to a market structure, as harmonisation of markets would be required to achieve the desired outcome; the study specifically proposes the establishment of a new role responsible for this within the Nordic area, the Balance Service Provider.

The technical feasibility of exploiting frequency response from various RES generators will also be demonstrated in some of the EU-SysFlex demonstrations projects (in WP6-9). Especially, some of the demonstration projects will be focused on harvesting resources from the distribution level and delivering them on the transmission system for support during various events. In WP2 and WP3, the EU-SysFlex project will further investigate the needs for the Pan-European system, which is much larger and highly interconnected. It will focus on designing a market for compensating the services needed accordingly (in WP3). This will create opportunities for flexible technologies to increase their participation and the corresponding revenues in the proposed market.

4. VOLTAGE CONTROL

4.1 DEFINITION OF VOLTAGE CONTROL

The management of voltage on a power system is essential for the reliable transportation of electrical energy from point to point. In a similar way to the relationship between frequency and active power balance, the system voltage is determined by the balance of reactive power production and absorption. Generators have traditionally been a primary source of reactive power, which compensates for the reactive power produced and absorbed by consumers and by the network itself. Voltage control becomes more challenging as reactive power supply and demand balance is disrupted due to penetration of renewable generation and displacement of synchronous generators (which traditionally provided the reactive power required). Without this reactive power capability, used in an efficient manner, system losses would increase, and system security would be compromised (EirGrid and SONI, 2011).

Reactive power, unlike active power, is predominately a local phenomenon, i.e. it is not easily transmitted over significant distances. However, the management of voltage requires a co-ordinated approach of reactive power control throughout the whole system as deficiencies in a local area at a certain point can have an inordinate impact on other voltages, potentially leading to a system collapse (EirGrid and SONI, 2011).

Strength of the electric power system is defined as the ability of the system to maintain its voltage during the injection of reactive power (DNV GL, 2015). In comparison with weaker systems, stronger systems will experience less voltage change following an injection of reactive power. Short Circuit Ratio (SCR) or Level (SCL), defined as ratio of the interconnected grid's short circuit Mega Volt Ampere (MVA) or kA (before connecting the generator), has been utilized to quantify the strength of the electric power system (DNV GL, 2015). System strength is a regional and provides an indication of the local dynamic performance of the system and behaviours in response to a disturbance (National Grid, 2016). The primary contributors of SCL today are large synchronous generators. Since SCL is a regional metric, it is highly dependent on the locations of generators, their fault current contribution and fault current delivery with respect to time.

Unlike frequency which is a system-wide characteristic, voltage exhibits a localised nature (EirGrid & SONI, 2014). This firstly means that the requirements largely differ from one region to another (i.e. different voltage levels require different admissible voltage ranges, etc.) and secondly the need for voltage control (i.e. reactive power support) between regions can also be different. Thus, voltage depends on the localised balance of reactive power supply and demand. This highlights that reactive power deployment for voltage support is more effective when it is located close to the region of interest (National Grid, 2016). In fact, this can help minimise losses resulting from large power transfer across distant regions of the network, and additionally the possibility of regional voltage excursion or instability can be reduced (National Grid, 2016). However, it should be noted here that, while voltage is a local attribute, excessive reactive power imbalance (e.g. due to displacement of synchronous generators that traditionally supplied reactive power) can create system-wide issues (Vournas, C. et al., 2017).

With the increase of RES penetration, the generation portfolio is drastically changing and this affects the voltage stability of the power system in ways described below (ENTSO-E, 2016) (EirGrid, 2017):

- Synchronous generators are progressively being displaced at the times of high RES production (ENTSO-E, 2016). As such, a key reactive power resource is being removed from the system.
- RES generation is typically located away from the load centres to coastal areas (e.g. offshore wind farms or large-scale onshore wind farms) or is distribution-connected (e.g. solar PV and small onshore wind farms), which leads to increased circuits loadings (Urdal, H. et al., 2016).
- The development of underground cables in the distribution grid and even the transmission grid and the development of distributed generation in the distribution networks (including closed distribution networks) have an increasing impact on the reactive power flows at the interface between transmission and distribution networks.
- Utilisation of harmonic filters for power quality improvement, causing high voltage issues.

The key message of the above points is that the transmission systems progressively include less reactive resources to (*i*) be able to compensate the reactive demand of the distribution networks, and (*ii*) cope with its own transmission related reactive demand (ENTSO-E, 2016), and the reactive power needs of the system are significantly changing due to the network reinforcements for accommodating RES generation.

On another level, penetration of renewables into the distribution systems has massively increased, which causes issues in the distribution feeders, e.g. voltage rise effects due to PV active power generation (Imperial College London & UK Power Networks, 2014). Such issues require mitigation either by using appropriate compensation measures, which increases cost, or utilisation of smart technologies as are the so-called active network management solutions. These improve the overall distribution network operation and release latent network capacity, hence they defer the needs for customer-funded reinforcements (UK Power Networks, 2014) (UK Power Networks FUN LV project, n.d.) (WPD SoLa Bristol, n.d.).

The projects, shown in Section 2, dealing with this system scarcity are listed in Table 4 below. Additionally, the table demonstrates, which aspects relevant to voltage control these studies have dealt with.

PROJECT TITLE	SHORT-CIRCUIT POWER	STEADY-STATE VOLTAGE CONTROL	DYNAMIC VOLTAGE CONTROL (DISTURBANCES)
Facilitation of Renewables Study			X
System Operability Framework	X	X	X
Massive Integration of Renewable Energy (MIGRATE) project	X		
PROMOTioN		X	X
Future Power System Security Program	X		
GRID4EU		X	X
e-Highway 2050	X		
Western Wind and Solar Integration Study			X
REserviceS		X	

TABLE 4 PROJECTS DEALING WITH VOLTAGE CONTROL CONSIDERATIONS

4.2 SHORT-CIRCUIT POWER

The inherent capability of a power system to withstand voltage disturbances is measured through the short-circuit power. It provides an indication of the local dynamic performance of the system and behaviours in response to a voltage disturbance (National Grid, 2016). This, in practice, can be measured as the fault current contributed by all system generators during a fault, and essentially indicates the behaviour of a power system in response to voltage disturbances.

Traditionally, this fault current has been supplied by synchronous generators, however with their displacement and the fact that generation is located away from the load centres (e.g. offshore wind farms), other system components are required to offer it. Note, though, that the contribution of fault current varies between different technologies with the synchronous generators maintaining the highest of all (EirGrid and SONI, 2010) (National Grid, 2016). Additionally, lower short-circuit levels can negatively impact on the protection schemes (e.g. overcurrent protection, differential protection, etc.), so due attention is required in the design of protection schemes in light of low short-circuit levels in the near future.

In fact, MIGRATE project (MIGRATE Consortium, 2016) indicates that TSOs around Europe expect a reduction of short-circuit power with the increase of renewable penetration and therefore a larger propagation of voltage dips caused by short-circuit events, which exposes a greater proportion of PE-interfaced generation to an under-voltage protection trip. The results of a series of studies and analyses, undertaken by the Australian Electricity Market Operator (AEMO) under the auspices of Future Power System Security (FPSS) Program, indicate also that at times of instantaneous high non-synchronous generation, system strength in South Australia can be compromised due to the displacement of large synchronous machines, which inherently contribute to system strength (Australian Electricity Market Operator, 2017).

It is important to note that a one-by-one replacement of a synchronous generator by a PE-interfaced generator with the same maximum capacity would significantly reduce the short-circuit power at the respective busbar. The overall effect of increasing PE penetration on the short-circuit power remains unclear and is, amongst others, dependent on PE technology, penetration level, pre-fault operating point, location, protection settings and controls (MIGRATE Consortium, 2016) (Australian Electricity Market Operator, 2017). Within this context, the e-Highway 2050 project makes reference to short-circuit current needs, which require further research, especially the influence of power electronics devices to the minimum short circuit currents, as it may lead to non-detection of some faults by the protection devices.

4.3 STEADY-STATE VOLTAGE CONTROL (VOLTAGE REGULATION)

Steady-state voltage control refers to steady-state operation and is concerned with the reactive power management in real-time to account for fluctuations. This action ensures efficient power transfer (i.e. reduced active power losses) (ENTSO-E, 2016). Depending on the given voltage level (e.g. high voltage, medium voltage, etc.) and the severity and timescale of the fluctuation, a set of reactive power resources may be needed to address it.

Maintaining steady voltage profiles and therefore mitigating voltage instability requires control of the balance of reactive power production and demand (EirGrid and SONI, 2010) and ensuring correct levels of voltage on the system are essential for the reliable transmission of electricity. Conventional generators have traditionally been a primary source of reactive power, which compensates for the reactive power produced and absorbed by consumers and by the lines and cables of the network itself. The Facilitation of Renewables (FOR) study of EirGrid and the System Operability Framework (SOF) of National Grid highlighted a reduction in online reactive power with the addition of significant amounts of wind generation (EirGrid and SONI, 2010) (National Grid, 2016). The studies have also shown that there are deficiencies in respect of both lagging and leading reactive power capabilities for some generators whilst, for the overall portfolio, the deficit is more pronounced for leading Mega Volt Ampere (MVArs) in comparison with the grid code standard (EirGrid and SONI, 2011). These deficiencies can be mitigated by either incentivising reactive capability through system services or by mandating increased capability of connecting generation in the grid code. Over the coming years it is expected that some of the older existing generation in the Irish power system will be replaced by newer generation with greater reactive capabilities compliant with the updated Grid Code. This consequently results in a fall of lagging reactive power (EirGrid and SONI, 2011) as can be seen in Figure 7.

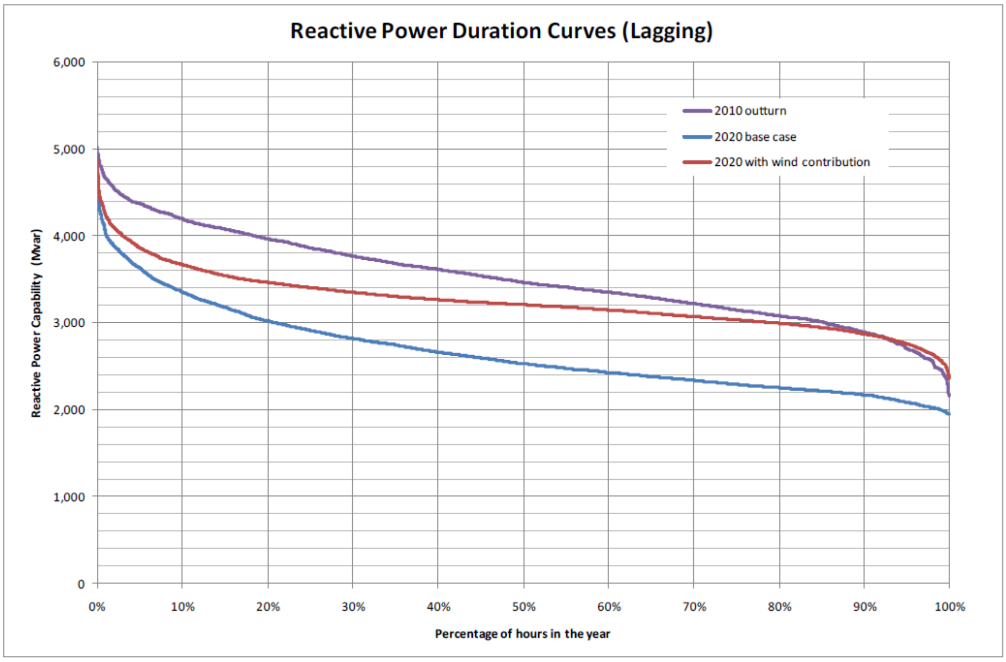

FIGURE 7 REACTIVE POWER DURATION CURVES – EVALUATED FROM 2010 ACTUAL DATA AND TWO MODELLED SCENARIOS IN 2020 (EIRGRID AND SONI, 2010)

The results of MIGRATE project (MIGRATE Consortium, 2016) largely agree with this, and this relates to the fact that when the grid penetration of dispersed renewable generation began, reactive power or voltage control capability was usually not required by the network codes. Hence, depending on the different dynamics of network code adjustment and renewable generation expansion, a different share of renewable generation in each control zone does not participate in voltage control. Increasing PE-interfaced generation replaces synchronous generators and this reduces the voltage control capabilities within the transmission grid by the capabilities of the replaced synchronous generators, if PE-interfaced generation does not provide the same capabilities. Additionally, depending on the location of the PE-interfaced generation and the replaced synchronous generators, the system might get higher loaded due to increased distances between load centres and PE-interfaced generation. Finally, PE-interfaced generation is often installed at the distribution level, so that voltage support for the transmission system is impeded due to one or more transformer impedances.

From a regulatory perspective, since both synchronous and non-synchronous generators can contribute, from a technical perspective, to reactive control, appropriate incentivisation will enable generators to participate in the reactive control. However, it is important to assess the technology capabilities and boundaries in order to assure the effective provision on each grid asset. For example, it needs to be taken into account that synchronous generators can provide reactive support irrespective of voltage level, while the capacitors' ability to provide reactive power depends on the voltage level (EirGrid and SONI, 2011).

In any case utilising non-synchronous generators for reactive power management would be beneficial, since voltage is a local phenomenon (EirGrid and SONI, 2010) and reactive power compensation is more effective when it is located closer to the region of imbalance (National Grid, 2016). Within this context, the distributed nature of non-synchronous generators potentially makes them an appropriate solution for voltage control. An additional benefit of utilising distributed generation for steady-state voltage regulation is the fact that losses from power transfers across the network can be minimised and the possibility of instability reduced. In fact, experimental results obtained through the GRID4EU project demonstrated that, for example, energy storage devices used at MV and LV levels were found to regulate voltage and power flow effectively, as well as reduce network losses (GRID4EU Technical Committee, 2016). Note that within this project, advanced on-load tap changer (i.e. MV/LV transformers) techniques have also been applied to achieve volt-var control. It was found that such schemes enhance the integration of RES and smooth voltage variation effects (i.e. voltage rise). It is worth mentioning at this point that the results of the REserviceS project (F. Van Hulle, et al., 2014) indicated that, unlike frequency support, which was beneficial for the system in all case studies with higher shares of variable generation, the cost-benefit ratio of voltage support from VG was case-specific. Thus, the voltage support provision from VG should be carefully compared with other alternative technologies (F. Van Hulle, et al., 2014).

Currently voltage regulation is highly dependent upon the synchronous generation, which is required to provide flexibility in this regard. Appropriate regulatory frameworks in association with the development of technical solutions should be promoted to enhance the provision of flexibility from distributed reactive power sources (i.e. DG units, storage equipment installed at lower voltage levels, etc.).

Notwithstanding the above, exploitation of the reactive power capabilities of large-scale non-synchronous generators connected at the transmission level would also be required. From this perspective, PROMOTioN project has investigated the capability of high voltage direct current (HVDC)-connected offshore WFs to provide reactive power aiming at supporting the mainland AC grid voltage. Different approaches are proposed, namely a fixed reactive power capability specified by relevant TSO within the onshore converter range (proposed example values of 0.41 pu ind-0.41 pu cap interval), a given power factor specified by TSOs (proposed example values of 0.925 ind - 0.925 cap interval) or a voltage control mode where the onshore Voltage Source Converter (VSC)-HVDC should provide reactive power proportionally to voltage variations.

It is recommended that a suitable market mechanism should be developed to enhance the utilisation of reactive power capabilities of non-synchronous generators through cost-reflective financial incentives (National Grid, 2016). In this regard, EirGrid and SONI have designed a suitable service, Steady-State Reactive Power (SSRP). The need for reactive power varies as demand varies and as the sources of generation vary; and since as noted above reactive power is difficult to transmit over long distances (unlike active power), reactive power sources are required to be distributed across the system. This suggests that there is not necessarily a strong link between the need for active power and reactive power from the same sources. It is therefore proposed that the reactive power product is restructured in a way that incentivises reactive capability across the widest possible active power range. SSRP is defined for conventional generators as the dispatchable reactive power range in MVAr that can be provided across the full range of active power output (i.e. from minimum generation to maximum generation).

4.4 DYNAMIC VOLTAGE CONTROL (DURING A DISTURBANCE)

During a disturbance, voltage stability is strongly influenced by loads in general and in particular by their dynamic behaviour with respect to active and reactive power consumption in response to this disturbance (MIGRATE Consortium, 2016) (Van Cutsem, 2000). This response is dependent on, amongst others, motor slip adjustments, distribution voltage regulators, tap-changing transformers, thermostats and PE control systems in case of PE-interfaced loads (MIGRATE Consortium, 2016).

Dynamic reactive power response approaches are proposed to alleviate voltage disturbances. Fast fault current injection is used to arrest the dip and support generators to ride-through it within the time imposed by the responsible SO. Synchronous generators have the inherent capability to both operate in lower voltages and to provide fault current rapidly. On the other hand, non-synchronous generators typically require higher voltages for their output not to be affected and their capability to offer fast fault current is more limited (EirGrid and SONI, 2010) (National Grid, 2016).

Post-disturbance, there is a requirement for the voltage to be contained within acceptable limits for protection purposes, until it is fully recovered back to nominal values. Undervoltage or overvoltage events arise from the increased demand of the system for reactive power after a disturbance has been cleared. Static and dynamic reactive power approaches in timescales ranging from ms to minutes are suggested to ensure that a voltage disturbance will not lead to a wide area event (e.g. voltage collapse). As the support from synchronous generation declines, there will be increased need for more such approaches to ensure post-disturbance containment and effective recovery (National Grid, 2016).

Non-synchronous generators can provide reactive power dynamically and support the system voltages. In this context, the Power Potential project in the UK aims to address multiple constraints on the transmission network and provide additional network capability for the distribution network through the utilisation of appropriate reactive resources in the distribution network (National Grid, 2016). To achieve this, it develops solutions to maximise the use of renewable energy resources (mainly distributed) to resolve transmission voltage constraints. In fact, a relevant research paper (Oulis Rousis, et al., 2017) has demonstrated that distributed resources and OWFs in the vicinity of the south-east region of the UK can mitigate severe transmission-level short-circuit events and prevent a voltage collapse.

Additionally, PROMOTioN project has demonstrated the response of the HVDC converter for DC-connected wind farms during dynamic voltage control by simulating a voltage step (first down step followed by an up voltage step) on the onshore AC grid. The results are presented in Figure 8 (PROMOTioN Consortium, 2017), in which it is possible to verify that the converter follows the voltage step (Figure 8b).

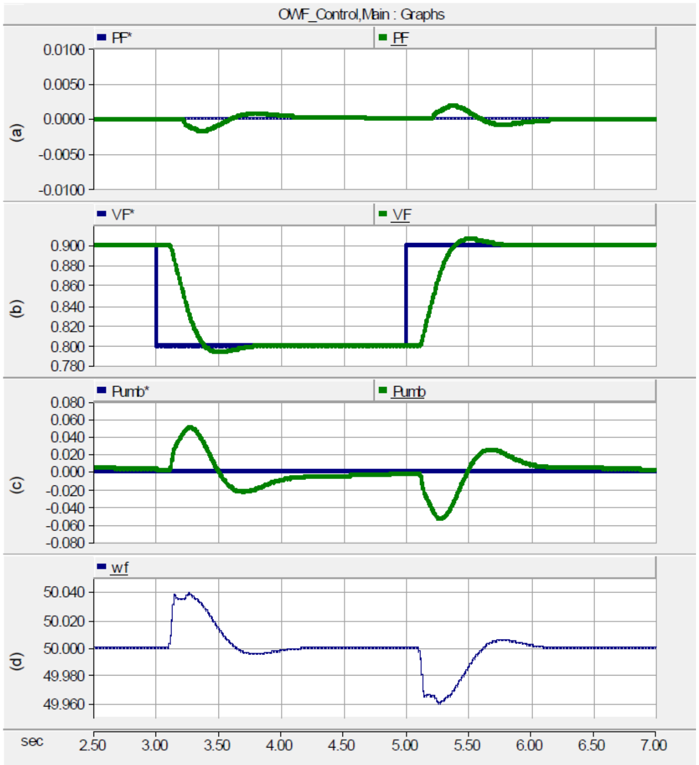

FIGURE 8 PROMOTION PROJECT VOLTAGE CONTROL RESULTS - (A) TOTAL OWF ACTIVE POWER; (B) OFFSHORE VOLTAGE VF1; (C) ACTIVE POWER THROUGH THE UMBILICAL CABLE; (D) FREQUENCY OF THE OFFSHORE AC GRID (PROMOTION CONSORTIUM, 2017)

The above considerations indicate that non-synchronous generators can provide reactive power support in a dynamic way. This will become necessary at high levels of instantaneous penetration of non-synchronous generation when there are relatively few conventional (synchronous) units left in the system. At these times, the electrical distance between the synchronous units is increased and in such cases provision of dynamic reactive power from non-synchronous generators would be even more beneficial given that the synchronous torque holding these units together as a single system is therefore weakened. EirGrid has leveraged this and accordingly designed a new service, the dynamic reactive response (DRR) of wind farms during disturbances (EirGrid Group).

Relying on non-synchronous generators for voltage support should, however, be considered carefully, as under-voltage tripping of non-synchronous generators can cause severe systemic issues (even voltage collapse) (Miller, Shao, Pajic, & D'Aquila, 2014). In fact, the study performed by (Miller, Shao, Pajic, & D'Aquila, 2014) has shown that a deliberate trip of distributed PV during disturbances resulted in a slower recovery and lower sustained voltages, as shown in Figure 9. This can cause local reactive power balance to be disrupted, with reactive power demand increasing by many times the amount of active power tripped.

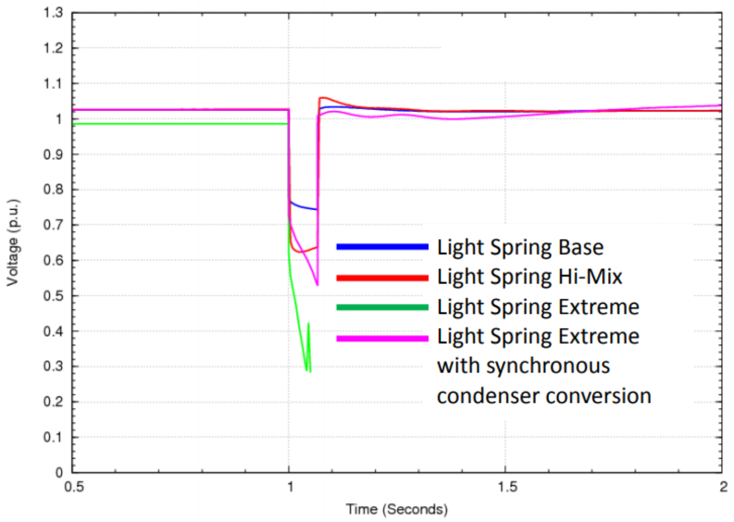

FIGURE 9 EXAMPLE OF BUS VOLTAGES FOR A FAULT OCCURING AT A HIGH WIND AREA IN THE WESTERN INTERCONNECTION UNDER VARIOUS SCENARIOS (MILLER, SHAO, PAJIC, & D'AQUILA, 2014)

4.5 SUMMARY OF VOLTAGE CONTROL-RELATED FINDINGS

Voltage magnitude in the transmission system is determined by the balance of reactive power demand and supply. Appropriate levels of voltage across the system are essential for the reliable operation of the transmission system. Synchronous generators have traditionally been a primary source of reactive power, which compensates for the reactive power produced and absorbed by consumers and by the lines and cables of the network itself. As synchronous generators are being progressively brought offline, studies indicate that voltage regulation becomes more challenging as this reactive power balance may be disrupted (i.e. if not compensated alternatively). The primary reason for voltage instability is, in fact, the inability of the system to maintain reactive power balance.

The issues identified largely relate to the reduced system strength (i.e. short-circuit power contribution) noted in many regions. Studies by (National Grid, 2016) and (Australian Electricity Market Operator, 2017) have revealed that since renewable generators do not have as much capability as synchronous generators to contribute in system strength, in cases of high instantaneous penetration of RES the system strength may be compromised.

This could mean that voltage control will become more challenging and existing network protection approaches may not detect faults equally as effectively.

Reactive power provision across various timescales can prove to be an effective solution. EirGrid has designed a suite of suitable services, including dynamic reactive power accounting for transient voltage response (in a timescale of ms to sec), steady-state reactive power to regulate voltage deviation during normal operation (i.e. in a timescale of sec to min) and finally network adequacy measures for the longer timescales (i.e. min to hours).

However, as synchronous generators are being progressively displaced, the aforementioned services should be procured from other sources. These can either be in the form of new reactive power compensating devices (e.g. STATCOMs, SVCs, etc.) or converter-fed RES, which have an inherent capability to independently produce/consume reactive power (Oulis Rousis, et al., 2017). The studies reviewed within this chapter show that dispersed RES can have a positive impact on voltage regulation during normal operating conditions. A typical issue observed in distribution networks with increased penetration of RES relates to voltage rise effects, which can be mitigated via utilisation of active network management schemes (UK Power Networks, 2014). Another topic of interest relating to voltage deviation in distribution networks concerns voltage drop (typically at low voltage levels) due to demand variation. As shown in the previous sections, both issues can be addressed by smart control techniques or by deploying flexible technologies distributed in the network.

The above idea of utilising distributed resources for mitigating voltage-related issues is enhanced by the fact that voltage is largely a local phenomenon, hence reactive power is most effective when close to the region of imbalance; this is something clearly demonstrated in several of the reviewed projects (GRID4EU with experimental demonstrations (GRID4EU Technical Committee, 2016), SOF (National Grid, 2016), etc.). Exploiting reactive power close to the region of imbalance would, additionally, lead to reduced losses (typically caused by transfer of reactive power across long distances). In that sense, DG units could offer the required reactive power and efficiently mitigate voltage deviation.

Reactive power is even more important during voltage disturbances, especially as system strength reduces over the years (MIGRATE Consortium, 2016) (Australian Electricity Market Operator, 2017). In such cases protection systems accounting for the smooth integration of RES may not operate satisfactorily, and even worse voltage stability may be compromised to a greater extent in the presence of severe contingencies (e.g. three-phase faults in the transmission system (Oulis Rousis, et al., 2017)). New voltage services can be created to exploit the dynamic reactive power response of RES generators. Note that wind farms (onshore/offshore and HVDC-connected), PV plants, energy storage systems, etc. have proved to be able to provide reactive power dynamically even for major disturbances in the transmission system (EirGrid and SONI, 2010) (GRID4EU Technical Committee, 2016). Hence, their full potential for providing such a service should be quantified and subsequently considered in a suitable market context.

However, another shortfall identified with respect to amassing the potential of distributed resources relates once again to the lack of an appropriate market/regulatory framework for allowing and incentivising the provision of reactive power from such resources. An appropriate market mechanism to create a level playing field for all players in association with enhanced collaboration between TSOs and DSOs could enhance such services and ensure that the system is secured in a cost-effective way.

5. ROTOR ANGLE STABILITY

5.1 DEFINITION OF ROTOR ANGLE STABILITY

Rotor angle stability refers to '*the ability of synchronous machines of a power system to remain in synchronism after being subjected to a disturbance'* (Kundur, P., 2004). It relates to the ability of each synchronous machine to maintain or restore equilibrium between its electromagnetic and mechanical torque whenever a disturbance occurs. In case of instability of a synchronous generator, the result is increasing angular swings leading to its loss of synchronism with other generators (Kundur, P., 1994).

The investigation of rotor angle stability involves the study of electromechanical oscillations in power systems (Kundur, P., 2004). A major parameter on the latter is the way power output of machines varies as the angles change. In steady-state operation, there is an equilibrium between the electrical and mechanical torque and the machine rotates at a constant speed. However, during disturbances this equilibrium is being violated, and therefore there is acceleration or deceleration of the rotors of the machines. Assuming that one machine may temporarily run faster than another one, the angular position of its rotor in relation to the slower machine will advance, leading to an angular difference (Kundur, P., 2004). If this difference exceeds certain limits (so that transfer of load from one to another cannot mitigate the angular separation), an increase in angular separation may be followed by a decrease in power transfer leading to further increase in angular separation. Instability may occur if the system cannot absorb the kinetic energy corresponding to these speed differences.

The oscillations described above mainly depend on two electromagnetic torque components, (*i*) synchronising torque (in phase with rotor angle deviation) and (*ii*) damping torque (in phase with speed deviation). System stability depends on the existence of both components, however lack of the first results in non-oscillatory instability, while lack of the second leads to oscillatory instability.

This characterisation can lead to a classification of the rotor angle stability, (*i*) small-signal stability and (*ii*) transient stability, which basically highlights two key areas of concern in modern power systems, as described in sections 5.2 and 5.3. The timeframe of interest for both types of rotor angle stability is in the scale of seconds. The review covered by the EU-SysFlex consortium describes the key findings regarding these aspects and potential solutions for resolving such cases. Table 5 clarifies which of the reviewed projects (refer to Section 2 for the full list of projects) have dealt with rotor angle stability and specifically which type of rotor angle stability.

PROJECT TITLE	SMALL-SIGNAL STABILITY	TRANSIENT STABILITY
Facilitation of Renewables Study		X
Massive Integration of Renewable Energy (MIGRATE) project (EU H2020)		X
Future Power System Security (FPSS) Program		X
e-Highway 2050	X	

TABLE 5 PROJECTS DEALING WITH ROTOR ANGLE STABILITY CONSIDERATIONS

Note that electromechanical oscillations between interconnected power systems are possible (CIGRE, 1996). Insufficient damping of one or more modes can lead to severe stability issues, e.g. (cascaded) generator or line tripping. As the modes and their damping are dependent on the whole system configuration including all control systems, alterations of this configuration due to increasing PE penetration affect the modes and their damping by several means (MIGRATE Consortium, 2016):

- Affecting the modes by displacing synchronous machines.
- Displacing power system stabilisers (PSSs) by displacing the associated synchronous machines.
- Affecting the synchronising forces by impacting the major path flows (by an altered relative position of generation and load).
- Interactions between PE controls and the damping torque of large synchronous generators.

Due to the introduction of PE interfaced equipment and their control loops, new oscillation modes may arise. So far, no general statements can be made about the absolute impact of increasing PE penetration on power oscillations, since this is dependent on multiple criteria, especially on the indirect effects caused by the displacement of synchronous generators with their PSSs and the alteration of load flows.

5.2 SMALL-SIGNAL ROTOR ANGLE STABILITY

Small-signal stability depends on the initial operating state of the system. Resulting instability can take two distinct forms: (*i*) increase in rotor angle through a non-oscillatory or aperiodic drift due to lack of synchronising torque, or (*ii*) rotor oscillations of increasing amplitude due to lack of sufficient damping torque (Kundur, P., 2004). The second category is the most common in today's power systems (Kundur, P., 2004). The problems in this type of stability can either be local or global in nature. The former are associated with angle oscillations of a single power plant against the rest of the system; these are called local modes or local oscillations. The latter involve oscillations of a group of generators maintaining synchronism in one area swinging against another group in another area; these are interarea modes or interarea oscillations.

The e-Highway 2050 project has dealt with the identification of inter-area mode oscillations (e-Highway 2050 Consortium, 2013). It was concluded that in the examined configurations (i.e. consisted of anticipated generation mix and proposed network upgrades) system stability would deteriorate but would still be within the range of power system stabilizers. In e-Highway 2050, the attention was brought to the inaccuracy of models and unknown dependency of low frequency modes on widely understood power system conditions. The results obtained in e-Highway 2050 should not be treated as acceptance or rejection of a given configuration nor as detailed remedy to identified problems, but rather like indication of a trend between different analysed scenarios. Damping was generally better in configurations with more synchronous generation, nevertheless spatial distribution of synchronous generation appeared to have an impact. The study also observed that network development via HVDC cables[6] usually led to higher damping of inter-area oscillations than network development via upgrade of existing overhead lines.

[6] The strategy of network development using HVDC cables is more expensive than using overhead lines, but it is more socially acceptable.

5.3 LARGE-DISTURBANCE ROTOR ANGLE STABILITY OR TRANSIENT STABILITY

This is concerned with the ability of a power system to maintain synchronism after a severe disturbance, e.g. a 3-phase short-circuit on a transmission line (EirGrid and SONI, 2010) (MIGRATE Consortium, 2016). Note that transient instability may also occur as a result of superposition of an interarea oscillation and a local oscillation. The system response in such a disturbance would involve large excursions of generator rotor angles from the pre-fault operating point and instability would occur due to insufficient synchronising torque. Thus, transient stability is distinctly dependent on the fault-clearing time. The maximum fault-clearing time of a three-phase short circuit, for which the rotor does not slip poles, is called Critical Clearing Time (CCT) and constitutes a key security criterion for transient stability. Furthermore, transient stability depends on the initial operating point of the system, the severity of the disturbance and the associated post-fault system state (Kundur, P., 2004). Increasing penetration of renewable generation based on PE – interfaced connections affects transient stability in various and interdepending ways, and the absolute impact could be negative or positive depending on the superposition and interaction of different influencing factors as listed here (MIGRATE Consortium, 2016):

- Impact of renewable penetration

While a moderate penetration rate of PE-interfaced renewable generation could improve transient stability of the power system thanks to the decreased loading of conventional power plants as well as of transmission lines, a higher penetration can reverse this impact, as the displacement of synchronous generators can reduce the system transient stability margin.

This has been proven by the findings of the EirGrid Facilitation of Renewables (FOR) Study, which showed that at high levels of wind generation there will be limited numbers of conventional synchronous generators online and thus there will be lower synchronising torque. This could lead to an increase in the number of contingencies with CCT less than 200 ms, indicating the system is less transiently stable (EirGrid and SONI, 2011). Moderate amounts of wind power increased dynamic stability. However, at high levels of wind power penetration, dynamic stability deteriorates significantly. This is illustrated in Figure 10 below.

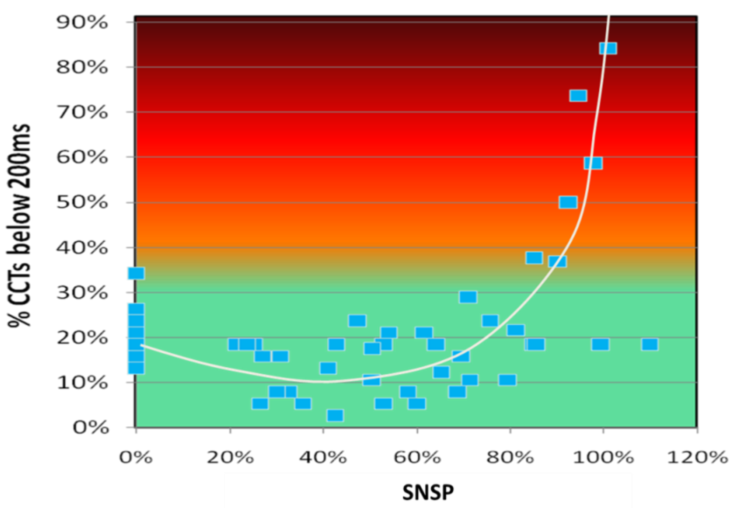

FIGURE 10 % OF CCTS BELOW 200MS -V- SYSTEM NON SYNCHRONOUS PENETRATION (SNSP) (EIRGRID AND SONI, 2011)

- Impact of dynamic voltage support

The effect on transient stability could be positive if modern renewable generators remain connected during system faults and provide dynamic voltage support.

The All Island TSO Facilitation of Renewables Studies report (EirGrid and SONI, 2010) also found that the provision of dynamic reactive power during voltage disturbances/faults can be used to mitigate some of the transient stability issues. Thus, the Dynamic Reactive Response product was designed and is being procured as part of DS3 System Services (EirGrid & SONI, 2014). Especially, at high levels of instantaneous penetration of non-synchronous generation, when there are relatively few conventional (synchronous) units left on the system, the electrical distance between these units is increased. The synchronous torque holding these units together as a single system is therefore weakened. It has been found that this can be mitigated by an increase in the dynamic reactive response (DRR) of wind farms during disturbances. Therefore, this service is particularly important at high levels of renewable non-synchronous generation.

- Impact of pre-fault operating point

The loading and pre-fault operating point of all generation sources impacts the transient stability, whereby lightly loaded generation resources have a larger transient stability margin. Similarly, for PE-interfaced renewable generation a lower load factor of wind or PV generators allows better voltage support by injecting higher reactive current without reducing the active currents. A specific issue related to the crowbar ignition of type-3 doubly-fed induction generator (DFIG) wind turbines (IEC, 2015) needs to be mentioned. In the event of a grid short circuit in the proximity of the turbine, crowbar circuit may be activated to short circuit the wind turbine rotor, in order to avoid damage to the rotor windings. In such a scenario, DFIG turbine behaves like a fixed speed induction generator, consuming reactive power and thereby leading to a deterioration in transient stability.

- Impact of renewable generation’s location

The voltage support provided by PE-interfaced generation installed electrically close to synchronous generators can enhance the overall system transient stability. Furthermore, the location of renewable generators could impact the system power flows. Increasing power flows, respectively increasing voltage angle differences among synchronous generators would have negative impacts on transient stability, especially in case of long distance transmission (MIGRATE Consortium, 2016).

- Impact of control and protection schemes

The undervoltage protection system of variable renewable generators could have a significant impact on transient stability. In the absence of dynamic voltage support from renewable generators, the ability of renewable generators to keep on providing active power during the fault can result in an acceleration of the synchronous generation in the vicinity. However, the provision of dynamic reactive support by renewable generation, during the fault contributes to a reduction in voltage depression and improvement in transient stability margins.

5.4 SUMMARY OF ROTOR ANGLE STABILITY-RELATED FINDINGS

The results of the review conducted show that transient stability margins across the European region will be reduced, mainly due to the displacement of synchronous machines by PE-interfaced variable renewable generators. This can lead to reduced damping of existing power oscillations or even introduction of new oscillation modes. Especially at high levels of instantaneous penetration, the stability of the power system may be compromised. One of the proofs is that the number of contingencies with reduced critical clearance times (< 200 ms) in such cases can be increased; e.g. see the case of the Irish power system (EirGrid and SONI, 2010). Hence, voltage disturbances can lead to transient instability due to lower levels of synchronising torque. Simulations performed in the Irish power system indicated that dynamic reactive response (DRR) provision can mitigate voltage-related transient stability issues, therefore the provision of a suitable system service can help mitigate the stability deterioration. When the synchronous generators in the system are significantly reduced, DRR can boost the synchronising torque holding these units together as a single system. However, it needs to be pointed out that such a service should be carefully designed to ensure that its deployment will indeed prolong the critical clearance times of contingencies and make the system more transiently stable.

On the other hand, MIGRATE project states that the increase of PE penetration affects transient stability in various, interdependent ways, and at the current stage it is not clear whether the absolute impact is negative or positive. For example, the German network development plan, issued by the TSOs and looking ten years ahead, concluded that there is only little risk of transient instability in Germany, even in a scenario with high wind penetration, high load and high transfer power flows from North to South (50Hertz Transmission GmbH et al., 2016). However, simulations showed that the remaining stability margins are reduced especially in TenneT operating zone. This report also mentioned the positive effects of the voltage support of modern wind turbines on transient stability and the negative effect of high loading of transmission lines. The overall impact of variable renewable generation integration on rotor angle stability depends on the superposition and interaction of several influencing factors (i.e. technology, specific penetration level, pre-fault operating point, etc.). This highlights the complexity of rotor angle stability issues and points out that it remains an open question according to current research findings.

6. CONGESTION MANAGEMENT

6.1 DEFINITION OF CONGESTION MANAGEMENT

Throughout this literature, several definitions of congestion have been identified. Congestion can be described within the Regulation (EC) No 714/2009 (European Union, 2009) as '*a situation in which an interconnected power system cannot accommodate all physical flows resulting from trade requested by market participants, because of a lack of capacity of relevant network element*'[7]. However, congestion is neither limited to interconnected power systems nor to interconnector flows between market areas. Indeed, the US DOE notes that transmission congestion arises when system and network constraints prevent grid users from transmitting as much power as they would like or that would otherwise be economically efficient (US Department of Energy, 2018). Additionally, ENTSO-E defines physical congestion as any network situation, where forecasted or realised power flows violate the thermal limits of the elements of the grid, and voltage stability or angle stability limits of the power system (ENTSO-E, 2015). The latest definition could also be applied to distribution networks, especially considering the increasing deployment of renewable generation that causes congestion constraints and a number of active network management approaches are considered to enhance the network utilisation.

Physical congestion is directly related to transmission and distribution capacity in the sense that under-developed networks in some areas of the system can lead to congestion. The traditional method of dealing with under-developed networks would be to invest in grid reinforcement. However, in recent years, there has been a drive towards increasing utilisation of existing assets and minimising the requirement for infrastructure investment. Indeed, in the Nordic power system, it has been determined that utilising the transmission capacity more efficiently will be needed in the future to increase the system's flexibility (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). In Central Western Europe area, Flow-Based market coupling (FB MC) also increased the utilisation of existing transmission capacity.

This is complicated by the transition to high penetration levels of variable renewable generation. Renewable generation resources are often located far from load centres, resulting in increased power flows in areas with weak networks. It has been shown in many reports (ENTSO-E, 2017) (ENTSO-E, 2018) (EDF R&D Division, 2015) that integrating a large share of variable RES requires a coordinated development of both RES and associated networks. It has been suggested that targeted network reinforcement of national grids along with interconnections could help to mitigate network congestions.

There are other mechanisms, besides network reinforcement, employed by system operators to avoid conditions that can result in electricity supply exceeding the capacity of the local/regional grid. Congestion management refers to the efficient use and allocation of capacity with the aim to maximise the benefits of power trade (Neuhoff, Hobbs, & Newbery, 2011). Two broad categories for providing congestion management can be

[7] Congestion defined as 'a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and/or the national transmission systems concerned'. In order to make the definition fit the current challenges they removed separation between international trade and national trade – the national trade was outside of scope of Regulation 714, and removed separation between interconnectors and internal grid elements.

identified, (i) technical and (ii) non-technical methods (Pillay, Karthikeyan, & Kothari, 2015). The former could be considered cost-free and initiated by system operators. These include network reconfiguration, operation of transformer tap-changers and conventional compensating devices, etc. The latter methods come at a cost and are usually market-based methods (e.g. congestion pricing, redispatching, counter-trading, etc.) and load shedding.

We would emphasize that the market congestion and physical congestion are not separate issues. They are just different aspects of congestion. For example, in a case where interconnected power systems cannot accommodate flows from all transactions, one approach is that SO accepts all transactions and afterward performs remedial actions (RAs) to bring the system back to a more secure state; in such a situation physical congestion is observed. The other approach is to accept only some transactions in a way that maximizes social welfare; in such a case market congestion is observed.

Commercial exchange capacities are also determined using the best forecast of load, generation and grid elements availability for long to short term markets. The allocation processes could saturate those commercial capacities and the load/generation pattern derived from this market output could lead to physical congestions.

In the European context, the market liberalisation has increased the opportunities for sharing power between market areas as a key mechanism for enhancing the competitiveness of markets. From a single market perspective (e.g. Day-Ahead market), the optimal market welfare value is reached when trades are not limited by commercial exchange capacities. At the same time it should be noted that a level of congestion may be economically effective, i.e. the costs of removing congestion would be higher than the benefits of doing so, as is illustrated in Figure 11 (ACER, 2014).

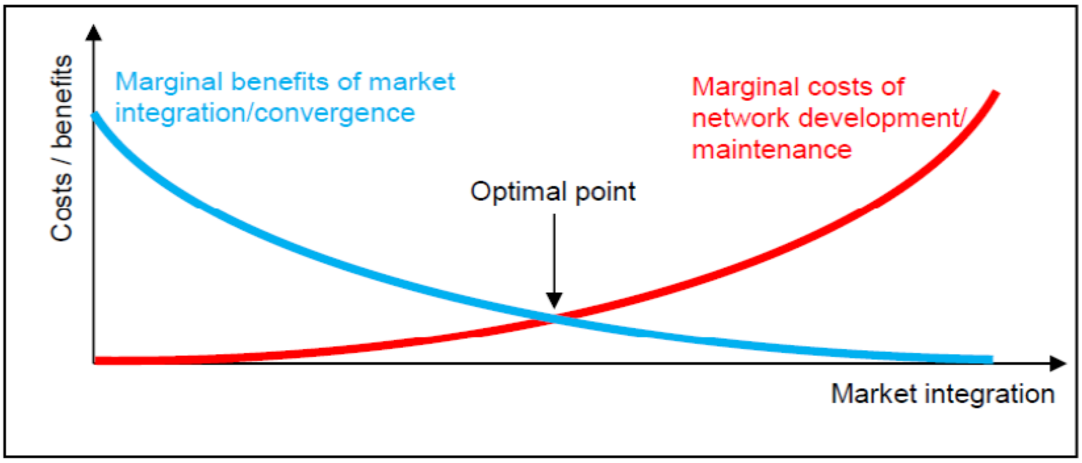

FIGURE 11 MARGINAL BENEFITS AND COSTS OF NETWORK DEVELOPMENT (ACER, 2014)

The projects, shown in Section 2, dealing with this system scarcity are listed in the Table 6 below. Additionally, the table demonstrates, which aspects relevant to congestion management these studies have dealt with.

PROJECT TITLE	NETWORK HOSTING CAPACITY	RES CURTAILMENT	CAPACITY ALLOCATION
GRID4EU	X		
GridTECH	X	X	
RAO tool			X
Coordinating cross-country congestion management			X
CIGRE-Innovation in the power systems industry, Volume 5, June 2019, pp. 119-125			X
UMBRELLA			X
e-Highway 2050	X		X
Eastern Renewable Generation Integration Study	X		
Challenges and Opportunities for the Nordic power system	X		X

TABLE 6 PROJECTS DEALING WITH CONGESTION MANAGEMENT CONSIDERATIONS

6.2 ACTIVE MANAGEMENT OF NETWORK CONGESTIONS

Network congestion occurs because the hosting capacity of a given grid is limited by the inherent characteristics of physical assets (i.e. lines, cables, transformers). Network reinforcement is usually not a cost-effective measure against congestion management, especially when a congestion appears only for limited time. Therefore, smart control strategies are being sought to increase the hosting capacity of a network in order to eliminate or defer investments for reinforcements driven by the growth in renewable generation deployment. This is particularly relevant in distribution networks where increased penetration of RES has disrupted the traditional top-down network philosophy, in which transmission-connected generators supplied the loads at the distribution level. In such cases, network expansion was easier and cheaper than setting up load curtailment schemes.

Renewable generation is predominantly located in the distribution level, which has led to considerable power flows in network assets (cables, overhead lines and transformers). An interesting observation is the fact that high levels of renewables penetration have sometimes resulted in rapid changes of transmission system power flows. For example, the Eastern Renewable Generation Integration Study has indicated that changes in the power flows are as a result of high levels of PV generation in some regions or the availability of lower-priced electricity from other regions at different times of the day (Bloom, et al., 2016). These effects can result in transmission system congestion.

The UMBRELLA project has also shown that the increasing share of variable generation sources (PV, wind) and, at the same time, the development of a unified European electricity market constitute new challenges for maintaining system security in the transmission system of the synchronous European area (Umbrella Project, 2016). The growing share of variable generation devices and also the introduction of non-conventional controllable devices (especially Phase Shifting Transformers (PSTs), HVDC lines, etc.) call for new approaches to system planning and operations and most importantly coordinated use of those devices by TSOs.

GRID4EU project has revealed that a promising resource for increasing network hosting capacity and thus relieving network congestion without capital-intensive investments, is smart control of on-load tap-changers (OLTCs) (GRID4EU Technical Committee, 2016). Specifically, two demonstration projects, in Italy and France, highlighted that the hosting capacity could be increased from 17% to 50% depending, of course, on the network configuration and the technologies involved. Another approach tested within this project for increasing the network capacity (17% increase achieved) is a grid reconfiguration approach implemented by the German demonstration project. Such reconfiguration requires switching operations from circuit breakers which could potentially increase their failure probability. Flexible demand and energy storage systems have been found to be beneficial in managing power flows, hence increasing network hosting capacity. A downfall noted with regards to energy storage is the fact that it currently appears to be very expensive. The project's analysis indicated that deployment of energy storage is not economically feasible if used only for distribution network services. This means that storage should also be utilised for the provision of other services for the transmission system to increase the network infrastructure's utilisation.

In the Nordic system, potential future location of reserves, and in particular reserves by less expensive resources, was found to be an important consideration in the analysis of potential grid reinforcements (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). More power transmission between hydro stations with reservoirs, and the load centres and interconnectors in the south are foreseen. The planned investments in the Nordic grid over the next ten years will reduce bottlenecks and improve system flexibility, however, tools and uncertainty analyses, as well as regional collaboration still need to be developed (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016).

The potential benefits related to the application of Special Protection Schemes (SPS) may also be significant when large volumes of renewable generation are connected in the remote areas of the transmission grid. In operational timescales, SPS could provide congestion management while in the long term defer network investments driven by increased penetration of renewable generation (Moreno, R. et al., 2012). In this context, there has been a growing interest in the use of SPS in order to facilitate a cost-effective integration of renewable generation. Great Britain (GB) system is an example of a power system with remote renewable generation, as large volumes of wind power generation are connected in Scotland, while the demand is mostly concentrated in England. In order to increase the North-South power transfer, National Grid (GB system operator) deployed an intertripping scheme in order to manage congestion and enhance the utilisation of this zone of the network (National Grid, n.d.). There has been significant interest in assessing the risks involved in the application of SPS schemes taking into account effects of unreliable performance of the protection systems (Calvo, J. et al., 2015).

6.3 RES CURTAILMENT

The topic of RES curtailment is directly related to the limited network hosting capacity. Typically, when DNOs face congestion in their networks, they resort to RES curtailment to relieve the stress. This is all despite the fact that this strategy may be perceived as undesirable as it contradicts the directives for increasing renewable generation levels in the power system. It is, however, of paramount importance to ensure the system's integrity. For example, the situations with high variable RES generation are challenging for the operation of the system, since traditional flexibility sources are no longer available and there are limited providers of the ancillary services which are essential for the security of the system (refer to frequency and voltage services described in the previous chapters) (EDF R&D Division, 2015). The aforementioned GridTECH project has also shown that other emerging technologies (grid-impacting technologies as they are referred to within the project), such as flexible AC transmission systems and Dynamic Line Rating (DLR), can relieve network congestion and therefore reduce undesirable RES curtailment (GridTECH Consortium, 2015).

In this context, the Flexible Plug & Play (FPP) project in GB, demonstrated that the use of smart grid technologies such as a Quadrature-booster (QB), DLR and Active Network Management (ANM), which allows control of renewable generation with non-firm access, may provide significant benefits when compared to traditional network reinforcement, as further explained in detail in (UK Power Networks, 2012). This project demonstrated the benefits of deploying DLR technology in distribution areas with considerable wind cooling effect enabling increase in power flows beyond the rated capacity of network circuits in periods with high outputs of wind generation. With respect to application of QB, the FPP project was the global first project to design and install one in the distribution network demonstrating significant benefits from releasing headroom in congested networks and minimising the curtailment of renewable energy sources.

There are three aspects of RES curtailment (WindEurope, 2016) (NREL, 2014) (Orvis, R. et al., 2017):

- Business aspect
- Technical aspect (including data exchange)
- Regulatory/legal aspect

The **business aspect** concerns remuneration for curtailment as well as resulting redispatching costs; however, it also relates to issues regarding profitability of RES generator. The **technical aspect** concerns the way the curtailment is executed: data interfaces, lead time, necessary functionalities of control systems, etc. The main part of **legal aspect** is whether RES curtailment is allowed at all, the activation and settlement aspects of curtailment, ex-post verification that curtailment was justified, etc.

6.4 NETWORK CAPACITY CALCULATION AND ALLOCATION

The Capacity Allocation & Congestion Management (CACM) Regulation by ENTSO-E provides 'the basis for the implementation of a single energy market across Europe. The CACM Regulation sets out the methods for allocating capacity in day-ahead and intraday timescales and outlines the way in which capacity will be calculated across the different zones. Putting in place harmonised cross-border markets in all timeframes will lead to a more efficient European market and will benefit customers' (ENTSO-E, 2015).

On a larger scale and specifically in the transmission system, conducting efficient congestion management in a wide, interconnected grid requires close cooperation of many TSOs. The report by (Kunz & Zerrahn, 2016) highlights the need of cost sharing as a means to incentivise cross-border coordination of remedial actions. In particular, it provides a review of approaches to harmonization of cross-border trade and operation of adjacent power systems, aimed at enhancing sustainability, security of supply and economic efficiency. Most importantly, it also provides results demonstrating the gains of increased coordination: 'the sharing of information about the network and dispatch status between national TSOs can considerably lower redispatch volumes' (Kunz & Zerrahn, 2016). The quantitative results were obtained using a model of the spot market and congestion management for the central-eastern European region (including Austria, Czech Republic, Germany, Poland and Slovakia). Considering the model along with 4 test cases, with different levels of coordination between countries (e.g. sharing information among national TSOs, counter-trading, multilateral remedial actions), allowed the authors to prepare guidelines for developing proper congestion management measures, both for internal and cross-border transmission lines (taking into account the so-called loop flows). Moreover, the necessity to provide incentives for national TSOs, dealing with different generation costs, congestion rates, etc., is highlighted. The authors claim that 'a mechanism to allocate congestion management costs in line with benefits on a national level' is necessary.

In the Nordic power system, most of the transmission interconnector capacity is allocated to day-ahead markets, however it has been found that utilising the transmission capacity more efficiently will be needed in the future to increase the system's flexibility (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). The report states that Nordic TSOs were due to make a decision in late 2016 whether flow-based or coordinated NTC is to be used. In the end the Nordic TSOs chose the flow-based approach (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016).

Considering the TSOs operating the European synchronous grid, the process for developing coordination of remedial actions (RAs) in order to manage the congestions has started. Coordination of RAs in congestion management calls for development of inter-TSO cost-sharing mechanisms. First of all, some of the RAs are costly by definition, like redispatching (XBR – Cross-Border Redispatching or MRA – Multilateral Redispatching). Secondly, even seemingly costless RAs like changing the PSTs taps may involve costs for some TSOs[8]. Therefore, to assure smooth and efficient congestion management among the TSOs, an underlying transparent cost-sharing mechanism is required. The ACER recommendation with respect to attribution of the RA costs to TSOs seems straightforward: the 'polluter-pays principle' states that the unscheduled flows over congested network elements should be attributed to TSOs/areas causing them ('polluters') and they should contribute to the costs of RAs counteracting these flows in proportion to their contribution to the overload[9]. However, an area-wide implementation of this principle is yet to be developed, with causes of such situation being attributed not only to political issues (for example, existence of prior bilateral agreements specifying rules of cost-sharing between some of the TSOs), but also to methodological questions (for example, how to incentivize national TSOs to cooperate and share costs with each other). These questions are related to identification of unscheduled flows (e.g. the so-called transit or loop flows) and their contribution to congestion, which require utilizing one of the so-

[8] As one example, consider a TSO which PST is used in the market capacity optimization in a way that restricts their use during DACF or IDCF processes – if a congestion occurs, this TSO is forced to exploit costly RAs. As another example, consider a PST that is used in IDCF by one TSO to overcome congestion, resulting in shifting the flows and causing congestion on a line operated by another TSO.

[9] For more formal definition of the principle see (ACER, 2016).

called power flow decomposition methods. Although many of them exist, they are not equivalent in the resulting identification[10]. This mechanism is recommended by the ACER.

The review reveals that the work conducted in this area is divided in two general branches, addressing two aspects of grid operations; energy market-oriented coordination and congestion management from a nodal perspective. The first issue is the energy market-oriented coordination, which aims at managing congestions from the zonal perspective of the pan-European Flow-Based Market Coupling (FB MC). In particular, the mechanisms being developed here serve the capacity calculation process and optimization of the FB MC trading domain for the day-ahead market. Within this category, the Remedial Actions Optimization (RAO) methodology, developed as a part of Flow Based Capacity Calculation methodology for CORE region (ENTSO-E, 2016), methodology has been designed to coordinate and optimize the use of remedial actions before the day-ahead electricity market of the CORE area is cleared. The aim of the RAO in this process is to identify the bottlenecks (i.e. most congested CNEs) which limit the potential trade flows, and use the available RAs in a coordinated manner in order to increase the flow-based trade domain volume. The study (e-Highway 2050 Consortium, 2013) made a qualitative assessment of possible governance. It was concluded that lack of coordination between the TSOs on the current energy and balancing markets makes it difficult for the system to effectively balance the growing share of renewable energy. Integration of the regional energy market should be carried out in all time frames, including the day-ahead market, the intraday market and the balancing market. Combined power systems with a large share of variable renewable energy generation require that the regional monitoring and control mechanisms are closer to real time and across larger geographical areas; this will enable the system to deal adequately with forecast errors relating to variable generation, such as wind and solar generation.

The second issue is related to the system security and congestion management from a nodal perspective. There are two approaches to capacity allocation: nodal and zonal approach. In a nodal approach, the aim is to guarantee the realization of market solution in the physical grid; i.e. after the day-ahead market closes, the market equilibrium of generation and load needs to be projected into a congestion-free operating state of the electric system. Next, in real-time operation, the system state needs to be monitored and corrected for congestions arising from unforeseen/random circumstances. Within this context, e-Highway has revealed that the approach based on zonal prices distorts location signals that drive investments in transmission and generation assets (e-Highway 2050 Consortium, 2013). A set of key alternative regulatory solutions for managing cross-border European electricity transmission networks by 2050 was proposed. It was proven that limit management based on price setting at the marginal level can contribute to efficient short-term price signals and long-term investment signals. It should be further assessed whether the locational marginal pricing (LMP) system can increase the efficiency of transmission capacity allocation in the European electricity system. LMP presents the short-term cost of electricity in a specific location. It allows to reveal network congestion effects through price discrepancies and provides efficient operational signals. However, the nodal market design is not compliant with the current network guidelines that assume the zonal market model and has not proven to reflect flexibilities in an adequate

[10] As the most widely used methods of decomposing power flows decomposition we can list Proportional Sharing Principle, Equivalent Bilateral Exchanges, Power Flow Decomposition, Power Flow Colouring ((Bialek & Kattuman, 2004), (Galiana, Conejo, & Gil, 2003), (Wolter & Huhnerbein, 2008), (FutureFlow, 2016)).

way. Moreover, nodal pricing tends to increase price volatility, thus increases risks from an investor point of view. The feasibility and consequences on prices of nodal pricing while taking into account all costly and non-costly remedial actions (PST taps adjustment, topology reconfiguration…) at a European level should be assessed.

The zonal approach, used by the EU, is based on the assumption that congestions within a bidding zone could be managed by non-costly remedial actions or are limited, therefore all transactions within a zone are accepted (i.e. we may observe only physical congestion within a bidding zone). Following the zonal approach, capacity allocation is performed only between bidding zones. Consequently, each market participant within a bidding zone observes the same price in wholesale market, while nearby market participants but within a different bidding zone may observe significantly different price even if congestion is far from them. Conversely, in the nodal approach individual impact of market participants on congestion is taken into account within the market framework. As such, two nearby market participants will observe significantly different prices only when there is congestion between them.

6.5 SUMMARY OF CONGESTION MANAGEMENT-RELATED FINDINGS

Network congestion, driven by increased connection of renewable energy sources, will prove to be a challenging topic in the near future for the operation of both distribution and transmission systems. Regarding the former, the increase in penetration of renewable generation will stress the networks towards their thermal and voltage limits. As a way to avoid extensive investments for network reinforcements, appropriate voltage control strategies, utilisation of smart techniques in the OLTCs of transformers and flexible technologies (such as Flexible Alternating Current Transmission System (FACTS), DSR, etc.) can be deployed to manage congestion, as demonstrated by GRID4EU and GridTECH projects (GRID4EU Technical Committee, 2016) (GridTECH Consortium, 2015). On top of increasing the hosting capacity, another positive effect would be the reduction of RES curtailment (DSOs currently curtail RES generation to relieve network congestion). In this context, it was also demonstrated that the use of smart grid technologies such as a quadrature-booster, dynamic line rating and active network management of renewable generation, may provide significant benefits when compared to traditional distribution network reinforcement (UK Power Networks, 2012).

Furthermore, increased monitoring of assets in order to allow for temporary overloadings has also been proposed. For example, typical distribution level transformers could operate overloaded by up to 40% without significant impact on their lifetime (Electricity North West Limited, 2015). In the same vein, dynamic line rating is a proposed method for temporarily increasing line ampacity (e.g. during high wind penetration) without investing in transmission reinforcements (Simms & Meegahapola, 2013). An essential step towards allowing such measures to be implemented would be the revision of planning and operational standards, which currently allow only for high redundancy levels leading to enhanced investments in network reinforcement. Similarly, potential benefits related to the application of special protection schemes may also be significant when large volumes of renewable generation are connected in remote areas of the transmission grid. In operational timescales special protection schemes could provide effective congestion management while in the long term deferring network investments driven by increased penetration of renewable generation (National Grid, 2016).

Interconnections will play a vital role in facilitating cost effective integration of renewable generation, that would be supported by the creation of a unified European energy market, as per the ENTSO-E regulations described in ANNEX II. However, relevant studies indicate that cross-border bottlenecks may be created; e.g. cold spells in the Nordic region during the winter can create congestions from the West to the East of Norway and from the North to the South of Sweden. Studies both in the Nordic countries and the EU H2020 e-Highway 2050 project have shown that the market needs to evolve to mitigate congestions in the European region. The Nordic studies propose the introduction of a new market, the Regulation Power Market (RPM), which will be responsible for the bids in the multinational area of the Nordic countries (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016). e-Highway 2050 project concludes that regional monitoring and control mechanisms need to be brought closer to real time and include larger geographical areas. The study also reveals that zonal pricing can lead to over-investments in transmission and generation assets. Nodal market approaches could be investigated. The bottom line of these ideas is that the energy market needs to evolve for network congestion issues to be mitigated in a cost-reflective manner.

Within this direction, capacity calculation and allocation may be a critical aspect for ensuring security of supply in an economically efficient manner. The reviews highlight that various methods exist for calculating and allocating capacity and managing congestion in wide areas such as the European Union. Use of remedial actions (e.g. PSTs) is employed to mitigate congestion in such cases, however when it comes to wide geographical areas it is still not clear what the most effective cost-sharing mechanism should be (ACER, 2016). ACER recommends that the ‘polluter-pays principle’ to be adopted, based on a cost-sharing methodology that could incentivise national TSOs to participate has not yet been developed yet.

7. SYSTEM RESTORATION

7.1 DEFINITION OF SYSTEM RESTORATION

Power systems are now regularly being pushed closer to their operational limits as a result of de-carbonisation and a drive towards greater utilisation of system assets. The increased extreme weather events together with large penetrations of variable generation resources can cause various voltage and frequency disturbances, as discussed in earlier sections of this report. Such events can lead to wide-area blackouts. In fact, power systems across the globe have experienced a number of blackouts in the recent years; e.g. the European power outage on 4th November 2006 which affected 15 million people (Liu, Fan, & Terzija, 2016).

Blackouts, while rare, could be considered inevitable, thus suitable restoration methods should be in place to ensure that the impact on the power system, public and economy is minimised. Power system restoration is the process required to restore the system to steady-state operation following a partial or complete collapse causing an extensive loss of supply. Restoration of the system consists of a very complex sequence of coordinated actions whose framework is studied and, as far as possible, prepared in advance (ENTSO-E OH, 2017). System restoration can be affected by several parameters such as the restoration time and the equipment availability.

There are three stages concerning system restoration (Liu, Fan, & Terzija, 2016) (Holtinnen et al., 2012):

- Black-start or preparation stage (also called re-energisation)
- Network reconfiguration
- Load restoration (or synchronisation)

Each of the stages poses different challenges, as will be discussed in sections 7.2 - 7.4. The re-energisation process can be implemented using two strategies:

- Top-down re-energisation refers to the utilisation of external voltage sources, where the grid is re-energised from a neighbouring TSO, starting from the tie-lines.
- Bottom-up re-energisation relies on capability of internal resources and is achieved using units that provide the capability of controlling voltage and speed/frequency during supplied isolated operation and stable operation in an islanded network. Those units are referred to as having black start capabilities.

Here we focus on the bottom-up re-energisation, which has attracted attention due to the high penetration of renewable generators and their proven capability of controlling voltage and frequency in power islands (National Grid, 2017). The projects, from the review presented in Section 2, dealing with this system scarcity are listed in Table 7 along with the specific aspects of the scarcity investigated.

PROJECT TITLE	BLACK-START	NETWORK RECONFIGURATION	LOAD RESTORATION
System Operability Framework	X		
GRID4EU	X	X	
REserviceS	X		

TABLE 7 PROJECTS DEALING WITH SYSTEM RESTORATION CONSIDERATIONS

7.2 BLACK-START (OR PREPARATION STAGE)

This is the stage in which a black-start generator provides power to a non-black-start generator (Jiang, et al., 2017). Currently, it is provided by some synchronous generators that have the capability to restart from an on-site supply without reliance on external supplies, and energise parts of the network to support the start-up of other generators (Liu, Fan, & Terzija, 2016). A black-start generator should have the capability to provide dynamic frequency and voltage control to alleviate large fluctuations typically expected during system restoration periods (National Grid, 2016). Additionally, a black-start generator should be able to handle instantaneous loading of large demand areas, connection of power islands, etc. progressively leading to whole-system restoration (National Grid, 2016). As more and more synchronous generators are de-energised, new black-start approaches need to be developed to ensure that other providers can participate in this process (National Grid, 2017).

For example, the SOF report states that National Grid has traditionally procured black-start services from thermal and coal generators. However, with the integration of renewables it is likely that these generators will start being out of merit making them costly to provide the service. For example, when black-start is delivered by thermal generation, these generators should be in a state of readiness to provide the capability quickly, effectively and reliably within the pre-defined restoration timescales (National Grid, 2017). As such, these generators should be warm and hence they are operated even though they may not be in merit (National Grid, 2017). National Grid is in search of new approaches in terms of providers and also restoration strategies (National Grid, 2017) including distributed generation and establishing small, self-contained energy islands (National Grid, 2017). A black-start provider typically has a set of capabilities, including (i) dynamic frequency control, (ii) dynamic voltage control and (ii) block loading. Consequently, modern technologies and control schemes could enable non-synchronous generators to provide this service (National Grid, 2016).

It was noted in the REserviceS project (F. Van Hulle, et al., 2014) that during the system restoration process TSOs have even higher demands for reliability and will avoid any components adding uncertainty. This means that the uncertainty and variability associated with wind and solar generation would need to be limited during this time in order for such resources to be considered suitable/ eligible for this service provision (F. Van Hulle, et al., 2014). However, in future islanding operation in suitable sub-networks, called cells could be enabled more (as explained within the REserviceS project (VTT, DTU, UCS, EWEA, 2012)) as power supply would depend entirely on distributed geenrators in the cell. These cells would guarantee availability of power to a certain level and would provide services such as voltage control, power exchange, fault management, and phase symmetry. This means being able to maintain stable frequency and voltage during islanding, keeping network impedance within range and phase symmetry, offer capability to handle fault currents, as well as being able to re-connect to main grid when in synchronism. This development could enable black start capability and support during restoration from wind and solar generators, as well as other distributed resources.

In fact, the GRID4EU project has demonstrated that battery energy storage systems (BESS) can be utilised to black-start a part of an islanded network following a distribution grid failure, hence demonstrating that black-start can be achieved without the use of rotating machines (GRID4EU Technical Committee, 2016). Specifically, batteries have been used to black-start the area and then to manage the reconnection of the PV plants and loads which resulted in significant voltage and frequency deviations (GRID4EU Technical Committee, 2016). Similarly, restoration could be initiated at the district level (e.g. from microgrids), utilising small-scale technologies such as batteries, which would then support the restoration of larger areas of the distribution network and then the transmission system (Strbac, et al., 2015).

7.3 NETWORK RECONFIGURATION

At this stage in the system restoration process, generators restored during the previous phase are used to energise bigger parts of the network creating a backbone network able to accommodate load restoration (Liu, Fan, & Terzija, 2016). Restoration strategies in this stage indicate that the energisation of parts of the network should occur in a sensible energisation sequence (e.g. start-up of primary units, restoration of grid supply points, and then restoration of regional interconnection) (Liu, Fan, & Terzija, 2016).

GRID4EU has developed an 'Autonomous Switching System', which uses a grid reconfiguration algorithm for restoring the grid (GRID4EU Technical Committee, 2016). It has been found that the algorithm is beneficial when restoring the grid as it reduces the time required for restoration to half (compared to other typical fault localisation, isolation and restoration techniques).

7.4 LOAD RESTORATION

The fundamental aim of system restoration is obviously the restoration of power supply to consumers. Therefore, following the first two stages large-scale load restoration can be carried out. No reference was made to load restoration strategies within the reviewed projects. Since EU-SysFlex is focused on a European power system with renewables above 50%, the review performed for the needs of this report is mainly focused on investigating the state-of-the-art strategies for provision of black-start from non-synchronous generators.

7.5 SUMMARY OF SYSTEM RESTORATION-RELATED FINDINGS

The literature review performed with respect to system restoration indicates that as the penetration of variable generation (both in transmission and distribution networks) becomes higher, the need for ancillary services, including system restoration, will accordingly increase. System restoration services have been traditionally provided by large-scale synchronous generators (e.g. hydro or coal plants), particularly black-start capability.

However, the transition to systems with penetrations of non-synchronous generation above 50% will result in a reduction in the number of synchronous generators and thus a reduction in traditional system restoration capability. As such, new strategies for system restoration need to be developed enabling non-synchronous generators to provide the required restoration. New restoration strategies should be designed that leverage the flexibility of other providers (GRID4EU Technical Committee, 2016) (National Grid, 2017).

A main area of concern is black-start capability, required to start the system following a collapse. This service has been typically procured from certain synchronous machines which require no external power supply to start. With their displacement other technologies need to be enabled for flexibility provision. In fact, the role of the black-start provider can indeed be covered by devices other than synchronous generators. Indeed, modern technologies enable converter-fed variable generation to provide both frequency and voltage control dynamically (Sakamuri, J. N., 2016) (De Rijcke, S. et al., 2012). The review reveals that battery storage systems could be used to black-start PV plants and consequently energise bigger and bigger areas of the grid. This creates an opportunity both for variable generators to provide services, which would increase their revenue, and for system operators, who can increase the flexibility in their systems and lower the operational costs (i.e. running out-of-merit generators only to provide a service in case of a disturbance increases the cost of operation). This suggests that system restoration in the future could be realised in a bottom-up way rather than following the traditional top-down philosophy.

On the one hand, system restoration capability could be enhanced by greater coordination between TSOs and DSOs, since a non-negligible amount of non-synchronous generation is connected to distribution systems. On the other hand, a market accounting for and suitably remunerating the capabilities of non-synchronous generators able to provide restoration services should be considered.

8. SYSTEM ADEQUACY

8.1 DEFINITION OF SYSTEM ADEQUACY

System adequacy refers to the existence of sufficient capacity to meet system demand. This capacity can be generation capacity or bulk system capacity (i.e. generation, transmission and distribution capacity) (Billinton & Allan, 1996). Traditionally, system adequacy is related to generation capacity. In general terms, system or generation capacity adequacy (sometime also called resource adequacy) refers to the relationship between available generation and load. It describes the ability of the generation system to meet demand in all situations. However, in systems with high RES penetration, flexibility requirements need to be considered in the assessment of adequacy (CAISO, 2018).

System adequacy is typically determined using probabilistic techniques and expressed using indices such as loss of load probability (LOLP) and loss of load expectation (LOLE) or expected energy not served (EENS) (Billinton & Allan, 1996). The LOLE is the expected number of hours in the period of the analysis, usually a year, during which load exceeds the generation capacity. In systems where conventional plants dominate, the traditional deterministic approach is sufficient. This is because there is limited impact of weather conditions on conventional generation capacity[11] and because generation outages are assumed to be independent events. However, with the transition to high levels of renewable generation, new approaches are required to consider the stochastic nature of renewables. There is also a need to assess spatial and temporal correlation of RES generation and the correlation between load and RES generation, etc. New approaches are explored in the academic literature (European Commission, 2016) (WindEurope, 2016) (ENTSO-E, 2014).

The projects, from the review presented in Section 2, dealing with this system scarcity are listed in Table 8 along with the specific aspects of the scarcity investigated.

PROJECT TITLE	UNCERTAINTY	INTER-DEPENDENCIES
Mid-Term Adequacy Forecast	X	X
GridTECH	X	X
GRID4EU		
System Operability Framework		X
e-Highway 2050		X
Technical and Economic Analysis of the European Electricity Power System with 60% Renewable Energy Sources	X	X

TABLE 8 PROJECTS DEALING WITH SYSTEM ADEQUACY CONSIDERATIONS

8.2 UNCERTAINTY OF RES GENERATION

High levels of variable RES in a system will transform the generation portfolio. There will be a reduction in base load generation and an increase in peaking plants (“back-up”) capacity which is required during periods with low

[11] Most common case: the drought and hot weather decrease generation capacity.

wind and solar PV across Europe (EDF R&D Division, 2015). This change in generation portfolio is compounded by the uncertain and weather-dependent nature of renewable generation. As the penetration levels of renewables increase, the uncertainty of renewable generation becomes increasingly relevant to system adequacy. For example, wind resource availability during winter peak demand varies from one year to another and given that extreme cold spells (i.e. low probability events) are difficult to forecast, it becomes clear that variable renewable generation creates significant challenges with respect to generation adequacy. Similarly, the impact of cold weather on the balance between generation and demand (ENTSO-E, 2017), particularly in countries heavily dependent on electric heating, can be profound to such an extent that ENTSO-E have looked at including cold spells in resource adequacy studies. It is found that the computation of the energy not served (EENS) metric is highly dependent on which climatic years are included in the analysis.

Capacity markets are often seen as a mechanism through which to assure generation adequacy (Cramton & Ockenfels, Economics and design of capacity markets forthe power sector, 2011). Indeed, the main purpose of a capacity market is to ensure that there are the correct incentives for investors to build adequate capacity in line with consumer preferences for reliability (Cramton, Ockenfels, & Stoft, Capacity Market Fundamentals, 2013). It has been shown that energy-only markets may not generate sufficient remuneration for conventional thermal generation, resulting in inadequate generation mixes to meet peak demand (Hoschle, De Jonghe, Six, & Belmans, 2015). In fact, the Mid-term Adequacy Study from ENTSO-E (ENTSO-E, 2017) shows that the absence of a capacity market, or the presence of unfavourable market conditions in several countries, could lead to mothballing of plants. For example, in Belgium, 4% of the thermal capacity stated for 2020 could be mothballed in 2020, while in Poland 3.4 GW of thermal capacity could be decommissioned in 2020 (ENTSO-E, 2017).

Similarly, in the Nordic countries, it is seen that a proportion of thermal capacity will shut down and the capacity margin will become gradually tighter. It is probable that tightening capacity margins could happen on the Continent and in the Nordic area at the same time. In Nordic countries cross-border dependency is most prevalent in Denmark and Finland. Capacity markets are not considered in Nordic system, due to uncertainty on how these markets will be operated. It is found that the consequences of not having capacity markets in Europe (Statnett 2015a) results in a tighter margin and higher price spikes. There must be room for higher price maximums and price signals must reach market participants in order for them to react adequately, be it short-term responses to shortage situations or long-term investment decisions (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016).

The study shows the importance of coordination between countries to maintain generation adequacy, as mothballing in one country has an impact on the neighbouring countries. Additionally, obtaining reliable information from the supply side of the system through, for example, a decommissioning plan 3-5 years ahead, is essential.

Additionally, uncertainty in the interconnectors power flows, which can rapidly change the power flow direction can impact on the security of supply. For example, in the UK, where increased interconnection is foreseen, an abrupt change in the power flow direction due to a price signal could create an instantaneous deficit between demand and supply. To avoid such situations, it is recommended that flexible sources and appropriate regulations are introduced to mitigate this (National Grid, 2016).

8.3 SYSTEM INTERDEPENDENCIES AND THEIR IMPACT ON SYSTEM ADEQUACY

This topic covers the dependencies found between various resources affecting system adequacy, including generation capacity, storage, energy efficiency measures, demand side response and interconnectors (ENTSO-E, 2017).

Relevant studies (ENTSO-E, 2017) (ENTSO-E, 2014) (European Commission, 2016) performed in Europe have indeed revealed that temporal and spatial dependencies in load and generation patterns from renewables, as well as in the availability of hydro and thermal power can affect the adequacy of the system. While renewables have been mostly installed in locations, where the respective natural resources (i.e. wind, sun, etc.) are most abundant, these locations do not always coincide with areas of high demand (e.g. urban centres). This leads to the need of transmitting renewable generation over significant distances. This issue becomes especially topical when considered from the perspective of the pan-European power system; integrating a large share of variable RES requires a coordinated development of RES and networks. The graph in Figure 12 reproduced from the ENTSO-E Mid-Term Adequacy Forecast (ENTSO-E, 2017) illustrates the benefit of spatial aggregation. It is noted that having an appropriate level of interconnection is key to supporting adequacy in large systems, such as the pan-European system (ENTSO-E, 2017) (EDF R&D Division, 2015) (ENTSO-E, 2018) and for the security of supply in systems operating with a low amount of conventional plants.

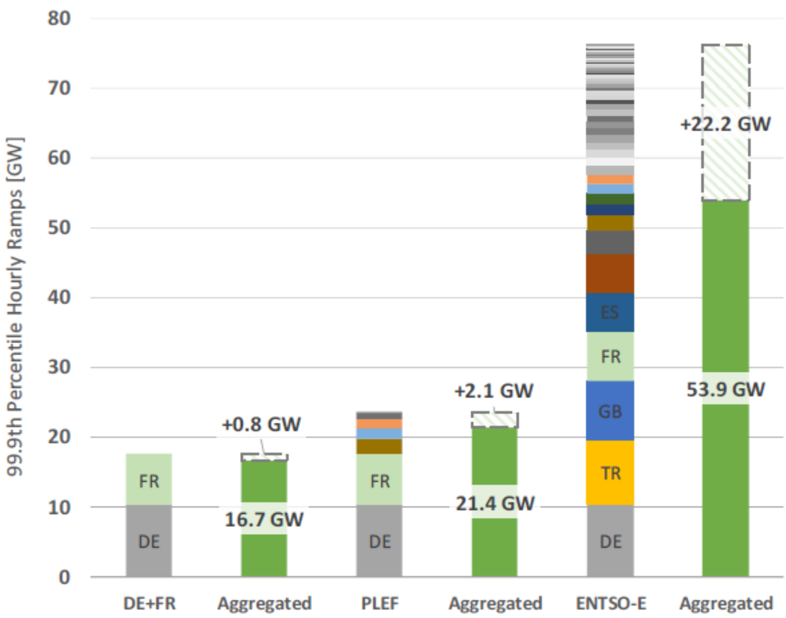

FIGURE 12 BENEFIT FROM SPATIAL AGGREGATION (ENTSO-E, 2017)

This concurs with the results from studies in the Nordic countries (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016) which highlights that cross-border adequacy assessments are required. This can become even more crucial given that, in the near future, aging thermal power stations will shut down creating tighter capacity margins. As previously mentioned during the discussion on frequency control, cross-border dependency is very prevalent in Denmark and Finland (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016).

Furthermore, an appropriate level of interconnection will lead to a reduction in the market prices. Innovation in grid communication will provide increased flexibility to the system (ENTSO-E, 2018). Therefore, it has been suggested that interconnectors are crucial for supporting adequacy in large systems (ENTSO-E, 2017). Interconnectors can enhance system adequacy on a wider geographical area, thus allowing the realisation of benefits from statistical balancing effects in both load and renewable generation.

As an example, when considering two interconnected countries, there is a probability that these two countries do not face the most critical peaks of load and low generation of variable renewables at the exact same time (i.e. different climatic conditions and cultural habits create the conditions for differences in the daily load). This demonstrates the significance of targeted network reinforcement of national grids along with interconnections between countries.

However, beneficial balancing effects to support systems in times of locally scarce generation capacity may only be deployed if sufficient grid infrastructures are present. In the same context, measures to overcome adequacy problems may be allocated to the supply-side, demand-side or the grid infrastructure. Therefore, decision-makers will need to coordinate their activities to ensure an efficient deployment of complementary measures. For instance, additional interconnection may supersede the need to enhance the generation capacity within a country (ENTSO-E, 2017).

According to the results of the e-Highway project (e-Highway 2050 Consortium, 2013), decisions on network development should take full account of the interdependencies existing between investments undertaken in several European countries and the associated benefits. Cross-border coordination of investments in generation and transmission should therefore be considered in a pan-European level. The evolution towards a more coordinated, pan-European network development planning process, working together with national organisations, is considered an effective way to correctly and timely identify major network bottlenecks and related infrastructure development (e-Highway 2050 Consortium, 2013). To achieve the objectives of European policy for a competitive, sustainable and reliable network, close cooperation at the operational level is also necessary. All potential cross-border transmission investments in the European system, together with their costs, should be considered in order to determine which network extensions and grid reinforcements are to be taken. A top-down approach is used in conjunction with bottom-up to properly take into account knowledge about regional or national networks, as well as network specificity and necessary investments to ensure the secure operation of local systems and the compatibility of regional and local expansion plans.

In addition to dependencies at the transmission system, the literature reveals that benefits can be realised by considering interdependencies with the grid infrastructure at the distribution level. For example, GridTECH has considered the interdependencies between pumped storage, PV generation and interconnection (i.e. Germany-Austria) which was found to reduce the curtailment of PV generation (GridTECH Consortium, 2015). The project has also shown that the security of supply can be increased by considering both grid infrastructure investments such as FACTS, upgrade and construction of new AC corridors, etc. and demand-side measures such as such as electric vehicles, demand side management and storage.

8.4 SUMMARY OF SYSTEM ADEQUACY-RELATED FINDINGS

The studies reviewed in this chapter indicate that as thermal plants are being decommissioned, capacity margins will become tighter. In fact, within this context the results of the EDF study (EDF R&D Division, 2015) demonstrate that fuel plants will be needed for backup capacity in order to achieve sufficient levels of security of supply. Additionally, (Statnett, Fingrid, Energinet, Svenska Kraftnat, 2016) indicates that there is a possibility for the decommissioning of thermal plants to happen simultaneously in Continental Europe and Nordic countries, which could make things worse. Uncertainty of generation capacity and system interdependencies appear to be areas that may affect the target to achieve a capacity-adequate European power system.

Operating conventional fossil fuel plants, as indicated by EDF (EDF R&D Division, 2015), would not be beneficial towards achieving the imposed decarbonisation targets. Another method to mitigate system inadequacy is to build new transmission corridors within and between countries (i.e. interconnections). As we move towards a unified energy market for the pan-European system, interconnections would enable countries to share capacity leading to a pro-EU approach rather than a member state centric one. Indeed, analysis presented by (D. Newbery, et al., 2013) indicates that adopting a pro-European wide approach in interconnections could reduce the requirement for additional generation capacity by up to 100 GW.

Therefore, interconnectors are considered as a key factor in supporting adequacy in a large-scale system such as the European one (D. Newbery, et al., 2013). Careful analysis, however, would be required both in the planning stages (i.e. to account for future location of reserves, RES deployment across Europe, disconnection of aging thermal stations, etc.) and during operational timescales (i.e. to ensure that the technically feasible rapid changes in interconnector power flows would not impact on the system security) to ensure that system adequacy will not be compromised.

In addition to interconnectors, suitably designed capacity markets need to be in place; these are currently not considered by most European countries. Such markets should create a level playing field between traditional generation and distributed energy resources (DER) (i.e. wind, PV, DSR, etc.). Note that even in the UK, where a Capacity Market exists, the market mechanism rules discriminate against DER: i.e. contract length for new central generation is 15 years, while for new DER the contract length is only one year (National Grid, 2018). In this context, it is important to consider innovative capacity market designs, particularly in the US. For example, the

Capacity Mechanism in New England allows *all new resources* to acquire a multiple-year obligation under similar rules. Additionally, in New England and PJM, non-network technologies, such as energy efficiency, can participate in the Capacity Mechanism and compete with conventional generation (Charles River Associates, 2017).

EU-SysFlex will address this topic within WP3 and will propose appropriate measures for ensuring capability adequate portfolios. Note that close coordination is required between countries to ensure that undesirable effects are avoided (e.g. simultaneous power plants decommissioning), and that high price spikes are mitigated (ENTSO-E, 2017).

9. CONCLUSIONS

This report provides the outcome of the review performed as part of Task 2.1 of the EU-SysFlex project. In total, 25 recent projects and research studies, as well as 3 regulations, have been reviewed. This comprehensive list of studies was reviewed to ensure that the EU-SysFlex project is informed of all the technical scarcities that have been identified in the scientific and industrial communities.

In this review, 6 main categories of technical scarcities are recurrently identified. These scarcities will manifest as we transition to power systems with high penetrations of variable, distributed and power electronics - interfaced RES. Figure 13 indicates the prevalence of the technical scarcities discussed in the projects and reports reviewed.

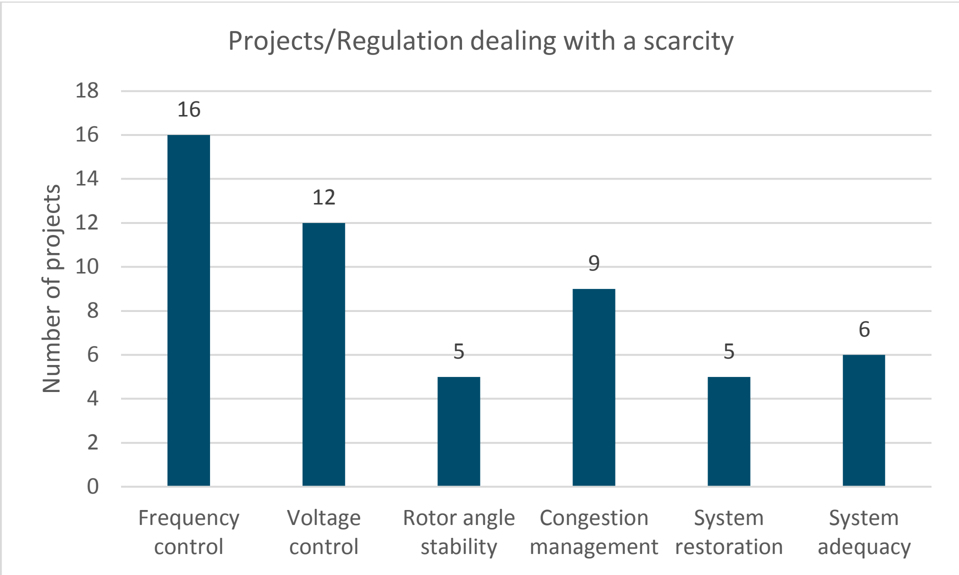

FIGURE 13 NUMBER OF PROJECTS DEALING WITH EACH SCARCITY

The extensive review performed within Task 2.1 has revealed that system scarcities may arise across a very wide spectrum from frequency, voltage and rotor angle stability to increased congestion, limited capability for restoration in case of a system collapse and system inadequacy.

The report provides a description of each of these technical scarcities, the associated issues and how they manifest as we move towards higher RES penetrations. In addition, some solutions identified to mitigate the scarcity are discussed. Table 9 summarises the findings.

SYSTEM SCARCITY	ASSOCIATED ISSUES	WHY IS IT BECOMING A SCARCITY?	SOLUTIONS IDENTIFIED
Frequency control	1) Inertia 2) Reserves 3) Ramping	Reduced synchronous generation on the system providing inertia and reserve capability means that frequency changes happen more quickly and are less manageable.	**Technical solutions**: Technologies providing frequency response in various timeframes, in the range of seconds to hours, e.g. compensators, wind, synthetic inertia, energy storage, demand side response, cross-border interconnection **System control:** TSO-DSO coordination, increased real-time monitoring of issues. **Enhanced market design:** Design of new services (e.g. reserves, response, etc.).
Voltage control	1) Short circuit power 2) Steady state voltage control 3) Dynamic voltage control	Less synchronous generation available to provide reactive power support. Reduced short circuit power due to the replacement of synchronous machines and the limited capacity of converters in terms of short-circuit current injection. Voltage variation effects due to connection of RES in the distribution system.	**Technical solutions**: Synchronous compensators, reactive power static compensator, inductance, condenser, wind, PV, SVCs, OLTCs **System control**: TSO-DSO coordination, increased real-time monitoring of issues. **Enhanced market design** (reactive): Design of new services (e.g. steady-state reactive power and dynamic reactive power).
Rotor angle stability	1) Small signal stability 2) Transient stability	Less synchronous generation to maintain inertia and stability. Reduction in synchronising torque deteriorates stability margins. Reduction of transient stability margins due to the displacement of conventional plants. Introduction of new power oscillation modes. Reduced damping of existing power oscillations.	**Technical solutions**: Some solutions are identified, e.g. voltage support from modern variable renewable generators, but further studies are needed for this complex phenomenon **System control**: Within the review, no such solutions have been identified to mitigate rotor angle instability issues. **Enhanced market design**: Design of new services (e.g. dynamic reactive power to increase transient stability).
Congestion management	1) Network hosting capacity 2) RES curtailment 3) Capacity allocation	Increase in distance between generation and load, and generation variability. Increased feed-in power (e.g. solar PV plants) and bidirectional power flows noted in distribution networks.	**Technical solutions**: Application of network control and measurement technologies, distributed energy resources, advanced control and forecasting tools **System control**: TSO-TSO coordination, TSO-DSO coordination **Enhanced market design:** Nodal network pricing, market for non-network technologies providing network flexibility services

System restoration	1) Black-start capability 2) Network reconfiguration 3) Load restoration	Less black start capable plants on the grid. Current restoration strategy mainly refers to large synchronous generation.	**Technical solutions**: Utilisation of distributed energy resources, microgrids, local power islands, flexible technologies **System control**: TSO-DSO coordination, enhanced restoration strategy **Enhanced market design:** black-start market, incorporation of black-start services in capacity market
System adequacy	1) Uncertainty of RES generation 2) System interdependencies	Reduction in load factors and decommissioning of conventional generation driven by penetration of renewables.	**Technical solutions**: Potential solutions lie in the utilisation of conventional generation, distributed generation, energy storage, demand side response, interconnection **System control**: Cross-border coordination, TSO-TSO coordination, TSO-DSO coordination **Enhanced market design:** Capacity market, incorporation of non-generation technologies in capacity market (energy storage, demand side response), cross-border capacity market, etc.

TABLE 9 SYSTEM SCARCITIES IDENTIFIED IN THE STATE-OF-THE-ART REVIEW

Increasing the share of distributed, variable and power electronics-interfaced renewable energy challenges the operating framework of the European power system in terms of energy balance, but also system stability and reliability. Reduced system inertia and system strength (investigated within this report from the perspective of short-circuit power) and displacement of synchronous generators are the primary reasons for the appearance of the identified issues. Additionally, there have increased power flows recently observed in the European power system due to the introduction of renewable energy, both in the distribution level due to distributed generation and the transmission system due to the fact that large-scale renewable plants are typically located far from the centres of demand. Such flows may create congestion issues in distribution networks and transmission corridors (including cross-border interconnectors). The high uncertainty characterising renewable generation which may create imbalances between demand and supply in operational timescales presents challenges for system adequacy. Last but not least, with the displacement of conventional generation, which traditionally provided black-start services, system operators are considering new restoration strategies in their operational procedures that will include application of distributed generation and establishment of small, self-contained energy islands.

The scarcities and associated issues, discussed in the reviewed studies, will be further investigated through the simulations that will follow within the other tasks of WP2 of the EU-SysFlex project. Similarly, the solutions highlighted in this literature review range from technical solutions to greater TSO-DSO cooperation and from the introduction of additional system services through to enhanced market designs.

The technical solutions as well as the market and system operators cooperation will be addressed by the EU-SysFlex project. To that end, as shown in Figure 14, the technical capabilities of new flexibilities will be demonstrated in this project through large-scale demonstrations in Germany, Italy, Finland (WP6) and Portugal

(WP7). Innovative technical solutions will be tested at a smaller scale in France (WP8). The already high RES operating Irish system will lead the way in terms of innovative system integration and operation (WP4).

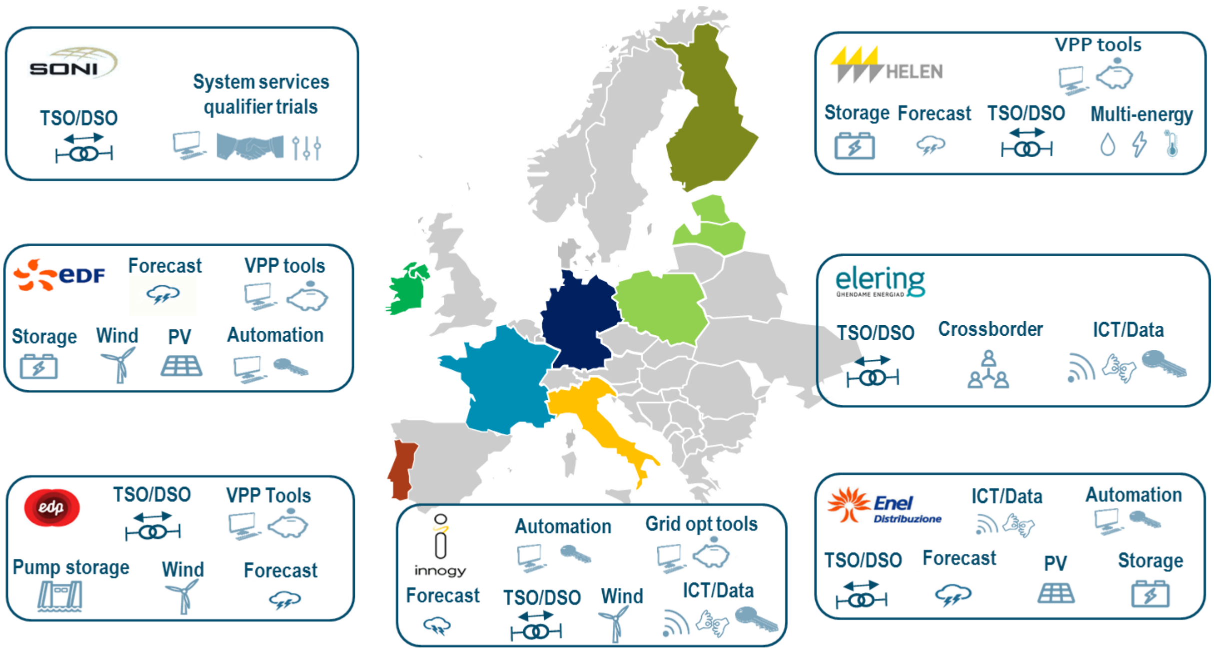

FIGURE 14 EU-SYSFLEX DEMONSTRATIONS OF INNOVATIVE SOLUTIONS

As pointed out in the chapters of this report, the increasing penetration of renewables in both the transmission and distribution levels of the system means that effective coordination between operators is required to ensure that conflicting actions are avoided. Specifically, actions that would resolve an issue in the transmission system could lead to violation of constraints in the distribution network at the same time. As an example, an over-frequency event in the transmission system could be resolved by demand disconnection in the distribution system. However, if this action occurred in a feeder with increased renewable generation (e.g. a feeder with solar PV generation during a sunny day), the action of load shedding could cause significant overvoltages in the feeder leading to its isolation through the operation of protective devices. Coordinated operation, as well as coordinated design, of the transmission and distribution networks would enable maximisation of system-wide benefits by managing the synergies and conflicts between local and national level objectives (EDF R&D Division, 2015). For example, maximising the value of combined benefits delivered through energy arbitrage, providing support to local and national network infrastructure, delivering various ancillary services to optimise system operation, while also reducing the investment in conventional and low carbon generation (Poyry, Imperial College London, 2017), and architectures in a market context, considering for provision of ancillary services (SmartNet Project, 2018). In an effort to promote greater levels of TSO-DSO cooperation, ENTSO-E has introduced the network codes to promote the TSO-DSO interaction and build a framework for coordination among system operators. In response to these regulations, National Grid in the UK, amongst other TSOs in Europe, have set up a project (i.e. Power Potential Project) for designing and developing a reactive power market with participation of DG units (National Grid, 2018).

All large-scale EU-SysFlex demonstrations will endeavour to provide solutions and tools for enhanced TSO-DSO coordination, considering options for greater interaction between system operators. In addition, the necessary data exchanges and operational procedures will be developed in WP4 and WP5.

It was also highlighted in the review that the current market framework is primarily focused on the energy side of the market. Consequently, the importance of flexibility and capacity markets has to be accounted for if the demonstrated solutions from the EU-SysFlex project are to be effectively introduced into the market. The decarbonisation of the European electricity system is expected to reduce energy prices (due to the low or zero production costs of renewables) while increasing the value of flexibility and capacity services (due to the inherent variability and non-controllability of renewable generation). This would require a new market design, developing new market segments across multiple timescales, ranging from (close to) real-time balancing markets to capacity markets with a horizon of multiple years.

Ancillary services are currently contracted in many cases by system operators with prices being determined based on their own cost projections and being fixed over a long temporal interval (months-ahead or even years-ahead). However, the actual economic value of flexibility services such as frequency response depends massively on system conditions (e.g. demand level, renewable penetration rate, system inertia) that change in a much faster timescale. Furthermore, strict limits are imposed in balancing markets regarding the minimum size and temporal availability of the participants, excluding at present many distributed generation, energy storage and demand response users from offering available flexibility. New energy storage and demand response technologies exhibit time-coupling operational characteristics, such as energy balance constraints and load recovery effects, which couple the requirements for provision of balancing services across different timescales. Ignoring these complicating properties in the market design can critically overestimate the value of services they can provide. Therefore, the new market design needs to recognise the interactions between different flexibility services.

Beyond the temporal element discussed above, recognising the locational element of balancing and capacity services becomes increasingly important as we move towards the low-carbon energy future. This is because different regions of a country and different countries in Europe are characterised by significantly different generation and demand conditions (especially due to the location-specific availability of wind and solar resources). Additionally, many parts of the European network become increasingly congested. Therefore, a need emerges to capture this location-specific value in new market arrangements. This can take different forms, from zonal to nodal pricing, and requires appropriate modifications in the balancing and capacity market designs.

Another crucial limitation of the current market framework is that the value of new flexible technologies in addressing the adequacy scarcity and deferring investment in generation and network capacity is not properly remunerated. At the generation level, despite the recent introduction of capacity markets in some European countries, new flexible technologies are not able at present to participate on an equal footing with traditional technologies. At the network level, the potential capacity provision of flexible technologies as well as their location-specific value is neglected in existing network standards. However, the quantification of the capacity contribution of new technologies, such as energy storage and demand response, is not as straightforward as the respective task for conventional generators, since their complicating time-coupling operation implies that their potential capacity contribution is time-specific. New market designs need to suitably quantify and recognise this capacity value and thus enhance significantly the business case for new players in the future European electricity market. Innovative market designs will be modelled and tested in WP3 of EU-SysFlex project to overcome these barriers.

As illustrated in Figure 15, the EU-SysFlex project will address the technical scarcities and associated issues and will also be all-encompassing, covering system economics and users expectations.

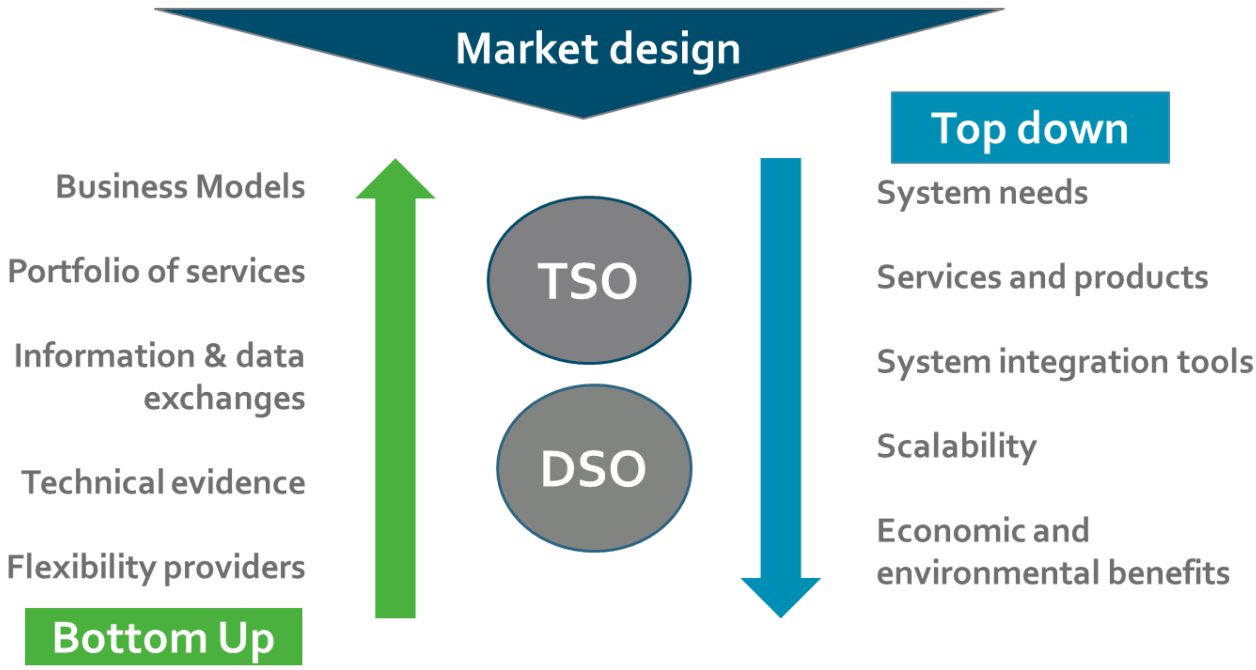

FIGURE 15 EU-SYSFLEX PROJECT APPROACH

Developing the needed flexibility and system services capability will require the right economic incentives, provided by a well-functioning electricity market, in order to deliver and reward the right flavour of flexibility, at the right time and at the right place.

The EU-SysFlex project aims at a large-scale deployment of solutions, including technical options, system control and a novel market design. The project results will contribute to enhancing system flexibility, resorting both to existing assets and new technologies in an integrated manner. WP2 is only a starting point for the project with Task 2.1 providing useful insights on effective system scarcity management. Task 2.1 will also directly inform the corresponding innovative services designed within Task 3.1 of WP3, as a basis for demonstrations' use cases. The demonstration WPs (i.e. WP6 – WP9) will then show the impacts of deploying different mitigation measures to address the various scarcities.

10. COPYRIGHT

Changes in this document will be notified and approved by the PMB. This document will be approved by the PMB.

This project has received funding from the European Union's Horizon 2020 research and innovation programme under EC-GA No 773505.

BIBLIOGRAPHY

50Hertz Transmission GmbH et al. (2016). *50Hertz Transmission GmbH, Amprion GmbH, TenneT Netzentwicklungsplan Strom 2025, Version 2015 – Zweiter Entwurf der Übertragungsnetzbetreiber*. Retrieved October 15, 2016, from www.netzentwicklungsplan.de

A. Morch, O. Wolfgang et al. (2016, October). *Market4RES - Final publication.* Retrieved March 20, 2018, from http://market4res.eu/wp-content/uploads/LR-Market4RES-final-publication.pdf

ACER. (2014, March 7). *Report on the influence of existing bidding zones on electricity markets.* Retrieved March 28, 2018, from http://www.acer.europa.eu/official_documents/acts_of_the_agency/publication/acer%20market%20report%20on%20bidding%20zones%202014.pdf

ACER. (2016, November). *Recommendation of the Agency for the Cooperation on the Common Capacity Calculation and Redispatching and Countertrading Cost Sharing Methodologies.* Retrieved from https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf

Allen, E.H. et al. (2012). No light in August: power system restoration following the 2003 North American blackout. *IEEE Power Energy Magazine*, 24-33.

Australian Electricity Market Operator. (2017). *South Australia System Strength Assessment.*

Banerjee, B. (2016). Grid Integration of Renewable Energy Systems. In D. Jayaweera, *Smart Power Systems and Renewable Energy System Integration* (pp. 75-97).

Bialek, J., & Kattuman, P. (2004). Proportional sharing assumption in tracing methodology. *IEE Proceedings - Generation, Transmission and Distribution, 151*(4), 526-532.

Bian, Y., Wyman-Pain, H., Li, F., Bhakar, R., Mishra, S., & Padhy, N. (2017). Demand Side Contributions for System Inertia in the GB Power System. *IEEE Transactions on Power Systems, PP*(99), 1-1.

Billinton, R., & Allan, R. (1996). *Reliability Evaluation of Power Systems* (2nd ed.). Plenum.

Bloom, A., Townsend, A., Palchak, D., Novacheck, J., King, J., Barrows, C., . . . Gruchalla, K. (2016). *Eastern Renewable Generation Integration Study.* Retrieved from https://www.nrel.gov/docs/fy16osti/64472.pdf

CAISO. (2018). *Flexible Resource Adequacy Criteria and Must Offer Obligation - Phase 2.* Retrieved from http://www.caiso.com/Documents/RevisedDraftFlexibleCapacityFrameworkProposal-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf

Calvo, J. et al. (2015). Cost-benefit analysis of unreliable System Protection Scheme operation. *IEEE PowerTech.* Eindhoven .

Castro, L. M., & Acha, E. (2016). On the Provision of Frequency Regulation in Low Inertia AC Grids Using HVDC Systems. *IEEE Transactions on Smart Grid, 7*(6), 2680-2690.

Charles River Associates. (2017, March 30). *A Case Study in Capacity Market Design and Considerations for Alberta.* Retrieved March 31, 2018, from https://www.aeso.ca/assets/Uploads/CRA-AESO-Capacity-Market-Design-Report-03302017-P1.pdf

CIGRE. (1996). *Analysis and Control of Power System Oscillations.* CIGRE Technical Brochure.

CIGRE Science & Engineering - Innovations in the Power Systems Industry. (2016). *The simple tie-line decomposition method - A new approach for a causation based cost sharing key.*

Cramton, P., & Ockenfels, A. (2011). *Economics and design of capacity markets forthe power sector.*

Cramton, P., Ockenfels, & Stoft, S. (2013). Capacity Market Fundamentals. *Economics of Energy & Environmental Policy, 2*(2).

D. Newbery, et al. (2013). *Benefits of an integrated European energy market.*

De Rijcke, S. et al. (2012). Grid Impact of Voltage Control and Reactive Power Support by Wind Turbines Equipped With Direct-Drive Synchronous Machines. *IEEE Transactions on Sustainable Energy*, 890-898.

dena - German Energy Agency. (2014, February 11). *Ancillary Services Study 2030 - Security and reliability of a power supply with a high percentage of renewable energy.* Retrieved from https://www.dena.de/fileadmin/dena/Dokumente/Themen_und_Projekte/Energiesysteme/dena-Studie_Systemdienstleistungen_2030/dena_Ancillary_Services_Study_2030.pdf

DGA Consulting. (2016). *International Review of Frequency Control Adaption: AEMO.*

DNV GL. (2015, May 27). *Integration of renewable energy sources: Strong challenge for a weak grid*. Retrieved from https://blogs.dnvgl.com/energy/integration-of-renewable-energy-sources-strong-challenge-for-a-weak-grid

DNV GL et al. (2014, June 12). *Integration of Renewable Energy in Europe - Final report.* Retrieved from https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe.pdf

DNV KEMA, COWI. (2013). *Technical Report on ENTSO-E Network Code: Requirements for Generators.*

EDF R&D Division. (2015, June). *Technical and Economic Analysis of the European Electricity System with 60% RES.* Retrieved from https://www.edf.fr/sites/default/files/Lot%203/CHERCHEURS/Portrait%20de%20chercheurs/summarystudyres.pdf

e-Highway 2050 Consortium. (2013). *e-Highway 2050*. Retrieved March 25, 2018, from http://www.e-highway2050.eu/e-highway2050/

EirGrid & SONI. (2014). *Delivering a Secure Sustainable Electricity System (DS3): Programme Overview - 2014.*

EirGrid. (2016, August 24). *DS3 System Services - Interim Tariffs Decision paper.* Retrieved from http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Decision-Paper-on-Interim-Tariffs-FINAL.pdf

EirGrid. (2017). Automated reactive power planning simulation of the Ireland and Northern Ireland power system. *2017 CIGRE.* Dublin.

EirGrid. (2017). *DS3 System Services - Qualification Trials Process Outcomes and Learnings.*

EirGrid and SONI. (2010). *All Island TSO Facilitation of Renewable Studies.* Retrieved from http://www.eirgridgroup.com/site-files/library/EirGrid/Facilitation-of-Renewables-Report.pdf

EirGrid and SONI. (2010). *All Island TSO Facilitation of Renewables Studies.* Retrieved from http://www.eirgridgroup.com/site-files/library/EirGrid/Facilitation-of-Renewables-Report.pdf

EirGrid and SONI. (2011, June). *Ensuring a Secure Reliable and Efficient Power System in a Changing Environment.* Retrieved from http://www.eirgridgroup.com/site-files/library/EirGrid/Ensuring-a-Secure-Reliable-and-Efficient-Power-System-Report.pdf

EirGrid and SONI. (2011, June). *Ensuring a Secure Reliable and Efficient Power System in a Changing Environment.* Retrieved from http://www.eirgridgroup.com/site-files/library/EirGrid/Ensuring-a-Secure-Reliable-and-Efficient-Power-System-Report.pdf

EirGrid Group. (n.d.). *The DS3 Programme: Delivering a Secure, Sustainable Electricity System .* Retrieved from http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-Programme-Brochure.pdf

Ela, E., Milligan, M., & Kirby, B. (2011, August). *Operating Reserves and Variable Generation .* Retrieved March 29, 2018, from https://www.nrel.gov/docs/fy11osti/51978.pdf

Electricity North West Limited. (2015). *Asset Health Technical Report - CLASS Research - WP3 Final Report.*

Electricity North West Limited. (2015). *Asset Health Technical Report - CLASS Research - WP3 Final Report.*

ENTSO-E. (2014, July 14). *Target Methodology for Adequacy Assessment.* Retrieved from https://docstore.entsoe.eu/Documents/SDC%20documents/SOAF/ENTSO-E_Target_Methodology_for_Adequacy_Assessment.pdf

ENTSO-E. (2015). *Capacity Allocation and Congestion Management.*

ENTSO-E. (2016, August 26). *EU 2016/1447 Network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules.* Retrieved March 24, 2018, from http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1447&from=EN

ENTSO-E. (2016). *Explanatory note DA FB CC methodology for Core CCR.* Retrieved from https://consultations.entsoe.eu/markets/core-da-ccm/user_uploads/explanatory-note-for-core-da-fb-cc-public-consultation_fv.pdf

ENTSO-E. (2016, November 16). *Reactive Power Management at T – D Interface.* Retrieved from https://docstore.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/161116_IGD_Reactive%20power%20management%20at%20T%20and%20D%20interface_for%20publication.pdf

ENTSO-E. (2017). *Mid-Term Adequacy Forecast - 2017 Edition.* Retrieved from https://www.entsoe.eu/Documents/SDC%20documents/MAF/MAF_2017_report_for_consultation.pdf

ENTSO-E. (2017). *Rate of change of frequency withstand capability - ENTSO-E guidance document for national implementation for network codes on grid connection.*

ENTSO-E. (2017). *Winter Outlook 2017/2018 and Summer Review 2017.*

ENTSO-E. (2018). *European Power System 2040 - Completing the map - The TYNDP 2018 System Needs Analysis.* Retrieved from https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/european_power_system_2040.pdf

ENTSO-E. (2018). *Future System Inertia 2.* Retrieved from https://www.entsoe.eu/publications/system-operations-reports/nordic/Pages/default.aspx

ENTSO-E EWIS. (2010, March 31). *European Wind Integration Study - Towards a successful integration of large scale wind power into European electricity grids - Final report.* Retrieved from http://www.wind-integration.eu/downloads/library/EWIS_Final_Report.pdf

ENTSO-E HVDC. (2016, August 26). *EU 2016/1447 Requirements for grid connection of high voltage direct current systems and direct current-connected power park modules.* Retrieved March 29, 2018, from http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1447&from=EN

ENTSO-E OH. (2017, September 26). *ENTSO-E Continental Europe Operation Handbook Policy 5 - Appendix.* Retrieved March 26, 2018, from https://www.entsoe.eu/Documents/Publications/SOC/Continental_Europe/oh/170926_Policy_5_ver3_1_43_RGCE_Plenary_approved.pdf

ENTSO-E RfG. (2016, April 14). *EU 2016/331 Requirements for grid connection of generators.* Retrieved March 29, 2018, from http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0631&from=EN

European Commission. (2009, April 23). *Directive 2009/28/EC on the promotion of the use of energy from renewable sources.* Retrieved from https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=EN

European Commission. (2013, December 16). *EU Energy, Transport and GHG Emissions - Trends to 2050 - Reference Scenario 2013.* Retrieved from https://ec.europa.eu/transport/sites/transport/files/media/publications/doc/trends-to-2050-update-2013.pdf

European Commission. (2016, January). *Generation and System Adequacy Analysis - METIS Studies (Study S04).* Retrieved from https://ec.europa.eu/energy/sites/ener/files/documents/metis_study_s04_-_a_common_approach_for_generation_and_system_adequacy.pdf

European Union. (2009, July 13). *Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003.* Retrieved March 21, 2018, from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

F. Van Hulle, et al. (2014, September). *Economic grid support services by wind and solar PV - Final publication of the REserviceS project.* Retrieved March 20, 2018, from http://www.reservices-project.eu/wp-content/uploads/REserviceS-full-publication-EN.pdf

Farhoodnea, M. et al. (2012). An enhanced method for contribution assessment of utility and customer harmonic distortions in radial and weakly meshed distribution systems. *International Journal of Electrical Power & Energy Systems*, 222-229. Retrieved from International Journal of Electrical Power & Energy Systems.

FutureFlow. (2016, December). *Cross-border balancing and redispatching mechanisms tailored to congested borders situation and design of a Common Activation Function.* Retrieved from http://preproduction.futureflow.eu/wp-content/uploads/2017/02/FutureFlow-WP1-D1.2-Cross-border-balancingand-redispatching-mechanisms-tailored-to-congested-borders-situation-and-design-of-a-Common-Activa.pdf

Galiana, F. D., Conejo, A. J., & Gil, H. A. (2003). Transmission network cost allocation based on equivalent bilateral exchanges. *IEEE Transactions on Power Systems, 18*(4), 1425-1431.

GRID4EU Technical Committee. (2016, March). *GRID4EU - Innovation for Energy Networks.* Retrieved from http://grid4eu.blob.core.windows.net/media-prod/29375/grid4eu-final-report_normal-res.pdf

GridTECH Consortium. (2015, April). *GridTECH.EU - Comprehensive Result Report D6.1.* Retrieved March 21, 2018, from http://www.gridtech.eu/images/Deliverables/GridTech_D6.1_Comprehensive_Result_Report.pdf

Guggilam, S., Zhao, C., Dall'Anese, E., Chen, C., & Dhople, S. (2018). Optimizing DER Participation in Inertial and Primary-frequency Response. *IEEE Transactions on Power Systems, PP*(99), 1-1.

Holtinnen et al. (2012, November). *REserviceS D2.2 - Ancillary services: technical specifications, system needs and costs.* Retrieved March 26, 2018, from http://www.reservices-project.eu/wp-content/uploads/D2.2_REserviceS_Ancillary-Services.pdf

Hoschle, H., De Jonghe, C., Six, D., & Belmans, R. (2015). Capacity remuneration mechanisms and the transition to low carbon power systems. *International Conference on the European Energy Market*.

IEA Wind Task 25. (2009). *Design and operation of power systems with large amounts of wind power - Final report Phase One 2006-08.* Retrieved from http://www.vtt.fi/inf/pdf/tiedotteet/2009/T2493.pdf

IEC. (2015). *IEC 61400-27-1:2015 Wind turbines - Part 27-1: Electrical simulation models - Wind turbines*. Retrieved March 28, 2018, from https://webstore.iec.ch/publication/21811

Ikaheimo, J., & Kiviluoma, J. (2017). On Frequency Stability in the Future Renewable Nordic Power System with Gas Sector Integration. *The 7th International Workshop on the Integration of Solar Power into Power Systems.* Berlin.

Imperial College London & UK Power Networks. (2014, December). *Strategic Investment Model for future Distribution Network Planning, report for the Flexible Plug and Play Project.* Retrieved March 31, 2018, from https://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/Project-Documents/FPP%20SDRC%209.5%20-%20Strategic%20Investment%20Model%20for%20Future%20Distribution%20Network%20Planning.pdf

Infield, D.G. (2004). Power quality from multiple grid-connected single-phase inverters. *IEEE Transactions on Power Delivery*, 1983-1989.

Jiang, Y., Chen, S., Liu, C. C., Xiaochuan Luo, W., Liu, S., Bhatt, N., . . . Forcum, D. (2017). Black-start capability planning for power system restoration. *International Journal of Electrical Power & Energy Systems*, 127-137.

Jianhua, Z. et al. (2011). Research on transmission congestion of power system containing wind farms based on genetic algorithm. *4th International Conference on Electric Utility Deregulation and Restructuring and Power Technologies*, (pp. 104-108).

Kundur, P. (1994). *Power System Stability and Control.* New York: McGraw-Hill.

Kundur, P. (2004). Definition and classification of power system stability IEEE/CIGRE joint task force on stability terms and definitions. *IEEE Transactions on Power Systems, 19*(3), 1387-1401.

Kunz, F., & Zerrahn, A. (2016). *Coordinating Cross-Country Congestion Management.* Retrieved from https://www.diw.de/documents/publikationen/73/diw_01.c.527010.de/dp1551.pdf

Li, C. et al. (2007). Analysis of the blackout in Europe on November 4, 2006. *International Power Engineering Conference, 2007. IPEC 2007.* Singapore.

Liu, Y., Fan, R., & Terzija, V. (2016). Power system restoration: a literature review from 2006 to 2016. *Journal of Modern Power Systems and Clean Energy, 4*(3), 332-341.

Marshall, C. (2015). *A Balancing Act: Ramping Capabilities in Wholesale Electricity Markets*. Retrieved March 24, 2018, from http://www.cleanenergyleaders.org/a-balancing-act-ramping-capabilities-in-wholesale-electricity-markets/

Massound, A. et al. (2014). A smart self-healing grid: in pursuit of a more reliable and resilient system. *IEEE Power Energy Magazine*, 108-112.

MIGRATE Consortium. (2016, December). *Massive InteGRATion of Power Electronic Devices - Deliverable D1.1 Report on system issues.* Retrieved from https://www.h2020-migrate.eu/_Resources/Persistent/9bf78fc978e534f6393afb1f8510db86e56a1177/MIGRATE_D1.1_final_TenneT.pdf

Miller, N., Shao, M., Pajic, S., & D'Aquila, R. (2014). *Western Wind and Solar Integration Study Phase 3 - Frequency Response and Transient Stability:Executive Summary.*

Mithulananthan, N. et al. (2014). Small-disturbance angle stability control with high penetration of renewable generation. *IEEE Transactions on Power Systems*, 1463–1472.

Moreno, R. et al. (2012). Integrated reliability and cost-benefit based standards for transmission network operation. *Proceedings of the Institution of Mechanical Engineers Part O Journal of Risk and Reliability*, 75-87.

National Grid. (2016). *Power Potential project - Bid document to Ofgem.* Retrieved from https://www.nationalgrid.com/sites/default/files/documents/Original%20NIC%20project%20submission.pdf

National Grid. (2016). *System Operability Framework.*

National Grid. (2017). *Product Roadmap for Frequency Response and Reserve.*

National Grid. (2017). *System Needs and Product Strategy.*

National Grid. (2018, January 13). *T-1 Capacity Market Auction for 2018/19 - Final Auction Results.* Retrieved from https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/174/Final%20Results%20T-1%202017%20(13.01.2018).pdf

National Grid. (2018). *THe Power Potential Project*. (National Grid) Retrieved March 19, 2018, from https://www.nationalgrid.com/uk/investment-and-innovation/innovation/system-operator-innovation/power-potential

National Grid. (n.d.). *Intertrip services*. Retrieved from https://www.nationalgrid.com/uk/electricity/balancing-services/system-security-services/intertrips

Neuhoff, K., Hobbs, B., & Newbery, D. (2011). *Congestion Management in European Power Networks: Criteria to Assess the Available Options - DIW Berlin.* Retrieved from https://www.diw.de/documents/publikationen/73/diw_01.c.387212.de/dp1161.pdf

NREL. (2003, August). *Report on Distributed Generation Penetration Study.* Retrieved March 30, 2018, from https://www.nrel.gov/docs/fy03osti/34715.pdf

NREL. (2008, July). *ERCOT Event on February 26, 2008: Lessons Learned.* Retrieved from https://www.nrel.gov/docs/fy08osti/43373.pdf

NREL. (2013). *Western Wind and Solar Integration Study Phase 2: Executive Summary.* Retrieved from https://www.nrel.gov/docs/fy13osti/58798.pdf

NREL. (2014, March). *Wind and Solar Energy Curtailment: Experience and Practices in the United States.* Retrieved from https://www.nrel.gov/docs/fy14osti/60983.pdf

Orvis, R. et al. (2017, October). *A roadmap for finding flexibility in wholesale markets.* Retrieved from http://energyinnovation.org/wp-content/uploads/2017/10/A-Roadmap-For-Finding-Flexibility-In-Wholesale-Power-Markets.pdf

Oulis Rousis, et al. (2017). Benefits of distributed power generation for voltage support in GB transmission system: Case study on the south-east region. Birmingham: IET.

Pillay, A., Karthikeyan, S., & Kothari, D. (2015). Congestion management in power systems – A review. *International Journal of Electrical Power & Energy Systems, 70*, 83-90.

Poyry, Imperial College London. (2017). *Roadmap for Flexibility Services to 2030.* London.

PROMOTioN Consortium. (2017). *PROMOTioN D3.4: Results on control strategies of WPPs connected to DR-HVDC.* Retrieved March 20, 2018, from https://www.promotion-offshore.net/fileadmin/PDFs/D3.4_PROMOTioN_Results_on_control_strategies_of_WPPs_connected_to_DR-HVDC.pdf

PROMOTioN consortium. (2017, September 26). *PROMOTioN D3.5: Performance of ancillary services provision from WFs connected to DR-HVDC.* Retrieved March 20, 2018, from https://www.promotion-offshore.net/fileadmin/PDFs/D3.5_PROMOTioN_Performance_of_ancillary_services_pro-vision_from_WFs_connected_to_DR-HVDC.pdf

Quintero, J. et al. (2014). Impact of increased penetration of converter control-based generators on power system modes of oscillation. *IEEE Transactions on Power Systems*, 2248–2256.

Quoc Hung, D. et al. (2016, March 9). *Technical Challenges, Security and Risk in Grid Integration of Renewable Energy.* Retrieved from https://link.springer.com/chapter/10.1007%2F978-3-319-30427-4_6

Sakamuri, J. N. (2016). Improved frequency control from wind power plants considering wind speed variation. *2016 Power Systems Computation Conference (PSCC)*, (pp. 1-7). Genoa.

Sakamuri, J. N., Hansen, A. D., Cutululis, N. A., Altin, M., Sau-Bassols, J., Prieto-Araujo, E., & Gomis-Bellmunt, O. (2017). Suitable Method of Overloading for Fast Primary Frequency Control from Offshore Wind Power Plants in MultiTerminal. *IEEE PowerTech Manchester 2017 Conference.* Manchester.

Shah, R. et al. (2012). Influence of large-scale PV on voltage stability of sub-transmision system. *International Journal on Electrical Engineering and Informatics*, 148-161.

Simms, M., & Meegahapola, L. (2013). Comparative analysis of dynamic line rating models and feasibility to minimise energy losses in wind rich networks. *Energy Conversion and Management, 75*, 11-20.

SmartNet Project. (2018). *SmartNet Project*. (EU) Retrieved 03 19, 2018, from http://smartnet-project.eu/partners/

Solar Power Europe. (n.d.). *Ensuring a cost-effective growth of solar power in Europe.* Retrieved March 30, 2018, from http://www.solarpowereurope.org/fileadmin/user_upload/documents/Policy_Papers/SolarPower_Position_Paper_on_post-2020_RES_regulatory_framework.pdf

Statnett, Fingrid, Energinet, Svenska Kraftnat. (2016). *Challenges and Opportunities for the Nordic power system.* Retrieved from http://www.statnett.no/Global/Dokumenter/Challenges%20and%20opportunities_Report.pdf

Statnett, Fingrid, Energinet.DK, Svenska Kraftnat. (2016). *Challenges and Opportunities for the Nordic power system.* Retrieved from http://www.statnett.no/Global/Dokumenter/Challenges%20and%20opportunities_Report.pdf

Strbac, G., Hatziargyriou, N., Lopes, J., Moreira, C., Dimeas, A., & Papadaskalopoulos, D. (2015). Microgrids: Enhancing the Resilience of the European Megagrid. *IEEE Power and Energy Magazine, 13*(3), 35-43.

Sun, L., Hou, Y., Peng, C., & Hu, J. (2017). Comparative studies on frequency responses of type 3 wind turbines and synchronous generators, 2017 IEEE Power & Energy Society General Meeting, pp. 1-5. Chicago, IL: IEEE.

Teng, F., & Strbac, G. (2016). Assessment of the Role and Value of Frequency Response Support From Wind Plants. *IEEE Transactions on Sustainable Energy, 7*(2), 586-595.

Teng, F., Trovato, V., & Strbac, G. (2016). Stochastic Scheduling With Inertia-Dependent Fast Frequency Response Requirements. *IEEE Transactions on Power Systems, 31*(2), 1557-1566.

UK Power Networks. (2012). *Flexible Plug and Play.* Retrieved from http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/Project-Documents/Overview+-+Flexible+Plug+and+Play+-+Oct+2014.pdf

UK Power Networks. (2014). *UKPN - LCNF Full Submission File.* Retrieved from http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/kent-active-system-management/Project-Documents/UKPN+Project+KASM+LCNF.pdf

UK Power Networks FUN LV project. (n.d.). *Flexible Urban Networks Low Voltage*. Retrieved from http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Urban-Networks-Low-Voltage/

Umbrella Project. (2016). *Toolbox for Common Forecasting, Risk Assessment and Operational Optimisation in Grid Security Cooperations of TSOs - Final report.*

Urdal, H. et al. (2016). Future System Challenges in Europe - Contributions to Solutions from Connection Network Codes. *2016 CIGRÉ USNC International Colloquium.* Paris.

US Department of Energy. (2018, March). *Annual U.S. Transmission Data Review.* Retrieved from https://www.energy.gov/sites/prod/files/2018/03/f49/2018%20Transmission%20Data%20Review%20FINAL.pdf

Van Cutsem, T. (2000). Voltage instability: Phenomenon, countermeasures andanalysis methods. IEEE Proceedings.

Verzijlbergh, R.A. et al. (2017). Institutional challenges caused by the integration of renewable energy sources in the European electricity sector. *Renewable and Sustainable Energy Reviews*, 660-667.

Vittal, E. et al. (2012). Rotor angle stability with high penetration of wind generation. *IEEE Transactions on Power Systems*, 353-362.

Vournas, C. et al. (2017). Effect of wind variability in the emergency reactive support provided by wind farms. *2017 IEEE Manchester PowerTech*, (pp. 1-6). Manchester.

VTT, DTU, UCS, EWEA. (2012, November). *Ancillary services: technical specifications, system needs and costs - Deliverable D2.2.* Retrieved from http://www.reservices-project.eu/wp-content/uploads/D2.2_REserviceS_Ancillary-Services.pdf

WECC. (2014, April). *WECC Wind Plant Dynamic Modeling Guidelines.* Retrieved from https://www.wecc.biz/Reliability/WECC%20Wind%20Plant%20Dynamic%20Modeling%20Guidelines.pdf

WindEurope. (2016, June). *Assessing respource adequacy in an integrated EU power system.* Retrieved from https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-System-Adequacy-Assessment.pdf

WindEurope. (2016, June). *WindEurope views on curtailment of wind power and its links to priority dispatch.* Retrieved from https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Priority-Dispatch-and-Curtailment.pdf

Wolter, M., & Huhnerbein, B. (2008). Identification of cross-border power flows in integrated networks based on the principle of superposition. *IEEE 2nd International Power and Energy Conference.* Johor Bahru.

Wood, A. J., & Wollenberg, B. F. (1996). *Power Generation, Operation and Control* (Second ed.). Wiley Interscience.

WPD SoLa Bristol. (n.d.). *Buildings, Renewables and Integrated Storage, with Tariffs to Overcome network Limitations project*. Retrieved from https://www.westernpower.co.uk/Innovation/Projects/Closed-Projects/SoLa-Bristol.aspx

Xue, Y.S. et al. (2013). Generalized congestion of power systems: insights from the massive blackouts in India. *Journal of Modern Power Systems and Clean Energy*, 91-100.

Yan, R. et al. (2015). Combined effect of high penetration wind and PV on power system frequency response. *Applied Energy*, 320-330.

Yingzhong, G. et al. (2011). Congestion-induced wind curtailment: sensitivity analysis and case studies. *North American Power Symposium*, (pp. 1-7).

Zeni, L., Sorensen, P., Anca, D., Hesselbaek, B., & Kjaer, P. (2015). *Power system integration of VSC-HVDC connected offshore wind power plants.* DTU LIbrary.

Zhu, J. e. (2017). Synthetic Inertia Control Strategy for Doubly-Fed Induction Generator Wind Turbine Generators Using Lithium-ion Supercapacitors. *IEEE Transactions on Energy Conversion, PP*(99), 1-1.

ANNEX I. SUMMARY OF REVIEWED STUDIES

This annex provides a short description to highlight their objectives and main outcomes. More detailed information can be found in Sections 3 - 8, each of which focuses on one system scarcity and analyses the key findings, lessons learnt and potential solutions for resolving the respective scarcity as suggested by the projects results. Additionally, any potential areas for further development identified within the reviewed studies are particularly highlighted (see last column of Table 10) and taken forward to be addressed within the EU-SysFlex project where applicable.

TABLE 10 SUMMARY OF REVIEWED STUDIES/ PROJECTS/ACTIVITIES/REGULATIONS

TITLE	OBJECTIVES	OUTCOMES	OPPORTUNITIES FOR FURTHER DEVELOPMENT	LOCATION
DS3 Study	System services under high RES penetration. Grid code modifications. Operational policies. Tool development.	Identification of specific programmes of work to facilitation very high levels of wind generation on the island of Ireland. Creation of 7 new system services on the Ireland. Transformational changes to the energy industry.	Further transformational changes have been identified and need to take place over the comes months and years. These include the creation of new policies and development of new tools for the control centre.	Ireland and Northern Ireland
All-Island Grid study	Technical feasibility assessment and cost benefit analysis for operating scenarios with high RES.	There are cost, emissions and fossil fuel dependency benefits as a consequence of facilitating high levels of wind generation.	It was emphasised that a robust technical study on power system dynamic behaviour needed to be performed. This lead to the Facilitation of Renewables study	Ireland and Northern Ireland
Facilitation of Renewables study	The objective of the “All Island Facilitation of Renewables Studies” was to understand the technical and operational challenges associated with high levels of wind generation of the All-Island power system	A range of technical scarcities at high levels of wind generation were identified.		Ireland and Northern Ireland
MIGRATE project	Key technical issues relating to grid stability, supply quality, control and security of supply under high penetration of renewable generation based on power-electronics interfaced connection.	A ‘TSO questionnaire’ was sent to the majority of TSOs within ENTSO-E, complemented by a literature survey, to identify all power system stability issues brought by the increasing penetration of PE.	Ongoing project, to be followed.	EU

		11 power system stability issues were identified, classified and described in detail. A 'prioritization questionnaire' was issued to assess and rank the stability issues with respect to their severity, probability of occurrence and expected timeframe. The lack of inertia is considered to be the most severe stability risk by the TSOs.		
System Operability Framework	It sets out a direction towards the development of suitable industry rules, tools and assets according to the operational needs of the system.	System inertia and system strength considerations. Balancing supply and demand becomes more difficult. Flexibility from DGs, DSR and interconnectors required. TSO-DSO interaction is discussed.	TSO-DSO interaction to be expanded. New frequency response services. Fast active power injection devices to cope with reduced inertia. Voltage support from DGs. New black-start strategies.	UK
60% RES Study (EDF R&D)	Investigation of the stability of the pan-European system with 60% RES. Cost-benefit analysis of storage. Market value of RES	Integrating a large share of variable RES requires a coordinated development of RES and networks Geographical diversity does help, but there is still significant variability at European level. Not only conventional generation, but also variable RES, will contribute to balancing and ancillary services. Variable RES production should potentially provide new services like fast frequency response (inertia). Storage and active demand may to a certain extent supplement generation to balance supply and demand. Fuel plant are needed for backup capacity for security of supply with high level of decarbonisation. Detailed comprehensive integration study for the pan-European interconnected system with		France

		dynamic analysis. New services are required to ensure the frequency stability of the system.		
PROMOTION	Topologies for meshed HVAC/DC offshore grids. Protection components and schemes for offshore grids. Standardisation initiated. Coherent EU regulatory framework.	This project points towards the European Grid Code for HVDC connections. Outcomes based on developing functionalities to achieve ENTSO-E grid-code compliance.		EU
Challenges and Opportunities for the Nordic power system	To identify solutions for security of supply and frequency quality.	Higher balancing prices and volatility of day-ahead prices, tighter capacity margin in 2025. FCR, and FRRm bids unbalanced. Inertia 1-19 % of time below 120-145 GWs (2025).	Market design developments required (particularly on reserves). Deeper assessment of cross-border generation adequacy.	Nordic countries
100% RES in Baltic sea countries	Frequency stability and hourly energy balances for close to 100% RES with gas.	Inertia reduced to half by 2025. 14 % of time frequency at nadir <49.2 Hz. WFs fast response reduces frequency load shedding.	Accurate modelling for synthetic inertia.	Nordic countries
e-highway 2050	A top-down planning methodology. Plan for the Pan-European Transmission Network from 2020 to 2050.	Development of methodology for grid planning. Grid architectures for 5 scenarios.	Voltage stability and dynamic issues to be captured more accurately. Uncertainties on scenario realization to be considered.	EU
MARKET4RES	Post-2020 framework for a liberalised electricity market with a large RES share.	Closer to real time products, reflect scarcity on pricing. Balancing markets: price for capacity and energy, small bid size and aggregation, marginal pricing. Varying prices to consumers, DR aggregators.	Difficult to give recommendations for capacity markets. For AS only balancing markets (FRRm) addressed.	EU
NORTHSEAGRID	Risk identification, cost-benefit calculations based on sensitivities and risk assessments, regulatory frameworks	Integrated construction reduces cost. Capacity sharing, increased availability and security of supply, flexibility from DSR lowers benefits. 'Positive Net Benefit Differential'	System flexibility limited to use of DSR. To be considered: TSO-DSO interaction, integration of new technologies. Market mechanism for sharing capacities, etc.	EU
GRID4EU	Development of 6 demonstrators. DSOs managing electricity supply and demand dynamically. TSO-DSO services provision.	Standards definition. Scalability and replicability. Energy losses reduction, fault awareness and isolation, congestion management, voltage control improvement.		EU

REserviceS	Identify system needs at high RES levels, technical & economic issues for AS RES, Market arrangements, Economic benefits	Technical feasibility of wind and & PV for AS, Voltage-related AS may not be beneficial, Market expansion, TSO-DSO interaction.	Generally accepted method for provision of AS, Financial incentives, voltage-AS, restoration services.	EU
GridTECH	Impact assessment of new technologies into the European electricity system (target years: 2020, 2030 & 2050).	FACTS and DLR for network congestion and curtailment. DSM and storage for flexibility & cost decrease. HVDC networks. Legislation.	More simulation-based results needed.	EU
RAO tool	To maximize the trading capacity in the Flow Based market through the usage of remedial actions.	Methods for maximizing trading capacity: Closed optimization & Heuristic Search. Criteria: maximization at market-clearing point & minimization of pre-congestions.	Heuristic/Smart search: sub-optimality during the extension to CWE ID. Closed optimization: Increase of computational time for combinations of topological RAs.	EU
Coordinating cross-country congestion management	To analyse the influence of implementing a Cross Country Congestion Management tool	1) The coordination between different TSOs provides a considerable reduction of redispatch volumes. 2)The cost sharing methodology development is fundamental for incentivising all involved TSOs.	The need of cost sharing methodology is pointed out. However, the development of that methodology is out of the scope.	Germany
UMBRELLA	Methodology for coordinating operational security analysis for TSOs.	Development of a time-coupled optimization method for RAs for security assessment.	Cost sharing principles. Zonal market. Probabilistic approach. Voltage stability.	EU
CIGRE - Innovation in the power systems industry Volume N°5, June 2016 pp. 119-125	To describe the Single Tie-line Decomposition Method (STD) for cost sharing of the remedial actions.	The methodology of identifying the keys for the cost sharing of the costly remedial actions for relieving congestions in the zonal Market. Developing a methodology that based on ‘Polluter-Pays-Principle.	Zonal market is considered. The internal line flows are not included in the methodology. The limitations in the capacity calculation methodology can cause mismatches in the generation shift key.	
Future system inertia 2	To anticipate and to avoid the effects of low-inertia situations, by means of proper forecasting tools and mitigation measures.	Low-inertia situations at 2020 and 2025. Kinetic energy estimation through SCADA/EMS. Active power injection by emergency power control, load and hydro storage pumps disconnection.	Implement EPC and load disconnection, real time forecast of kinetic energy and inertia and EPC. Dynamic assessment of FCR-D and inertia. Coordination of FFR and FCR-D. Product development of FFR.	Nordic countries
Future Power System Security Program (FPSS)	Formalises and broadens work initiated by AEMO over the last few years to explore and adapt to the changing generation mix.	Four key areas of concern include frequency control, management of extreme conditions, visibility of the power system and system		Australia

	Focuses on power system security and aims to address immediate risks, whilst also developing solutions for the future power system.	strength.		
Western Wind and Solar Integration Study	Investigate the large-scale transient stability and frequency response of the WI under high RES penetration. Identify means to mitigate any adverse performance impacts.	No substantial issues were identified, however good system planning and engineering practices need to be followed to ensure that stability margins are not breached.		USA
Eastern Renewable Generation Integration Study (ERGIS)	Gives insights on operational impacts of high percentages of RES in the EI. Demonstrates advanced techniques for unit commitment and economic dispatch modelling	Shown thermal and hydro generation changes as RES generation increases. System-wide transmission flows change as more distribution-connected comes online. The operating practices of generators and TSOs may need to be revised in the future.		USA
Mid-term Adequacy Forecast 2017	A Pan-European assessment of power system adequacy spanning the timeframe until 2025. Provide stakeholders with support to take decisions driven and affected by the level of adequacy in the European power system.	Climate severely impacts adequacy. Estimated reliability levels throughout Europe are heterogeneous. Strong system interdependencies call for a Pan-European perspective. Substantial capacities at risk of being mothballed. Common standard needed for data, models and metrics. Adequacy assessments require coordinated efforts.	Additional data collection. Advanced modelling methods and tools. Methodology standardisation.	EU
European Power System 2040: Completing the map & assessing the cost of non-grid	Long-term study to prepare for the 2040 future system - Long-term scenarios until 2040 - 3 different market tools (PowerSym, BID, Antares) Comprehensive study of system and flexibility needs to meet European climate	Importance of reinforcement of national grids along with cross border exchanges - Required to meet European climate targets - Reduction of yearly market prices - Increase of security of supply in systems operating with a low amount of conventional plants New solutions to increase frequency and voltage stability:		EU

	targets.	- New responsibilities for market participants Increased flexibility for the system through: - Innovation in grid communication (ICT/digital solution) - New market design - Policy and regulatory coordination		
ENTSO-E 'Requirements for Generators'	Legal framework for grid connections to facilitate Union-wide electricity trade, system security, higher competition, obligations of system operators.	It sets out the requirements for various types of generators and procedures to be followed for connection to networks around the EU.	'Emerging technologies', such as battery storage, not considered. Congestion management and system adequacy covered in separate regulations.	EU
ENTSO-E 'Network Code on HVDC Connections'	A network code which lays down the requirements for grid connections of HVDC systems and DC-connected power park modules.	It sets out the minimum technical design and operational requirements for the connection of the applicable systems to AC-systems.	Black-start capability of HVDC systems not a strict requirement that HVDC systems should provide this capability; no financial incentive exist.	EU
ENTSO-E 'Demand Connection Code'	A code applicable to new demand and distribution systems connected to transmission system.	It sets out the requirements for connection of demand facilities and distribution systems.	Storage except for hydro pump not covered. Voltage control not considered in priority ranking between the two systems.	EU

ANNEX II. ENTSO-E REGULATIONS

This annex summarises the main requirements imposed by the ENTSO-E Regulations (i.e. Requirements for Generators, Network Code on HVDC Connections and Demand Connection Code) with respect to each of the system scarcities identified in the main body of the report. It provides in an effective way the context around the future developments required and highlights two key areas considered within the ENTSO-E regulations: (i) need for interactions between transmission and distribution systems and also between countries (i.e. cross-border interaction) and (ii) need for a unified European market. These especially emphasise the significance of the EU-SysFlex project, which primarily focuses on providing technical solutions to achieve secure and safe operation of the pan-European power system under very high penetration of renewables, and to do so it will attempt to demonstrate effective TSO-DSO coordination and an enhanced market design.

For the sections to follow, it is important note that generators are classified in four categories within the ENTSO-E Requirements for Generators Code (RfG) code:

- Type A (connection point below 110 kV and maximum capacity of 0.8 kW or more)
- Type B (connection point below 110 kV and maximum capacity at or above a threshold proposed by each relevant TSO)
- Type C (connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO)
- Type D (connection point at 110 kV or above. Also, if its connection point is below 110 kV and its maximum capacity is at or above a threshold specified)

Accordingly, demand facilities are classified within the DCC, as follows:

- Transmission-connected demand facilities
- Transmission-connected distribution facilities
- Distribution systems
- Demand units of demand facilities or CDS

II.1 FREQUENCY CONTROL

Frequency Tolerance

All generators and relevant demand facilities are subject to a **frequency tolerance** given by Figure 16 and detailed by geographical region; i.e. they should remain connected at the frequency ranges and time periods indicated.

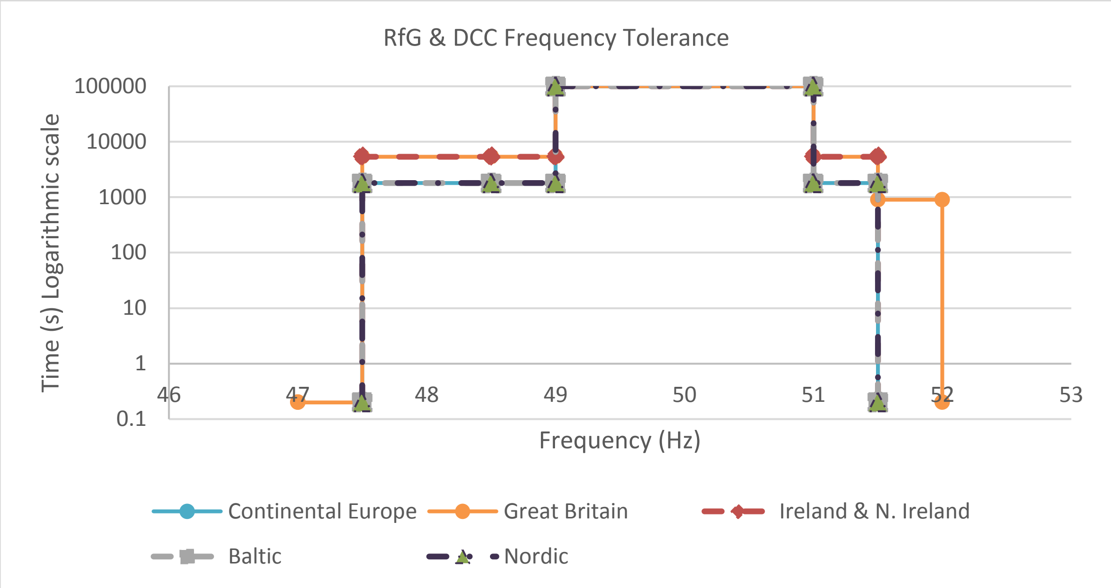

FIGURE 16 RfG AND DCC FREQUENCY TOLERANCE

Accordingly, the ENTSO-E Network Code for HVDC Connections (HVDC code) specifies that all HVDC systems and DC connected power park modules are subject to the frequency tolerance illustrated in Figure 17.

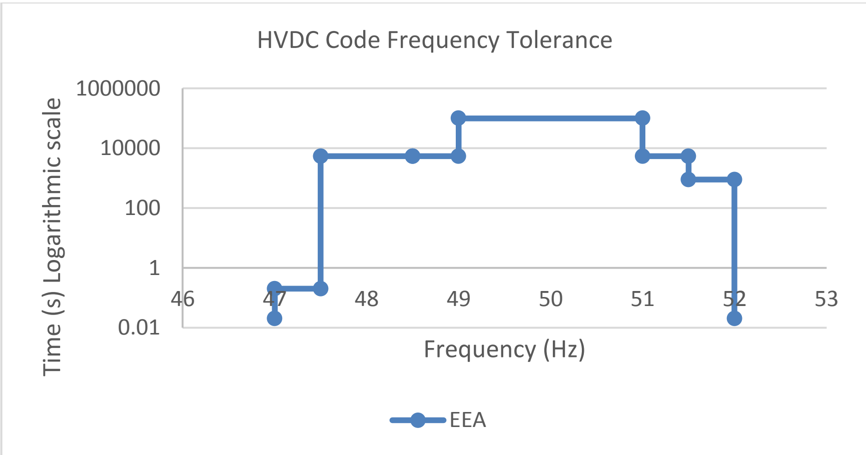

FIGURE 17 NETWORK CODE ON HVDC CONNECTIONS – FREQUENCY TOLERANCE

Frequency Response

Generators are required to activate their Limited Frequency Sensitivity Mode for Over-frequency (LFSM-O) and thus provide active power frequency response according to Figure 18. Frequency thresholds and droop settings are to be specified by each TSO, nevertheless the threshold should be between 50.2 – 50.5 Hz and the droop between 2 – 12%, and respective delays shall not exceed 2 sec.

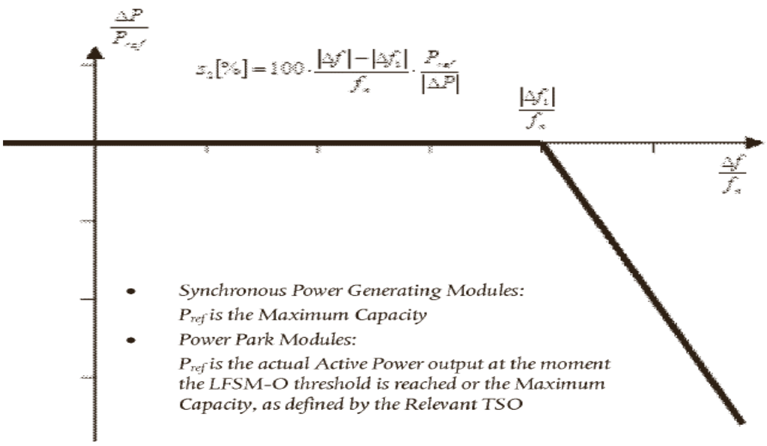

FIGURE 18 ACTIVE POWER FREQUENCY RESPONSE CAPABILITY OF GENERATORS IN LFSM-O MODE

HVDC systems shall also contribute to LFSM-O mode and adjust their active power frequency response following Figure 19 (in which P_{max} indicates the maximum HVDC active power transmission capacity). Parameters are threshold limited following generators' parameters, while the HVDC droop setting should be adjustable from 0.1% upwards.

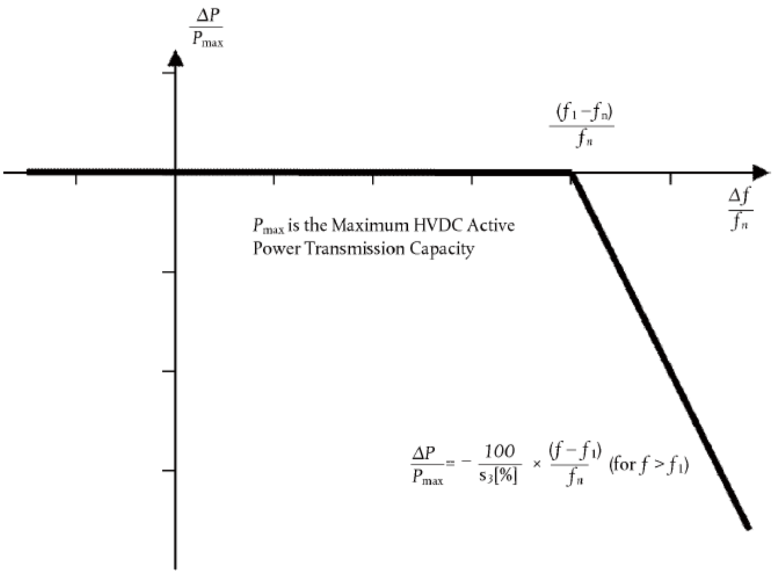

FIGURE 19 ACTIVE POWER FREQUENCY RESPONSE CAPABILITY OF HVDC SYSTEMS IN LFSM-O

In a similar way, generators and HVDC systems should activate their Limited Frequency Sensitivity Mode for Under-frequency (LFSM-U) according to Figure 20. Note that for HVDC systems P_{max} is given by the maximum HVDC active power transmission capacity.

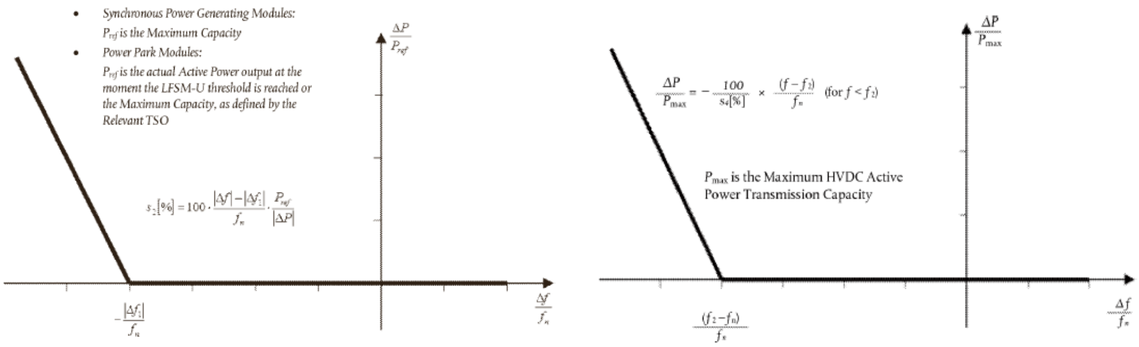

FIGURE 20 ACTIVE POWER FREQUENCY RESPONSE CAPABILITY IN LFSM-U, GENERATORS (LEFT) – HVDC SYSTEMS (RIGHT)

Both generators and HVDC systems have their frequency threshold limited between 49.5 – 49.8 Hz, and generators' droop setting is limited between 2 – 12% whereas the droop setting of HVDC systems is limited to values above 0.1%. Note the LFSM-U requirements only applies to type-C and type-D generators.

Additionally, type-C and type-D generators and HVDC systems are required to respond to frequency deviations when in Frequency Step-change Mode (FSM). Furthermore, generators are required to exchange the following information to ensure adequate real-time monitoring of FSM: (*i*) status signal of FSM (on/off), (*ii*) scheduled active power output, (*iii*) actual value of the active power output, (*iv*) actual parameter settings for active power frequency response, droop and deadband. Generators are then required to activate their response following the curve shown in Figure 21, while they are required to provide this response with parameters within the ranges specified in Table 11.

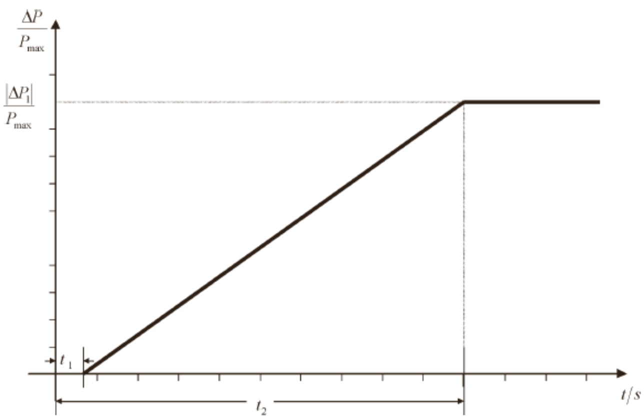

FIGURE 21 ACTIVE POWER FREQUENCY RESPONSE CAPABILITY OF GENERATORS

PARAMETERS	RANGES OR VALUES
Active power range related to maximum capacity (frequency response range) $\frac{\lvert \Delta P_1 \rvert}{P_{max}}$	1.5-10%
Maximum admissible initial delay t_1 (for generators <u>with</u> inertia, and unless justified otherwise)	2 sec
Maximum admissible initial delay t_1 (for generators <u>without</u> inertia, and unless justified otherwise)	Specified by the relevant TSO.
Maximum admissible choice of full activation time t_2, unless the relevant TSO specifies otherwise.	30 sec

TABLE 11 PARAMETERS FOR FULL ACTIVATION OF ACTIVE POWER FREQUENCY RESPONSE IN FSM

Similarly, HVDC systems should activate their response for frequency deviations and step changes as shown in Figure 22 (left and right respectively). The specific parameters are given in Table 12.

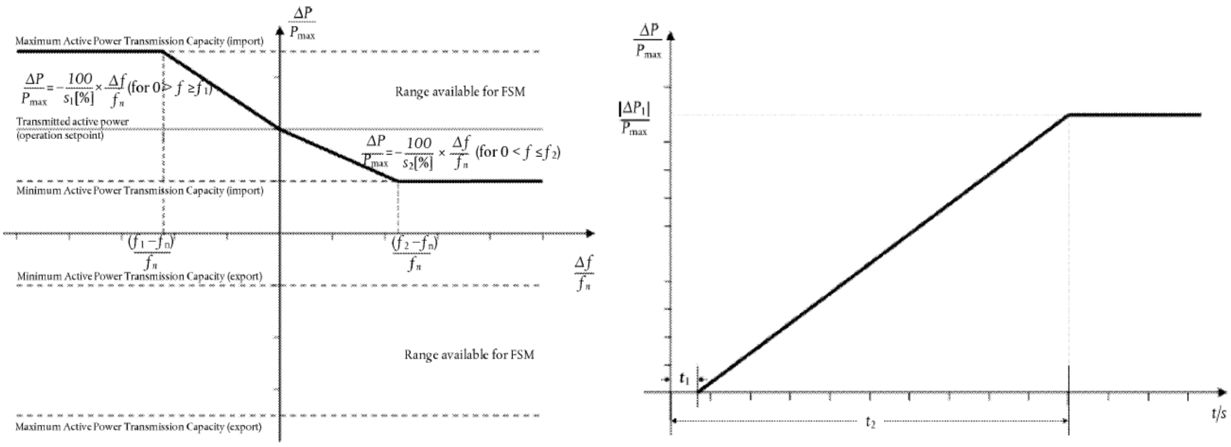

FIGURE 22 ACTIVE POWER FREQUENCY RESPONSE OF AN HVDC SYSTEM IN FSM, DEVIATIONS (LEFT) – STEP CHANGES (RIGHT)

PARAMETERS	RANGES
Frequency response deadband	0 - ± 500 mHz
Droop s_1 (upward regulation)	Minimum 0.1%
Droop s_2 (downward regulation)	Minimum 0.1%
Frequency response insensitivity	Maximum 30 mHz

TABLE 12 PARAMETERS FOR ACTIVE POWER FREQUENCY RESPONSE OF HVDC SYSTEMS IN FSM

Synthetic inertia, which should be provided by generators and HVDC systems, is to be agreed between individual TSO and the system owner. TSOs should also specify the admissible active power reduction when frequency is falling below 49 Hz and 49.5 Hz, however Figure 23 specifies the boundaries in which the capability can be specified by the relevant TSO.

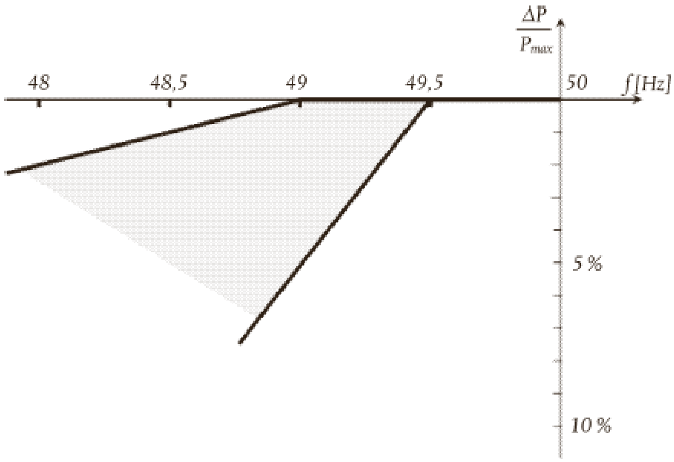

FIGURE 23 MAXIMUM POWER CAPABILITY REDUCTION WITH FALLING FREQUENCY

Moreover, type-A and type-B generators should offer the capability to cease active power output within 5 sec, if instructed.

General Requirements

- Each TSO shall specify frequency ranges within which generator automatic connection is allowed, a corresponding delay and maximum admissible gradient of increase in active power output.
- TSOs shall also specify the frequency ranges that HVDC systems shall be capable to automatically disconnect, how an HVDC system shall modify its active power output during disturbances, and limit the maximum allowed time for responding to 10 ms. During frequency changes greater than 2.5 Hz/s in magnitude, HVDC systems should remain connected and be equipped with an independent control mode to modulate the frequencies of all connection points (and maintain stable frequencies).
- In contrast, during low frequency events the relevant demand facilities[12] shall disconnect a portion of their demand per the below ranges, times, and steps:
    - 47 Hz < f < 50 Hz, adjustable in steps of 0.05 Hz
    - No more than 150 ms after the command signal
    - Voltage lock-out: Blocking of the function when the voltage is in a range of 30% to 90% p.u.
    - Provide active power flow direction at the point of disconnection
- The TSO should coordinate with the owner of the facility and specify the frequency control capabilities for demand side response with respect to: (i) a change of active power related to a measure (such as RoCoF), (ii) the operating principle of the control system and its parameters and (iii) the response time for very fast active power control < 2 seconds.

[12] This requirement applies only to transmission-connected demand facilities and transmission-connected distribution systems

II.2 VOLTAGE CONTROL

Voltage Tolerance

Generators shall operate within pre-defined voltage ranges. Specifically, Type-D generators shall remain connected in voltage ranges, as specified by Figure 24, albeit in various areas TSOs may specify shorter time periods for certain events (e.g. for a simultaneous overvoltage & underfrequency).

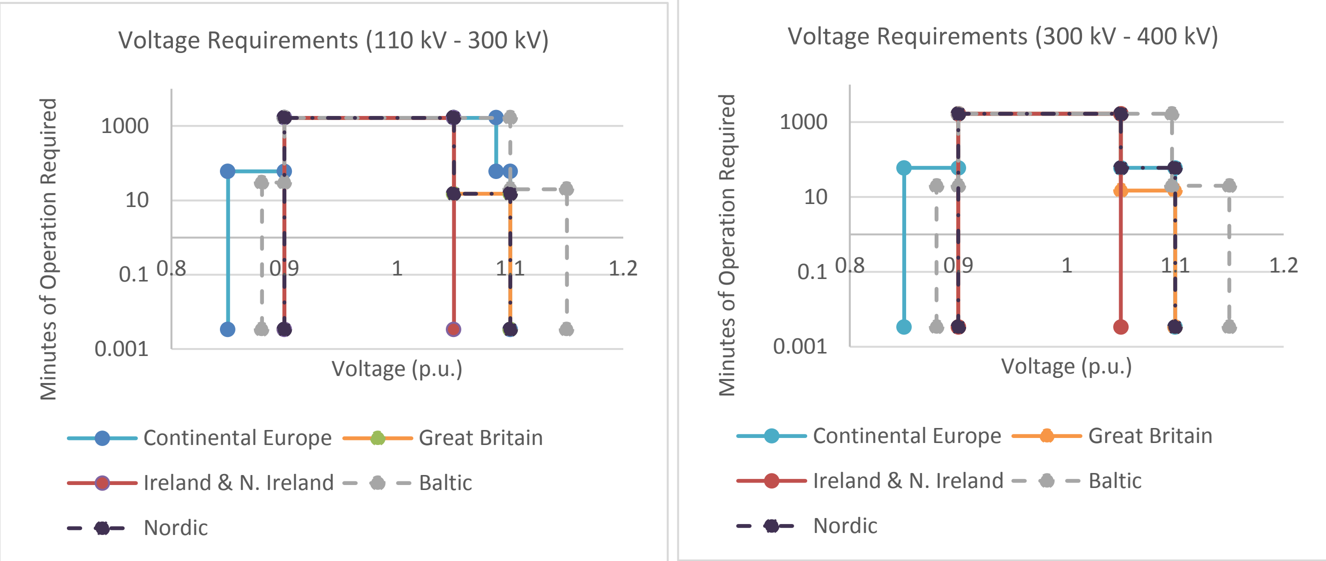

FIGURE 24 VOLTAGE RANGE TOLERANCE FOR TYPE-D GENERATORS

Accordingly, AC-connected offshore power park modules shall follow the diagrams of Figure 25.

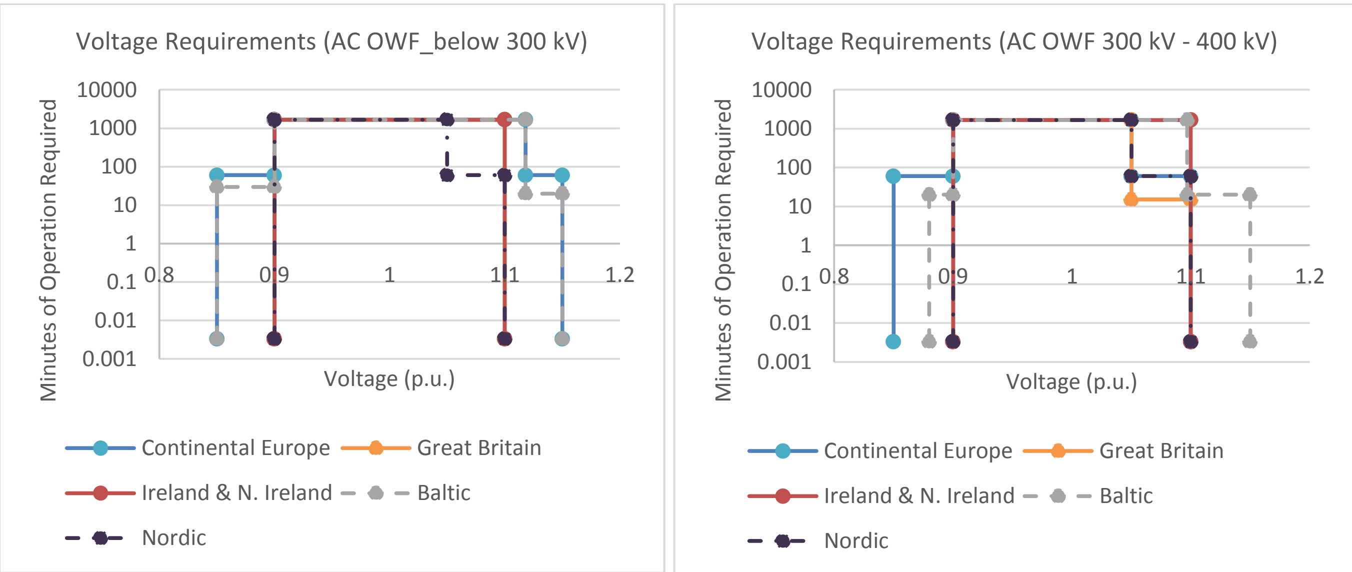

FIGURE 25 VOLTAGE RANGE TOLERANCE FOR AC-CONNECTED OWFs

Similarly, demand facilities should remain connected at the voltage ranges and time periods specified by Figure 26. Note that for transmission-connected distribution systems below 110 kV at the connection point, the TSO shall specify the voltage range that the system shall withstand.

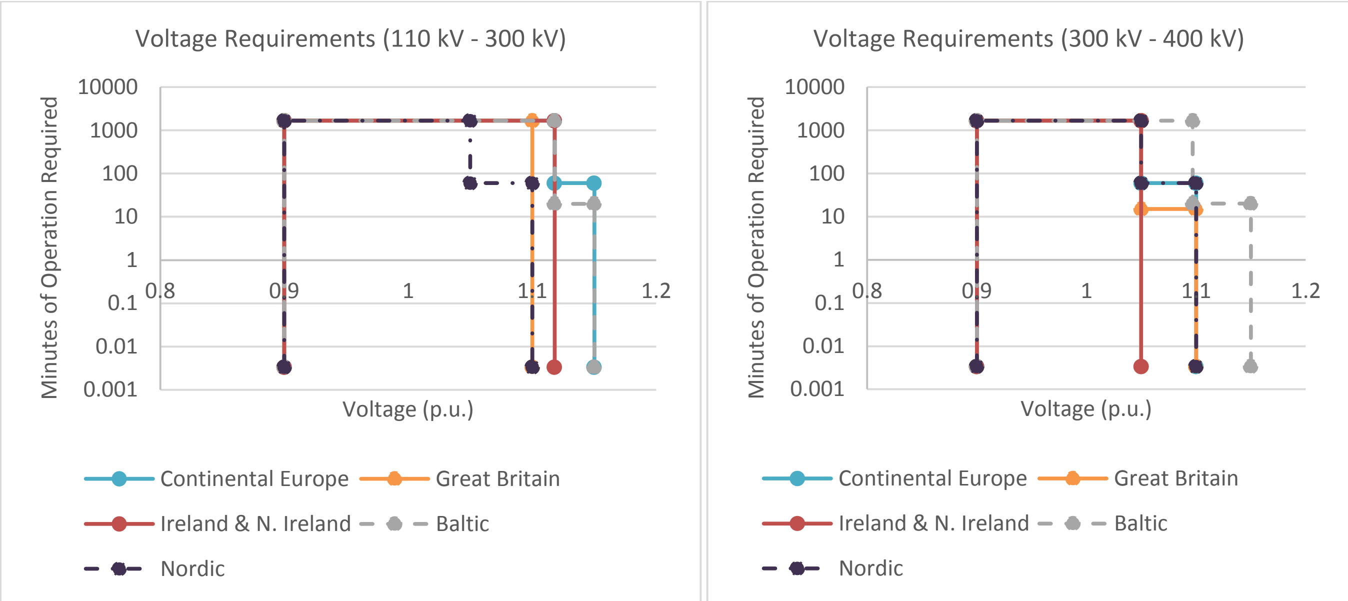

FIGURE 26 VOLTAGE RANGE TOLERANCE FOR DEMAND FACILITIES

Within the same context, HVDC systems shall remain connected for the voltages ranges and time periods shown in Figure 27.

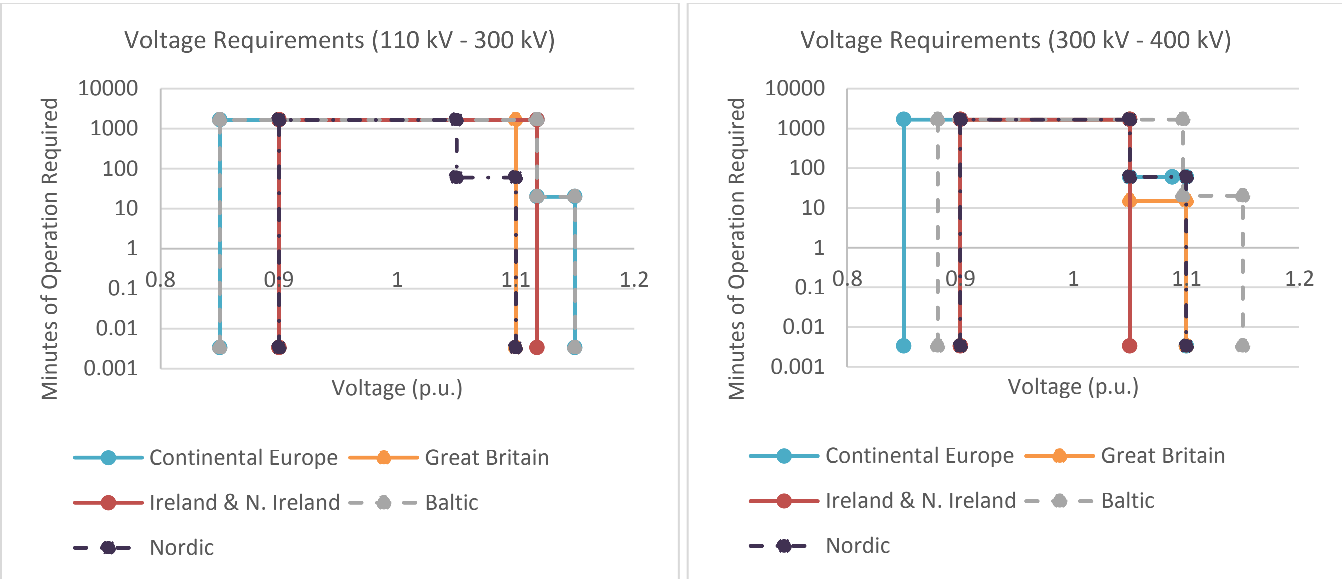

FIGURE 27 VOLTAGE RANGE TOLERANCE FOR HVDC SYSTEMS

Last but not least, DC-connected power park modules shall follow Figure 28.

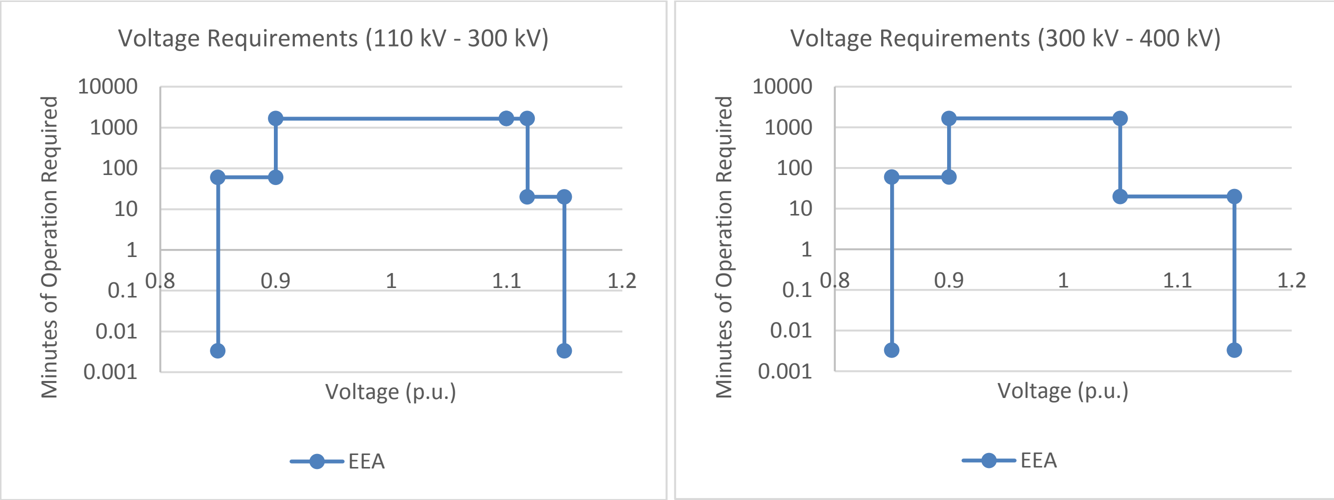

FIGURE 28 VOLTAGE RANGE TOLERANCE FOR DC-CONNECTED POWER PARK MODULES

Fault Ride Through Capability

Active/Reactive power output during **Fault Ride Through** (FRT) mode from type-C and type-D generators (including power park modules) are to be prioritised according to each TSO's preferences although provision needs to be within 150 ms. For all generator types except for type-A, generators' FRT capability should be specified according to a relevant profile given by each TSO and according to the general profile given in Figure 29. The profile shall express a lower limit of the of the actual course of L-L voltages before, during and after a symmetrical fault. Response to asymmetrical faults shall be specified separately by each TSO.

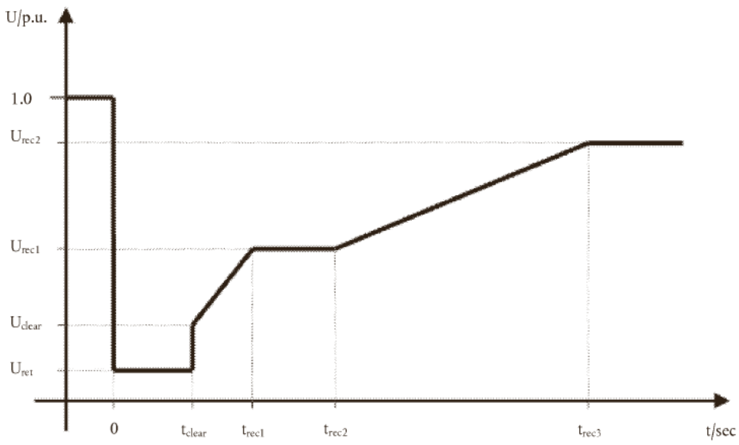

FIGURE 29 FRT PROFILE OF GENERATORS

For type-B, type-C, type-D (for connection below 110 kV) and AC-connected OWFs (again below 110 kV), the parameters of the above shown generic profile shall be as per Table 13.

	VOLTAGE PARAMETERS (pu)			TIME PARAMETERS (sec)	
	SYNCHRONOUS GENERATORS	POWER PARK MODULES		SYNCHRONOUS GENERATORS	POWER PARK MODULES
U_{ret}	0.05-0.3	0.05-0.15	t_{clear}	0.14-0.15	0.14-0.15
U_{clear}	0.7-0.9	U_{ret}-0.15	t_{rec1}	t_{clear}	t_{clear}
U_{rec1}	U_{clear}	U_{clear}	t_{rec2}	t_{rec1}-0.7	t_{rec1}
U_{rec2}	0.85-0.9 and ≥ U_{clear}	0.85	t_{rec3}	t_{rec2}-1.5	1.5-3.0

TABLE 13 PARAMETERS FOR THE GENERIC PROFILE SHOWN IN FIGURE 3-TYPE B, C & GENERATORS, AND OWFs (< 110 kV)

Similarly, for type-D and AC-connected OWFs the parameters shall be as per Table 14.

	VOLTAGE PARAMETERS (pu)			TIME PARAMETERS (sec)	
	SYNCHRONOUS GENERATORS	POWER PARK MODULES		SYNCHRONOUS GENERATORS	POWER PARK MODULES
U_{ret}	0	0.05-0.15	t_{clear}	0.14-0.15	0.14-0.15
U_{clear}	0.25	U_{ret}	t_{rec1}	t_{clear}-0.45	t_{clear}
U_{rec1}	0.5-0.7	U_{clear}	t_{rec2}	t_{rec1}-0.7	t_{rec1}
U_{rec2}	0.85-0.9$_r$	0.85	t_{rec3}	t_{rec2}-1.5	1.5-3.0

TABLE 14 PARAMETERS FOR THE GENERIC PROFILE SHOWN IN FIGURE 3-TYPE D GENERATORS, AND OWFs (≥110 kV)

On the contrary, the FRT capability of HVDC systems does not depend on the voltage level and all of them should follow the diagram of Figure 30 and the parameters of Table 15.

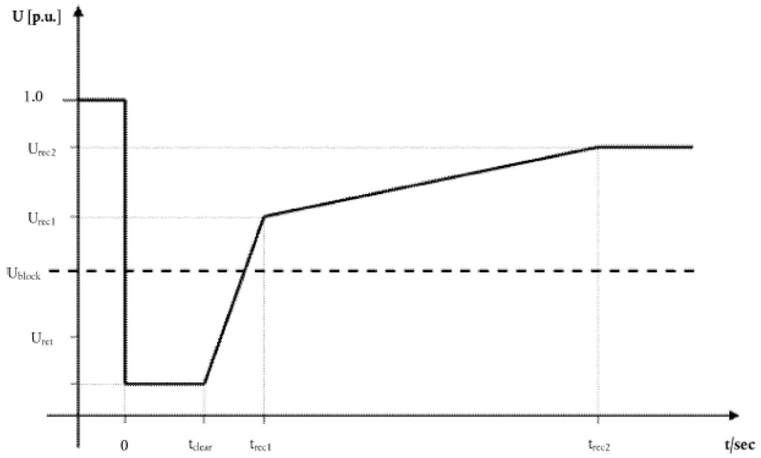

FIGURE 30 FRT PROFILE OF AN HVDC CONVERTER STATION

	VOLTAGE PARAMETERS (pu)		TIME PARAMETERS (sec)
U_{ret}	0.00-0.30	t_{clear}	0.14-0.25
U_{rec1}	0.25-0.85	t_{rec1}	1.5-2.5
U_{rec2}	0.85-0.90	t_{rec2}	t_{rec1}-10.0

TABLE 15 PARAMETERS FOR FIGURE 19

Reactive Power Capability

With regards to the **reactive power capabilities** at maximum capacity, the requirements for type-C and type-D generators (including power park modules) supplementary reactive power shall be specified by each TSO (i.e. for special cases where there is no step-up transformer). The U-Q/Pmax profile shall be specified by each TSO (at the connection point), but the specified curve shall not exceed the inner envelope as depicted in Figure 31. The envelope can have any shape, but its position should be within the fixed outer loop.

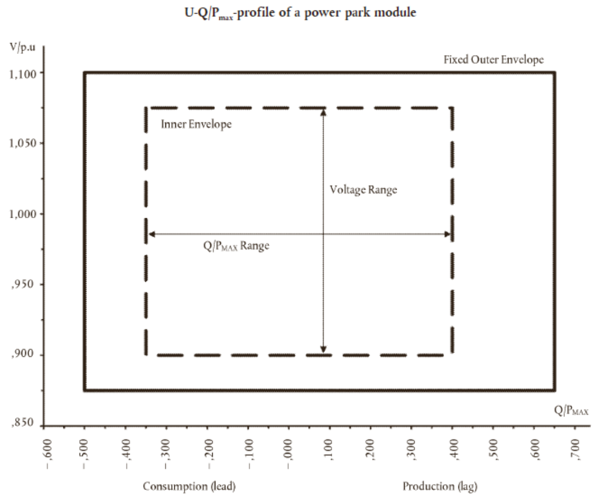

FIGURE 31 U-Q/PMAX PROFILE OF TYPE-C & D GENERATORS AND POWER PARK MODULES

Dimensions of the envelop applicable to each synchronous area are given on Table 16. The right-hand side is for AC connected offshore power parks.

	MAXIMUM RANGE OF Q/P_{max}	MAXIMUM RANGE OF STEADY-STATE VOLTAGE LEVEL (pu)	MAXIMUM RANGE OF Q/P_{max}	MAXIMUM RANGE OF STEADY-STATE VOLATGE LEVEL (pu)
Continental Europe	0.75	0.225	0.75	0.225
Nordic	0.95	0.150	0.95	0.150
Great Britain	0.66	0.225	0 or 0.33	0.225
Ireland & N. Ireland	0.66	0.218	0.66	0.218
Baltic	0.80	0.220	0.8	0.22

TABLE 16 PARAMETERS FOR INNER ENVELOPE OF FIGURE 20

When operating below maximum capacity, generators of type-C and type-D are also subject to the following envelope (i.e. Figure 32):

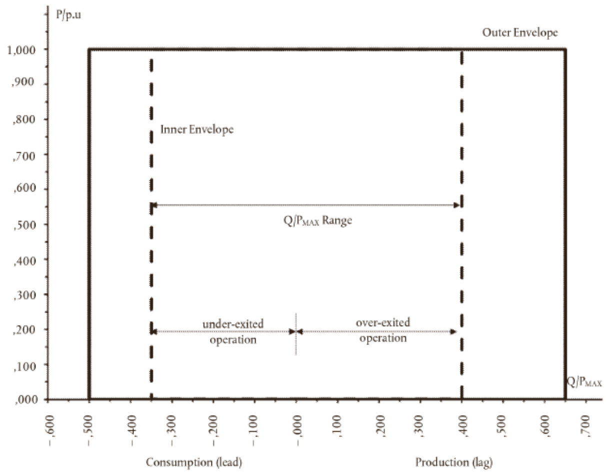

FIGURE 32 P-Q/Pmax PROFILE OF TYPE-C & D POWER PARK MODULES

HVDC systems are required to follow a specific U-Q/Pmax profile as defined by each TSO, which its curve shall not exceed the inner envelop of Figure 33. Dimensional parameters are given in Table 17.

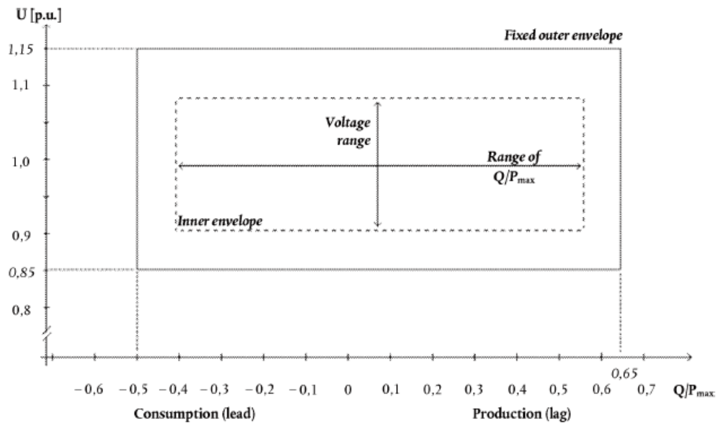

FIGURE 33 U-Q/Pmax OF HVDC SYSTEMS AND DC-CONNECTED POWER PARK MODULES

RANGE OF WIDTH OF Q/P_{MAX} PROFILE	RANGE OF STEADY-STATE VOLTAGE LEVEL (pu)
0.00-0.95	0.100-0.225

TABLE 17 MAX AND MIN RANGE OF BOTH Q/P_{MAX} AND STEADY-STATE VOLTAGE FOR HVDC SYSTEMS AND DC-CONNECTED PPM

General Requirements

- Demand facilities should follow individual TSO's requirement for active control of reactive power. The facilities should maintain steady-state operation at the connection point within the range of 0.9 leading/lagging.
- Generators shall ensure the following control modes:
  - Voltage control: Q exchange covering a voltage range of 0.95 - 1.05 pu (in steps no greater than 0.01 pu), and a slope 2-7%. Q exchange with the grid should be zero when the voltage is equal to the setpoint. Following a voltage step change, the park should achieve 90% of the change in reactive power in 1 sec < t_1 <5 sec and settle in the required value within t sec < t_2 < 60 sec. Time specification is TSO-dependent.

  - Reactive power control: The part shall be capable of setting the Q anywhere in the range discussed above with steps no greater than 5 MVAr or 5% (whichever is smaller).
  - Power factor control: Each TSO to specify the detailed parameters (target power factor values, tolerance, period of time to achieve it, etc.).
- HVDC converter stations should have the **capability to limit** any **voltage changes** to a steady-state level as the TSO's requirement. This level shall not exceed 5% of the pre-synchronisation voltage. The requirement applies equally to DC-connected power park modules.
- HVDC systems must provide fast fault current at a connection point during symmetrical three-phase faults. Each TSO shall specify the characteristics of the fault current, timing and accuracy, among other parameters. It is the TSO's discretion to specify relevant service for 1- and 2- phase faults.
- An HVDC converter station shall be able to operate within the following control modes:
  - Voltage control: Following a voltage step change, the park should achieve 90% of the change in reactive power in 0.1 sec < t_1 <10 sec, and settle in the required value within 1 sec < t_2 < 60 sec. Time specification is TSO-dependent.
  - Reactive power control.
  - Power factor control.
- Demand facilities are requested to **withstand** TSO-specific **short circuit** at their connection point. Additionally, minimum and maximum short-circuit currents at the connection point shall be specified by the TSO as an equivalent network. The TSO shall request the contribution of the short-circuit current from the relevant demand facilities.
- Generators, demand facilities and HVDC systems should be disconnected when the voltage reaches TSO specified levels.

II.3 ROTOR ANGLE STABILITY

General Requirements

During **loss of angular stability** or loss of control, type-C and type-D generators should be disconnected automatically to preserve system security. Suitable instrumentation shall be included to provide fault recording and monitoring of dynamic system behaviour. These should record (and exchange) voltage, active and reactive power, and frequency as a minimum.

II.4 CONGESTION MANAGEMENT

Congestion management is not captured within any of the three ENTSO-E network codes included in the review. A separate regulation has been published on July 2015 covering this topic; i.e. Capacity Allocation and Congestion Management (ENTSO-E, 2015). Considerations relating to these guidelines have been included in Sections 6 and 8, however an exhaustive review was not carried out.

II.5 SYSTEM RESTORATION

General Requirements

- If incidentally disconnected, the TSOs should specify if generators are required to reconnect immediately after the incident is cleared.
- Generators should be governed following the devices' priority ranking:
    - Network & Power generating module protection
    - Synthetic inertia
    - Frequency control
    - Power restriction
    - Power gradient constraint
- Data exchanged with the TSO should be done in real-time or periodically with time stampings.
- **Black Start Capability** is not mandatory, however given that the TSO requests so, the generators shall provide a quotation for offering the service and ensuring system security. A generator participating in this service shall be able to provide the services listed hereafter: frequency & voltage control, LFSM-O, LFSM-U, and take part in island operation. Voltage and frequency limits are to be respected during provision of this service.
- The TSO may also specify that HVDC systems shall provide black start capability. This means that in case one converter station is energised, the HVDC system shall energise the busbar of the AC substation to which another converter station is connected within a certain timeframe.

II.6 SYSTEM ADEQUACY

System adequacy is not covered within any of the three ENTSO-E network codes included in the review.